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Florida Department of Environmental Regulation

Twin Towers Office Bldg. • 2600 Blair Stone Road • Tallahassee, Florida 32399-2400

Lawton Chiles, Governor — Carol M. Browner, Secretary

April 5, 1991

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Ms. Jewell A. Harper
Air Enforcement Branch
U.S. EPA - Region IV
345 Courtland Street, N.E.
Atlanta, Georgia 30365

Dear Ms. Harper:

Re: Florida Power & Light - Martin Coal Gasification/Combined Cycle Project - Federal No. PSD-FL-146

Enclosed for your review and comment is a copy of the Technical Evaluation and Preliminary Determination for the above referenced project. Please submit any comments or questions to Tom Rogers or Barry Andrews at the above address or call them at (904)488-1344 at your earliest convenience.

Sincerely,

Barry D. Andrews

for C. H. Fancy, P.E.
Chief
Bureau of Air Regulation

CHF/BA/t

enclosure

c: I. Goldman, SE Dist.
C. Shaver, NPS
G. Sams, HBG&S

Reading File
Barry Andrews
Tom Rogers
4-5-91 BA

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PS Form 3800, June 1985

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3. Article Addressed to: Ms. Jewell A. Harper, Chief Air Enforcement Branch Air, Pesticides & Toxics Mgnt. Div. U.S. EPA, Region IV 345 Courtland Street, N.E. Atlanta, Georgia 30365	4. Article Number P 407 852 645 Type of Service: ☐ Registered ☐ Insured ☒ Certified ☐ COD ☐ Express Mail ☐ Return Receipt for Merchandise Always obtain signature of addressee or agent and DATE DELIVERED.
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7. Date of Delivery APR 08 1991	

PS Form 3811, Apr. 1989 ★ U.S.G.P.O. 1989-238-815 **DOMESTIC RETURN RECEIPT**

Technical Evaluation
and
Preliminary Determination

Florida Power & Light

Martin Coal Gasification/Combined Cycle Project

Martin County

Permit Number: PSD-FL-146

Department of Environmental Regulation
Division of Air Resources Management
Bureau of Air Regulation

November 5, 1990

NOTICE OF CERTIFICATION HEARING
ON AN APPLICATION TO CONSTRUCT AND OPERATE AN
ELECTRICAL POWER PLANT
TO BE LOCATED NEAR INDIANTOWN, FLORIDA

1. Application number PA 89-27 for certification to authorize construction and operation of an electrical power plant near Indiantown, Florida, is now pending before the State of Florida Department of Environmental Regulation pursuant to the Florida Electrical Power Plant Siting Act, Part II, Chapter 403, Florida Statutes. This project, known as the Martin Coal Gasification/Combined Cycle Project, involves expansion of the electric generating facilities at the existing Martin Plant owned and operated by Florida Power & Light Company (FPL). Certification of this project would allow construction and operation of new sources of air pollution which would consume an increment of air quality resources. The department review has resulted in an assessment of the Prevention of Significant Deterioration impacts and a determination of Best Available Control Technology necessary to control the emission of air pollutants from these sources.

2. The proposed 2192 acre site for the Martin Coal Gasification/Combined Cycle Project is located in the western portion of Martin County, approximately 7 miles northwest of the unincorporated community of Indiantown. The Project site is a portion of the approximate 11,300 acre FPL Martin Site. Two generating units are currently in operation at the Martin Site but are not within the site to be certified under this proceeding. The Project consists of four 400 megawatt combined cycle units consisting of combustion turbines, heat recovery steam generators, steam turbines and switchyards. Coal gasification facilities will be constructed onsite to supply coal-derived gas to the combined cycle units. The site will contain storage areas for coal, fuel oil and coal gasification by-products. Associated linear facilities include a 230 kV circuit to be constructed within an existing FPL transmission line right-of-way between the Martin Site Substation and the Indiantown Substation. A natural gas distribution line will be constructed from the Florida Gas Transmission Company main line to the project site. General locations of the site and proposed corridors are shown on the map accompanying this notice.

3. The Department of Environmental Regulation has evaluated the application for the proposed power plant. Certification of the plant would allow its construction and operation. The application and the department's evaluation is available for public inspection at the addresses listed below:

STATE OF FLORIDA DEPARTMENT OF
ENVIRONMENTAL REGULATION
Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

STATE OF FLORIDA DEPARTMENT OF
ENVIRONMENTAL REGULATION
Southeast District Office
1900 South Congress Avenue, Suite A
West Palm Beach, Florida 33406

MARTIN COUNTY PUBLIC LIBRARY
701 E. Ocean Boulevard
Stuart, Florida 34994

INDIANTOWN TELEPHONE SYSTEM
15925 S.W. Warfield Blvd.
Indiantown, Florida 34956
Attn: Mary Ann Holt

FLORIDA POWER & LIGHT COMPANY
Attn: Wiley Sanders
851 Johnson Avenue
Stuart, Florida 34994
(407) 286-6900

The business address of the applicant for the project is:

FLORIDA POWER & LIGHT COMPANY
6001 Village Boulevard
West Palm Beach, Florida 33407-0768
(407) 640-2042

4. Pursuant to Section 403.508, Florida Statutes, the certification hearing will be held by the Division of Administrative Hearings beginning on October 29, 1990, at 10:00 a.m., at the Family Worship Center, 15285 Indian Mound Drive, Indiantown, Florida, in order to take written and oral testimony on the effects of the proposed power plant or any other matter appropriate to the consideration of the site. Need for the facility has been predetermined by the Florida Public Service Commission at a separate hearing.

5. Pursuant to 403.508(4), F.S.: "(a) Parties to the proceeding shall include: the applicant; the Public Service Commission; the Department of Community Affairs; the water management district as defined in Chapter 373, in the jurisdiction of which the proposed electrical power plant is to be located; and the Department. (b) Upon the filing with the Department of a notice of intent to be a party at least 15 days prior to the date set for the land use hearing, the following shall also be parties to the proceeding:

1. Any county or municipality in whose jurisdiction the proposed electrical power plant is to be located.

2. Any state agency not listed in paragraph (a) as to matters within its jurisdiction.

3. Any domestic non-profit corporation or association formed in whole or in part to promote conservation or natural beauty; to protect the environment, personal health, or other biological values; to preserve historical sites; to promote consumer interests; to represent labor, commercial or industrial groups; or to promote orderly development of the area in which the proposed electrical power plant is to be located.

(c) Notwithstanding paragraph (4)(d), failure of an agency described in subparagraphs (4)(b)1 and (4)(b)2 to file a notice of intent to be a party within the time provided herein shall constitute a waiver of the right of the agency to participate as a party in the proceeding.
(d) Other parties may include any person, including those persons enumerated in paragraph (4)(b) who failed to timely file a notice of intent to be a party, whose substantial interests are affected and being determined by the proceeding and who timely file a motion to intervene pursuant to Chapter 120, F.S., and applicable rules. Intervention pursuant to this paragraph may be granted at the discretion of the designated hearing officer and upon such conditions as he may prescribe any time prior to 15 days before the commencement of the certification hearing.
(e) Any agency whose properties or works are being affected pursuant to 403.509(2) shall be made a party upon request of the department or the applicant."

6. When appropriate, any person may be given an opportunity to present oral or written communication to the designated hearing officer. If the designated hearing officer proposes to consider such communication, then all parties shall be given an opportunity to cross-examine or challenge or rebut such communications. Those wishing to intervene in these proceedings must be represented by an attorney or other person who can be determined to be qualified to appear in administrative proceeding pursuant to Chapter 120, Florida Statutes, or Section 17-103.020, Florida Administrative Code.

7. Notices or petitions made prior to the hearing should be made in writing to:

Ms Mary Clark
Hearing Officer
Division of Administrative Hearings
The DeSoto Building
1230 Apalachee Parkway
Tallahassee, Florida 32399-1550

Copies of such submittals should be forwarded by mail to existing parties, including the Department of Environmental Regulation.

8. Those wishing to intervene in these proceedings, unless appearing on their own behalf, must be represented by an attorney or other person who can be determined to be qualified to appear in administrative hearings pursuant to Chapter 120, F.S., or Chapter 17-1031020, F.A.C.

9. This public notice is also provided in compliance with the federal Coastal Zone Management Act, as specified in 15 CFR Part 930, Subpart D. Public comments on the applicant's federal consistency certification should be directed to the Federal Consistency Coordinator, Division of Environmental Permitting, Department of Environmental Regulation, 2600 Blair Stone Road, Tallahassee, Florida 32399-2400.

10. On December 29, 1989, Florida Power and Light Company applied to the DER to construct the aforementioned electrical power plant. The application is also subject to U.S. Environmental Protection Agency (EPA) regulations for Prevention of Significant Deterioration of air quality (PSD), codified at 40 CFR 52.21, and Florida Administrative Code Chapter 17-2.04. These regulations require that, before construction on a source of air pollution subject to PSD may begin, a permit must be obtained from DER. Such permit can only be issued if the new construction has been determined by DER to comply with the requirements of the PSD regulations, which are described in 40 CFR 52.21 and 17-2.04, F.A.C. These requirements include a restriction on incremental increases in air quality due to the new source and application of best available control technology (BACT).

The DER has been granted a delegation by EPA to carry out the PSD review of this source. Acting under that delegation, the DER has prepared a draft permit which is included in the DER's staff analysis report. The DER has made a preliminary determination that the proposed construction will comply with all applicable PSD regulations. The degree of Class II increment consumption that will result from the construction is:

Pollutant	Annual Average	24-hr Average	3-hr Average
Particulate	70%	78%	
Sulfur Dioxide	30.5%	72%	49%
Nitrogen Dioxide	12.4%		

The source is located approximately 145 kilometers from the nearest Class I area.

Construction and operation of the source will not cause a violation of any ambient air quality standard nor will it cause an exceedance of any PSD increment therefore the DER intends to recommend approval of this project. Persons wishing to comment on this issue may do so at the hearing or by submitting comments in writing within 30 days of this notice.

NOTICE OF RESCHEDULED CERTIFICATION HEARING
ON AN APPLICATION TO CONSTRUCT AND OPERATE AN
ELECTRICAL POWER PLANT
TO BE LOCATED NEAR INDIANTOWN, FLORIDA

1. Application number PA 89-27 for certification to authorize construction and operation of an electrical power plant near Indiantown, Florida, is now pending before the State of Florida Department of Environmental Regulation pursuant to the Florida Electrical Power Plant Siting Act, Part II, Chapter 403, Florida Statutes. This project, known as the Martin Coal Gasification/Combined Cycle Project, involves expansion of the electric generating facilities at the existing Martin Plant owned and operated by Florida Power & Light Company (FPL).

2. The proposed 2,192 acre site for the Martin Coal Gasification/Combined Cycle Project is located in the western portion of Martin County, approximately 7 miles northwest of the unincorporated community of Indiantown. The Project site is a portion of the approximate 11,300 acre FPL Martin Site. Two generating units are currently in operation at the Martin Site but are not within the site to be certified under this proceeding. The Project consists of four 400 megawatt combined cycle units consisting of combustion turbines, heat recovery steam generators, steam turbines and switchyards. Coal gasification facilities will be constructed onsite to supply coal-derived gas to the combined cycle units. The site will contain storage areas for coal, fuel oil and coal gasification by-products. Associated linear facilities include a 230 kV circuit to be constructed within an existing FPL transmission line right-of-way between the Martin Site Substation and the Indiantown Substation. A natural gas distribution line will be constructed from the Florida Gas Transmission Company main line to the project site.

3. The Department of Environmental Regulation has evaluated the application for the proposed power plant. Certification of the plant would allow its construction and operation. The application and the Department's evaluation are available for public inspection at the addresses listed below:

STATE OF FLORIDA DEPARTMENT OF
ENVIRONMENTAL REGULATION
Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

STATE OF FLORIDA DEPARTMENT OF
ENVIRONMENTAL REGULATION
Southeast District Office
1900 South Congress Avenue, Suite A
West Palm Beach, Florida 33406

MARTIN COUNTY PUBLIC LIBRARY
701 E. Ocean Boulevard
Stuart, Florida 34994

INDIANTOWN TELEPHONE SYSTEM
15925 S.W. Warfield Blvd.
Indiantown, Florida 34956
Attn: Mary Ann Holt

FLORIDA POWER & LIGHT COMPANY
Attn: Wiley Sanders
851 Johnson Avenue
Stuart, Florida 34994
(407) 286-6900

The business address of the applicant for the project is:

FLORIDA POWER & LIGHT COMPANY
5500 Village Boulevard
West Palm Beach, Florida 33407-0768
(407) 840-3035

The written reports on the Project and any written testimony will be available for public inspection beginning October 30, 1990, at the Indiantown Telephone System, 15925 S.W. Warfield Blvd., Indiantown, Florida.

4. Pursuant to Section 403.508, Florida Statutes, the certification hearing has been rescheduled and will be held by the Division of Administrative Hearings beginning on November 5, 1990, at 11:00 a.m., at the Family Worship Center, 15285 Indian Mound Drive, Indiantown, Florida, in order to take written and oral testimony on the effects of the proposed power plant or any other matter appropriate to the consideration of the site. Need for the facility has been predetermined by the Florida Public Service Commission at a separate hearing. The hearing was originally scheduled to begin October 29, 1990, but has been rescheduled. Additional details on this proceeding appeared in an earlier notice in this newspaper.

5. Pursuant to Section 403.508(4), Florida Statutes, parties to the proceeding shall include: the applicant; the

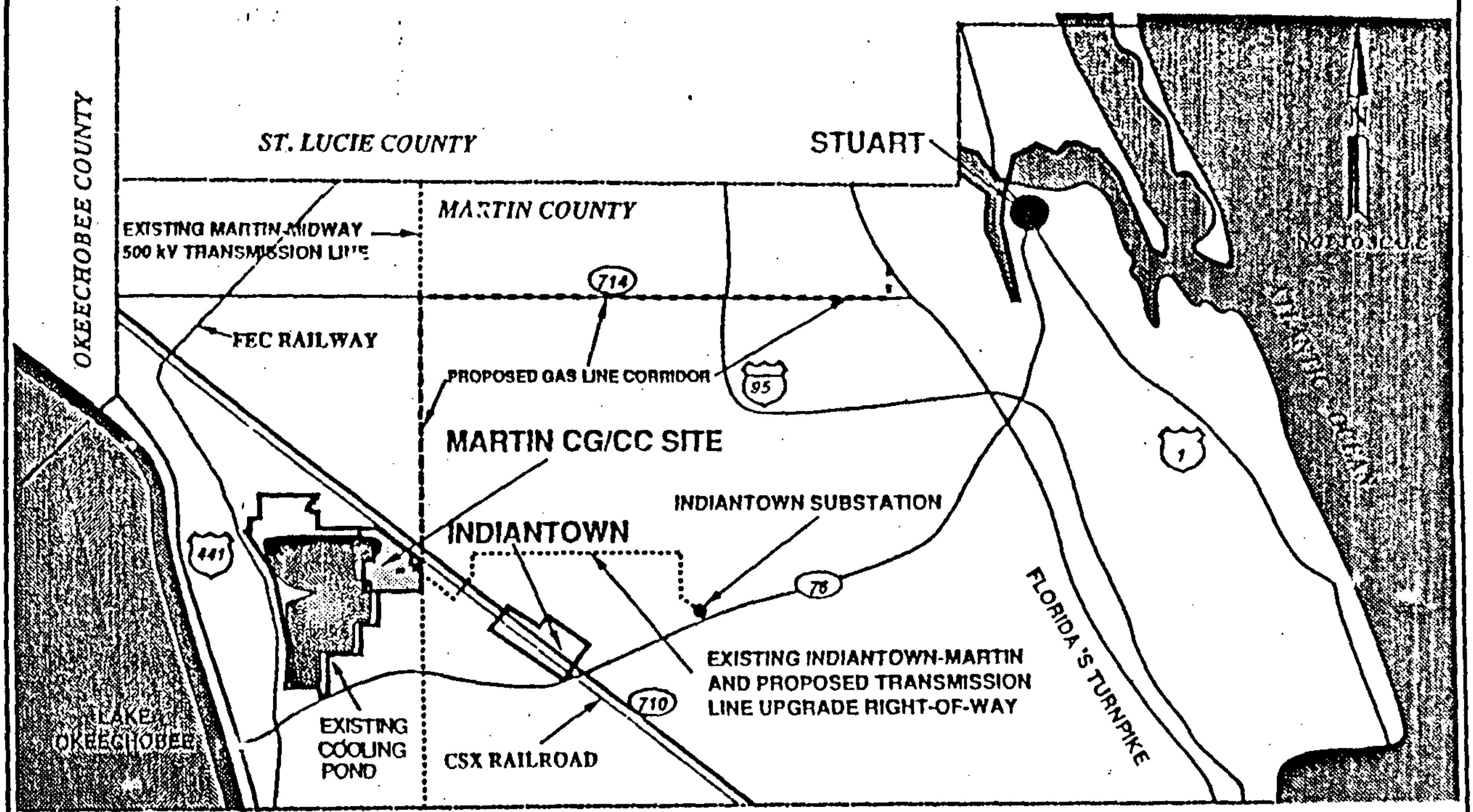
Public Service Commission, the Department of Community Affairs; the water management district as defined in Chapter 373, in the jurisdiction of which the proposed electrical power plant is to be located; the Department of Environmental Regulation, and those who timely intervene in the proceeding.

6. Members of the public will be given an opportunity to present oral or written communication to the designated hearing officer during the hearing. If the designated hearing officer proposes to consider such communication, then all parties shall be given an opportunity to cross-examine or challenge or rebut such communications. Members of the public may offer comments on the Project on Monday, November 5, 1990, at 7:00 p.m. and on Tuesday, November 6, 1990, at 2:00 p.m. at the hearing site.

7. Notices or petitions made prior to the hearing should be made in writing to:

Ms. Mary Clark
Hearing Officer
Division of Administrative Hearings
The DeSoto Building
1230 Apalachee Parkway
Tallahassee, Florida 32399-1550

Copies of such submittals should be forwarded by mail to existing parties, including the Department of Environmental Regulation. The DOAH Case No. is 90-0259



FPL MARTIN CG/CC PROJECT SITE AND ASSOCIATED FACILITIES

The primary fuel for the first phase of the Martin CG/CC Project is natural gas. Light oil will be used as a backup fuel. Provisions are being made to leave room on site for coal gasification units as a future source of fuel.

2. Air Quality Impact Analysis

Introduction

The Florida Power & Light Company (FPL) is proposing a generation expansion project at its Martin Power Plant site, located in the western portion of Martin County, about 161 km north of Miami, 64 km northwest of West Palm Beach, 13 km northwest of Indiantown, and 8 km east of Lake Okeechobee. Currently, the FPL Martin plant consists of two 863 megawatts (MW) fossil fuel steam generating units burning low-sulfur No. 6 fuel oil or natural gas. The Martin Expansion Project will consist of the construction of four 400 MW coal gasification combined cycle (CG/CC) units. Each combined cycle unit will consist of two combustion turbines (CT's) and two heat recovering steam generators (HRSG's). The CG/CC units will be primarily fired with natural gas and with No. 2 distillate fuel oil as a backup during periods of natural gas supply interruption. Each CT/HRSG train will be served by a dedicated stack. Coal gasification facilities will be added later on, which will include four units, to serve as the source of fuel for the four combined cycle units. Each coal gasification unit will have two stacks, one flare stack used during start-up, shutdown and emergency conditions and one tail gas treating incinerator stack which will be used continuously.

The proposed facility will also include two 60,000 lb/hr (nominal) steam auxiliary boilers capable of firing natural gas and fuel oil and two 750 kilowatts (KW) diesel generators firing diesel fuel. The auxiliary steam boilers will be used to serve the start-up steam needs of the four CG/CC units and the two emergency diesel generators will be used for in-plant power during loss of off-site power. In addition, the coal gasification plants, to be built in the future, will consist of coal and limestone receiving, storage and preparation facilities, gasifiers, oxygen plant, product gas cleaning facilities and auxiliary equipment. The operation of these units will result in significant net emission increases of regulated air pollutants over the current emissions levels for the Martin plant and, thus, is subject to review by the Department under the prevention of significant deterioration (PSD) regulations.

The proposed facility will be located in a Class II PSD area. The nearest PSD Class I area to the proposed facility is the Everglades National Park which is located approximately 145 km south of the facility site. The pollutant emissions estimated by the applicant, considering control equipment, indicate that the following ten compounds will be emitted in PSD-significant amounts: carbon monoxide (CO), nitrogen dioxide (NO_2), volatile organic compounds (VOC), particulate matter (PM and PM_{10}), sulfur dioxide (SO_2), and lead (Pb), and the non-criteria pollutants beryllium (Be), mercury (Hg), sulfuric acid mist (H_2SO_4), and inorganic arsenic (As). Table 1 lists the significant and net emission rates for the proposed facility.

Table 1. Significant and Net Emission Rates (Tons per Year) for the Proposed Project.

Pollutant	Significant Emission Rate	Existing Emission	Proposed Maximum Emission[1]	Net Emission Change	Applicable Pollutant (Yes/No)
Criteria Pollutants					
CO	100	0	4785	4785	Yes
NO_2	40	0	15172	15172	Yes
SO_2	40	0	30065	30065	Yes
PM (TSP)	25	0	2264	2264	Yes
PM_{10}	15	0	2264	2264	Yes
VOC	40	0	774	774	Yes
Pb	0.6	0	11.5	11.5	Yes
Non-Criteria Pollutants					
Asbestos	0.007	0	N/A	N/A	No
Be	0.0004	0	0.018	0.018	Yes
F-	3	0	1.9	1.9	No
Hg	0.1	0	0.98	0.98	Yes
Vinyl Chloride	1.0	0	N/A	N/A	No
Total Reduced Sulfur	10	0	N/A	N/A	No
Hydrogen Sulfide	10	0	N/A	N/A	No
Reduced Sulfur Compunds	10	0	N/A	N/A	No
Sulfuric Acid Mist	7	0	3677	3677	Yes
Other Pollutants Regulated Under the Clean Air Act					
Benzene	N/A	0	N/A	N/A	No
Inorganic Arsenic	N/A	0	0.62	0.62	Yes

[1] Assume the worst-case operating conditions.

The air quality impact analysis required by the PSD regulations for these pollutants include:

- o An analysis of existing air quality;
- o A PSD increment analysis (NO_2, PM and SO_2 only);
- o An Ambient Air Quality Standards (AAQS) analysis;
- o An analysis of impacts on soils, vegetation, and visibility and of growth-related air quality impacts; and
- o A "Good Engineering Practice" (GEP) stack height determination.

The analysis of existing air quality generally relies on preconstruction monitoring data collected with EPA-approved methods. The AAQS analysis depends on the air quality dispersion modeling carried out in accordance with EPA guidelines.

Based on these required analyses, the Department has reasonable assurance that the proposed facility, as described in this report and subject to the conditions of approval proposed herein, will not cause or contribute to violation of any PSD increment or ambient air quality standard. A discussion of the modeling methodology and required analysis follows.

3. Modeling Methodology

The EPA-approved Industrial Source Complex Short-Term (ISCST) dispersion model was used in the air quality impact analysis. This model determines ground-level concentrations of inert gases or small particles emitted into the atmosphere by point, area, and volume sources. The model incorporates elements for plume rise, transport by the mean wind, Gaussian dispersion, and pollutant removal mechanisms such as deposition and transformation. The ISCST model allows for the separation of sources, building wake downwash, and various other input and output features. 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 in each modeling scenario.

The general modeling approach for each air quality impact analysis consisted of a screening phase and a refined phase. For the screening modeling analysis, model results were calculated for a range of operating conditions for which the maximum ground-level impacts would be expected to occur. The screening analysis identified the critical receptors associated with highest and highest second-highest short-term concentrations for all applicable pollutants and averaging periods. The refined modeling analysis ensure that the highest concentrations were identified by using a finer mesh receptor grid. The applicant received prior approval from the Department on the methodology by submitting a modeling protocol.

The initial screening modeling used both a polar and a cartesian receptor grid. The cartesian grid section begins at the plant boundary line and extends out to cover a 10 km square area centered over the proposed source and having a 0.5 km grid resolution. The cartesian receptor grid section was combined with a polar grid section consisting of 36 radials, with the center of the grid coinciding with the center of the proposed facility, each separated by 10-degree increments and extending outward at ring distances 6.5, 8.5, 10.5, 12.5, and 15.0 km. This receptor grid included a total of 493 receptors.

The determination of the significant impact area used the same receptor grid described above, except that the polar section of it was extended to ring distances of 20.0, 25.0, 30.0, 40.0, and 50.0 km. This receptor grid consisted of a total of 673 receptors.

The screening analysis of the background source interaction used a polar receptor grid consisting of 24 radials ranging in direction from 10 degrees to 240 degrees in 10-degree increments and extending outward at ring distances of 10.0, 15.0, 17.5, 20.0, 22.5, 25.0, 30.0, 35.0, 40.0, and 45.0 km with reference to the proposed source location. No radials were included in the northwest quadrant due to the lack of existing sources in that direction. This receptor grid consisted of 240 receptors.

After the screening modeling was completed, refined short-term modeling was conducted using a receptor grid centered on the receptors which had the highest, second-highest short-term concentrations. The receptors were located at intervals of 100 meters between the distances considered in the screening phase along nine radials, at two degree increments, centered on the radial which produced the maximum concentration.

Meteorological data used in the modeling consisted of five years (1982-1986) of hourly surface data and concurrent twice-daily upper air sounding from West Palm Beach, Florida.

All stacks of the proposed facility were co-located as one stack in the modeling analyses, which included the 8 CT/HRSG stacks of the four CG/CC units, the two auxiliary steam boiler stacks, and the two diesel generator stacks plus the four tail gas stacks of the four gasifier incinerators when the coal-derived gas was used. The stack parameters of the CT/HRSG stack were used as the stack parameters in the modelings. This step was considered conservative because the auxiliary boilers were operated during the start-up and shut-off of the CG/CC units and the diesel generators were used during loss of the off-site power.

Five cases for combined cycle operation that were selected as having the potential to cause maximum impacts are: firing natural gas at 100% load at 95°F and 40°F ambient temperatures, firing No. 2 fuel oil at 100% load at 95°F and 40°F ambient temperatures, and using coal-derived gas at 100% load at 75°F ambient temperature. The worst-case scenario was determined in the screening phase of the modeling. The results of the model runs indicated the worst-case emissions occurred during the years 1984 and 1986 when No. 2 fuel oil at 40°F and coal-derived gas at 75°F were used, and, thus, these conditions were used in the refined modeling. Subsequent agreements on limitations on fuel oil firing changed some of the annual average worst-case conditions from fuel oil firing to coal-derived gas firing, but the short-term worst-case conditions remained the same. Table 2 and Table 3 summarize the stack parameters and the emission characteristics of the proposed facility, respectively.

Table 2. Stack Parameters for the Proposed Facility.

Source	Height (m)	Exit Temperature (K)	Exit Velocity (m/s)	Diameter (m)
CT/HRSG[1]	65.0	410.8	18.8	6.1
Incinerator[2]	22.9	921.9	9.1	2.3
Steam Boiler[3]	18.3	534.7	15.2	1.1
Diesel Generator[4]	7.6	785.8	39.6	0.3

[1] For the stack of the CT/HRSG unit firing No. 2 fuel oil at 40°F.
[2] For the stack of the tail gas incinerator firing coal-derived gas at 75°F.
[3] For the stack of the steam boiler firing fuel oil at 40°F.
[4] For the stack of the diesel generator.

Table 3. Maximum Pollutant Emissions for the Proposed Project.

Pollutant	Source	Annual Rate (TPY)	Short-Term Rate (lb/hr)
CO	CT/HRSG[1]	586.9	134.0
	Incinerator[2]	N/A	N/A
	Steam Boiler[3]	15.8	3.6
	Diesel Generator[4]	29.4	6.7
NO_x	CT/HRSG[1]	1717.0	461.0
	Incinerator[2]	267.3	61.0
	Steam Boiler[3]	47.3	10.8
	Diesel Generator[4]	136.0	31.1
PM[5]	CT/HRSG[1]	83.3	60.6
	Incinerator[2]	N/A	N/A
	Steam Boiler[3]	6.2	1.4
	Diesel Generator[4]	9.7	2.2
	Fugitive Sources	1566.0	357.6
SO_2	CT/HRSG[1]	3653.0	919.8
	Incinerator[2]	140.2	32.0
	Steam Boiler[3]	134.5	51.2
	Diesel Generator[4]	5.5	2.07
VOC	CT/HRSG[1]	93.7	11.0
	Incinerator[2]	N/A	N/A
	Steam Boiler[3]	1.3	0.3
	Diesel Generator[4]	10.9	2.5

[1] For a single CT/HRSG stack, firing No. 2 fuel oil at 40°F for the short-term emission rate and firing coal gas for the annual emission rate (except for CO where coal-gas firing is worst-case for short term as well.)

[2] For a single tail gas incinerator stack.

[3] For a single steam boiler stack.

[4] For a single diesel generator stack.

[5] Assume PM (TSP) and PM_{10} to be the same.

Table 4 summarizes the maximum predicted concentrations for all modeled pollutants from the model results. For carbon monoxide the maximum predicted concentrations are less than the defined significant levels for this pollutant. As such, no further analysis for impact in the class II area is required.

A more detailed description of the modeling methodology and analysis, along with the model output, are contained in the FPL Martin application. The Department has reviewed the applicant's analysis and found that it conforms with the guidelines established by the EPA and followed by the Department.

4. Analysis of Existing Air Quality

Preconstruction ambient air quality monitoring is required for all pollutants subject to PSD review. In general, one year of quality assured data using an EPA reference, or the equivalent monitor must be submitted. Sometimes less than one year of data, but no less than four months, may be accepted when Departmental approval is given.

An exemption to the monitoring requirement can be obtained if the maximum air quality impact, as determined by air quality modeling, is less than a pollutant-specific "de minimus" concentration. In addition, if current monitoring data exists and these data are representative of the proposed source area, then at the discretion of the Department these data may be used.

The maximum predicted ambient impacts of the proposed facility for those pollutants subject to PSD review are listed in Table 4. The monitoring "de minimus" level for each pollutant is also listed. The predicted maximum impacts for CO, NO_2, Pb, Be, and Hg are less than their respective "de minimus" impact levels. Therefore, no preconstruction monitoring is required for these pollutants. H_2SO_4 and As are not listed because there is neither a significant impact level nor a "de minimus" level defined for them.

The preconstruction ambient monitoring analysis was required and was performed for SO_2, PM_{10}, and ozone. The applicant obtained ambient monitoring data through three air monitoring networks: (1) two on-site stations, the West site and the East site, began collecting data on October 1, 1988 and continued for one full year, (2) the existing FPL Martin site air quality monitoring network has collected data in the vicinity of the Martin site on a once every sixth day basis since October, 1973, and (3) the FDER air quality monitoring network in the area, consisting of 43 sites, within a 50 km radius of the Martin site has monitored for PM only except for six sites in Palm Beach County which also monitor for CO, NO_2, SO_2, or ozone. The air quality monitoring data indicate good background air quality for the Martin site. Table 5 summarizes the ambient air quality monitoring data for pollutants NO_2, SO_2, PM, and ozone from the two on-site stations of the Martin site for the period from October, 1988, through September, 1989, and for pollutant CO from the monitoring site in Palm Beach

Table 4. Maximum Predicted Concentrations for Comparison to the Significant Impact and De Minimus Ambient Levels ($\mu g/m^3$).

Pollutant	Averaging Time	Maximum Predicted Concentration	Significant Impact Level	De Minimus Level
CO	1-hour	60.7	2000.0	N/A
	8-hour	22.4	500.0	575.0
NO_2	Annual	2.9	1.0	14.0
SO_2	3-hour	252.4	25.0	N/A
	24-hour	65.5	5.0	13.0
	Annual	5.6	1.0	N/A
PM[1]	24-hour	28.8	5.0	10.0
	Annual	8.1	1.0	N/A
Pb	3-month	0.023[a]	N/A	0.1
VOC	Tons per Year	774 TPY	N/A	100 TPY
Be	24-hour	0.00002	N/A	0.0005
Hg	24-hour	0.0017	N/A	0.25

[1] Assume PM (TSP) and PM_{10} to be the same.

[a] The highest second-high 24-hour average is used here.

Table 5. Summary of FPL Martin On-Site Air Quality Monitoring Data for the Period October 1988 Through September 1989.

Pollutant	Averaging Time	Monitoring Site	Highest Concentration Monitored ($\mu g/m^3$)	Florida Standard ($\mu g/m^3$)
CO[1]	1-hour	Palm Beach	8016	40000
	8-hour	Palm Beach	5726	10000
NO_2	1-hour	West	62	N/A
	Annual	East	5	100
PM	24-hour	East	39	150
	Annual	West	14	60
SO_2	3-hour	East	61	1300
	24-hour	East	13	260
	Annual	East	2	60
VOC	1-hour	East	165	235
	Annual	West	47	N/A

County for year 1988.

5. PSD Increment Analysis (NO_2, PM and SO_2)

a. Class II Area

The proposed project is located in a Class II area. This area is also designated as an attainment area for NO_2, PM and SO_2. Therefore, a PSD increment analysis is required to show compliance with the Class II NO_2, PM and SO_2 increments.

The PSD increment represents the amount that new sources in an area may increase ambient ground-level concentrations of a pollutant. At no time, however, can the increased loading of a pollutant cause or contribute to a violation of the ambient air quality standard.

Atmospheric dispersion modeling, as previously described, was performed to quantify the amount of PSD increment consumed. The modeling results, considering all increment consuming sources in the area of the proposed facility site, indicate the proposed facility doesn't contribute to a violation of the PSD Class II increments. Table 6 summarizes the modeling results and the comparisons to the PSD Class II increments standard.

b. Class I Area

The nearest PSD Class I Area to the proposed facility is the Everglades National Park which is located approximately 145 kilometers south of the site. Model results indicate the significant impact areas for the proposed source are greater than 50 km for SO_2, 9.5 km for PM, and 7.5 km for NO_2. Although the proposed source has a significant impact for SO_2 at a distance greater than 50 km from its site, the model is limited to use within a 50 km distance for regulatory applications. However, given the predicted impacts at 50 km for each of these pollutants, and the long distance to the Everglades, it is unlikely that the proposed source would significantly impact the Class I Area.

6. Ambient Air Quality Standard (AAQS) Analysis

Of the pollutants subject to review, only CO, NO_2, PM, SO_2, ozone, and Pb have an AAQS. Except for ozone, dispersion modeling was performed as detailed earlier for the proposed project. The modeling results indicate that, except for CO, the predicted maximum concentration increases for all pollutants are greater than the significant impact levels defined in the State regulations (see Table 4). As such, no further modeling of other sources is required for CO. Significant impact levels for Pb and O_3 are not defined. Ozone is a photochemically formed pollutant resulting mainly from motor vehicle emissions. The

Table 6. PSD Class II Increment Analysis.

Pollutant	Averaging Time	Proposed Project Increment	All PSD Cosuming Increment	PSD Class II Increment
NO_2	Annual	2.9	3.6	25.0
SO_2	3-hour	252.4	252.4	512.0
	24-hour	65.5	65.8	91.0
	Annual	5.6	6.6	20.0
PM[1]	24-hour	28.8	28.8	37.0
	Annual	8.1	8.3	19.0

Note: All increments are in $\mu g/m^3$.
[1] Assume PM (TSP) and PM_{10} to be the same.

regulated pollutant for ozone formation is volatile organic compounds (VOC) which cannot be modeled for source-specific applications. Ozone, by way of VOC's, is regulated through BACT.

In general, the total ambient air quality impacts are determined by adding the predicted modeled concentrations of the proposed facility plus other background sources to an estimated background concentration for each pollutant. Table 7 summarizes the estimates of the predicted maximum air quality for these pollutants in the vicinity of the proposed project.

Beryllium (Be), mercury (Hg), sulfuric acid mist (H_2SO_4), and inorganic arsenic (As) do not have an AAQS. However, these pollutants were modeled and the results were compared to the Department's acceptable ambient concentrations ("no-threat" levels). Table 8 summarizes the results of this analysis. The predicted concentrations for each of these pollutants except H_2SO_4 is less than their respective "no-threat" levels. The primary contribution to the high emission of H_2SO_4 was caused by the use of coal gas as fuel. However, the coal gas facility will be added later on and there is an agreement between the applicant and the Department that the future controlled emissions will result in predicted maximum impacts less than the "no-threat" level.

Given existing air quality in the area of the proposed project, emissions from this project are not expected to cause or contribute to a violation of an AAQS.

7. Additional Impacts Analysis

a. Impacts on Soils and Vegetation

The maximum ground-level concentration predicted to occur for each pollutant as a result of the proposed project, including a background concentration, will be below the applicable AAQS including the national secondary standard developed to protect public welfare-related values. As such, this project is not expected to have a harmful impact on soils and vegetation.

b. Impact on Visibility

The EPA Level-1 visibility screening analysis was performed by the applicant for impact on the Everglades National Park area, located 145 km to the south. The results indicate that no impact on visibility is expected in this area as a result of the proposed facility.

c. Growth-Related Air Quality Impacts

The proposed project is not expected to significantly change employment, population, housing or commercial/industrial development in the area to the extent that an air quality

Table 7. Ambient Air Quality Standards (AAQS) Analysis.

Pollutant	Averaging Time	Maximum Predicted Impact	Monitored Background Impact	Total Impact	Florida AAQS
CO	1-hour	60.7	8016	8077	40000
	8-hour	22.4	5726	5748	10000
NO_2	Annual	5.5	5	10.5	60
SO_2	3-hour	291	61	352	1300
	24-hour	81.5	13	94.5	260
	Annual	12.8	2	14.8	60
PM (TSP)	24-hour	30.2	39	69.2	150
	Annual	9.7	14	23.7	60
PM_{10}	24-hour	30.2	39	69.2	150
	Annual	9.7	14	23.7	50
Pb	3-month	0.026	Neg.	0.026	1.5

Note: All impacts are in $\mu g/m^3$.

Table 8. "No-Threat" Level Analysis.

Pollutant	Averaging Time	Maximum Predicted Impact ($\mu g/m^3$)	"No-Threat" Level ($\mu g/m^3$)
Be	8-hour	0.00006	0.02
	24-hour	0.00002	0.005
	Annual	0.000002	0.0004
Hg	8-hour	0.003	0.1
	24-hour	0.0017	0.024
H_2SO_4	8-hour	11.4	10.0
	24-hour	7.2	2.4
As	8-hour	0.0019	2.0
	24-hour	0.0012	0.5
	Annual	0.0001	0.0002

impact will result.

d. GEP Stack Height Determination

Good Engineering Practice (GEP) stack height means the greater of: (1) 65 meters or (2) the maximum nearby building height plus 1.5 times the building height or projected width, whichever is less. The CT/HRSG stacks are located within the area of influence for the CG/CC plant control buildings and the HRSG structures. The coal gasification plant tail gas treatment incinerator stacks are located within the area of influence for the coal gasification plant building structures. The lesser dimension for each case is the height, 18.3 meters for CG/CC plant control buildings, 17.4 meters for the HRSG structures, and 12.2 meters for the coal gasification plant buildings. The calculated GEP stack height of each case is, thus, 45.8 meters, 43.5 meters, and 30.5 meters, respectively. Therefore, the GEP stack height for each case is 65 meters. The actual stack height of the HRSG stack is greater than 65 meters. Hence, the HRSG stack is credited to 65 meters in the modeling analysis. The actual stack height of the coal gasification plant tail gas treatment incinerator stack is 22.9 meters and is less than the GEP stack height. The building downwash effect was included in the modeling analysis for the coal- derived gas 100% load 75°F ambient temperature fuel scenario.

8. Best Available Control Technology

The Applicant is proposing the construction of four 400 MW coal gasification combined cycle units. Each combined cycle unit will consist of two combustion turbines and two heat recovery steam generators (i.e., a total of eight CTs and eight HRSGs for the four combined cycle units). Each CT will be served by a single HRSG, exhausting to an individual stack. There will be no HRSG bypass stacks for simple cycle operation; simple cycle operation will be accomplished by passing the exhaust gases through the HRSG and dumping steam from the HRSG directly to the condenser. The expected primary fuel is natural gas, with No. 2 distillate fuel oil as a backup (oil usage not to exceed 500 hrs per year per turbine). A coal gasification facility will be phased in later on, to serve as the source of fuel for the combined cycle units.

The proposed facility will include two 60,000 lb/hr (nominal) steam auxiliary boilers capable of firing natural gas and fuel oil and two 750 kW diesel generators firing diesel fuel. The auxiliary steam boilers will be used to serve the start-up steam needs of the four combined cycle units and the two emergency diesel generators will be used for in-plant power during loss of off-site power.

The coal gasification facility will serve as a source of medium Btu, low sulfur (less than 0.8% sulfur) coal-derived gas. The coal used in the gasification facility will have a maximum sulfur content of 4.3% and have a heating value of approximately 10,600 Btu/lb. The coal gasification plants will consist of coal and limestone receiving, storage and preparation facilities, gasifier, oxygen plant, product gas cleaning facilities and auxiliary equipment. The coal gasification facility will include four units, each capable of supporting 400 MW of combined cycle capacity. Each coal gasification unit will have two stacks, one flare stack used during start-up, shutdown and emergency conditions and one tail gas treating incinerator stack which will be used continuously.

The applicant has indicated the maximum tonnage of regulated air pollutants emitted from the proposed facility based on operation at 100 percent capacity and 8,760 hours per year to be as shown on Table 8.

TABLE 8

Pollutant	Combined Cycle	Gasifier Incinerator Stacks	Steam Boilers	Diesel Generators	Fugitive Sources	Maximum Total	PSD Significient Emission Rate
SO_2	29,224	560.6	269	10.9	neg.	30,065	40
PM	666	neg.	12.3	19.4	1,566	2,264	25
PM_{10}	666	neg.	12.3	19.4	1,566	2,264	15
NOx	13,736	1,069	94.6	272	neg.	15,172	40
CO	4,695	neg.	31.5	58.8	neg.	4,785	100
VOC	750	neg.	2.63	21.7	neg.	774	40
Pb	10.6	0.88	neg.	neg.	neg.	11.5	0.6
Be	0.01	0.008	neg.	neg.	neg.	0.01	0.0004
Hg	0.84	0.14	neg.	neg.	neg.	0.98	0.1
AS	0.60	0.021	neg.	neg.	neg.	0.62	0
H_2SO_4	3,574	68.7	33	1.3	neg.	3,677	7
Fluorides	1.9	neg.	neg.	neg.	neg.	1.9	3

NOTE: In some cases the sum of the emissions for the individual sources do not equal the maximum total emissions since the gasifer wouldn't be used when the turbines are fired on oil.

Florida Department of Environmental Regulation

Twin Towers Office Bldg. ● 2600 Blair Stone Road ● Tallahassee, Florida 32399-2400

Lawton Chiles, Governor | Carol M. Browner, Secretary

PERMITTEE:
Florida Power & Light Company
Post Office Box 078768
West Palm Beach, FL 33407-0768

Permit Number: PSD-FL-146
Expiration Date:
County: Martin
Latitude/Longitude: 27° 3' 18"N
80° 34' 02"W
Project: Martin CG/CC Project

This permit is issued under the provisions of Chapter 403, Florida Statutes and Florida Administrative Code Chapters 17-2, 17-4 and 17-17. The above named Permittee is hereby authorized to perform the work or operate the facility shown on the Application and approved drawing(s), plans, and other documents attached hereto or on file with the Department and made a part hereof and specifically described as follows:

Phase I of the Martin CG/CC Project consists of the addition of two new combined cycle units (Units 3 and 4) to the existing Martin Plant to be fired with natural gas and fuel oil. Each of the units will comprise two advanced combustion turbines and two heat recovery steam generators in a combined cycle configuration. The units will each have a generating capacity of approximately 400 megawatts, with natural gas as the primary fuel and low sulfur distillate oil as an alternate fuel. The Martin CG/CC Project has been certified under the Florida Electrical Power Plant Siting Act (Site Certification Number PA 89-27).

Nitrogen oxide emissions will be controlled by the use of dry low NO_x combustors for natural gas firing and steam injection for oil firing. In addition, fuel oil firing will be limited to an aggregate of 2000 hours per year for the four combustion turbines (CTs) comprising the two units and annual NO_x emissions will be limited to 3108 tons per year.

Construction shall be in accordance with the attached permit application and additional information submitted except as otherwise noted in the Specific Conditions.

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GENERAL CONDITIONS:

1. The terms, conditions, requirements, limitations, and restrictions set forth herein are "Permit Conditions" and as such are binding upon the Permittee and enforceable pursuant to the authority of Sections 403.161, 403.727, or 403.859 through 403.861, Florida Statutes. The Permittee is hereby 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 any 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 does not constitute a waiver of 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 acknowledgement 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 and 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.

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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 any records that must be kept under the conditions of the permit;

b. Inspecting 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 non-compliance, including exact 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.

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Florida Power & Light Company	Expiration Date:
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West Palm Beach, FL 33407-0768	Latitude/Longitude: 27° 3' 18"N 80° 34' 02"W
	Project: Martin CG/CC Project

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 proscribed by Section 403.73 and 403.111, Florida Statutes. Such evidence shall only be used to the extent it is consistent.

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 grated by Florida Statutes or Department rules.

11. This permit is transferable only upon Department approval in accordance with Florida Administrative Code Rules 17-4.12 and 17-30.300, as applicable. The Permittee shall be liable for nay 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 during the entire period of construction or operation.

13. This permit also constitutes:

    (x) Determination of Best Available Control Technology (BACT)
    (x) Determination of Prevention of Significant Deterioration (PSD)
    (x) Compliance with New Source Performance Standards

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 rention 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 for 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:

- the date, exact place, and time of sampling or measurements;
- the person responsible for performing the sampling or measurements;
- the date(s) analyses were performed;
- the person responsible for performing the analyses;
- the analytical techniques or methods used; and
- 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 submitted or correctly promptly.

SPECIFIC CONDITIONS:

The construction and operation of Martin CG/CC Project shall be in accordance with all applicable provisions of Chapters 17-2, F.A.C. In addition to the foregoing, the Project shall comply with the following Conditions of Certification as indicated.

(The following emission limitations and conditions reflect final BACT determinations for Units 3 and 4 firing natural gas and oil. Emission limitations and conditions concerning Phases II and III of the Project are preliminary based on information furnished by the Permittee in order to support certification of ultimate site capacity and shall be determined finally upon review of supplemental applications.)

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1. The maximum heat input to each CT shall neither exceed 1,966 MMBtu/hr while firing natural gas, nor 1,846 MMBtu/hr while firing fuel oil (@ 40°F). For coal derived gas firing the maximum heat input to each CT shall not exceed 2,100 MMBtu/hr (@ 75°F). These heat input limitations are subject to change. Any changes shall be provided at least 90 days before commercial operation for each fuel available to the site which a unit is capable of firing, at which time this condition may be modified to reflect those parameters. Each combined cycle unit's fuel consumption shall be continuously determined and recorded.

2. Each of the eight CTs may operate continuously, i.e., 8,760 hrs/year.

3. Only natural gas, light distillate fuel oil, or coal derived gas shall be fired in the combustion turbines.

4. The maximum allowable emissions from each CT in accordance with the BACT determination, shall not exceed the following, at 40°F (except during periods of startup and shutdown):

			Emission Limitations[d]			
			Units 3 & 4		Units 5 & 6	
Pollutant	Fuel	Basis	lb/hr/CT	TPY[a]	lb/hr/CT	TPY[a]
NOx	Gas	25 ppmvd @ 15% O_2	177	comb. } 3108	177	comb. } 3108
	Oil	65 ppmvd @ 15% O_2	461	tot.	461	tot.
	CG	42 ppmvd @ 15% O_2	392	6868	392	6868
VOC[b]	Gas	1.6 ppmvd	3	comb. } 57	3	comb. } 57
	Oil	6 ppmvd	11	tot.	11	tot.
	CG	9 ppmvd	21.4	375	21.4	375
CO	Gas	30 ppmvd	94.3	comb. } 871	94.3	comb. } 871
	Oil	33 ppmvd	105.8	tot.	105.8	tot.
	CG	33 ppmvd	134	2348	134	2348
PM/PM_{10}	Gas		18	comb. } 100	18	comb. } 100
	Oil		60.6	tot.	60.6	tot.
	CG		19	333	19	333
Pb	Gas		neg.	comb. } 0.015	neg.	comb. } 0.015
	Oil		0.015	tot.	0.015	tot.
	CG		0.3	5.3	0.3	5.3
SO_2	Gas		91.5	comb. } 568	91.5	comb. } 568
	Oil[c]		920	tot.	920	tot.
	CG		834	14612	834	14612

3032/trh

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a) Tons per year (TPY) emission limits listed for natural gas and oil combined apply as an emission cap based on limiting oil firing to an annual aggregate of 2,000 hours for the four CTs, with compliance to be demonstrated in annual operation reports.
b) Exclusive of background concentrations.
c) Sulfur dioxide emissions based on maximum of 0.5 percent sulfur in oil for hourly emissions and an average sulfur content of 0.3 percent for annual emissions.
d) These limitations for Units 5 and 6 and coal gasification shall not be binding for subsequent BACT determinations.

5. The following emissions, determined by BACT, are tabulated for PSD and inventory purposes:

Pollutant	Fuel	Maximum Allowable Emissions (@ 40°F) Units 3 & 4 lb/hr/CT		Units 3 & 4 TPY[a]	Units 5 & 6 lb/hr/CT		Units 5 & 6 TPY[a]
H_2SO_4[b] Acid Mist	Gas	11.2	comb. tot.	70	11.2	comb. tot.	70
	Oil	113			113		
	CG	102		1787	102		1787
Mercury	Gas	0.021	comb. tot.	0.34	0.021	comb. tot.	0.34
	Oil	0.0052			0.0052		
	CG	0.024		0.42	0.024		0.42
Fluoride	Oil	0.055		0.055	0.055		0.055
Beryllium	Oil	0.004		0.004	0.004		0.004

a) Tons per year (TPY) emission limits listed for natural gas and oil combined apply as an emission cap based on limiting oil firing to an annual aggregate of 2,000 hours for the four CTs, with compliance to be demonstrated in annual operation reports.
b) Sulfuric acid mist emissions assume a maximum of 0.5 percent sulfur in fuel oil for hourly emissions and an average sulfur content of 0.3 percent for annual emissions.

6. The maximum allowable emissions from each gasifier incinerator stack shall not exceed the following at 75°F.

Pollutant	Lb/hr/Stack	TPY/Stack	4 Stacks
NOx	61	268	1069
VOC	Negl.	Negl.	Negl.
CO	Negl.	Negl.	Negl.
PM/PM10	Negl.	Negl.	Negl.
SO_2	32	140.2	555
Beryllium	0.0005	0.002	0.008
Mercury	0.008	0.035	0.140
Lead	0.05	0.22	0.88

7. Auxiliary steam boilers and diesel generators shall operate only during startup and shutdown, periodic maintenance testing, and for emergency power generation, respectively. NO_x emissions for the auxiliary steam boilers shall not exceed 0.1 lb/MMBtu for natural gas firing or 0.2 lb/MMBtu for oil firing. NO_x emissions for the diesel generators shall not exceed 12.0 grams/hp-hr.

Sulfur dioxide emissions limitations for the auxiliary steam boilers and diesel generators are established by firing natural gas or limiting the light distillate fuel oil's sulfur content to 0.3 percent on an annual basis.

8. Visible emissions shall neither exceed 10 percent opacity while burning natural gas or coal derived gas, nor 20 percent opacity while burning distillate oil.

9. Nitrogen oxide emissions from each gas turbine/heat recovery steam generator unit shall be controlled by using dry low NO_x combustors for natural gas with steam injection for fuel oil firing. The Permittee shall install duct module(s) suitable for future installation of SCR equipment on each combined cycle generating unit.

10. Initial (I) compliance tests shall be performed on each CT using both fuels. The stack test for each turbine shall be performed within 10 percent of the maximum heat rate input for the tested operating temperature. Annual (A) compliance tests shall be performed on each CT with the fuel(s) used for more than 400 hours

in the preceding 12-month period. Tests shall be conducted using EPA reference methods in accordance with the November 2, 1989, version of 40 CFR 60 Appendix A:

a. 5 or 17 for PM (I, A, for oil only)

b. 8 for sulfuric acid mist (I, for oil only)

c. 9 for VE (I, A)

d. 10 for CO (I, A)

e. 20 for NO_x (I, A)

f. 18 for VOC (I, A)

g. Trace elements of Lead (Pb) and Beryllium (Be) shall be tested (I, for oil only) using EMTIC Interim Test Method. As an alternative, Method 104 for Beryllium (Be) may be used; or Be and Pb may be determined from fuel analysis using either Method 7090 or 7091, and sample extraction using Method 3040 as described in the EPA solid waste regulations SW 846.

h. ASTM D 2880-71 (or equivalent) for sulfur content of distillate oil (I, A)

i. ASTM D 1072--80, D 3031-81, D 4084-82 or D 3246-81 (or equivalent) for sulfur content of natural gas (I, and A if deemed necessary by DER)

j. Mercury (Hg) shall be tested using EPA Method 101 (40 CFR 61, Appendix B) (I).

Other DER approved methods may be used for compliance testing after prior Departmental approval.

11. The average annual sulfur content of the light distillate fuel oil shall not exceed 0.3 percent by weight. The maximum sulfur content of the light distillate fuel oil shall not exceed 0.5 percent. Compliance shall be demonstrated in accordance with the requirements of 40 CFR 60.334 by testing for sulfur content of oil storage tanks once per day when firing oil using ASTM D 2880-71, testing for nitrogen content, and testing for heating value.

12. Continuous emission monitoring shall be installed, operated, and maintained in accordance with 40 CFR 60, Appendix F for each combined cycle unit to monitor nitrogen oxides. G

a. Each continuous emission monitoring system (CEMS) shall meet performance specifications of 40 CFR 60, Appendix B.

b. CEMS data shall be recorded and reported in accordance with Chapter 17-2, F.A.C., and 40 CFR 60. The record shall include periods of startup, shutdown and malfunction.

c. A malfunction means any sudden and unavoidable failure of air pollution control equipment to operate in a normal or usual manner. Failures that are caused entirely or in part by poor maintenance, careless operation or any other preventable upset condition or preventable equipment breakdown shall not be considered malfunctions.

d. The procedures under 40 CFR 60.13 shall be followed for installation, evaluation and operation of all CEMS.

e. For purposes of reports required under this certification, excess emissions are defined as any calculated average emission concentration, as determined pursuant to Condition II.A.18 herein, which exceeds the applicable emission limits in Condition II.A.4.

13. To determine compliance with the oil firing heat input limitation, the Permittee shall maintain daily records of fuel oil consumption and hourly usage for each turbine and heating value for such fuel. All records shall be maintained for a minimum of three years after the date of each record and shall be made available to representatives of the Department upon request.

14. The project shall comply with all the applicable requirements of Chapter 17-2, F.A.C. and the June 27, 1989, version of 40 CFR 60 Subpart GG, Gas Turbines.

15. Any change in the method of operation, fuels, or equipment, shall be submitted for approval to DER's Bureau of Air Regulation (BAR).

PERMITTEE:
Florida Power & Light Company
Post Office Box 078768
West Palm Beach, FL 33407-0768

Permit Number: PSD-FL-146
Expiration Date:
County: Martin
Latitude/Longitude: 27° 3' 18"N
80° 34' 02"W
Project: Martin CG/CC Project

16. The Permittee shall have required sampling tests of the emissions performed within 60 days after achieving the maximum turbine firing rate, but not later than 180 days from the start of operation. Thirty (30) days notice prior to the initial sampling test and fifteen (15) days notice before subsequent annual testing shall be provided to the Southeast District Office. Written reports of the tests shall be submitted to the Southeast District Office within 45 days of test completion.

17. If construction does not commence on Phase I within 18 months of issuance of this certification/permit, then the Permittee shall obtain from DER a review and, if necessary, a modification of the control technology and allowable emissions for the unit(s) on which construction has not commenced (40 CFR 52.21(r)(2)). Units to be constructed or modified in later phases of the project will be reviewed and limitations revisited under the supplementary review process of the Power Plant Siting Act.

18. Quarterly excess emission reports, in accordance with the November 2, 1989, version 40 CFR 60.7(c) and 60.334(c) shall be submitted to DER's Southeast District Office. Annual reports shall be submitted to the District Office in accordance with Rule 17-2.700(7), F.A.C.

19. Literature of equipment selected shall be submitted as it becomes available. A CT-specific graph of ambient temperature and heat inputs to the CT shall be submitted to DER's Southeast District Office and the BAR.

20. Stack sampling facilities shall be provided for each of the CT and incinerator stacks.

21. Construction period fugitive dust emissions shall be minimized by covering or watering dust generation areas.

22. The materials handling and storage operations may be continuous, i.e. 8,760 hrs/yr.

3032/trh

23. The material handling/usage rates shall not exceed the following:

Material	Handling/Usage Rate TYP
Coal	6,935,000
Slag and Fly Slag	1,700,000
Sulfur	310,000
Spent Solvent	80
Spent Claus Catalyst	80
Demineralizer Resin Beds	70

24. The maximum particulate matter emissions from the material handling and storage activities shall not exceed 1,566 tons per year. Emissions from these sources shall be controlled using the following measures:

Fugitive Dust Source	Control Technology
Coal Unloading	Enclosed with Dry Collection System
Limestone Unloading	Wet Suppression System[1]
Conveyors and Transfer Points (Coal, Limestone, Slag)	Transfer Points Enclosed with Dry Collection System. Conveyors Covered.
Coal Storage (Inactive)	Crusting Agent Application (60% Control)
Coal Storage (Active)	Surfactant Application[1]
Coal Storage (Active) and Reclaiming	Surfactant Application[1]
Limestone Storage	Crusting Agent Application[1]

PERMITTEE: Florida Power & Light Company Post Office Box 078768 West Palm Beach, FL 33407-0768	Permit Number: PSD-FL-146 Expiration Date: County: Martin Latitude/Longitude: 27° 3' 18"N 80° 34' 02"W Project: Martin CG/CC Project

Fugitive Dust Source	Control Technology
Slag Transport to By-Product Storage Area	Paved Road Covered Conveyor (95% Control)
Slag By-Product Storage Area (Inactive)	Topsoil Covered and Seeded (100% Control)
Slag By-Product Storage Area (Active)	Compaction, Temporary Cover (Natural or Synthetic)
Sulfur Storage	Stored in Molten State in Tanks or in Crystalline Slab Arrangement.[1]

[1]Undefined rate of fugitive dust control.

The emissions from the above listed sources where baghouses are used are subject to the particulate emission limitation requirements of 0.03 gr/dscf. However, DER will not require particulate tests in accordance with EPA Method 5 unless the VE limit of 5 percent opacity is exceeded for a given source, or unless DER, based on other information, has reason to believe the particulate emission limits are being violated.

25. Visible Emissions (VE) shall not exceed 5 percent opacity from any source in the material handling and treatment area, in accordance with Chapter 17-2, F.A.C.

26. Initial and annual Visible Emission compliance tests for al the emission points in the material handling and treatment area, including, but to limited to, the sources specified in this permit, shall be conducted in accordance with the November 2, 1989, version of 40 CFR 60, using EPA Method 9 or DER approved method.

27. Compliance test reports shall be submitted to DER within 45 days of test completion in accordance with Chapter 17-2.700(7), F.A.C.

PERMITTEE:
Florida Power & Light Company
Post Office Box 078768
West Palm Beach, FL 33407-0768

Permit Number: PSD-FL-146
Expiration Date:
County: Martin
Latitude/Longitude: 27° 3' 18"N
80° 34' 02"W
Project: Martin CG/CC Project

28. Any changes in the method of operation, raw materials processed, equipment, or operating hours or any other changes pursuant to Rule 17-2.100, F.A.C., defining modification, shall be submitted for approval to DER's BAR.

Issued this _________ day of
_______________________, 1991.

STATE OF FLORIDA DEPARTMENT
OF ENVIRONMENTAL REGULATION

____
Carol M. Browner
Secretary

3032/trh

Florida Administrative Code Rule 17-2.500 (2)(f)(3) requires a BACT review for all regulated pollutants emitted in an amount equal to or greater than the significant emission rates listed in the previous table. For VOC emissions neither BACT nor LAER review is required since the area is attainment for ozone.

Date of Receipt of A BACT Application

December 29, 1989

BACT Determination Requested by the Applicant

	Combined Cycle Units
Pollutant	Determination
NOx	25 ppmvd (natural gas firing) 42 ppmvd (coal derived gas firing) 65 ppmvd (No. 2 fuel oil firing)
SO_2	Firing of natural gas No. 2 fuel oil or coal derived gas with a maximum sulfur content of 0.5 and 0.3%, respectively.
CO	30 ppmvd (natural gas firing) 33 ppmvd (No. 2 fuel oil and coal derived gas firing)
VOC	1.6 ppmvd (natural gas firing) 6 ppmvd (No. 2 fuel oil firing) 9 ppmvd (coal derived gas firing)
PM & PM_{10}	Good combustion, and type of fuels fired
Pb	Good combustion, and type of fuels fired
H_2SO_4	Firing of natural gas, coal derived gas and No. 2 fuel oil
Be	Firing of natural gas, coal derived gas and No. 2 fuel oil
AS	Firing of natural gas, coal derived gas and No. 2 fuel oil

Coal Gasification Plant/Sulfur Removal and Recovery Systems

Raw Product Gas

Pollutant	Control Technology
Sulfur	Acid Gas Removal (95.1%)
NOx	See combined cycle summary
CO	See combined cycle summary
VOC	See combined cycle summary
Particulates	Water scrubbing
Lead	See combined cycle summary
Beryllium	See combined cycle summary
Mercury	See combined cycle summary
Inorganic Arsenic	See combined cycle summary

CG Emission (Tail Gas Treatment)

Pollutant	Control Technology
SO_2	Tail gas treatment (99.9% sulfur recovery, 250 ppm)
NOx	Combustion controls
Lead	Efficient Operation
Mercury	Efficient Operation
Beryllium	Efficient Operation
Inorganic Arsenic	Efficient Operation

Material Handling and Storage

Fugitive Dust Source	Control Technology
Coal Unloading	Enclosed with Dry Collection System
Limestone Unloading	Wet Suppression System[1]
Conveyers and Transfer Points (Coal, Limestone, Slag)	Transfer points enclosed with Dry Collection System. Conveyers covered
Coal Storage (Inactive)	Crusting Agent Application (60% Control)
Coal Storage (Active)	Surfactant Application[1]
Coal Storage (Active) and Reclaiming	Surfactant Application[1]
Limestone Storage	Crusting Agent Application[1]

Slag Transport By-Product Storage Acre	Paved Road Covered Conveyer (95% Control)
Slag By-Product Storage Area (Inactive)	Topsoil Covered and Seeded (100% Control)
Slag By-Product Storage Area (Active)	Compaction, Temporary Cover (Natural or Synthetic)
Sulfur Storage	Stored in Molten state in tanks or in crystalline

[1] - Undefined rate of fugitive dust control

Auxiliary Boilers, Diesel Generators, and Flare Stacks

No BACT limitations are proposed for these sources since their operation is expected to be infrequent (start-up and shut-down, and emergencies).

BACT Determination Procedure

In accordance with Florida Administrative code chapter 17-2, Air Pollution, this BACT determination is 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. In addition, the regulations state that in making the BACT determination the Department shall give consideration to:

(a) Any Environmental Protection Agency determination of Best Available Control Technology pursuant to Section 169, 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).

(b) All scientific, engineering, and technical material and other information available to the Department.

(c) The emission limiting standards or BACT determinations of any other state.

(d) The social and economic impact of the application of such technology.

The EPA currently stresses that BACT should be determined using the "top-down" approach. The first step in this approach is to determine for the emission source in question the most stringent control available for a similar or identical source or source category. If it is shown that this level of control is technically or economically infeasible for the source in question, then the next most stringent level of control is determined and similarly evaluated. This process continues until the BACT level under consideration cannot be eliminated by any substantial or unique technical, environmental, or economic objections.

The air pollutant emissions from combined cycle power plants can be grouped into categories based upon what control equipment and techniques are available to control emissions from these facilities. Using this approach, the emissions can be classified as follows:

o Combustion Products (Particulates and Heavy Metals). Controlled generally by good combustion of clean fuels.

o Products of Incomplete Combustion (CO, VOC, Toxic Organic Compounds). Control is largely achieved by proper combustion techniques.

o Acid Gases (SOx, NOx, HCl, Fl). Controlled generally by gaseous control devices.

Grouping the pollutants in this manner facilitates the BACT analysis because it enables the equipment available to control the type or group of pollutants emitted and the corresponding energy, economic, and environmental impacts to be examined on a common basis. Although all of the pollutants addressed in the BACT analysis may be subject to a specific emission limiting standard as a result of PSD review, the control of "nonregulated" air pollutants is considered in imposing a more stringent BACT limit on a "regulated" pollutant (i.e., particulates, sulfur dioxide, fluorides, sulfuric acid mist, etc.), if a reduction in "nonregulated" air pollutants can be directly attributed to the control device selected as BACT for the abatement of the "regulated" pollutants.

Combustion Products

The Combined Cycle/Coal Gasification project's projected emissions of particulate matter, PM_{10}, beryllium, mercury and inorganic arsenic exceed the significant emission rates given in Florida Administrative Code Rule 17-2.500, Table 500-2. A review of the BACT/LAER Clearinghouse indicates that the proposed PM/PM_{10} emission levels of 0.011 lbs/MM Btu and 0.035 lbs/MM Btu per turbine are consistent with previous BACT determinations for similar equipment firing natural gas and No. 2 fuel oil respectively. For coal derived gas the emission level is nearly equivalent to that for natural gas. As this is the case, these emission limitations are reasonable as BACT for the Martin project.

In general, the BACT/LAER Clearinghouse does not contain specific emission limits for beryllium, mercury and arsenic from turbines. BACT for heavy metals is typically represented by the level of particulate control. As this is the case, the emission factors for particulate matter/ PM_{10} when firing natural gas, coal derived gas and No. 2 fuel oil are judged to represent BACT for beryllium and mercury.

Products of Incomplete Combustion

The emissions of carbon monoxide, volatile organic compounds and other organism from combustion turbines are largely dependent upon the completeness of combustion and the type of fuel used. The applicant has indicated that the carbon monoxide emissions from the proposed turbines are based on exhaust concentrations of 30 ppmvd for natural gas and 33 ppmvd for No. 2 fuel oil and coal derived gas. Volatile organic compound emissions have been based on exhaust concentrations of 1.6, 6, and 9 ppmvd for natural gas, fuel oil firing, and coal derived gas, respectively.

A review of the BACT/LAER clearinghouse indicates that several of the largest combustion turbines (those with heat inputs greater that 1,000 MMBtu/hour) have been permitted with CO limitations which are similar to those proposed by the applicant. For VOC the clearinghouse also indicates that the proposed emissions are consistent with that established for other turbines of similar size, thereby suggesting that the proposed emission levels for both CO and VOC are reasonable. Although the majority of BACT emissions limitations have been based on combustion controls for carbon monoxide and volatile organic compounds minimization, additional control is achievable through the use of catalytic oxidation.

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 wet injection. These installations have been required to utilize LAER technology, and typically have CO limits in the 10 ppm range (corrected to dry conditions).

In an oxidation catalyst control system, CO emissions are reduced by allowing unburned CO to react with oxygen a the surface of a precious metal catalyst such as platinum. Combustion of CO starts at about 300°F, with efficiencies above 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 CT/HRSG combinations, the oxidation catalyst can be located directly after the CT or in the HRSG. Catalyst size depends upon the exhaust flow, temperature and desired efficiency. The existing gas turbine applications have been limited to smaller cogeneration facilities burning natural gas.

Given the applicant's proposed BACT level for carbon monoxide stated above, an evaluation can be made of the cost and associated benefit of using catalytic oxidation as follows:

The applicant has indicated that the estimated cost per ton of CO removal using catalytic oxidation would exceed $14,000 based on cost estimates for a facility using similar equipment (FPL Lauderdale facility). Although the applicant did not itemize the cost analysis, a projection of the cost to reduce CO emissions can be computed since the Martin and Lauderdale facilities are proposing to use combined cycle equipment of similar size (i.e. Volumetric and mass flow rates per unit very similar). The cost to control CO using catalytic oxidation for the Lauderdale facility was estimated to be $6,989,029 on an annual basis. Taking into consideration that the Martin facility will utilize twice as many combined cycle units as was proposed for Lauderdale, it is projected that the annual cost for utilizing catalytic oxidation at the Martin facility would be approximately $13,978,058.

The projected total emissions of CO for the eight combined cycle units at the Martin facility are 1,742, and 4,695 tons per year for natural gas/No. 2 fuel oil, and coal derived gas firing, respectively.

Assuming that catalytic oxidation will reduce the CO emissions by an additional 80%, and basing the projected emission rates to an operating temperature of 75° F in each case, the oxidation catalyst would control 1,394 and 3,756 tons of CO annually for the natural gas/No. 2 fuel oil, and coal derived gas firing modes, respectively.

When these reductions are taken into consideration with the total projected levelized annual cost of $13,978,058, the cost per ton of controlling CO ranges from a low of \$3,722 for coal derived gas firing to a high of \$8,024 for natural gas/No. 2 fuel oil firing. These costs could be reasonable for coal derived gas firing based on the cost per ton figures that are now being established for other pollutants such as NOx. For NOx costs up to \$4,000 per ton have been judged to be reasonable with regard to using selective catalytic reduction as a BACT requirement. Assuming catalytic oxidation would also be capable of controlling VOC emissions with 80% efficiency, the total cost of control for both CO and VOC's would range from \$3,209 to \$7,935 per ton which further decreases the cost of this type of control.

It should be noted that the proposed basis for the CO emissions may be high depending on the equipment selection. A review of previous projects indicates that some equipment being evaluated has proposed CO emission rates as low as 10 ppmvd for natural gas firing and as low as 26 ppmvd for oil firing. As this is the case, the applicant's proposal for CO emissions may exceed that calculated above. If the actual emission rates were equivalent to that of these other facilities, the cost of using catalytic oxidation would likely be greater.

For coal derived gas firing there is not a good data base to determine whether the proposed CO emission rate of 33 ppmvd is reasonable for a combined cycle facility. It was for this mode of generation that the cost to control CO and VOC was determined to be the lowest at \$3,209 per ton. As this is the case, it is recommended that the use of catalytic oxidation be revisited as BACT at the time that the applicant proceeds with the coal gasification phase. This type of approach would allow for the cost of using catalytic oxidation to be based specifically on the coal derived gas firing mode when completing the BACT determination.

Acid Gases

The emissions of sulfur dioxide, nitrogen oxides, fluorides, and sulfuric acid mist, as well as other acid gases which are not "regulated" under the PSD Rule, represent a significant proportion of the total emissions and need to be controlled if deemed appropriate. Sulfur dioxide emissions from combustion turbines are directly related to the sulfur content of the fuel being combusted.

The applicant has proposed the use of natural gas and No. 2 fuel oil with a maximum sulfur content of 0.5% to control sulfur dioxide emissions. A review of the latest edition (1989) of the BACT/LAER Clearinghouse indicates that sulfur dioxide emissions from combustion turbines have been controlled by limiting fuel oil sulfur content to a range of 0.1 to 0.3%, with the average for the facilities listed being approximately 0.24 percent.

Although the applicant has stated that the No. 2 fuel oil will have a maximum sulfur content of 0.5 percent, the nominal average sulfur content is expected to be 0.3 percent. This sulfur content is consistent with what has been established as BACT on a national basis and for recent permitting of gas turbines in Florida. As this is the case, an average annual sulfur content of 0.3 percent is judged to represent BACT.

For coal derived gas firing the applicant has proposed gas with a maximum sulfur content of 0.3% to control sulfur dioxide emissions. A review of other fuel derived gas fired facilities indicates that gas sulfur controls of 0.3% have been established as BACT. As this is the case, a coal derived gas sulfur content not to exceed 0.3% is also judged to be BACT for this facility.

The applicant has stated that BACT for nitrogen oxides will be met by using wet (water or steam) injection necessary to limit emissions to 65 ppmvd at 15% oxygen when burning No. 2 fuel oil 42 ppmvd at 15% oxygen when burning coal derived gas, and 25 ppmvd at 15% oxygen for natural gas firing.

A review of EPA's BACT/LAER Clearinghouse indicates that the lowest NOx emission limit established to date for a combustion turbine is 4.5 ppmvd at 15 percent oxygen. This level of control was accomplished through the use of water injection and a selective catalytic reduction (SCR) system.

Selective catalytic reduction is a post-combustion method for control of NOx emissions. The SCR process combines vaporized ammonia with NOx in the presence of a catalyst to form nitrogen and water. The vaporized ammonia is injected into the exhaust gases prior to passage through the catalyst bed. The SCR process can achieve up to 90% reduction of NOx with a new catalyst. As the catalyst ages, the maximum NOx reduction will decrease to approximately 86 percent.

Given the applicant's proposed BACT level for nitrogen oxides control stated above, an evaluation can be made of the cost and associated benefit of using SCR as follows:

The applicant has indicated that the total levelized annual cost (operating plus amortized capital cost) to install SCR for natural gas firing at 90 percent capacity factor and fuel oil firing at 10 percent capacity factor is $15,651,500 for Units 3 and 4 (four combined cycle units). Taking into consideration the total levelized annual cost, a cost/benefit analysis of using SCR can now be developed. For natural gas firing/oil firing at these capacity factors and @ 75° F the NOx emissions with wet injection from each gas turbine and associated heat recovery steam generator is expected to be 3,173 tons/year from the four combined cycle units.

Assuming that SCR will reduce the NOx emissions by an additional 65%, the SCR would control 2,062 tons of NOx annually for natural gas/oil firing. When this reduction is taken into consideration with the total levelized annual cost of $15,651,500, the cost per ton of controlling NOx is $7,590. This cost ($7,590/ton) exceeds costs that have been previously justified as BACT.

Since SCR has been determined to be BACT for several combined cycle facilities, the EPA has clearly stated that there must be unique circumstances to consider the rejection of such control on the basis of economics. In a recent letter from EPA Region IV to the Department regarding the permitting of a combined cycle facility (Tropicana Products Inc.), the following statement is made:

> "In order to reject a control option on the basis of economic considerations, the applicant must show why the costs associated with the control are significantly higher for this specific project than for other similar projects that have installed this control system or in general for controlling the pollutant."

A review of the combined cycle facilities in which SCR has been established as a BACT requirement indicates that the majority of these facilities had NOx emission levels of 42 ppmvd at 15% oxygen using steam injection as the only control method. As this is the case, the proposed project is not similar(proposal uses advanced turbines capable of maintaining NOx emissions at 25 ppmvd @15% oxygen for natural gas firing) to other facilities in which SCR has been established as BACT, thereby supporting the rejection of SCR as BACT for the proposed facility.

For coal derived gas firing, the NOx emissions for each turbine are expected to be 392 pounds per hour based on an operating temperature of 75° F and a proposed emission level of 42 ppmvd. Based on this emission rate and a 100 percent capacity factor the maximum annual NOx emissions from four combined cycle units would be 6,868 tons/year.

Assuming that the cost and efficiency of controlling NOx for coal derived gas firing compared to that for natural gas,the SCR would control 4,464 tons of NOx annually for coal derived gas firing. When this reduction is taken into consideration with the total levelized annual cost of $15,651,500, the cost per ton of controlling NOx would be $3,506 for coal derived gas firing. This cost is well below that calculated for natural gas firing and would be judged to be more reasonable as BACT for the facility. Although the SCR system cost may actually be higher to control NOx emissions for coal derived gas firing, it is not expected that the resulting cost of control would escalate to the point of rejecting the technology. As this is the case, an in depth cost analysis for SCR use is warranted when the applicant proceeds with the coal derived gas option.

<u>Tail Gas Incinerators, Steam Boilers, and Diesel Generators</u>

A review of the proposed emission rates for the tail gas incinerators, steam boilers, and diesel generators indicates that equipment in and of itself represents BACT for these sources.

The predominant emissions from the tail gas incinerators are nitrogen oxides and sulfur dioxide. The sulfur dioxide emissions proposed for the facility are based on the highest removal efficiency that is now being maintained at other coal gasification facilities. This is accomplished by using an acid gas removal system followed by a Claus sulfur recovery plant and SCOT tail gas treatment system. This equipment is capable of providing an overall sulfur removal rate of 95 percent and is judged to represent BACT for the facility.

The nitrogen oxides emissions from the tail gas incinerators are due to thermal NOx which results from the high temperatures needed to treat the tail gases. As this is the case nitrogen oxides are formed as a result of controlling the other emissions such as SO_2. Based on this, the equipment itself is judged to represent BACT for NOx.

The applicant has not provided specific BACT emission levels for the steam boilers and diesel generators. For sulfur dioxide emissions BACT shall be represented by limiting fuel oil sulfur content to an average of 0.3% as was judged to represent BACT for the combined cycle facility on an annual basis. For nitrogen oxide emissions, typical BACT limitations would be 0.1 and 0.2 lb/MMBtu for the steam boilers when firing natural gas and diesel respectively. For the diesel generators BACT for NOx is typically represented by limiting emissions to 12.0 grams per horsepower hour. As this is the case, these emissions limitations in conjunction with a low operation frequency are judged to represent BACT for the Martin facility.

Fugitive Sources

The applicant has indicated that fugitive particulate emissions may result from the storage and handling of coal, limestone, slag, and sulfur. BACT for controlling these activities is proposed as follows:

- Minimize number of material transfer points
- Apply crusting agent application to inactive storage areas
- Enclose conveyors and transfer points
- Provide induced collection systems for dust
- Provide wet suppression systems (surfactant)
- Cover by-product storage areas (upon completion of cell)
- Handle and store sulfur in a molten or continuous crystalline state.

A review of the control strategy indicates that the applicant is taking all reasonable measures to minimize fugitive particulate emissions and is representative of BACT.

Environmental Impact Analysis

The predominant environmental impacts associated with this proposal are related to the use of SCR for NOx control. The use of SCR results in emissions of ammonia, which may increase with increasing levels of NOx control. In addition, some catalysts may contain substances which are listed as hazardous waste, thereby creating an additional environmental burden. Although the use of SCR does have some environmental impacts, the disadvantages may not outweigh the benefit which would be provided by reducing the proposed nitrogen oxide emissions by an additional 65 percent. However, the benefit of NOx control by using SCR is substantiated by the fact that nearly one half of all BACT determinations have established SCR as the control measure for nitrogen oxides over the last five years.

In addition to the criteria pollutants, the impacts of toxic pollutants associated with the combustion of natural gas, coal derived gas, and No. 2 fuel oil have been evaluated. Two of the toxic pollutants (mercury and beryllium) exceed PSD significant levels. Other toxics are expected to be emitted in minimal amounts, with the total emissions combined to be less that one ton per year.

Although the emissions of the toxic pollutants could be controlled by particulate control devices such as a baghouse or scrubber, the amount of emission reductions would not warrant the added expense. As this is the case, the Department does not believe that the BACT determination would be affected by the emissions of the toxic pollutants associated with the firing of natural gas, coal derived gas, or No. 2 fuel oil.

Potentially Sensitive Concerns

With regard to controlling NOx emissions with SCR the applicant has expressed the following technical concerns:

1. SCR has generally been limited to facilities which burn natural gas or small amounts of fuel oil . Catalyst contamination will result from sulfur for unlimited fuel oil and coal derived gas firing.

2. Continuous operation of SCR on large (>75 MW) gas turbines using distillate oil and coal derived gas has not been demonstrated: and therefore, technical, economic and environmental uncertainties would result.

BACT Determination by DER

Based on the information presented by the applicant and the studies conducted, the Department believes that the use of dry low NOx combustors together with No. 2 fuel oil firing limitations is justifiable as BACT. Although a review of the permitting activities for combined cycle proposals across the nation indicates that SCR has been required and most recently proposed for installations with a variety of operating conditions (i.e. natural gas, fuel oil), the addition of SCR on low NOx combustion turbines is judged to be prohibitively expensive. Technically, although the concerns expressed by the applicant were valid at one time, the most recent experiences indicate that these problems have been resolved through advances in catalysts and experiences gained through operation. In addition the concern for storing ammonia on site has in other cased been addressed through the use of aqueous rather than anhydrous ammonia.

However, from a cost standpoint, the incremental cost of controlling NOx from the already low NOx emitting turbines at $7,590 to $8,827/ton depending upon the mix of oil and gas firing, is judged to be unreasonable based on what has been concluded in other BACT determinations.

For sulfur dioxide BACT is represented by firing natural gas or No. 2 fuel oil with an average sulfur content not to exceed 0.3 percent. The emission limitations for PM, PM_{10}, CO and VOCs are based on previous BACT determinations for similar facilities, with the heavy metals beryllium and mercury being addressed through the particulate limitation and sulfuric acid mist being addressed through the sulfur dioxide limitation. For coal derived gas firing the economic evaluation for both NOx and CO control indicates that the use of SCR and oxidation catalysts appear to be reasonable based on other BACT determinations. It should be noted, however, that there are very few BACT determinations that have been completed for facilities of this type using coal gasification and the expense of using such controls could be greater for this type of fuel. As this is the case, it is recommended that BACT be reevaluated at the time that the applicant decides to proceed with the gasification phase of the project. The emission limits for the Martin project are thereby established as follows:

Pollutant			Emission Limitations[d]			
			Units 3 & 4		Units 5 & 6	
	Fuel	Basis	lb/hr/CT	TPY[a]	lb/hr/CT	TPY[a]
NOx	Gas	25 ppmvd @ 15% O_2	177	comb.}	177	comb.}
	Oil	65 ppmvd @ 15% O_2	461	tot. }3108	461	tot. }3108
	CG	42 ppmvd @ 15% O_2	392	6868	392	6868
VOC[b]	Gas	1.6 ppmvd	3	comb.}	3	comb.}
	Oil	6 ppmvd	11	tot. } 57	11	tot. } 57
	CG	9 ppmvd	21.4	375	21.4	375
CO	Gas	30 ppmvd	94.3	comb.}	94.3	comb.}
	Oil	33 ppmvd	105.8	tot. }871	105.8	tot. }871
	CG	33 ppmvd	134	2348	134	2348
PM/PM_{10}	Gas		18	comb.}	18	comb.}
	Oil		60.6	tot. }100	60.6	tot. }100
	CG		19	333	19	333

Pb	Gas	neg.	comb.}		neg.	comb.}	
	Oil	0.015	tot.}	0.015	0.015	tot.}	0.015
	CG	0.3		5.3	0.3		5.3
SO_2	Gas	91.5	comb.}		91.5	comb.}	
	Oil[c]	920	tot. }	568	920	tot. }	568
	CG	834		14612	834		14612

NOTES: a - Tons per year (TPY) emission limits listed for natural gas and oil combined aply as an emission cap based on limiting oil firing to an annual aggregate of 2,000 hours for the 4 CTs, with compliance to be demonstrated in annual operation reports.

b - Exclusive of background concentrations.

c - Sulfur dioxide emissions based on a maximum of 0.5 percent sulfur in oil for hourly emissions and an average sulfur content of 0.3 percent for annual emissions.

d - These limitations for Units 5 and 6 and coal gasification shall not be binding for subsequent BACT determinations.

Tail Gas Incinerators, Steam Boilers and Diesel Generators

Tail Gas Incinerators - BACT to be evaluated at coal gasification phase of the project.

Steam Boilers - Infrequent or emergency mode of operation. However, BACT for these facilities typically limits NOx emissions from boilers to 0.1 lb/MMBtu and 0.2 lb/MMBtu for natural gas and oil firing respectively. The proposed facility should meet these levels.

Diesel Generators - Infrequent or emergency mode of operation. However, BACT for these facilities typically limits NOx emissions from diesel generators by limiting emissions to at least 12.0 grams/hp-hr. The proposed facility should meet this level.

Sulfur Dioxide emissions limitations for the steam boilers and diesel generators in established by firing natural gas or limiting the No. 2 fuel oils sulfur content to 0.3% on an annual basis.

Material Handling and Storage

Fugitive Dust Source	Control Technology
Coal Unloading	Enclosed with Dry Collection System

Limestone Unloading	Wet Suppression System[1]
Conveyers and Transfer Points (Coal, Limestone, Slag)	Transfer points enclosed with Dry Collection System. Conveyers covered
Coal Storage (Inactive)	Crusting Agent Application (60% Control)
Coal Storage (Active)	Surfactant Application[1]
Coal Storage (Active and Reclaiming	Surfactant Application[1]
Limestone Storage	Crusting Agent Application[1]
Slag Transport to By-Product Storage Area	Paved Road Covered Conveyer (95% Control)
Slag By-Product Storage Area (Inactive)	Topsoil Covered and Seeded (100% Control)
Slag By-Product Storage Area (Active)	Compaction, Temporary Cover (Natural or Synthetic)
Sulfur Storage	Stored in molten state in tanks or in crystalline slab arrangement

1 - Undefined rate of fugitive dust control

B. Availability of Water

The primary source of water for the plant is surface water. Makeup water to the cooling reservoir is provided from the St. Lucie Canal. As needed, water is provided to replace net evaporation and seepage losses from the reservoir. The makeup water replacing water lost due to seepage is considered nonconsumptive use of water. The average makeup water required to replace the evaporation is estimated to be 32,000 acre-ft per year (19,750 gpm) with a maximum of 50,000 acre-ft per year (30,926 gpm). Consequently, average the total makeup water required from the St. Lucie Canal will be approximately 35,909 gpm (seepage plus net evaporation minus recycled minus input from plant process water).

Potable water is water taken from groundwater wells and treated to meet drinking water quality standards. Potable water will be used for drinking, sanitary, hygiene, and

Table 1. Martin Project Capital Costs And Cost Recovery For SCR

Cost Component	Costs ($)
Direct Capital Costs	
SCR Associated Equipment	6,476,200
Ammonia Storage Tank	290,100
HRSG Modification	1,782,300
Indirect Capital Costs	
Installation	3,609,800
Engineering, Erection Supervision, Start-up, and O&M Training	2,005,100
FPL Project Support	1,685,800
Ammonia Emergency Preparedness Program	406,100
Liability Insurance	37,100
AFUDC	4,766,100
Contingency	5,264,700
Total Capital Costs	26,323,400
Annualized Capital Costs	3,091,900
Recurring Capital Costs	
SCR Catalyst (Materials & Labor)	12,275,200
Contingency	3,068,800
Total Recurring Capital Costs	15,344,000
Annualized Recurring Capital Costs	6,170,100

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Table 2. Martin Project Annualized Costs For SCR[1]

Cost Component	Costs ($)
Direct Annual Costs	
Operating Personnel	276,600
Ammonia	273,500
Accident/Emergency Response Plan	14,100
Inventory Cost	238,200
Catalyst Disposal Cost	255,700
Contingency	299,700
Energy Costs	
Electrical	184,900
Heat Rate Penalty	1,350,300
MW Loss Penalty	340,300
Fuel Escalation Costs	1,423,000
Contingency	653,500
Total Direct Annual Costs	5,309,800
Indirect Annual Costs	
Overhead	396,400
Property Taxes and Insurance	683,300
Annualized Capital Costs	3,091,900
Recurring Capital Costs	6,170,100
Total Indirect Annual Costs	10,340,700
Total Annual Costs	15,651,500

[1]Based on 90% capacity factor on natural gas at ~~80%~~ 65% NO_x removal, and 10% capacity factor on oil at 65% NO_x removal. Gas emissions at 25 ppmvd, and oil emissions at 65 ppmvd (corrected to 15% oxygen).

Note: All calculations rounded off to the nearest $100.

Table 3. Martin Repowering Project Basis For Capital Costs and Cost Recovery For SCR (Page 1 of 2)

Cost Component	Basis for Cost
Direct Capital Costs	
SCR Associated Equipment	Vendor estimate (housing, NH_3 injection grid, controls, vaporizer, HRSG wash); from Steuler International Corp. (see Attachment A); 1990 cost of $6,395,000 escalated to 1993 (see Table 8); $3,260,000 catalyst housing and $3,135,000 for vaporizer and HRSG wash system.
Ammonia Storage Tank	Engineering estimate (two 18,000-gallon NH_3 tanks, concrete pit, piling, rock, pipe rock); from Armstrong Engineering Associates (Attachment B); 1990 cost of $286,000 escalated to 1993 (see Table 8); $146,832 for tanks and $139,200 for concrete works.
HRSG Modification	Vendor estimate (HRSG space increase about 20 feet); from Vogt; 1990 cost of $1,760,000 escalated to 1993 (see Table 8).
Indirect Capital Costs	
Installation	Engineering estimate; 1990 cost of $3,564,000 escalated to 1993 (see Table 8); this cost is 42.23% of SCR Associated Equipment, Ammonia Storage Tank and HRSG Modification; EPA,1990 (OAQPS Control Cost Manual, EPA 450/3-90-006) suggests 30 to 72 % (see Attachment C).
Engineering, Erection Supervision Startup and O&M Training	Engineering estimate; 1990 cost of $1,980,000 escalated to 1993 (see Table 8); this cost is 10.3% of equipment costs; EPA (1990) suggests 10 to 20% of equipment costs (see Attachment C).
FPL Project Support	FPL estimate; 1990 cost of $1,664,700 escalated to 1993 (see Table 8); this cost is 8.7% of equipment costs; EPA (1990) suggests 15 to 30% of equipment costs for construction and field expenses and contractor fees (see Attachment C).
Ammonia Emergency Preparedness Program	Engineering estimate (SARA Title III requirements); from Ebasco (see Attachment D); 1990 cost of $401,000 escalated to 1993 (see Table 8).
Liability Insurance	Based on capital costs; 1990 cost of $36,600 escalated to 1993 (see Table 8).
AFUDC	Allowance for funds used during construction (allowed by PSC 25-6.0141, F.A.C.); based on cash flows in Table 6 and calculated using an incremental cost of capital of 12.11%; cash flow in a given year is averaged (divided by 2) to obtain costs; this cost is similar to interest during construction which is allowed for in EPA (1990).

Table 3. Martin Repowering Project Basis For Capital Costs and Cost Recovery For SCR (Page 2 of 2)

Cost Component	Basis for Cost
Contingency	25 percent of direct and indirect capital costs and AFUDC; based on order of magnitude accuracy in estimating other costs; FPL estimating procedures use this level of contingency for order of magnitude estimates; this estimate is appropriate based on the requirement of meeting a guaranteed emission limit (see Attachment E).
Total Capital Costs	Sum of direct and indirect cost, AFUDC and contingency
Annualized Capital Costs	Capital recovery of 10% over 20 years; capital recovery factor is 0.1174.
Recurring Capital Costs	
SCR Catalyst (Materials and Labor)	Vendor estimate (Zeolite); based on 1990 catalyst cost of $10,740,000 (see Attachment A) and installation labor of catalyst modules of $16,896 (96 hours x 8 persons x $22/hour); this cost escalated to 1993 using CPI forecast in Table 9 of 14.11%.
Contingency	25 percent of SCR catalyst; adjusted for order of magnitude cost.
Total Recurring Capital Costs	Sum of SCR catalyst and contingency
Annualized Recurring Capital Costs	Capital recovery of 10% over 3 years; capital recovery factor of 0.4021

Table 4. Martin Repowering Project Basis For Annualized Cost[a]

Cost Component	Basis for Cost
Direct Capital Costs	
Operating Personnel	One person for 3.5 shifts/day, $22/hour; 365 days per year ($22/hour x 365 days x 8 hr/day x 3.5 shifts day); escalated to 1993 based on CPI (see Table 10)
Ammonia	$300/ton; NH_3:NO_x = 1:1 volume; verbal quote based on delivery to plant (NO_x tons removed x 300 x 17/46); escalated to 1993 based on CPI (see Table 10)
Accident/Emergency Response Plan	Annual calibration, training, and inspection of ammonia system; (see Attachment D); escalated to 1993 based on CPI (see Table 10)
Inventory Costs	Spare catalyst for 1/3 of total catalyst costs for one HRSG times 22.22% (see Attachment F); escalated to 1993 based on CPI (see Table 10)
Catalyst Disposal Costs	Annual costs for disposal of catalyst; vendor estimate of 5% of catalyst costs divided by 3 (15,344,032 x 0.05 x 1/3)
Contingency	25 percent of operating personnel, ammonia, accident/emergency response plans and inventory costs; order of magnitude estimate
Energy Costs	
Electrical	500 kW/hr; varies with capacity factor; (500 kW/hr x 8,760 hr x $0.028/kWH); escalated to 1993 based on oil escalation factor to 1.3850 (1993 oil cost of $3.85/10⁶ Btu divided by 1990 cost of $2.95/10⁶ Btu.
Heat Rate Penalty	5" pressure loss; reduction of heat rate of 0.64 percent; varies with capacity factor; see Attachment G for pressure drop curves (67 Btu/KWH x 630.8 MW x 1,000 kW/MW x $2.62/10⁶ Btu x 8,760 hr/yr); escalated to 1993 based on gas escalation factor of 1.3855 (1993 gas cost of $3.63/10⁶ Btu divided by 1990 cost of $2.62/10⁶ Btu)
MW Loss Penalty	4.037 mw lost; base load capacity replacement costs of $84,296.4/MW based on 1993 IGCC costs
Fuel Escalation	Real cost increase of fuel.
Contingency	25 percent of heat rate, mw loss and fuel escalation
Total Direct Annual Costs	Sum of direct annual cost components

ble 4. Martin Repowering Project Basis For Annualized Cost[a]

Cost Component	Basis for Cost
ndirect Annual Costs	
Overhead	Based on EPA OAQPS Control Cost Manual [0.6 x (Ammonia cost + 1.15 labor O&M) + 0.15 x labor O&M]
Property Taxes and Insurance	1.64 percent of capital costs; (see attachment H)
Annualized Capital Cost	From capital cost summary
Recurring Capital Cost	From capital cost summary
tal Indirect Annual Costs	
tal Annual Costs	

Based on 90 percent capacity factor on natural gas at 65 percent NO_x removal and 10 percent capacity factor on oil at 65 percent NO_x removal.

Table 5. Cost Effectiveness of SCR[1] (Oil-Based Catalyst) on the Martin Project as a Function of Capacity Factoring

	Capacity Factor (Percent)								
Oil	0	5	10	15	20	25	30	35	40
Gas	100	95	90	85	80	75	70	65	65
Total	100	100	100	100	100	100	100	100	100
Cost Effectiveness ($/ton)	8,827	8,160	7,588	7,094	6,663	6,282	5,945	5,643	5,371

[1]Gas - 25 to 9 ppm (65% reduction in NO_x)
Oil - 65 ppm to 25 ppm (65% reduction in NO_x)

Costs adjusted for tons NO_x removed using the following equation:

(2,713.8 TPY gas NO_x x 0.65 x CF_G) + (7,305.8 TPY oil NO_x x 0.65 x CF_{OIL}) - tons NO_x removed

where: 2,713.8 TPY @ 25 ppm (corrected) and 75°F on gas firing
7,305.8 TPY @ 65 ppm (corrected) and 75°F on oil firing
0.65 is tons removed
CF_G - Capacity Factor Gas
CF_{OIL} - Capacity Factor Oil

United States Department of the Interior

OFFICE OF THE SECRETARY
WASHINGTON, D.C. 20240

ER 91/9

MAR 5 1991

Heinz J. Mueller, Chief
Environmental Policy Section
Federal Activities Branch
Environmental Protection Agency, Region IV
345 Courtland Street, N.E.
Atlanta, Georgia 30365

Dear Mr. Mueller:

The Department of the Interior has reviewed the draft environmental impact statement for the Martin Coal Gasification/Combined Cycle Project, Martin County, Florida, and has the following comments.

Air Quality

On page 1-8 and in other subsequent sections such as noted on page 2-5, the draft statement indicates this project will require a Prevention of Significant Deterioration (PSD) permit under the Clean Air Act, as amended. We were unable to find the identification of the Class I area for which the PSD analysis would be done in Chapters 1, 2, or 3. Likewise, the maps included in the text do not identify the Class I area. The discussion about adverse impacts to air quality on page 5-19 indicates the lack of impacts to Everglades National Park. We believe the introductory sections should identify and very briefly describe the Class I area that triggered the PSD analysis for this project. The Class I area should also be shown on a map in the final statement.

Fish and Wildlife Resources

We agree that the mitigation plan, included as Appendix P of this document, will adequately compensate for wetland losses associated with this project. Our Fish and Wildlife Service advises that they are pleased with the endangered wood stork enhancement area as shown on page P-44. They recommend the National Pollution Discharge Elimination System permit be conditioned to further limit the discharge of cadmium to the receiving waters of the St. Lucie Canal.

If there are further questions on endangered species matters, please contact the Field Supervisor, P.O. Box 2676, 1360 U.S. 1, Suite 5, Vero Beach, Florida 32960, telephone (407) 562-3909.

Water Budget

The water budget analysis in the document should be further expanded. To simply state that an additional 80 cfs per day loss to the system is unmeasurable, does not consider the cumulative impacts of this 19,850-acre feet per year withdrawal along with many such withdrawals throughout the Central and Southern Florida Flood Control Project. A water withdrawal plan which calls for the withdrawal of water only during "surplus" periods should be evaluated and presented in the final statement.

Fish and Wildlife Coordination Act Comments

These comments do not preclude separate evaluation and comments by our U.S. Fish and Wildlife Service pursuant to the Fish and Wildlife Coordination Act, since project implementation requires a Section 404 permit from the U.S. Army Corps of Engineers. We understand the permit application will be accompanied by a mitigation plan for wetland losses.

We hope these comments will be helpful to you in the preparation of a final statement for this project.

Sincerely,

Jonathan P. Deason
Director
Office of Environmental Affairs

EBASCO

May 10, 1991
ENV/FPL/170/91-023

Mr. Peter Cunningham, ESQ
Hopping Boyd Green & Sams
123 South Calhoun Street
Post Office Box 6526
Tallahassee, FL 32314

Dear Mr. Roberts:

Subject: FPL/MARTIN
PSD CLASS I LONG RANGE TRANSPORT ISSUES

Attached for your information and use is a discussion of PSD Class I Long Range Transport Issues. Should you have any questions, please feel free to contact me at (404) 662-2377.

Very truly yours,

Douglas J. Fulle
Consulting Scientist

DJF:trh
Attachment

cc: W. Ondler (FPL)
J. Jackson
M. Mitckes
File 158.236

TRH/3001

FPL MARTIN

PSD Class I - Long Range Transport Issues

ISCST MODEL

The Industrial Source Complex Short Term (ISCST) Model used for air quality impact assessment for the FPL Martin project is EPA's most widely used steady-state Gaussian plume model. As stated in EPA's Guideline On Air Quality Models document (which basically serves as the definitive guide in any modeling determination), "Gaussian models are not considered applicable for regulatory use with receptors beyond a nominal distance of 50 km."

There are several very significant reasons for this limitation. In most cases, maximum impact at long distances from an elevated source will occur under E and F stability categories. Stability category is a measurement of vertical mixing in the atmosphere and these two categories represent stable conditions typical of little cloud cover and low wind speeds existing only at night. For receptors located in the range of 145 km from the emission source, travel time to the receptors at low wind speeds will be on the order of 20 hours. However, as previously indicated, the stability conditions associated with these light wind speeds cannot persist this long. Additionally, the Gaussian distribution assumes uniform conditions in the vertical direction. In reality, the lapse rate changes with elevation as does the wind speed. Modeling error or uncertainty introduced by this assumption is augmented with a Gaussian model implemented for mesoscale (50-250 km) receptors.

Yet another area of potential error for mesoscale range modeling is the ISCST model's inability to account for pollutant removal from the atmosphere by chemical reaction, wet and dry deposition, etc. The model does contain a dry deposition option, but this feature is considered of minimal accuracy and requires input data seldom available and is, therefore, not generally implemented. Other more exotic considerations, such as the Coriolis effect which will tilt the plume to the right in the northern hemisphere, become significant for transport on meso and long-range transport distances.

As a bottom line, the present prevailing regulatory philosophy toward modeling receptors at distances greater than 50 km is best summarized in the Guideline on Air Quality Models Section 7.2.6 which is attached. This is a "draft" since the Guideline is presently undergoing a revision.

MESOSCALE MODELS

Although not classified as "regulatory-preferred" models, computer models are presently available for mesoscale modeling exercises. The most commonly utilized and readily available of these models is probably EPA's MESOPUFF II. This model, which has not been extensively verified by tracer field studies, is a regional-scale, Lagrangian, variable-trajectory, puff superposition model. The model incorporates removal and transformation mechanisms and utilizes gridded wind speed and direction data (at two levels - at and above the atmospheric boundary layer) to attempt to minimize several of the debilities previously indicated for Gaussian models in the mesoscale modeling regime. The model also requires extensive gridded precipitation data as well as land use information across the computational grid. Preparation of this input data for model execution is quite rigorous and nontrivial.

7.2.6 Long Range Transport (LRT) (beyond 50 km)

Section 165(e) of the Clean Air Act requires that suspected significant impacts on PSD Class I areas be determined. However, 50 km is the useful distance to which most Gaussian models are considered accurate for setting emission limits. Since in many cases PSD analyses may show that Class I areas may be threatened at distances greater than 50 km from new sources, some procedure is needed to (1) determine if a significant impact will occur, and (2) identify the model to be used in setting an emission limit if the Class I increments are threatened (models for this purpose should be approved for use on a case-by-case basis as required in Section 3.2). This procedure and the models selected for use should be determined in consultation with the EPA Regional Office and the appropriate Federal Land Manager (FLM). While the ultimate decision on whether a Class I area is adversely affected is the responsibility of the permitting authority, the FLM has an affirmative responsibility to protect air quality related values that may be affected.

If LRT is determined to be important, then estimates utilizing an appropriate refined model for receptors at distances greater than 50 km should be obtained. MESOPUFF-II, listed in Appendix B, may be applied on a case-by-case basis when LRT estimates are needed. Additional information on applying this model is contained in the EPA document "A Modeling Protocol For Applying MESOPUFF-II to Long-Range Problems."[101]

PRIORITY ITEM

Department of Environmental Regulation

Routing and Transmittal Slip

To: (Name, Office, Location)	Date
1. Buck ~~Oven~~	1/28
2. Dan Thompson	
3. Carol Browner	
4. Gary Smallridge, OGC	1-31-91

Remarks:

RE: Power Plant Siting Board on February 12, 1991

Attached are documents pertaining to FPL's Martin Coal Gasification/Combined Cycle Project which is to be considered by the Cabinet Aides on February 6th and by the Governor and Cabinet (sitting as the Power Plant Siting Board) on February 12th.

RECOMMENDATION:

Secretary Browner should initial next to her name on the first attachment.

Attachments:
1. Ltr to Siting Board
2. Agenda
3. Proposed Final Order
4. Final Order

JAN 28 1991

Must File Friday 2/1 ~~[illegible]~~ approve before then to make necessary comments

From: Gary Smallridge

Date 1-25-91

Phone 8-9730, Ext 39

TAB 1

4. As part of the conditions accepted by the Permittee for issuance of a permit for Unit 9, the Permittee agreed to burn natural gas and not fuel oil in Units 6 through 8.

5. The permits pertaining to Units 6 through 9 are now being reconsidered by the Department on request of the Permittee. That reconsideration is addressing, among other matters, the need for additional air pollution control equipment on Unit 9 so that Units 6 through 8 may continue to use oil. However, at this time a decision has not been made by the Department as to the specific requirements that the Permittee must meet.

6. The public's health, safety and welfare will be placed in immediate danger if the Permittee is unable to provide electric to its customers; to operate traffic signals; and to effectively provide police and fire protection.

CONCLUSIONS OF LAW

1. The conditions have been met which satisfy the requirements of Section 120.59(3).

2. Extraordinary action is necessary to prevent unnecessary hardship to the public.

3. Temporary relief will not result in a violation of federal ambient air quality standards.

4. A final order of this nature is appealable or enjoinable from the date it is rendered.

Based on the above findings of fact and conclusions of law,

IT IS ORDERED THAT:

The Permittee is authorized to burn fuel oil in Units 6 through 8 if, and only if, natural gas is totally unavailable (?) to the Permittee at any price during some portion of the period of ????????????? unless sooner rescinded. The Permittee must comply with all other permit conditions pertaining to Units 6 through 9. Further, the Permittee shall report to the Department's Bureau of Air Regulation by February 28, 1991, the amount of fuel oil used during the aforementioned period in Units 6 through 8, and document the unavailability of natural gas during the aforementioned period.

DONE AND ENTERED this ________ day of May, 1991, in Tallahassee, Florida.

STATE OF FLORIDA DEPARTMENT
OF ENVIRONMENTAL REGULATION

____
CAROL M. BROWNER
SECRETARY

FILING AND ACKNOWLEDGEMENT:
Filed on this date, pursuant to Section 120.52(11), Florida Statutes (1989), with the designated Department Clerk, receipt of which is hereby acknowledged.

________________ ________
Clerk Date

TAB 2

TAB 3

TAB 4

TAB 5

TAB 6

TAB 7

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY

REGION IV

345 COURTLAND STREET, N.E.
ATLANTA, GEORGIA 30365

RECEIVED
FEB 7 1990
DER-BAQM

FEB 2 1990

4APTMD-APB-cdw

Mr. Hamilton S. Oven, Jr., P.E.
Administrator, Office of Siting Coordination
Division of Air Resource Management
Florida Department of Environmental Regulation
Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

RE: Florida Power and Light Company, Martin Plant

Dear Mr. Oven:

This is to acknowledge receipt of the prevention of significant deterioration (PSD) application and site certification application for the above referenced source by letter dated January 5, 1990. We have reviewed the package as requested and have the following questions and comments.

General

1. Did FP&L request a formal consultation and receive a biological opinion from the U.S. Fish and Wildlife Service?

BACT ANALYSES

Combined cycle combustion turbines (CT): The major points of concern are in regards to the BACT determinations for NO_x and SO_2. The applicant proposed steam injection as the control technology for NO_x, rejecting the use of Selective Catalytic Reduction (SCR). The basis for rejection, according to the applicant, was significant adverse energy, economic and environmental impacts.

The major environmental concerns raised by the applicant appear to be the possibility of ammonia slip, the possibility of the formation of SO_3 and ammonium bisulfate, the deactivation of the catalyst due to plugging from sulfur oxides, and the disposal problems related to changing out any vanadium pentoxide catalysts - a hazardous waste under RCRA regulations. What the applicant fails to point out, however, is that there are SCR systems on the market which do not use vanadium pentoxide, or any other metal, as a catalyst. For example, one SCR system makes use of a ceramic molecular sieve to promote the reaction. The ceramic catalyst system has been applied on gas turbines and diesel engines. The system does not promote the conversion of SO_2 to SO_3 and has virtually no catalyst poisoning, plugging or masking problems. The ammonia slip is also limited. In addition, the catalyst is not considered a hazardous waste.

The energy impacts described by the applicant are not those which would put a strain on the local energy supply or which appear to be significantly different than typical plant energy usage.

The economic impacts provided by the applicant consist of $6,976 per ton of NO_x removed. Apparently the number is derived from dividing the installed equipment costs by the incremental reduction from water injection to SCR. This analysis does not provide the total cost per ton of NO_x removed.

In regards to NO_x control it should also be noted that turbines are on the market which are capable of achieving 25 ppm of NO_x with steam injection. In any case, the justifications presented by the applicant for rejecting SCR as a control technology do not appear to be convincing. There are SCR technologies on the market which do not have a hazardous waste by-product. SCR has been applied in the United States on gas and fuel oil fired turbines and diesel engines. It would seem, then, that technical feasibility is not an issue.

The control of SO_2 from the CT groups was proposed to be the use of natural gas, low sulfur fuel oil, and low sulfur coal gas. The applicant proposed that natural gas be the primary fuel with fuel oil to be used as a backup. In addition, the applicant desired the flexibility to use coal derived gas as economics permit. The percent sulfur content proposed was 0.5% S in the fuel oil and 0.8% S in the coal gas. It should be noted that the typical turbine firing fuel oil listed in the BACT/LAER Clearinghouse was limited to a sulfur content of 0.3% or less along with a usage capacity of 25%. In fact, the Chesterfield facility listed by the applicant was limited to a sulfur content of less than 0.3% for coal derived gas. It is apparent that the sulfur contents proposed by the applicant do not represent BACT. In addition, any permit issued for the source should contain a provision limiting the use of fuel oil to an emergency fuel as defined in the NSPS.

<u>Modelling/Monitoring</u>

1. No modelling input/output tables were included.

2. No explanation was given as to why on-site meteorology was not used in modelling.

3. The monitoring report indicated that the NAAQS for particulate matter was 260 ug/m^3 and 75 ug/m^3 for 24 hour and annual averages respectively. As you know, the PM_{10} NAAQS are 150 ug/m^3 and 50 ug/m^3 for the 24 hour and annual averages, respectively.

Thank you for the opportunity to review these packages. If you have any questions regarding these comments, please contact Gregg Worley or Lew Nagler (modelling) of my staff at (404) 347-2864.

Sincerely yours,

Bruce P. Miller

Bruce P. Miller, Chief
Air Programs Branch
Air, Pesticides, and Toxics
Management Division

cc: Clair Fancy, FDER
Barry Andrews, FDER

For Routing To Other Than The Addressee

To: Patti Location:
To: Location:
To: Location:
From: BO Date:

State of Florida
DEPARTMENT OF ENVIRONMENTAL REGULATION

Interoffice Memorandum

F.Y.I.

TO: Power Plant Siting Review Personnel

FROM: Buck Oven HBO

DATE: January 2, 1990

SUBJECT: FPL - Power Plant Siting Application
PA 89-27, Module No. 8183

Attached please find a copy of the above referenced application for the Martin Coal Gasification Combined Cycle Project as submitted by FPL on December 29. Please review the application for completeness by January 12, 1990, and submit any requests for additional data to me. For those of you in Tallahassee, please attend a brief meeting with me on this project on January 12th at 9:00 a.m. in room 338-D. FPL is planning to visit the Department on February 14th at 10:30 p.m. in 338-D to discuss this project with us. Please submit any requests for curing insufficient information for this project to me by February 10, 1990.

Attachment