FPL

Florida Power & Light Company, P.O. Box 088801, North Palm Beach, FL 33408-8801

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FEB 4 1993

Division of Air
Resources Management

February 3, 1993

Clair Fancy, Bureau Chief
Bureau of Air Regulation
State of Florida
Department of Environmental Regulation
2600 Blair Stone Road
Tallahassee, FL 32399

RE: Florida Power & Light Company
Applications for NO_x RACT Determination

Dear Mr. Fancy:

Enclosed please find the original and three copies of Applications for Determination of Reasonably Available Control Technology (RACT) for each of FPL's plants in the tri-county ozone nonattainment area (Dade, Broward and Palm Beach) submitted pursuant to Rule 17-296.570, F.A.C. The five plants addressed in the enclosed applications are:

Plant	County
Port Everglades	Broward
Lauderdale (turbines)	Broward
Cutler	Dade
Turkey Point	Dade
Riviera	Palm Beach

Also enclosed is a copy of the Technical Support Document entitled "Reasonably Available Control Technology (RACT) Assessment of Florida Power & Light Company's Facilities Located in the Dade, Broward and Palm Beach Ozone Nonattainment Area".

Please feel free to call me at (407) 625-7607 if you have any questions.

Sincerely,

Lynn Smallridge 625-7648

561-625-7637

Mary Archer

Elsa A. Bishop
Elsa A. Bishop
Supervisor
Air Permitting & Programs
Florida Power & Light Company

/gbb

Enclosures

cc: Preston Lewis
John Reynolds
Stephanie Brooks
Claire Lardner, Esquire

FLORIDA POWER & LIGHT COMPANY

PROPOSED RACT FOR AIR POLLUTION SOURCES

1. PORT EVERGLADES POWER PLANT 1/2/3/4 GT 1-12

2. LAUDERDALE POWER PLANT GT 1-24
   UNITS 4 & 5 PERMITTED UNDER POWER PLANT SITING

3. CUTLER POWER PLANT 5/6

4. TURKEY POINT POWER PLANT 1/2

5. RIVIERA POWER PLANT 3/4

Section # 1

APPLICATION FOR PERMIT
PROPOSED RACT FOR AIR POLLUTION SOURCES

PORT EVERGLADES POWER PLANT

1. Application - Unit No. 1, Oil & Gas Fired, 200 MW Class (240 MW Gross Capacity)

2. Application - Unit No. 2, Oil & Gas Fired, 200 MW Class (240 MW Gross Capacity)

3. Application - Unit No. 3, Oil & Gas Fired, 400 MW Class (440 MW Gross Capacity)

4. Application - Unit No. 4, Oil & Gas Fired, 400 MW Class (440 MW Gross Capacity)

5. Application - Gas Turbine Units 1-12, 486 MW Gross Winter Capacity

6. Proposed Reasonably Available Control Technology (RACT) for Florida Power & Light Company (FPL) Port Everglades Plant

Florida Department of Environmental Regulation

APPLICATION FOR PERMIT OF
PROPOSED RACT FOR AIR POLLUTION SOURCE(s)

If major alterations have occurred, the applicant should complete the Standard Air Permit Application Form.

Source Type: Fossil Fuel Steam Generator   Renewal of DER Permit No. AO-06-143214

Company Name: Florida Power & Light Company County: Broward

Identify the specific emission point source(s) addressed in this application (i.e., Lime Kiln No. 4 with Venturi Scrubber; Peaking Unit No. 2, Gas Fired):

Port Everglades Power Plant, Unit No. 1, Oil & Gas Fired, 200 MW Class (240 MW Gross Capacity)

Source Location: Street: 8100 Eisenhower Blvd.   City: Ft. Lauderdale

UTM: East 587.4 km Zone 17   North 2885.2 km

Latitude: 26° 05' 08"N   Longitude: 80° 07' 31"W

1. Attach a check made payable to the Department f Environmental Regulation in accordance with operation permit fee schedule set forth in Florida Administrative Code Rule 17-4.05.

2. Have there been any alterations to the plant since last permitted? [ ] Yes [X] No If minor alterations have occurred, describe on a separate sheet and attach.

3. Attach the last compliance test report required per permit conditions if not submitted previously. **All compliance test reports have been submitted**

4. Have previous permit conditions been adhered to? [X] Yes [ ] No If no, explain on a separate sheet and attach. **Except as previously reported.**

5. Has there been any malfunction of the pollution control equipment during tenure of current permit? [ ] Yes [X] No If yes, and not previously reported, give brief details and what action was taken on a separate sheet and attach.

6. Has the pollution control equipment been maintained to preserve the collection efficiency last permitted by the Department? [X] Yes [ ] No

7. Has the annual operating report for the last calendar year been submitted? [X] Yes [ ] No If no, please attach.

8. Please provide the following information if applicable:

A. Raw Materials and Chemical Used in Your Process:

Description	Contaminant Type	%Wt	Utilization Rate lbs/hr
MgO or $Mg(OH)_2$ Additive	Particulate	100	90 lb/day estimated average for 1991
Evaporation of boiler cleaning water with approximately 3% of monoammonium citrate solution	Particulate	100	Approximately 40,000 gallons of water every 3 year

B. Product Weight (lbs/hr): Not applicable

C. Fuels: In order to improve start-up combustion, small amounts of light oil (No. 2 fuel oil), natural gas if available, or propane gas, are sometimes fired to preheat the boiler prior to ignition of residual fuel oil. Very small quantities of on-specification used oil, entirely from FPL operations, may be consumed while burning residual oil.

Type (Be Specific)	Consumption* Avg/hr*	Max/hr**	Maximum Heat Input (MMBTU/hr)
Residual Fuel Oil	Variable	377	2300
Natural Gas	Variable	2.4	2400

D. Potential Equipment Operating Time Up To: hrs/day 24; days/wk 7; wks/yr 52; hrs/yr (power plants only); 6589 hours of operation during 1992. More operating time is typical when ambient temperature is either unusually high or low, or during other unusual system demands.

The undersigned owner or authorized representative*** of **Florida Power & Light Company** is fully aware that the statements made in this application for a renewal of a permit to operate an air pollution source are true, correct and complete to the best of his knowledge and belief. Further, the undersigned agrees to maintain and operate the pollution source and pollution control facilities in such a manner as to comply with the provisions of Chapter 403, Florida Statutes, and all the rules and regulations of the Department. He also understands that a permit, if granted by the Department, will be non-transferable and he will promptly notify the Department upon sale or legal transfer of the permitted facility. **This certification pertains solely to air pollution related requirements.**

Elsa A. Bishop

Signature, Owner or Authorized Representative
(Notarization is mandatory)

E. A. Bishop, Supervisor
Air Permitting and Programs
Typed Name and Title

P. O. Box 088801
Address

North Palm Beach
City

Florida 33408-8801
State Zip

2/1/93
Date

(407) 625-7607
Telephone No.

*During actual time of operation.
**Units: Natural Gas-MMCF/hr; Fuel Oils-barrels/hr; Coal-
***Attach letter of authorization if not previsouly submitted.

Florida Department of Environmental Regulation

APPLICATION FOR PERMIT OF
PROPOSED RACT FOR AIR POLLUTION SOURCE(s)

If major alterations have occurred, the applicant should complete the Standard Air Permit Application Form.

Source Type: Fossil Fuel Steam Generator Renewal of DER Permit No. AO-06-143215

Company Name: Florida Power & Light Company County: Broward

Identify the specific emission point source(s) addressed in this application (i.e., Lime Kiln No. 4 with Venturi Scrubber; Peaking Unit No. 2, Gas Fired):

Port Everglades Power Plant, Unit No. 2, Oil & Gas Fired, 200 MW Class (240 MW Gross Capacity)

Source Location: Street: 8100 Eisenhower Blvd. City: Ft. Lauderdale

UTM: East 587.4 km Zone 17 North 2885.2 km

Latitude: 26° 05' 08"N Longitude: 80° 07' 31"W

1. Attach a check made payable to the Department of Environmental Regulation in accordance with operation permit fee schedule set forth in Florida Administrative Code Rule 17-4.05.

2. Have there been any alterations to the plant since last permitted? [ ] Yes [X] No If minor alterations have occurred, describe on a separate sheet and attach.

3. Attach the last compliance test report required per permit conditions if not submitted previously. **All compliance test reports have been submitted**

4. Have previous permit conditions been adhered to? [X] Yes [ ] No If no, explain on a separate sheet and attach. **Except as previously reported.**

5. Has there been any malfunction of the pollution control equipment during tenure of current permit? [ ] Yes [X] No If yes, and not previously reported, give brief details and what action was taken on a separate sheet and attach.

6. Has the pollution control equipment been maintained to preserve the collection efficiency last permitted by the Department? [X] Yes [ ] No

7. Has the annual operating report for the last calendar year been submitted? [X] Yes [ ] No If no, please attach.

8. Please provide the following information if applicable:

A. Raw Materials and Chemical Used in Your Process:

Description	Contaminant Type	%Wt	Utilization Rate lbs/hr
MgO or $Mg(OH)_2$ Additive	Particulate	100	90 lb/day estimated average for 1991
Evaporation of boiler cleaning water with approximately 3% of monoammonium citrate solution	Particulate	100	Approximately 40,000 gallons of water every 3 year

B. Product Weight (lbs/hr): **Not applicable**

C. Fuels: In order to improve start-up combustion, small amounts of light oil (No. 2 fuel oil), natural gas if available, or propane gas, are sometimes fired to preheat the boiler prior to ignition of residual fuel oil. Very small quantities of on-specification used oil, entirely from FPL operations, may be consumed while burning residual oil.

Type (Be Specific)	Consumption* Avg/hr*	Max/hr**	Maximum Heat Input(MMBTU/hr)
Residual Fuel Oil	Variable	377	2300
Natural Gas	Variable	2.4	2400

D. Potential Equipment Operating Time Up To: hrs/day 24; days/wk 7; wks/yr 52; hrs/yr (power plants only); 6340 hours of operation during 1992. More operating time is typical when ambient temperature is either unusually high or low, or during other unusual system demands.

The undersigned owner or authorized representative*** of **Florida Power & Light Company** is fully aware that the statements made in this application for a renewal of a permit to operate an air pollution source are true, correct and complete to the best of his knowledge and belief. Further, the undersigned agrees to maintain and operate the pollution source and pollution control facilities in such a manner as to comply with the provisions of Chapter 403, Florida Statutes, and all the rules and regulations of the Department. He also understands that a permit, if granted by the Department, will be non-transferable and he will promptly notify the Department upon sale or legal transfer of the permitted facility. **This certification pertains solely to air pollution related requirements.**

Elsa A. Bishop
Signature, Owner or Authorized Representative
(Notarization is mandatory)

E. A. Bishop, Supervisor
Air Permitting and Programs
Typed Name and Title

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2/1/93

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*During actual time of operation.
**Units: Natural Gas-MMCF/hr; Fuel Oils-barrels/hr; Coal-
***Attach letter of authorization if not previsouly submitted.

Florida Department of Environmental Regulation

APPLICATION FOR PERMIT OF
PROPOSED RACT FOR AIR POLLUTION SOURCE(s)

If major alterations have occurred, the applicant should complete the Standard Air Permit Application Form.

Source Type: Fossil Fuel Steam Generator Renewal of DER Permit No. AO-06-143217

Company Name: Florida Power & Light Company County: Broward

Identify the specific emission point source(s) addressed in this application (i.e., Lime Kiln No. 4 with Venturi Scrubber; Peaking Unit No. 2, Gas Fired):

Port Everglades Power Plant, Unit No. 3, Oil & Gas Fired, 400 MW Class (440 MW Gross Capacity)

Source Location: Street: 8100 Eisenhower Blvd. City: Ft. Lauderdale

UTM: East 587.4 km Zone 17 North 2885.2 km

Latitude: 26° 05' 08"N Longitude: 80° 07' 31"W

1. Attach a check made payable to the Department of Environmental Regulation in accordance with operation permit fee schedule set forth in Florida Administrative Code Rule 17-4.05.

2. Have there been any alterations to the plant since last permitted? [X] Yes [ ] No If minor alterations have occurred, describe on a separate sheet and attach. **As agreed to in connection with the Lauderdale Repowering Project, and as previously reported to DER, low NOx burners were installed. Boiler tubing was replaced to bring operating conditions back to original design.**

3. Attach the last compliance test report required per permit conditions if not submitted previously. **All compliance test reports have been submitted**

4. Have previous permit conditions been adhered to? [X] Yes [ ] No If no, explain on a separate sheet and attach. **Except as previously reported.**

5. Has there been any malfunction of the pollution control equipment during tenure of current permit? [ ] Yes [X] No If yes, and not previously reported, give brief details and what action was taken on a separate sheet and attach.

6. Has the pollution control equipment been maintained to preserve the collection efficiency last permitted by the Department? [X] Yes [ ] No

7. Has the annual operating report for the last calendar year been submitted? [X] Yes [ ] No If no, please attach.

8. Please provide the following information if applicable:

A. Raw Materials and Chemical Used in Your Process:

Description	Contaminant Type	%Wt	Utilization Rate lbs/hr
MgO or $Mg(OH)_2$ Additive	Particulate	100	180 lb/day estimated average for 1991
Evaporation of boiler cleaning water with approximately 3% of monoammonium citrate solution	Particulate	100	Approximately 75,000 gallons of water every 3 year

B. Product Weight (lbs/hr): **Not applicable**

C. Fuels: In order to improve start-up combustion, small amounts of light oil (No. 2 fuel oil), natural gas if available, or propane gas, are sometimes fired to preheat the boiler prior to ignition of residual fuel oil. Very small quantities of on-specification used oil, entirely from FPL operations, may be consumed while burning residual oil.

Type (Be Specific)	Consumption* Avg/hr*	Max/hr**	Maximum Heat Input (MMBTU/hr)
Residual Fuel Oil No. 6	Variable	631	3850
Natural Gas	Variable	4.02	4025

D. Potential Equipment Operating Time Up To: hrs/day 24; days/wk 7; wks/yr 52; hrs/yr (power plants only); 7085 hours of operation during 1992 More operating time is typical when ambient temperature is either unusually high or low, or during other unusual system demands.

The undersigned owner or authorized representative*** of **Florida Power & Light Company** is fully aware that the statements made in this application for a renewal of a permit to operate an air pollution source are true, correct and complete to the best of his knowledge and belief. Further, the undersigned agrees to maintain and operate the pollution source and pollution control facilities in such a manner as to comply with the provisions of Chapter 403, Florida Statutes, and all the rules and regulations of the Department. He also understands that a permit, if granted by the Department, will be non-transferable and he will promptly notify the Department upon sale or legal transfer of the permitted facility. **This certification pertains solely to air pollution related requirements.**

*During actual time of operation.
**Units: Natural Gas-MMCF/hr; Fuel Oils-barrels/hr; Coal-
***Attach letter of authorization if not previsouly submitted.

Elsa A. Bishop
Signature, Owner or Authorized Representative
(Notarization is mandatory)

E. A. Bishop, Supervisor
Air Permitting and Programs
Typed Name and Title

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State Zip

2/1/93
Date

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Telephone No.

Florida Department of Environmental Regulation

APPLICATION FOR PERMIT OF
PROPOSED RACT FOR AIR POLLUTION SOURCE(s)

If major alterations have occurred, the applicant should complete the Standard Air Permit Application Form.

Source Type: Fossil Fuel Steam Generator Renewal of DER Permit No. AO-06-143212

Company Name: Florida Power & Light Company County: Broward

Identify the specific emission point source(s) addressed in this application (i.e., Lime Kiln No. 4 with Venturi Scrubber; Peaking Unit No. 2, Gas Fired):

Port Everglades Power Plant, Unit No. 4, Oil & Gas Fired, 400 MW Class (440 MW Gross Capacity)

Source Location: Street: 8100 Eisenhower Blvd. City: Ft. Lauderdale

UTM: East 587.4 km Zone 17 North 2885.2 km

Latitude: 26° 05' 08"N Longitude: 80° 07' 31"W

---

1. Attach a check made payable to the Department of Environmental Regulation in accordance with operation permit fee schedule set forth in Florida Administrative Code Rule 17-4.05.

2. Have there been any alterations to the plant since last permitted? [X] Yes [ ] No If minor alterations have occurred, describe on a separate sheet and attach. **As agreed to in connection with the Lauderdale Repowering Project, and as previously reported to DER, low NOx burners were installed. Boiler tubing was replaced to bring operating conditions back to original design.**

3. Attach the last compliance test report required per permit conditions if not submitted previously. **All compliance test reports have been submitted**

4. Have previous permit conditions been adhered to? [X] Yes [ ] No If no, explain on a separate sheet and attach. **Except as previously reported.**

5. Has there been any malfunction of the pollution control equipment during tenure of current permit? [ ] Yes [X] No If yes, and not previously reported, give brief details and what action was taken on a separate sheet and attach.

6. Has the pollution control equipment been maintained to preserve the collection efficiency last permitted by the Department? [X] Yes [ ] No

7. Has the annual operating report for the last calendar year been submitted? [X] Yes [ ] No If no, please attach.

8. Please provide the following information if applicable:

A. Raw Materials and Chemical Used in Your Process:

Description	Contaminant Type	%Wt	Utilization Rate lbs/hr
MgO or $Mg(OH)_2$ Additive	Particulate	100	180 lb/day estimated average for 1991
Evaporation of boiler cleaning water with approximately 3% of monoammonium citrate solution	Particulate	100	Approximately 75,000 gallons of water every 3 year

B. Product Weight (lbs/hr): **Not applicable**

C. Fuels: In order to improve start-up combustion, small amounts of light oil (No. 2 fuel oil), natural gas if available, or propane gas, are sometimes fired to preheat the boiler prior to ignition of residual fuel oil. Very small quantities of on-specification used oil, entirely from FPL operations, may be consumed while burning residual oil.

Type (Be Specific)	Consumption* Avg/hr*	Max/hr**	Maximum Heat Input(MMBTU/hr)
Residual Fuel Oil	Variable	631	3850
Natural Gas	Variable	4.02	4025

D. Potential Equipment Operating Time Up To: hrs/day 24; days/wk 7; wks/yr 52; hrs/yr (power plants only); 7134 hours of operation during 1992. More operating time is typical when ambient temperature is either unusually high or low, or during other unusual system demands.

The undersigned owner or authorized representative*** of **Florida Power & Light Company** is fully aware that the statements made in this application for a renewal of a permit to operate an air pollution source are true, correct and complete to the best of his knowledge and belief. Further, the undersigned agrees to maintain and operate the pollution source and pollution control facilities in such a manner as to comply with the provisions of Chapter 403, Florida Statutes, and all the rules and regulations of the Department. He also understands that a permit, if granted by the Department, will be non-transferable and he will promptly notify the Department upon sale or legal transfer of the permitted facility. **This certification pertains solely to air pollution related requirements.**

*During actual time of operation.
**Units: Natural Gas-MMCF/hr; Fuel Oils-barrels/hr; Coal-
***Attach letter of authorization if not previsouly submitted.

Elsa A. Bishop
Signature, Owner or Authorized Representative
(Notarization is mandatory)

E. A. Bishop, Supervisor
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Date

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Telephone No.

Florida Department of Environmental Regulation

APPLICATION FOR PERMIT OF
PROPOSED RACT FOR AIR POLLUTION SOURCE(s)

If major alterations have occurred, the applicant should complete the Standard Air Permit Application Form.

Source Type: Stationary Gas Turbines Renewal of DER Permit No. AO-06-148762

Company Name: Florida Power & Light Company County: Broward

Identify the specific emission point source(s) addressed in this application (i.e., Lime Kiln No. 4 with Venturi Scrubber; Peaking Unit No. 2, Gas Fired):

Port Everglades Power Plant, Gas Turbine Units 1-12, 486 MW Gross Winter Capacity

Source Location: Street: 8100 Eisenhower Blvd. City: Ft. Lauderdale

UTM: East 587.2 km Zone 17 North 2885.5 km

Latitude: 26° 05′ 07"N Longitude: 80° 07′ 34"W

---

1. Attach a check made payable to the Department of Environmental Regulation in accordance with operation permit fee schedule set forth in Florida Administrative Code Rule 17-4.05.

2. Have there been any alterations to the plant since last permitted? [ ] Yes [X] No If minor alterations have occurred, describe on a separate sheet and attach.

3. Attach the last compliance test report required per permit conditions if not submitted previously. **NONE REQUIRED**

4. Have previous permit conditions been adhered to? [X] Yes [ ] No If no, explain on a separate sheet and attach. **Except as previously reported.**

5. Has there been any malfunction of the pollution control equipment during tenure of current permit? [ ] Yes [X] No If yes, and not previously reported, give brief details and what action was taken on a separate sheet and attach.

6. Has the pollution control equipment been maintained to preserve the collection efficiency last permitted by the Department? [X] Yes [ ] No

7. Has the annual operating report for the last calendar year been submitted? [X] Yes [ ] No If no, please attach.

8. Please provide the following information if applicable:

A. Raw Materials and Chemical Used in Your Process:

Description	Contaminant Type	%Wt	Utilization Rate	lbs/hr
Liquid Detergent	NONE		Occasional use of a few gallons depending upon unit operating time.	

B. Product Weight (lbs/hr): Not applicable

C. Fuels: **Per Generating Unit**

Type (Be Specific)	Consumption* Avg/hr*	Max/hr**	Maximum Heat Input(MMBTU/hr)
No. 2 Distillate Fuel Oil	Variable	118	675
Natural Gas	Variable	0.70	702

D. Potential Equipment Operating Time Up To: hrs/day 24; days/wk 7; wks/yr 52; hrs/yr (power plants only); 905 Site Hours of operation (anywhere from one to twelve units at the same time) during 1992. More operating time is typical when ambient temperature is either unusually high or low or during unusual system demands.

The undersigned owner or authorized representative*** of **Florida Power & Light Company** is fully aware that the statements made in this application for a renewal of a permit to operate an air pollution source are true, correct and complete to the best of his knowledge and belief. Further, the undersigned agrees to maintain and operate the pollution source and pollution control facilities in such a manner as to comply with the provisions of Chapter 403, Florida Statutes, and all the rules and regulations of the Department. He also understands that a permit, if granted by the Department, will be non-transferable and he will promptly notify the Department upon sale or legal transfer of the permitted facility. **This certification pertains solely to air pollution related requirements.**

*During actual time of operation.
**Units: Natural Gas-MMCF/hr; Fuel Oils-barrels/hr; Coal-
***Attach letter of authorization if not previsouly submitted.

Elsa A. Bishop
Signature, Owner or Authorized Representative
(Notarization is mandatory)

E. A. Bishop, Supervisor
Air Permitting and Programs
Typed Name and Title

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2/1/93
Date

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Telephone No.

PROPOSED
REASONABLY AVAILABLE CONTROL TECHNOLOGY (RACT)
FOR
FLORIDA POWER & LIGHT COMPANY (FPL)
PORT EVERGLADES PLANT

PERSPECTIVE

The information contained in this application and the supporting documents provides FPL's recommended RACT emission limit for the Port Everglades Plant. The basis of this recommendation is a comprehensive assessment of all of FPL's facilities in the moderate nonattainment area. This involved an evaluation of the 12 fossil fuel fired steam electric units and 36 gas turbines at five plants in the nonattainment area. The proposed RACT strategy would provide the Florida Department of Environmental Regulation (FDER):

1. A technically feasible, demonstrated, and cost effective control strategy based on FPL specific units which is consistent with guidance provided by the U.S. Environmental Protection Agency (EPA);
2. A 16 percent reduction in nitrogen oxides (NO_x) emissions from all of FPL facilities in the nonattainment area between the 1990 baseline year and the period 1995-2000, despite a 34 percent increase in energy used to serve customer demand (see Figure 1);
3. A 38 percent reduction in the weighted average emission rate from all of FPL facilities in the nonattainment area (i.e., a reduction in weighted average emission rate of 0.6 lb/10^6 Btu in 1990 to 0.38 lb/10^6 Btu in 1995-2000); and
4. Assurance that these significant NO_x emission reductions would be achieved by May 31, 1995.

The application consists of four sections including an introduction, description of existing sources, RACT assessment, and proposed RACT and rationale, along with supporting attachments.

INTRODUCTION

Purpose

The Port Everglades plant is located in Broward County which has been classified as a moderate nonattainment area. Major facilities emitting NO_x and volatile organic compounds (VOCs) which are located in nonattainment areas classified as moderate or higher must apply for a new or revised operation permit by March 1, 1993 [pursuant to Rule 17-296.570 Florida Administrative Code (F.A.C.)]. The application will be reviewed by FDER for the purpose of establishing RACT emission limits for NO_x and VOCs on a case-by-case basis. The Port Everglades plant is a major emitting facility for NO_x and VOCs subject to the RACT Determination procedure of FDER Rule 17-296.570 (4) F.A.C. This application and the attached technical support document titled "Reasonably Available Control Technology (RACT) Assessment of Florida Power & Light Company's Facilities Located in the Dade, Broward and Palm Beach Ozone Nonattainment Area" provides information required by FDER Rules, including FPL's recommended RACT determination for the Port Everglades Plant sources.

RACT Requirements

The term "RACT" is defined in FDER rules as follows:

> RACT is the lowest emission limit that a particular source is capable of meeting by the application of control technology that is reasonably available considering technological and economic feasibility. [FDER Rule 17-2.100 (163) F.A.C.]

This longstanding regulatory definition, which EPA originally promulgated to guide states is establishing RACT emission limits for existing sources in nonattainment areas, clearly reflects the case-by-case, fact-specific nature of RACT determinations. Indeed, FDER's RACT Determination Procedure clearly states that RACT is to be established by the Department on a case-by-case basis. Consideration is given to RACT emission limiting standards established by other states, information available from EPA guidance documents, technological and economic feasibility, and all other relevant information [see FDER Rule 17-296.570 (4)(b) F.A.C.].

FACILITY DESCRIPTION

General

The Port Everglades plant consists of four fossil fuel steam electric units and twelve gas turbines. Of the four fossil fuel steam electric units, Units 1 and 2 are the oldest (in-service as of 1960 and 1961, respectively) and have a nominal generating capability of 220 MW each. Units 3 and 4 have a nominal generating capability of 400 MW each and have in-service dates of 1964 and

1965, respectively. The fossil fuel steam units are fired with natural gas and/or residual oil. All units are single-wall fired with high heat release rates, i.e., greater than 80,000 Btu/hr-ft^3.

Each gas turbine (GT) has a nominal generating capability of 40.5 MW and is fired with natural gas or distillate oil. These units were brought in-service in 1971 and are used for peaking purposes.

NO_x Emissions

FPL conducted emission tests in 1991 and 1992 to "benchmark" NO_x emission rates for the affected units. Where units were substantially identical, only one unit was tested. The benchmarking tests are representative of the normal operation of the units and provide representative emission estimates for developing control options (refer to Technical Support Document for test results).

Test results indicated NO_x emission rates for Units 1 and 2 of 0.40 and 0.22 lb/10^6 Btu for oil and natural gas firing, respectively. For Units 3 and 4, test results indicated NO_x emission rates of 0.77 and 0.55 lb/10^6 Btu heat input for oil and natural gas firing, respectively. The NO_x emission rate when firing oil in Units 1 and 2 was slightly lower than EPA's AP-42 emission factor, while the NO_x emission rate for natural gas firing was much lower than the AP-42 emission factor, i.e., 0.22 lb/10^6 Btu compared to 0.55 lb/10^6 Btu. In contrast, the NO_x emission rate from Units 3 and 4 when firing natural gas was equal to the AP-42 emission factor, while the NO_x emission rate when firing oil was much higher than the AP-42 emission factor, i.e., 0.77 lb/10^6 Btu compared to 0.45 lb/10^6 Btu.

The NO_x emission rates for the GTs were determined to be 0.82 and 0.43 lb/10^6 Btu for oil and gas firing, respectively. The NO_x emission rate indicated for firing oil is somewhat higher than the AP-42 emission factor of 0.698 lb/10^6 Btu. When firing natural gas, the GTs emission rate is about the same as the AP-42 emission factor of 0.44 lb/10^6 Btu.

The NO_x emission rates determined from the benchmarking tests were used to estimate 1990 NO_x emissions. Based on the 1990 actual fuel use data, the Port Everglades plant had NO_x emissions of 14,830.8 tons which is about 42 percent of the total NO_x emissions from FPL's facilities located in Dade, Broward, and Palm Beach counties. Units 3 and 4 NO_x emissions totaled 11,520.9 tons or about 78 percent of the plant's total. Only about 2 percent of the plant's NO_x emissions is attributable to the gas turbines.

Table 1 presents a summary of the characteristics and emissions for each unit at the Port Everglades plant. Refer to Technical Support Document for additional information.

VOC Emissions

VOC emission rates were determined through source testing of both the fossil fuel fired steam electric and gas turbine units. The VOC emissions for the steam units were determined in 1992 using EPA Method 25A. Emissions from the GTs were determined as part of the licensing activities associated with the Lauderdale Repowering Project. Table 2 presents the VOC emission rates determined for the sources at the Port Everglades Plant. The emission rates determined using EPA test methods are lower than the AP-42 emission factors for these sources. For the steam electric units, the maximum emission rates determined through testing were 0.0004 and 0.0002 $lb/10^6$ Btu for oil and gas firing, respectively. In contrast, EPA AP-42 emissions factors are 0.005 and 0.0013 $lb/10^6$ Btu, respectively. For the GTs, the emission rates determined through testing were 0.0013 and 0.0034 $lb/10^6$ Btu for oil and gas firing, respectively. The AP-42 emissions factors for GTs are 0.017 and 0.024 $lb/10^6$ Btu for oil and gas firing, respectively. VOC source test data are presented in Appendix B.

The Port Everglades Plant also has tanks for storing and handling fuels and solvents. A total of 19 tanks are used for this purpose and small amounts of VOCs are emitted through breathing and handling losses. Of the 19 tanks, 12 are used for handling and storing No. 6 fuel oil which has a minimum of VOC emissions. The No. 6 fuel oil tanks include:

1. 4-day tanks for No. 6 fuel oil which range in capacity from 3,000 to 12,000 barrels (bbl), with a total capacity of 30,000 bbl, and
2. 8 storage tanks for No. 6 fuel oil which range in capacity from 25,000 to 200,000 bbl with a total capacity of 885,000 bbl.

The plant also has two 25,000-bbl tanks for storing No. 2 distillate fuel oil. Miscellaneous tanks include a 2,000-gallon (gal) pressurized tank for gasoline, a 600-gal tank which is empty, and a 275-gal rectangular tank for mineral spirits. One large 250,000-bbl capacity tank at the facility is empty, and one tank is being leased for storage of Jet A.

Table 2 presents actual 1990 and potential VOC emissions for the Port Everglades Plant. Although the facility is a "major facility" for VOC emissions by virtue of its potential emissions, both historical and projected emissions are much less than 100 tons per year. (See Appendix A for VOC calculations.)

NO_x RACT CONTROL ALTERNATIVES

Regulatory Guidance

For NO_x emissions from fossil fuel fired steam generators and gas turbines, EPA will not issue Control Technology Guidance (CTG) documents. EPA has issued, in a supplement to the general preamble to the regulations related to the implementation of Title I of the Clean Air Act Amendments of 1990 for state implementation plans, some guidance for certain electric utility boilers [57 Federal Register (FR) 55620, November 25, 1992].

EPA's guidance concluded that RACT for utility generators should reflect " the most effective level of combustion modification reasonably available to an individual unit". EPA specified by reference the application of low NO_x burners but recognized that in some cases overfire air and flue gas recirculation may be appropriate while in other cases RACT would require no additional control.

For oil/gas wall-fired units, EPA indicated that in the majority of cases, RACT should result in an overall level of control equivalent to 0.3 lb/10^6 Btu with compliance based on a 30 day rolling average. EPA encourages the states to adopt emission averaging concepts including averaging within the same transport region. However, EPA states that: "The actual NO_x emission reduction that can be achieved on a specific boiler depends on a number of site-specific factors including, but not limited to, furnace dimensions and operating characteristics, design and condition of burner controls, design and condition of stream control systems, and fan capacity. The combustion modification technology must be custom-designed for each boiler application."

The approach taken by FPL to identify RACT for each unit is consistent with EPA guidance and is based on a unit-specific analysis of NO_x control options that realistically considered the technological and economic feasibility for each unit.

For gas turbines, EPA has not provided guidance on RACT. The recognized control technique for reducing NO_x emissions from simple cycle gas turbines is combustion modifications primarily involving water injection for the type of gas turbine at the Port Everglades Plant. Combustion modifications involving staged combustion is not currently available for the FPL gas turbines.

Combustion Modifications--Boilers

Combustion modifications, which EPA suggests as the control technology that would achieve RACT, was evaluated for Port Everglades Units 1 through 4 (see Technical Support Document). Four major types of combustion modifications were evaluated, including low-NO_x burner (LNB) technology, off-stoichiometric combustion (OSC), over-fire air (OFA), and flue gas recirculation (FGR). The results of the evaluation, which are summarized in Table 3, suggest that LNB technology is the most cost effective for these units. The cost effectiveness for LNB technology is about $800 per ton of NO_x reduced for all four units. In contrast, the cost effectiveness of OFA and FGR is about $3,300 and $3,000 per ton of NO_x reduced, respectively.

For Units 1 and 2, LNB technology can achieve a minimum of 10 percent NO_x reduction which would be equivalent to a proposed RACT emission rate of 0.2 and 0.36 lb/10^6 Btu for natural gas and oil firing, respectively. LNB technology is feasible for these units and the amount of reduction proposed is viable. Because of the design of these units (i.e., large furnace volume and medium/low heat release rates currently producing relatively low NO_x emission rates), the effectiveness of FGR is unknown. Thus, reductions for this technology may be overstated in Table 3.

LNB technology has recently been installed on Units 3 and 4, resulting in a minimum NO_x reduction of 25 percent or emission rates of 0.41 and 0.58 lb/10^6 Btu when firing natural gas and oil, respectively. The low-NO_x burners installed at Port Everglades Units 3 and 4 are made by Todd Combustion. The model is the Dynaswirl LN, and a configuration drawing is attached in Appendix C. The post-installation unit startup dates were April 4, 1992 and May 20, 1992 for Units 3 and 4, respectively. The vendor's burner performance guarantees for NO_x emissions at full load were a maximum of 0.53 lb/MMBtu and 0.39 lb/MMBtu on oil and gas fuels, respectively. The compliance tests were performed on November 17 and 18, 1992. The results were NO_x emission rates of 0.39 lb/MMBtu and 0.52 lb/MMBtu on gas and oil fuels, respectively. A summary of the test results is attached in Appendix C. These tests have demonstrated that the installation of low-NO_x burners at Port Everglades Units 3 and 4 has resulted in a reduction of NO_x emission rates (lb/MMBtu) of at least 25 percent. Additional information about these burners is available in the technical paper, "Retrofit of Low NO_x Oil/Gas Burners to Two 400 MW Utility Boilers, and the Effects on Overall Emissions and Boiler Performance", presented at Power Gen '92.

Application of OFA and FGR on Units 3 and 4 requires extensive modifications, and completing needed modifications by May 31, 1995, would not be possible for all FPL units located in Dade, Broward, and Palm Beach counties.

Post-Combustion Technologies--Boilers

The post-combustion technologies evaluated included selective non-catalytic reduction (SNCR) and selective catalytic reduction (SCR). Although, EPA has not considered these technologies to be appropriate or necessary for fossil fuel steam units in its RACT guidance, SNCR and SCR were evaluated as alternatives to combustion modifications. The evaluation found that SNCR was not feasible since the temperature and residence times required for the reaction of ammonia and NO_x are not available in Units 3 and 4. The cost of SCR would make this technology economically infeasible. For both SNCR and SCR, achieving the RACT compliance date for all units would not be possible. Table 4 summarizes the economic and technical attributes of the post-combustion technologies evaluated.

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Gas Turbines

NO_x emissions can be reduced through water injection in the combustion zone of gas turbines. Water injection reduces the flame temperature and the thermal NO_x that is formed. Water injection equipment is available for the type of turbine at the Port Everglades Plant to reduce NO_x emissions by 60 percent or to 42 parts per million volume dry (ppmvd) corrected to 15 percent oxygen. Current NO_x emissions are about 100 ppmvd corrected to 15 percent oxygen. The amount of water required at full load is about 25 gallons per minute per turbine which is about 0.75 lb water per lb of fuel.

The annualized cost to install and operate water injection is estimated to be about $130,000 per turbine or $1,560,000 per year for the 12 Port Everglades gas turbines. The cost effectiveness for the gas turbines is calculated to be over $10,000 per ton of NO_x removed. This is a result of the limited operation of the gas turbines which were operated at less than 2 percent capacity factor in 1990.

Although water injection would reduce NO_x concentrations, it would also increase emissions of carbon monoxide and VOCs. Testing performed on similar units with water injection indicate that carbon monoxide emission would increase by about 84 percent and VOC emissions would increase by over 100 percent.

VOC RACT CONTROL ALTERNATIVES

Sources of VOC emission at the Port Everglades Plant include the fossil fuel fired steam generators, combustion turbines and evaporative losses from tanks and solvent (mineral spirits) usage. EPA has not established CTG documents for VOC controls on fossil fuel steam generators or combustion turbines. Typically, VOCs from these sources are controlled by good combustion practices. FPL's combustion control systems are sufficiently sophisticated to ensure maximum boiler efficiency. This results in actual VOC emissions that are lower than those expected using AP-42 emission factors (see discussion above). Such combustion systems also reduce particulate emissions and carbon monoxide emissions.

CTG's have been established for evaporative losses from tanks storing and handling highly volatile compounds with high vapor pressures. However, the volatility of No. 6 fuel oil and No. 2 distillate oil is low, resulting in very little VOC emissions. Current FDER RACT rules for petroleum liquid storage tanks only regulate petroleum liquids with a true vapor pressure of greater than 1.5 pounds per square inch (psia) [see FDER Rule 17-2.650(1)(f)17 F.A.C.]. The true vapor pressures of No. 6 and No. 2 fuel oils are 0.00006 and 0.0090 psia, respectively. With such low true vapor pressures, the VOC emissions from tanks storing and handling No. 6 and No. 2 fuel oils are several orders of magnitude lower than petroleum products that are regulated. Indeed, VOC emissions for all tanks with the exception of the mineral spirits usage are less than 2 tons per year.

PROPOSED RACT AND RATIONALE

EPA's guidance, while suggesting NO_x emission rates as RACT for certain utility boilers, clearly provides for the evaluation of design-specific factors when establishing RACT. Units 3 and 4 are unique in those design features that affect NO_x emissions and the ability to apply combustion control technology. The specific design factors unique to these units are the single-wall fired configuration and small furnace design with associated high heat release rates (as indicated by Btu/hr-ft^3). These design features are illustrated in Figure 2.

Of the 59,000-MW oil/gas fired utility steam generators nationwide, about 41 percent are single-wall fired units. In contrast to units designed as single-wall fired, tangentially and opposed-wall fired units have inherently lower NO_x emissions and can generally meet 0.3 lb $NO_x/10^6$ Btu heat input. Units 3 and 4 were designed and fabricated by Foster-Wheeler (FW). FW-designed oil/gas-fired boilers make up about 49 percent of all U.S. single-wall fired designs; the other major manufacturer, Babcock and Wilcox (B&W), makes up the remainder (i.e., 51 percent). In general, B&W designs have larger furnace volumes and lower NO_x emission rates. As shown in Figure 2, about 66 percent of FW designs are pre-New Source Performance Standards (NSPS); the post-NSPS designs meet a 0.3 lb $NO_x/10^6$ Btu limit. Of the pre-NSPS designs, 57 percent are high heat release rate (>80,000 Btu/hr-ft^3) units. Low (<45,000 Btu/hr-ft^3) and medium (45,000 to 80,000 Btu/hr-ft^3) heat release units make up 10 and 33 percent, respectively, of the pre-NSPS units. Fifty percent of the high heat release units are located in non-attainment areas;

all these units are owned by FPL and located in Dade, Broward, and Palm Beach counties (see Figure 2).

In contrast to the FPL single-wall fired oil/gas units, NO_x emission rates from many other oil/gas-fired units are inherently lower due to larger furnace volume for a similarly sized unit. This is particularly true of units originally designed to burn coal and converted to oil/gas firing to meet particulate and sulfur dioxide emission limits. Such units, many of which are in the northeast United States (e.g., Con Edison), have large furnace volumes and low heat release rates resulting in inherently lower NO_x emission rates. These units generally can meet the EPA-suggested guidance levels without additional controls.

Boilers with high heat release rates have inherently higher NO_x emission rates, and options for reasonably available controls are limited. The application of LNB technology is the most readily adaptable to these units and the most cost-effective.

Considerable experience in low-NO_x burner technology was gained through the installation of low-NO_x burners in Port Everglades Units 3 and 4. This experience is relatively unique in that there have been very few utility-sized retrofits of low-NO_x oil/gas burners in the U.S. FPL's operational experience with LNB technology, while demonstrated to achieve required NO_x reduction requirements, was not without design, startup, and operational problems (e.g., oil safety shutoff valve system seal failures, burner management system interface logic design issues, et.al). Considerable time, effort, and funds were spent on plant components having no influence on the burner's combustion/emission performance. Lessons learned from this project therefore indicate that substantial cost savings are possible by concentrating on design changes to only those components which effect combustion/emissions performance. Toward a goal of achieving maximum NO_x reductions using the most cost effective approach, FPL has undertaken a program, with contract support from the existing burner manufacturer, International Combustion Limited (ICL), to develop optimized designs for converting the existing burners to a low-NO_x configuration. This program consists of design development of combustion/emission related burner components and prototype testing to compare design alternatives and select the optimum design prior to actual implementation. It is currently anticipated that these efforts will result in a low-NO_x burner configuration consisting of an axial flow, single register, fuel staged design.

LNB technology is proposed as RACT for Port Everglades Units 1 through 4. The advantages of this technology are:

1. Technologically Feasible--Unlike other technologies, LNB technology has been retrofitted on Units 3 and 4 at the Port Everglades plant with a demonstrated NO_x reduction of 25 percent. This technology can be installed on Units 1 and 2. EPA has also suggested this technology as being the most appropriate for RACT.
2. Cost Effectiveness--LNB technology represents a cost effective approach. The $/ton of NO_x removed is $800, in contrast to EPA's recommendation for the NO_x reductions required under the acid rain provisions (Title IV) of the Clean Air Act (57FR55620), which was approximately $300 per ton of NO_x removed.
3. Achievement of Compliance Date--Installation of LNB technology can be achieved by May 31, 1995, for Port Everglades Units 1 and 2. It may not be possible to convert both units with other control alternatives.

The proposed RACT emission rate is based on a 10 percent reduction in maximum uncontrolled NO_x emissions for Units 1 and 2 and a 25 percent reduction for Units 3 and 4. Maximum uncontrolled emission rates are those rates determined from the benchmarking tests (or subsequent tests determined by FDER). The proposed RACT limits are:

PPE Units 1 and 2--0.20 lb/10^6 Btu gas; 0.36 lb/10^6 Btu oil

PPE Units 3 and 4--0.41 lb/10^6 Btu gas; 0.58 lb/10^6 Btu oil

The current emission rates for gas and oil are proposed as RACT for the gas turbines since the application of water injection is not cost effective based on the limited operation of these units (i.e., cost effectiveness of water injection is estimated to exceed $10,000 per ton NO_x). The proposed RACT is to limit the cumulative capacity factor of these units to less than or equal to 10 percent; if capacity factors exceed this rate water injection may be required.

The proposed RACT for VOC sources at the Port Everglades Plant is the current emission rates. Actual emissions from the facility are substantially less than 100 tons per year suggesting that any control would have limited value. Moreover, there are no additional control technologies for limiting VOC emissions from combustion sources or oil tanks that are reasonably available for these sources.

Certification by Professional Engineer Registered in Florida

This is to certify that the engineering features of this reasonably available control technology (RACT) application have been prepared or examined by me and found to be in conformity with modern engineering principles applicable to the treatment and disposal of pollutants characterized in the application.

Signed: Kennard F. Kosky

Date: 2/2/93

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SEAL

Table 1. Summary of NO_x Emission Rates and 1990 Emissions for FPL Port Everglades Plant

Unit[a]	Nominal Size (MW)	NO_x Emission Rate ($lb/10^6$ Btu) Oil	Gas	1990 NO_x Emissions (tons)	Percent of Total Plant Emissions
PPE 1	220	0.40	0.22	1,355.3	9.1%
PPE 2	220	0.40	0.22	1,701.8	11.5%
PPE 3	400	~~0.77~~ .74	~~0.55~~ .52	7,614.0	51.3%
PPE 4	400	~~0.77~~ .74	~~0.55~~ .52	3,906.9	26.3%
PPEGT 1-12	40.5 (each)[b]	0.82	0.43	252.8	1.7%
			Total:	14,830.8	

Note: See Tables 2-1, 2-2 and 2-3 in Technical Support Document.

[a] PPE = Port Everglades
GT = Gas Turbine
[b] Total of 486 MW for 12 gas turbines.

Table 2. Actual and Potential VOC Emissions for the FPL Port Everglades Plant Using Emission Rates Based on Test Results

Unit Name	Heat Input (10^9 Btu)[a] Oil	Gas	VOC Emission Rate ($lb/10^6$ Btu)[b] Oil	Gas	VOC Emissions (TPY)
Actual Emissions					
PPE-1	2,477.6	7,815.8	0.0004	0.0002	1.3
PPE-2	5,452.8	5,557.1	0.0004	0.0002	1.6
PPE-3	12,815.2	9,746.1	0.0004	0.0002	3.5
PPE-4	7,321.2	3,957.2	0.0004	0.0002	1.9
PPEGT 1-12	99.8	985.5	0.0013	0.0034	1.7
Tanks[c]	NA	NA	NA	NA	1.8
Solvents[d]	NA	NA	NA	NA	9.4
			Plant Total		21.3
Potential Emissions					
PPE-1	$2300(10)^6 \times 8760 =$ 20,148.0 $(10)^9$	21,067.8	0.0004	0.0002	4.0 6.1
PPE-2	20,148.0	21,067.8	0.0004	0.0002	4.0 6.1
PPE-3	33,726.0	35,259.0	0.0004	0.0002	10.3
PPE-4	33,726.0	35,259.0	0.0004	0.0002	10.3
PPEGT 1-12	73,794.2	70,956.0	0.0013	0.0034	168.6
Tanks[c]	NA	NA	NA	NA	1.8
Solvents[d]	NA	NA	NA	NA	9.4
			Plant Total		212.6

$2.0148(10)^{13} \times \frac{4(10)^{-4}}{(10)^6} / 2000 = 4.03$ TPY $+ 2.1 = 6.1$ TPY

THIS IS INCORRECT! CAN'T BURN OIL & GAS @ SAME TIME.

Note: NA = not applicable.

[a] 1990 heat input values as provided by FPL.
[b] Boiler and gas turbine VOC emission rates based on stack test results. Boiler emission rates based on tests conducted at the Riviera and Port Everglades plants.
[c] Refer to Tables A1 and A2 in Appendix A for detailed calculations.
[d] Emissions based on an annual usage of 2,500 gal of mineral spirits.

Table 3. Summary of RACT Factors for Combustion Modifications FPL Port Everglades Plant

		Alternative Control Technology[a]			
Factor	Unit	LNBT	OSC	OFA	FGR
NO_x Reduction		10/25%	≤20%[b]	10%	45%
Capital Cost	PPE 1	$ 3,366,000	NA	$ 4,405,000	$ 18,875,000
	PPE 2	3,366,000	NA	4,405,000	18,875,000
	PPE 3	3,658,000	NA	4,459,000	20,981,000
	PPE 4	3,658,000	NA	4,459,000	20,981,000
	Plant Total:	14,048,000	NA	17,728,000	79,712,000
Annualized Cost	PPE 1	592,000	NA	855,000	3,517,000
	PPE 2	592,000	NA	855,000	3,517,000
	PPE 3	682,000	NA	1,038,000	4,153,000
	PPE 4	682,000	NA	1,038,000	4,153,000
	Plant Total:	2,548,000	NA	3,786,000	15,340,000
Cost Effectiveness ($/ton)	PPE 1&2	3,873	NA	6,216	5,681
	PPE 3&4	474	NA	2,403	2,136
	Plant Total:	800	NA	3,324	2,992
Schedule Requirements:					
Duration of Outage		6 Weeks	Variable	3 Months	6 Months
Total Duration per Unit:		9 Months	Variable	12-14 Months	24 Months
Achieve Compliance Date?		Yes	Unknown	No	No
Technical Feasibility		Yes	Possible	Possible	Possible
Energy Penalties		Minor	Minor	Moderate	Major
Other Environmental Impacts		Minor	Minor	Yes	Yes

Note: NA = not available or unknown at this time.

[a] See Tables 3-1, 3-2, 4-1, B-1, B-2, and B-3 in Technical Support Document.
[b] OSC would not likely achieve the desired NO_x reduction. Refer to Sections 3.2.2 in Technical Support Document.

Table 4. Summary of RACT Factors for Post-Combustion Technologies FPL Port Everglades Plant

Factor	Unit	Alternative Control Technology[a] SNCR	SCR
NO_x Reduction		35%	55%
Capital Cost	PPE 1	$ 6,549,327	$ 18,460,094
	PPE 2	6,549,327	18,460,094
	PPE 3	13,206,961	29,049,296
	PPE 4	13,206,961	29,049,296
	Plant Total:	39,512,576	95,018,780
Annualized Cost	PPE 1	2,118,224	6,987,320
	PPE 2	2,118,224	6,987,320
	PPE 3	4,479,712	11,220,972
	PPE 4	4,479,712	11,220,972
	Plant Total:	13,195,872	36,416,584
Cost Effectiveness ($/ton)	PPE 1&2	4,399	9,235
	PPE 3&4	2,963	4,722
	Plant Total:	3,310	5,812
Schedule Requirements:			
Duration of Outage		2 Months	6 Months
Total Duration per Unit:		12-14 Months	24 Months
Achieve Compliance Date?		No	No
Technical Feasibility		Questionable	Possible
Energy Penalties		Minor	Major
Other Environmental Impacts		Yes	Yes

[a] See Tables 3-1, 3-2, 4-1, B-4, and B-5 in Technical Support Document.

Figure 1
COMPARISON OF HEAT INPUT AND NO_x EMISSION RATES FOR FPL PLANTS IN DADE, BROWARD, AND PALM BEACH COUNTIES

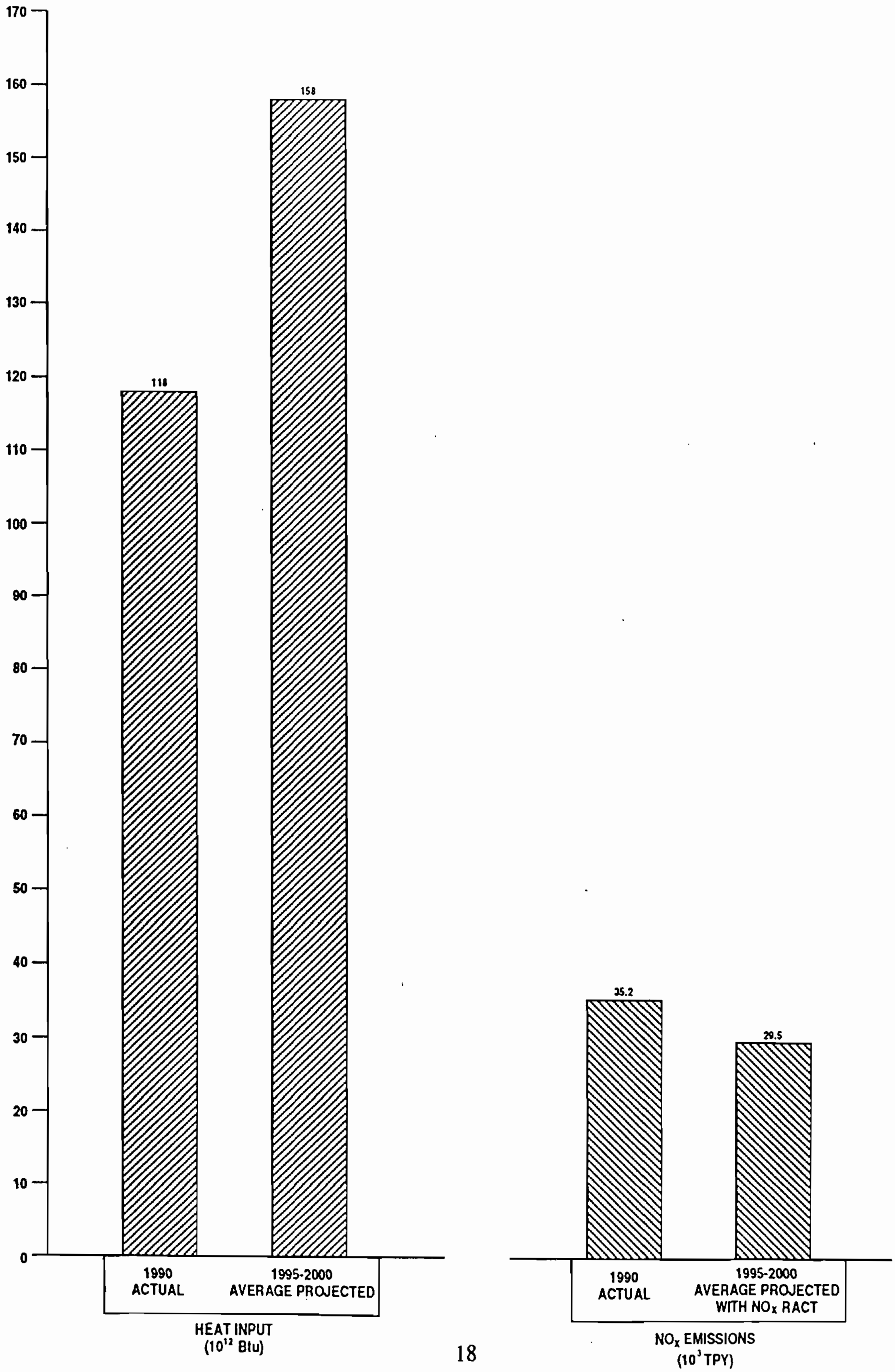
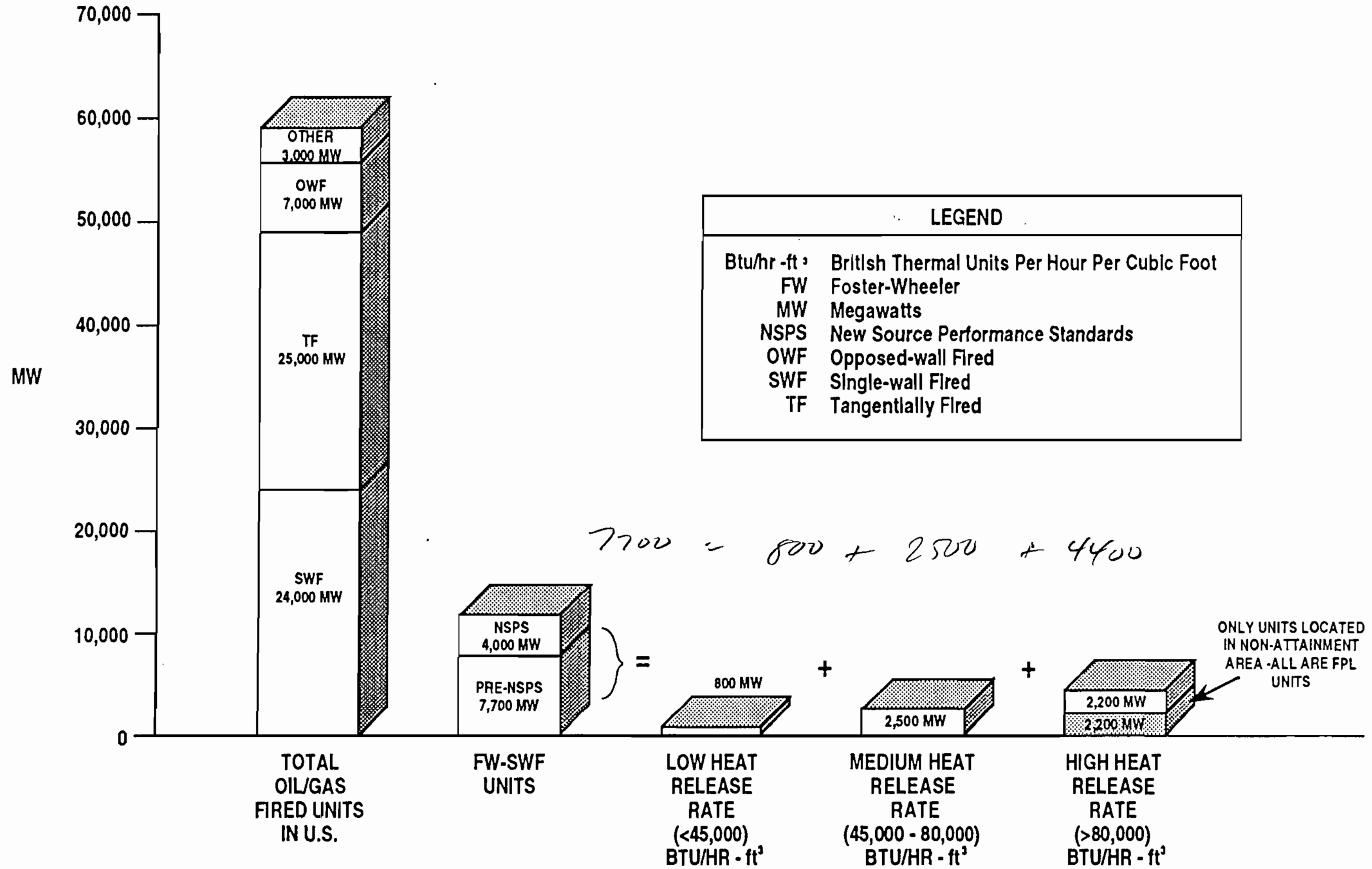


Figure 2
OIL/GAS-FIRED UTILITY STEAM GENERATORS



Attachments:

1. Appendix A--VOC Emission Calculations.
2. Appendix B--VOC Test Results.
3. Appendix C--Low NO_x Burner Configuration and Acceptance Test Data.
4. FDER Renewal Application Form.
5. Technical Support Document.

APPENDIX A

VOC CALCULATIONS FOR TANKS

Table A1. VOC Emission Calculations for Fixed Roof Storage Tanks at the FPL Port Everglades Plant (Page 1 of 2)

	Tank No.						
	1M #6 Fuel	2M #6 Fuel	3M #6 Fuel	4M #6 Fuel	903 #2 Diesel	904 #2 Diesel	905 Empty
Breathing Loss							
Mv = Molecular wt of vapor[a]	190	190	190	190	130	130	0
Pa = Avg. atmospheric pressure (psia)	14.7	14.7	14.7	14.7	14.7	14.7	0.0
P = True vapor pressure (psia)[b]	0.00009	0.00009	0.00009	0.00009	0.012	0.012	0.00
D = Tank diameter (ft)	20	20	35	35	67	67	0
H = Avg. vapor space height (ft)[c]	29.0	29.0	35.5	35.5	20.0	20.0	0.0
T = Avg. ambient diurnal temp. chg. (°F)	14.8	14.8	14.8	14.8	14.8	14.8	0.0
Fp = Paint factor[d]	1.33	1.33	1.33	1.33	1.33	1.33	0.00
C = Adj. factor sm. diameter tanks	0.9	0.9	1.0	1.0	1.0	1.0	0.00
Kc = Product factor	1.0	1.0	1.0	1.0	1.0	1.0	0.0
Lb = Fixed roof breathing loss (TPY) = $2.26 \times 10^{-2} x MvP/Pa\text{-}P^{.68} D^{1.73} H^{.51} T^{.50} FpCKc/2,000$	0.0028	0.0028	0.0091	0.0091	0.40	0.40	0.00
Working Loss							
Mv = Molecular wt. of vapor[a]	190	190	190	190	130	130	0
P = True vapor pressure (psia)[b]	0.00009	0.00009	0.00009	0.00009	0.012	0.012	0.000
V = Tank capacity (gal)	126,000	126,000	504,000	504,000	1,050,000	1,050,000	0
Qb = Throughput (barrels)	1,134,000	1,324,000	2,280,000	2,149,000	15,707	15,707	0.00
Qg = Throughput (gallons)	47,628,000	55,608,000	95,760,000	90,258,000	659,694	659,694	0
N = Total thruput per yr (gal) / Tank capacity (gal)	378	441	190	179	1	1	0
Kn = Turnover factor	0.24	0.24	0.30	0.32	1.00	1.00	0.00
Kc = Product factor	1.0	1.0	1.0	1.0	1.0	1.0	0.0
Lw = Fixed roof working loss (TPY) = $2.40 \times 10^{-5} x MvPVNKnKc/2,000$	0.0023	0.0027	0.0059	0.0059	0.012	0.012	0.000
Total Loss (Lt)							
Lb + Lw = Lt (TPY)	0.0051	0.0055	0.015	0.015	0.41	0.41	0.00

Table A1. VOC Emission Calculations for Fixed Roof Storage Tanks at the FPL Port Everglades Plant (Page 2 of 2)

	Tank No.							
	800 #6 Fuel	801 #6 Fuel	802 #6 Fuel	804 #6 Fuel	805 #6 Fuel	806 #6 Fuel	807 #6 Fuel	808 #6 Fuel
Breathing Loss								
Mv = Molecular wt of vapor[a]	190	190	190	190	190	190	190	190
Pa = Avg. atmospheric pressure (psia)	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7
P = True vapor pressure (psia)[b]	0.00009	0.00009	0.00009	0.00009	0.00009	0.00009	0.00009	0.00009
D = Tank diameter (ft)	140	140	140	65	65	65	185	185
H = Avg. vapor space height (ft)[c]	20.0	29.5	28.0	21.5	21.5	21.5	22.5	22.5
T = Avg. ambient diurnal temp. chg. (°F)	14.8	14.8	14.8	14.8	14.8	14.8	14.8	14.8
Fp = Paint factor[d]	1.33	1.33	1.33	1.33	1.33	1.33	1.33	1.33
C = Adj. factor sm. diameter tanks	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Kc = Product factor	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Lb = Fixed roof breathing loss (TPY) = $2.26 \times 10^{-2} x MvP/Pa\text{-}P^{.68} D^{1.73} H^{.51} T^{.50} FpCKc/2{,}000$	0.075	0.091	0.088	0.021	0.021	0.021	0.13	0.13
Working Loss								
Mv = Molecular wt. of vapor[a]	190	190	190	190	190	190	190	190
P = True vapor pressure (psia)[b]	0.00009	0.00009	0.00009	0.00009	0.00009	0.00009	0.00009	0.00009
V = Tank capacity (gal)	4,620,000	6,300,000	6,300,000	1,050,000	1,050,000	1,050,000	8,400,000	8,400,000
Qb = Throughput (barrels)	869,330	1,185,450	1,185,450	197,575	197,575	197,575	1,580,600	1,580,600
Qg = Throughput (gal)	36,511,860	49,788,900	49,788,900	8,298,150	8,298,150	8,298,150	66,385,200	66,385,200
N = Total thruput per yr (gal) / Tank capacity (gal)	8	8	8	8	8	8	8	8
Kn = Turnover factor	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
Kc = Product factor	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Lw = Fixed roof working loss (TPY) = $2.40 \times 10^{-5} x MvPVNKnKc/2{,}000$	0.0075	0.010	0.010	0.0017	0.0017	0.0017	0.014	0.014
Total Loss (Lt)								
Lb + Lw = Lt (TPY)	0.082	0.10	0.099	0.022	0.022	0.022	0.14	0.14
Total Emissions for Fixed Roof Tanks (TPY):	1.49							

Note: All calculations based on AP42 methodologies.
Emissions based on 1991 throughputs.

[a] Based on 60 degrees F.
[b] Based on 80 degrees F.
[c] Taken as half the tank height.
[d] All tanks are light green. Use paint factor for light gray since there is no factor for green.

Table A2. VOC Emission Calculations for External Floating Roof Storage Tanks at the FPL Port Everglades Facility

	Tank No. 901 Empty	Tank No. 902 Jet A
Rim Seal Loss		
Ks = Seal factor	0.0	0.20
V = Avg. wind speed (mph)	0.0	9.2
n = Seal related wind speed exponent	0.0	2.6
P = True vapor pressure (psia)[a]	0.0	0.015
Pa = Avg. atmospheric pressure (psia)	0.0	14.7
P* = Vapor pressure function	0.0	0.00026
$= \frac{P/Pa}{[1+(1-P/Pa)^{0.5}]^2}$		
D = Tank diameter (feet)	0.0	212
Mv = Avg. molecular wt.[b]	0.0	130
Kc = Product factor	0.0	1.0
Lr = Rim Seal Loss (TPY)		
$= KsV^n P^*DMvKc/2{,}000$	0.0	0.23
Withdrawal Loss		
Q = Throughput (bbl)[c]	0.0	2,500,000
C = Clingage factor	0.0	0.0015
Wl = Avg organic liquid density (lb/gal)[b]	0.0	7.0
D = Tank diameter (feet)	0.0	212
Nc = No. of columns	0.0	0
Fc = Effective column diameter (feet)	0.0	0
Lw = Withdrawal Loss (TPY)		
$= \frac{(0.943)QCWl}{D} * [1+NcFc/D]/2{,}000$	0.0	0.058
Total Loss (Lt)		
Lr+Lw = Lt (TPY)	0.0	0.28
Total Emissions for Floating Roof Tanks (TPY):		0.28

Note: All calculations based on AP-42 methodologies.
Jet A fuel is synonymous with jet kerosene.

[a] Based on 80°F.
[b] Based on 60°F.
[c] Based on 1988 throughput.

APPENDIX B

VOC TEST RESULTS

ACE
AIR CONSULTING
& ENGINEERING, INC.

2106 N.W. 67th Place • Suite 4 • Gainesville, Florida • 32606
(904) 335-1889 FAX (904) 335-1891

April 28, 1992

Mr. Michael J. Taylor
Emission Test Group
Florida Power & Light Company
Post Office Box 4830
Princeton, Florida 33092-4830

Dear Mr. Taylor:

Enclosed is an emission summary of testing performed April 9, 10, and 14, 1992 at the Port Everglades and Riviera Plants.

The Riviera Plant was unable to obtain clearance for a gas firing so only oil testing was performed.

Total hydrocarbons as propane testing was conducted using a Ratfisch RS55 FID analyzer with heated components. CO emissions were measured with a Thermo Environmental Model 48 gas correlation NDIR.

All sampling was conducted using a moisture knockout trap prior to analysis (dry basis). The Riviera Plant testing for VOC's was conducted using both a dry system and a wet system to demonstrate that no VOC's were condensing in the dry system. The wet system used heat trace line at 300°F from the point of sample.

All instruments were calibrated and operated using EPA Method 25A and 10 methodology using NBS Traceable Protocol 1 calibration gases.

If you wish a formal test report for these tests please contact me.

Thank you for allowing Air Consulting and Engineering, Inc. (ACE) to perform this valued work.

Respectfully,

AIR CONSULTING AND ENGINEERING, INC.

Stephen L. Neck

Stephen L. Neck, P.E.

SLN/cvt

cc: Ken Kosky, KBN Engineering & Applied Sciences, Inc.

ACE File: 169 92 01

Emission Sumary
FPL - Riviera Plant
Unit 4 - 4/14/92

"F" Factor Gas = 8710
"F" Factor Oil = 9190

Test Description	O2%	CO ppm	CO lbs/MMBTU	C_3H_8 ppm	C_3H_8 lbs/MMBTU
Oil firing all sampling on dry basis 10170-1117	5.16	5038	4.47	0.27	0.0004
Oil firing VOC sampled on wet basis 1148-1248	5.20	4256	3.78	0.30	0.0004

Emission Sumary
FPL - Port Everglades
Units 2 and 4 - 4/9-10/92

"F" Factor Gas = 8710
"F" Factor Oil = 9190

Test Description	O2%	CO ppm	CO lbs/MMBTU	C_3H_8 ppm	C_3H_8 lbs/MMBTU
Unit 4 - 4/9/92					
Gas Firing East 0850-0926	2.57	0.00	0.0000	0.00	0.0000
Gas Firing West 0940-1000	2.81	0.00	0.0000	0.00	0.0000
Oil Firing West 1100-1130	2.64	7.63	0.0058	0.00	0.0000
Oil Firing East 1220-1300	2.51	3.00	0.0023	0.00	0.0000
Unit 2 - 4/10/92					
Gas Firing 0815-0916	5.92	0.71	0.0006	0.14	0.0002
Oil Firing 1032-1132	5.58	0.48	0.0004	0.00	0.0000

VOC EMISSION ESTIMATES FOR GAS TURBINES 1-24

Emission estimates for VOCs from gas turbines contained in EPA Air Pollutant Emission Factors ,i.e., AP-42 are for unburned hydrocarbons. Investigations into the possible VOC emissions for the type of gas turbine unit at the Lauderdale Plant were unsuccessful in determining the amount of unreactive hydrocarbons, i.e., methane and ethane, that may be in the amount of unburned hydrocarbons. As a result, source testing which excluded these nonreactive hydrocarbons was performed as allowed by FDER Rule 17-2.100(223) F.A.C. The results of these tests are presented in the following report.

The emissions from the tests were evaluated statistically to determine an upper limit that would be applicable to all 24 gas turbines. The results of this evaluation indicated an upper bound for the emissions as follows:

Natural Gas - 0.0034 lb VOC per million Btu heat input
No. 2 Fuel Oil - 0.0013 lb VOC per million Btu heat input

The natural gas emission factor reflects an upper confidence limit of 95 percent. This confidence limit was chosen to account the generally higher VOC emissions on natural gas relative to fuel oil and the greater operating usage on natural gas. In addition, natural gas can contain minute quantities of ethylene, propane, butane and, hexane and higher molecular weight gases that are considered VOCs. The fuel oil emission factor was based on a 90 percent confidence limit. All statistics were based on the t distribution.

SOURCE TEST REPORT

VOLATILE ORGANIC COMPOUND EMISSIONS
EXCLUDING METHANE AND ETHANE

FLORIDA POWER AND LIGHT COMPANY
LAUDERDALE POWER PLANT
GAS TURBINE PEAKING UNITS 8 AND 23

NOVEMBER 8 AND 10, 1989

Prepared for:

KBN ENGINEERING AND APPLIED SCIENCES, INC.
1034 N.W. 57th STREET
GAINESVILLE, FLORIDA 32605

Prepared by:

AIR CONSULTING AND ENGINEERING, INC.
2106 N.W. 67th PLACE, SUITE 4
GAINESVILLE, FLORIDA 32606
(904) 335-1889

163-89-05

Table 1 Emission Summary
Florida Power and Light Company
Ft. Lauderdale Power Plant
November 8 and 10, 1989

Date	Fuel	Load MW	C_3H_8 ppm	O_2 %	Fuel Factor	Emission Rate* lb/MMBTU Carbon
<u>Unit 8</u>						
11/8/89	Natural gas	32.5	0.41	16.82	8710	0.0017
11/8/89	Distillate	32.5	0.20	16.51	9190	0.0008
<u>Unit 23</u>						
11/10/89	Distillate	33.0	0.46	16.90	8710	0.0020
11/10/89	Oil	32.5	0.11	16.75	9190	0.0005

* $E = (\text{ppm } C_3H_8)\ (2.595 \times 10^{-9})\ (\text{Fuel Factor}) \left(\frac{20.9}{20.9 - \%O_2}\right) (36)$

Where 36 = molecular weight of carbon in C_3H_8

APPENDIX C

LOW NO_x BURNER CONFIGURATION AND ACCEPTANCE TEST DATA

DEC 28 '92 04:36PM

FGR WOULD REQUIRE INSTALLATION OF ID FANS

NO REARRANGEMENT OF BURNERS

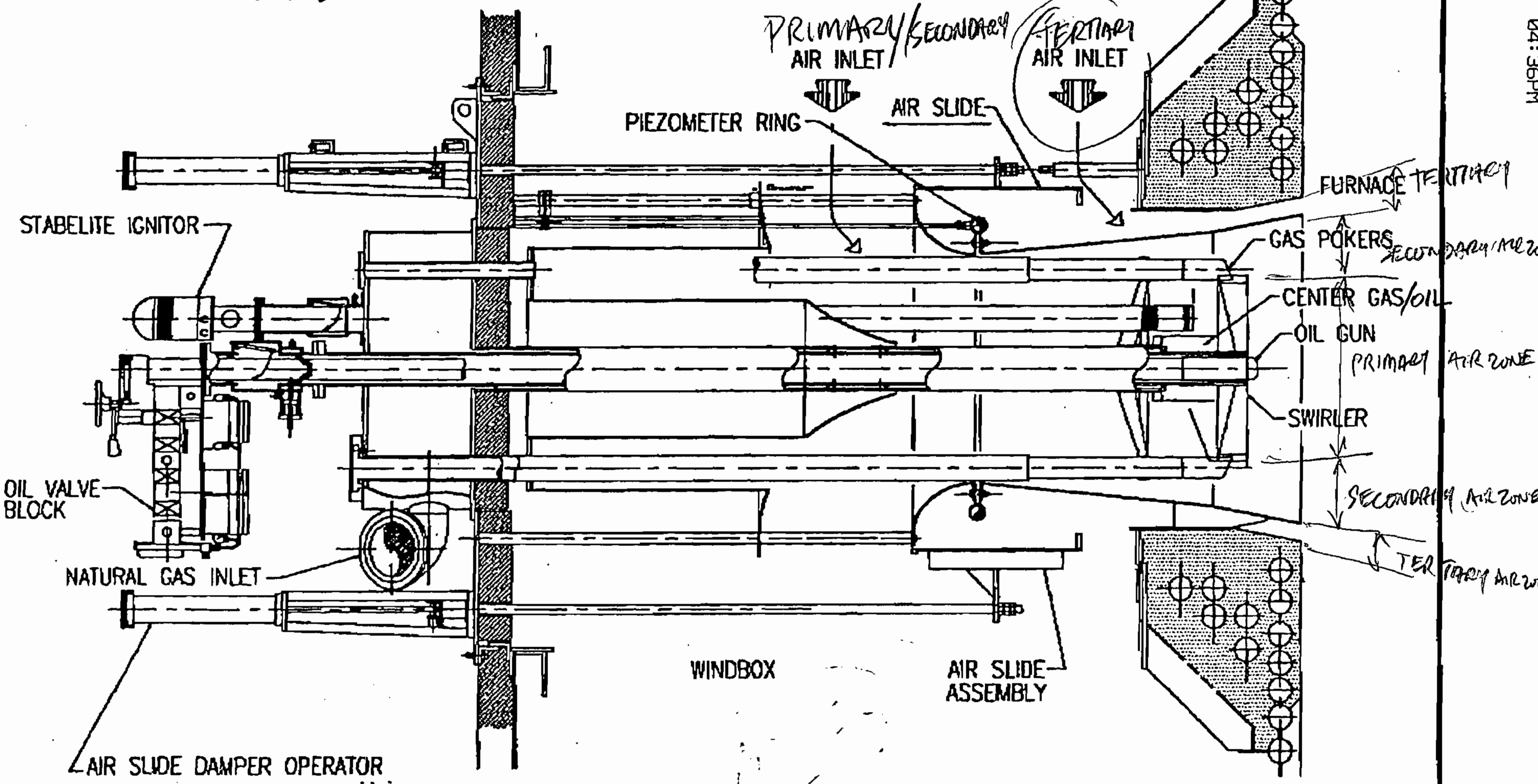
Todd Combustion

DYNASWIRL – LN BURNER

NON-ADJUSTABLE SWIRL

AIR-STAGED (3 ZONES)

NO FGR



JVP 12/28/92

FLORIDA POWER & LIGHT
PORT EVERGLADES – UNITS 3 & 4 BURNER CONFIGURATION

P.3

FLORIDA POWER AND LIGHT COMPANY
PLANT SERVICES OPERATIONS SUPPORT
700 UNIVERSE BLVD.
JUNO BEACH, FLORIDA 33408-0240

NOx EMISSION TEST

GAS

PLANT: PORT EVERGLADES
UNIT: 3
TEST: NITROGEN OXIDE EMISSIONS
METHOD: 40 CFR Pt. 60, App. A, 3A & 7E

	BASELINE 3 RUN AVG (BOTH) RUN 1-3	load ↑ EAST/WEST TOTAL RUN 1	O_2 ↓ EAST/WEST TOTAL RUN 2	CO_2 ↑ EAST/WEST TOTAL RUN 3
DATE OF RUN	3/19/91	11/18/92	11/18/92	11/18/92
GROSS LOAD (AVG MMBTU/HR)	3510	3684	3684	3684
START TIME (24-HR CLOCK)		948	1131	1302
END TIME (24-HR CLOCK)		1115	1248	1421
CO2 (CORRECTED % DRY)	10.2	10.7	10.6	10.6
O2 (CORRECTED % DRY)	2.8-3.9	2.3	2.3	2.3
Fo TEST		1.746	1.759	1.759
NET TIME OF RUN (MIN)		60	60	60
MEASURED CONCENTRATION (PPM NOx)		346.3	335.4	345.8
AVG ZERO BIAS CHECK (PPM NOx)		0.0	0.0	0.0
UPSCALE CAIBRATION GAS (PPM NOx)		494.0	494.0	494.0
AVG UPSCALE BIAS CHECK (PPM NOx)		487.8	483.5	484.3
CORRECTED CONCENTRATION (PPM NOx)		350.7	342.7	352.8
HEAT INPUT OIL (%)		0.0	0.0	0.0
HEAT INPUT GAS (%)		100.0	100.0	100.0
WEIGHTED AVERAGE F FACTOR (DSCF/MMBTU)		8710.0	8710.0	8710.0
NOx EMISSIONS (LB/MMBTU)		0.409	0.399	0.410

AVERAGE NOx EMISSION(LB/MMBTU) 0.52 0.41
NOx EMISSION STANDARD(LB/MMBTU) 0.41 ← BASIS? GUARANTEE

STM #/hr = 2,464,000
FROM TODD
(DIFF TEST)

$$\begin{array}{r} .52 \\ .41 \\ \hline .11/.52 \end{array} \approx 21\% \text{ REDUCTION}$$

HOW MUCH OF THE 21% IS DUE TO LOWER EXCESS O_2?

EXISTING LEA BURNERS SHOULD BE MORE THERMALLY EFFICIENT THAN LNB's.

FLORIDA POWER AND LIGHT COMPANY
PLANT SERVICES OPERATIONS SUPPORT
700 UNIVERSE BLVD.
JUNO BEACH, FLORIDA 33408-0240

NOx EMISSION TEST OIL

PLANT: PORT EVERGLADES
UNIT: 3
TEST: NITROGEN OXIDE EMISSIONS
METHOD: 40 CFR Pt. 60, App. A, 3A & 7E

(COMPARED TO RUNS 1-3)
load ↑ excess O_2 ↓ CO_2 ↑

	BASELINE 3 RUN AVG (BOTH) RUNS 1-3	TOTAL RUN 4	TOTAL RUN 5	TOTAL RUN 6
DATE OF RUN	3/20/91	11/18/92	11/18/92	11/18/92
GROSS LOAD (AVG MMBTU/HR)	3,392.7	3504	3504	3504
START TIME (24-HR CLOCK)		1512	1643	1816
END TIME (24-HR CLOCK)		1629	1758	1930
CO2 (CORRECTED % DRY)	14.1	14.6	14.6	14.4
O2 (CORRECTED % DRY)	2.7-3.1	2.5	2.5	2.6
Fo TEST		1.265	1.265	1.271
NET TIME OF RUN (MIN)		60	60	60
MEASURED CONCENTRATION (PPM NOx)		432.7	436.3	437.4
AVG ZERO BIAS CHECK (PPM NOx)		0.0	0.0	0.0
UPSCALE CAIBRATION GAS (PPM NOx)		494.0	494.0	494.0
AVG UPSCALE BIAS CHECK (PPM NOx)		497.0	493.5	495.5
CORRECTED CONCENTRATION (PPM NOx)		430.0	436.7	436.1
HEAT INPUT OIL (%)		100.0	0.0	100.0
HEAT INPUT GAS (%)		0.0	0.0	0.0
WEIGHTED AVERAGE F FACTOR (DSCF/MMBTU)		9190.0	9190.0	9190.0
NOx EMISSIONS (LB/MMBTU)		0.535	0.543	0.545

AVERAGE NOx EMISSION(LB/MMBTU)	0.74	0.54
NOx EMISSION STANDARD(LB/MMBTU)		0.58

← BASIS ? GUARANTEE

$\frac{-.54}{0.2} / 0.74 \approx$ 27% REDUCTION

BASELINE

9986 lb/hr × 18 = 179,748 lb/hr

$179{,}748\ \frac{lb}{hr} \times 151{,}000\ \frac{BTU}{gal} \times \frac{gal}{8.0\ lb} = 3{,}392\ \frac{MMBTU}{HR}$

$\frac{3{,}392\ MMBTU/HR}{2{,}504{,}000\ lb\ STEAM/HR} = 1{,}357.1\ \frac{BTU}{lb\ STEAM}$

TODD BURNER

10,406 lb/hr × 18 = 187,308 lb/hr

$187{,}308\ \frac{lb}{hr} \times 151{,}000 \times \frac{1}{8} = 3535.4\ \frac{MMBTU}{HR}$

$\frac{3535.4\ MMBTU/HR}{2{,}459{,}000\ lb\ STEAM/HR} = 1{,}438\ \frac{BTU}{lb\ STEAM}$

5.9 % MORE FUEL

FLORIDA POWER AND LIGHT COMPANY
PLANT SERVICES OPERATIONS SUPPORT
700 UNIVERSE BLVD.
JUNO BEACH, FLORIDA 33408-0240

NOx EMISSION TEST

GAS

PLANT: PORT EVERGLADES
UNIT: ~~3~~ 4
TEST: NITROGEN OXIDE EMISSIONS
METHOD: 40 CFR Pt. 60, App. A, 3A & 7E

load ↑ O_2 ↓ CO_2 ↑

	BASELINE 3 RUN AVG. (BOTH) RUNS 1-3	TOTAL RUN 1	TOTAL RUN 2	TOTAL RUN 3
DATE OF RUN	3-27-91	11/17/92	11/17/92	11/17/92
GROSS LOAD (AVG MMBTU/HR)	3,459	3625	3625	3625
START TIME (24-HR CLOCK)		955	1133	1303
END TIME (24-HR CLOCK)		1117	1249	1422
CO2 (CORRECTED % DRY)	10.8	11.0	11.0	10.8
O2 (CORRECTED % DRY)	1.9-2.6	1.8	1.8	2.0
Fo TEST		1.744	1.749	1.750
NET TIME OF RUN (MIN)		60	60	60
MEASURED CONCENTRATION (PPM NOx)		326.6	310.5	323.8
AVG ZERO BIAS CHECK (PPM NOx)		0.0	0.0	0.0
UPSCALE CAIBRATION GAS (PPM NOx)		494.0	494.0	494.0
AVG UPSCALE BIAS CHECK (PPM NOx)		483.0	480.3	479.3
CORRECTED CONCENTRATION (PPM NOx)		334.0	319.4	333.8
HEAT INPUT OIL (%)		0.0	0.0	0.0
HEAT INPUT GAS (%)		100.0	100.0	100.0
WEIGHTED AVERAGE F FACTOR (DSCF/MMBTU)		8710.0	8710.0	8710.0
NOx EMISSIONS (LB/MMBTU)		0.379	0.362	0.383

AVERAGE NOx EMISSION(LB/MMBTU)	.57	0.37
NOx EMISSION STANDARD(LB/MMBTU)	-.37	0.41

← WHAT IS THE BASIS ? WAS THIS THE GUARANTEE ?

.20/.57 = 35% REDUCTION

FLORIDA POWER AND LIGHT COMPANY
PLANT SERVICES OPERATIONS SUPPORT
700 UNIVERSE BLVD.
JUNO BEACH, FLORIDA 33408-0240

NOx EMISSION TEST OIL

PLANT: PORT EVERGLADES
UNIT: 4
TEST: NITROGEN OXIDE EMISSIONS
METHOD: 40 CFR Pt. 60, App. A, 3A & 7E

load ↓ excess O_2 ↓ CO_2 ↑

		TOTAL RUN 4	TOTAL RUN 5	TOTAL RUN 6
DATE OF RUN	3-22-91	11/17/92	11/17/92	11/17/92
GROSS LOAD (AVG MMBTU/HR)	3488	3412	3412	3412
START TIME (24-HR CLOCK)		1523	1651	1822
END TIME (24-HR CLOCK)		1637	1806	1936
CO2 (CORRECTED % DRY)	14.3	14.7	14.7	14.6
O2 (CORRECTED % DRY)	2.3-2.8	2.3	2.4	2.5
Fo TEST		1.270	1.263	1.264
NET TIME OF RUN (MIN)		60	60	60
MEASURED CONCENTRATION (PPM NOx)		393.9	405.1	408.0
AVG ZERO BIAS CHECK (PPM NOx)		0.0	0.0	0.0
UPSCALE CAIBRATION GAS (PPM NOx)		494.0	494.0	494.0
AVG UPSCALE BIAS CHECK (PPM NOx)		490.3	491.0	494.0
CORRECTED CONCENTRATION (PPM NOx)		396.9	407.6	408.0
HEAT INPUT OIL (%)		100.0	0.0	100.0
HEAT INPUT GAS (%)		0.0	0.0	0.0
WEIGHTED AVERAGE F FACTOR (DSCF/MMBTU)		9190.0	9190.0	9190.0
NOx EMISSIONS (LB/MMBTU)		0.488	0.504	0.506

AVERAGE NOx EMISSION(LB/MMBTU)	.79	0.50
NOx EMISSION STANDARD(LB/MMBTU)		0.58

$10,266 \frac{lb}{hr} \times 18 = 184,788 \frac{lb}{hr}$

$184,788 \frac{lb}{hr} \times 151,000 \frac{Btu}{gal} \times \frac{gal}{8.0\ lb} = 3,488$

SECTION #2

APPLICATION FOR PERMIT
PROPOSED RACT FOR AIR POLLUTION SOURCES

LAUDERDALE POWER PLANT

1. Application - Gas Turbine Site I, Units 1-12, Oil and Gas Fired, 486 MW Gross Capacity

2. Application - Gas Turbine Site II, Units 13-24, Oil and Gas Fired, 486 MW Gross Capacity

3. Proposed Reasonably Available Control Technology (RACT) for Florida Power & Light Company (FPL) Lauderdale Plant

LAUDERDALE UNITS 4 & 5 (REPOWERED UNITS PERMITTED UNDER SITE CERTIFICATION ACT - TO START UP IN 1993)

LAUDERDALE TURBINES 1-12

Florida Department of Environmental Regulation

APPLICATION FOR PERMIT OF
PROPOSED RACT FOR AIR POLLUTION SOURCE(s)

If major alterations have occurred, the applicant should complete the Standard Air Permit Application Form.

Source Type: Stationary Gas Turbines Renewal of DER Permit No. AO-06-148760

Company Name: Florida Power & Light Company County: Broward

Identify the specific emission point source(s) addressed in this application (i.e., Lime Kiln No. 4 with Venturi Scrubber; Peaking Unit No. 2, Gas Fired):

Lauderdale Power Plant, Gas Turbine Site I, Units 1-12, Oil and Gas Fired, 486 MW Gross Capacity

Source Location: Street: 2 Mi W. of Ravenswood Road on Edgewater City: Hollywood

UTM: East 580.4 km Zone 17 North 2883.5 km

Latitude: 26° 04' 16"N Longitude: 80° 11' 56"W

---

1. Attach a check made payable to the Department of Environmental Regulation in accordance with operation permit fee schedule set forth in Florida Administrative Code Rule 17-4.05.

2. Have there been any alterations to the plant since last permitted? [X] Yes [ ] No If minor alterations have occurred, describe on a separate sheet and attach. **See attached sheet.**

3. Attach the last compliance test report required per permit conditions if not submitted previously. **NONE REQUIRED**

4. Have previous permit conditions been adhered to? [X] Yes [ ] No If no, explain on a separate sheet and attach. **Except as previously reported.**

5. Has there been any malfunction of the pollution control equipment during tenure of current permit? [ ] Yes [X] No If yes, and not previously reported, give brief details and what action was taken on a separate sheet and attach.

6. Has the pollution control equipment been maintained to preserve the collection efficiency last permitted by the Department? [X] Yes [ ] No

7. Has the annual operating report for the last calendar year been submitted? [X] Yes [ ] No If no, please attach.

8. Please provide the following information if applicable:

A. Raw Materials and Chemical Used in Your Process:

Description	Contaminant Type	Contaminant %Wt	Utilization Rate	Utilization lbs/hr
Liquid Detergent	NONE		Occasional use of a few gallons depending upon unit operating time.	

B. Product Weight (lbs/hr): **Not applicable**

C. Fuels: **Per Generating Unit**

Type (Be Specific)	Consumption* Avg/hr*	Consumption* Max/hr**	Maximum Heat Input (MMBTU/hr)
No. 2 Distillate Fuel Oil	Variable	118	675
Natural Gas	Variable	0.70	702

D. Potential Equipment Operating Time Up To: hrs/day 24; days/wk 7; wks/yr 52; hrs/yr (power plants only); 576 Site Hours of operation (anywhere from one to twelve units at the same time) during 1992. More operating time is typical when ambient temperature is either unusually high or low or during unusual system demands.

The undersigned owner or authorized representative*** of **Florida Power & Light Company** is fully aware that the statements made in this application for a renewal of a permit to operate an air pollution source are true, correct and complete to the best of his knowledge and belief. Further, the undersigned agrees to maintain and operate the pollution source and pollution control facilities in such a manner as to comply with the provisions of Chapter 403, Florida Statutes, and all the rules and regulations of the Department. He also understands that a permit, if granted by the Department, will be non-transferable and he will promptly notify the Department upon sale or legal transfer of the permitted facility. **This certification pertains solely to air pollution related requirements.**

Elsa A. Bishop
Signature, Owner or Authorized Representative
(Notarization is mandatory)

E. A. Bishop, Supervisor
Air Permitting and Programs
Typed Name and Title

P. O. Box 088801
Address

North Palm Beach
City

Florida 33408-8801
State Zip

2/1/93
Date

(407) 625-7607
Telephone No.

*During actual time of operation.
**Units: Natural Gas-MMCF/hr; Fuel Oils-barrels/hr; Coal-
***Attach letter of authorization if not previsouly submitted.

Lauderdale Gas Turbines Stack Extensions

The stacks of Units 1 & 2 of the Lauderdale Power Plant Gas Turbines Site I were altered in order to raise exhaust output slightly higher to avoid entering the combustion turbine compressors. This change was part of the engineering for the repowering of the Lauderdale Plant. The alterations entailed the removal of the top EB-5 box without baffles and replacement with a new box with baffles in between the EB-2 and EB-4. This arrangement gives us 18 inches more than the current height of other units at Site I, with these two units now having baffles all the way up.

LAUDERDALE TURBINES 13-24

Florida Department of Environmental Regulation

APPLICATION FOR PERMIT OF
PROPOSED RACT FOR AIR POLLUTION SOURCE(s)

If major alterations have occurred, the applicant should complete the Standard Air Permit Application Form.

Source Type: Stationary Gas Turbines   Renewal of DER Permit No. AO-06-148761

Company Name: Florida Power & Light Company County: Broward

Identify the specific emission point source(s) addressed in this application (i.e., Lime Kiln No. 4 with Venturi Scrubber; Peaking Unit No. 2, Gas Fired):

Lauderdale Power Plant, Gas Turbine Site II, Units 13-24, Oil and Gas Fired, 486 MW Gross Capacity

Source Location: Street: 2 Mi W. of Ravenswood Road on Edgewater City: Hollywood

UTM: East 580.4 km Zone 17   North 2883.5 km

Latitude: 26° 04' 16"N   Longitude: 80° 11' 56"W

1. Attach a check made payable to the Department of Environmental Regulation in accordance with operation permit fee schedule set forth in Florida Administrative Code Rule 17-4.05.

2. Have there been any alterations to the plant since last permitted? [X] Yes [ ] No If minor alterations have occurred, describe on a separate sheet and attach. **See attached sheet.**

3. Attach the last compliance test report required per permit conditions if not submitted previously. **NONE REQUIRED**

4. Have previous permit conditions been adhered to? [X] Yes [ ] No If no, explain on a separate sheet and attach. **Except as previously reported.**

5. Has there been any malfunction of the pollution control equipment during tenure of current permit? [ ] Yes [X] No If yes, and not previously reported, give brief details and what action was taken on a separate sheet and attach.

6. Has the pollution control equipment been maintained to preserve the collection efficiency last permitted by the Department? [X] Yes [ ] No

7. Has the annual operating report for the last calendar year been submitted? [X] Yes [ ] No If no, please attach.

8. Please provide the following information if applicable:

A. Raw Materials and Chemical Used in Your Process:

Description	Contaminant Type	%Wt	Utilization Rate	lbs/hr
Liquid Detergent	NONE		Occasional use of a few gallons depending upon unit operating time.	

B. Product Weight (lbs/hr): Not applicable

C. Fuels: **Per Generating Unit**

Type (Be Specific)	Consumption* Avg/hr*	Max/hr**	Maximum Heat Input(MMBTU/hr)
No. 2 Distillate Fuel Oil	Variable	118	675
Natural Gas	Variable	0.70	702

D. Potential Equipment Operating Time Up To: hrs/day 24; days/wk 7; wks/yr 52; hrs/yr (power plants only); 697 Site Hours of operation (anywhere from one to twelve units at the same time) during 1992. More operating time is typical when ambient temperature is either unusually high or low or during unusual system demands.

The undersigned owner or authorized representative*** of Florida Power & Light Company is fully aware that the statements made in this application for a renewal of a permit to operate an air pollution source are true, correct and complete to the best of his knowledge and belief. Further, the undersigned agrees to maintain and operate the pollution source and pollution control facilities in such a manner as to comply with the provisions of Chapter 403, Florida Statutes, and all the rules and regulations of the Department. He also understands that a permit, if granted by the Department, will be non-transferable and he will promptly notify the Department upon sale or legal transfer of the permitted facility. **This certification pertains solely to air pollution related requirements.**

*During actual time of operation.
**Units: Natural Gas-MMCF/hr; Fuel Oils-barrels/hr; Coal-
***Attach letter of authorization if not previsouly submitted.

Elsa A. Bishop
Signature, Owner or Authorized Representative
(Notarization is mandatory)

E. A. Bishop, Supervisor
Air Permitting and Programs
Typed Name and Title

P. O. Box 088801
Address

North Palm Beach
City

Florida 33408-8801
State Zip

2/1/93
Date

(407) 625-7607
Telephone No.

Lauderdale Gas Turbines Stack Extensions

The stacks of Units 1 & 2 of the Lauderdale Power Plant Gas Turbines Site I were altered in order to raise exhaust output slightly higher to avoid entering the combustion turbine compressors. This change was part of the engineering for the repowering of the Lauderdale Plant. The alterations entailed the removal of the top EB-5 box without baffles and replacement with a new box with baffles in between the EB-2 and EB-4. This arrangement gives us 18 inches more than the current height of other units at Site I, with these two units now having baffles all the way up.

are located in nonattainment areas classified as moderate or higher must apply for a new or revised operation permit by March 1, 1993 [pursuant to Rule 17-296.570 Florida Administrative Code (F.A.C.)]. The application will be reviewed by FDER for the purpose of establishing RACT emission limits for NO_x and VOCs on a case-by-case basis. The RACT requirements apply to all major VOC- and NO_x-emitting facilities except those new and modified facilities which have been or would be subject to new source review [i.e., Prevention of Significant Deterioration (PSD)]; see FDER Rule 17-296.510(1)(b) F.A.C. Although the Lauderdale Plant is a major emitting facility for NO_x and VOCs subject to the RACT determination procedure of FDER Rule 17-296.570 (4) F.A.C., the repowered Lauderdale units were reviewed under the FDER rules governing PSD and are therefore not subject to the RACT rules (see FDER permit PSD-FL-145, March 1991). This application and the attached technical support document titled "Reasonably Available Control Technology (RACT) Assessment of Florida Power & Light Company's Facilities Located in the Dade, Broward and Palm Beach Ozone Nonattainment Area" provide appropriate information required by FDER rules for those sources subject to RACT and include FPL's recommended RACT determination for the Lauderdale Plant sources.

RACT Requirements

The term "RACT" is defined in FDER rules as follows:

> RACT is the lowest emission limit that a particular source is capable of meeting by the application of control technology that is reasonably available considering technological and economic feasibility. [FDER Rule 17-2.100 (163) F.A.C.]

This longstanding regulatory definition, which EPA originally promulgated to guide states in establishing RACT emission limits for existing sources in nonattainment areas, clearly reflects the case-by-case, fact-specific nature of RACT determinations. Indeed, FDER's RACT Determination Procedure clearly states that RACT is to be established by the Department on a case-by-case basis. Consideration is given to RACT emission limiting standards established by other states, information available from EPA guidance documents, technological and economic feasibility, and all other relevant information [see FDER Rule 17-296.570 (4)(b) F.A.C.].

PROPOSED
REASONABLY AVAILABLE CONTROL TECHNOLOGY (RACT)
FOR
FLORIDA POWER & LIGHT COMPANY (FPL)
LAUDERDALE PLANT

PERSPECTIVE

The information contained in this application and the supporting documents provides FPL's recommended RACT emission limit for the Lauderdale Plant. The basis of this recommendation is a comprehensive assessment of all of FPL's facilities in the moderate nonattainment area. This involved an evaluation of the 12 fossil fuel fired steam electric units and 36 gas turbines at five plants in the nonattainment area. The proposed RACT strategy would provide the Florida Department of Environmental Regulation (FDER):

1. Technically feasible, demonstrated, and cost effective control strategy based on FPL specific units which is consistent with guidance provided by the U.S. Environmental Protection Agency (EPA);
2. A 16 percent reduction in nitrogen oxides (NO_x) emissions from all of FPL facilities in the nonattainment area between the 1990 baseline year and the period 1995-2000, despite a 34 percent increase in energy used to serve customer demand (see Figure 1);
3. A 38 percent reduction in the weighted average emission rate from all of FPL facilities in the nonattainment area (i.e., a reduction in weighted average emission rate of 0.6 lb/10^6 Btu in 1990 to 0.38 lb/10^6 Btu in 1995-2000); and
4. Assurance that these significant NO_x emission reductions would be achieved by May 31, 1995.

The application consists of four sections including an introduction, description of existing sources, RACT assessment, and proposed RACT and rationale, along with supporting attachments.

INTRODUCTION

Purpose

The Lauderdale Plant is located in Broward County which has been classified as a moderate nonattainment area. Major facilities emitting NO_x and volatile organic compounds (VOCs) which

FACILITY DESCRIPTION

General

In 1990, the Lauderdale Plant consisted of two fossil fuel steam electric units and 24 gas turbines. The two fossil fuel steam electric units, Units 4 and 5, had commercial in-service dates of 1957 and 1958, respectively, and had a nominal generating capability of 160 MW each. In 1991, FPL received authorization [i.e., site certification under Florida's Power Plant Siting Act (PA86-26) and prevention of significant deterioration (PSD) approval (PSD-FL-145)] to repower Units 4 and 5. The Repowering project consisted of replacing each steam unit with a combined cycle unit. Each combined cycle unit consists of two advanced combustion turbines (CTs) and electric generators, and associated heat recovery steam generators (HRSGs). Steam from the HRSGs will be used in the existing steam electric generators. Units 4 and 5 will each have a generating capability of 480 MW and will be fired with natural gas and light distillate oil. The firing of light distillate oil is limited to a annual equivalent capacity factor of 25 percent. Units 4 and 5 will begin commercial operation in 1993.

Each existing gas turbine (GT) has a nominal generating capability of 40.5 MW and is fired with natural gas or distillate oil. These units were brought in-service in 1970 (GTs 1-12) and 1972 (GTs 13-24) and are used for peaking purposes.

NO_x Emissions

The NO_x emissions for existing Units 4 and 5 were calculated based on AP-42 emission factors; i.e., 0.45 lb/10^6 Btu for oil firing and 0.55 lb/10^6 Btu for natural gas firing. These units are being repowered with combustion turbines for which best available control technology (BACT) has been established. The NO_x emission rates for the repowered units will be 0.257 lb/10^6 Btu for oil firing and 0.16 lb/10^6 Btu for natural gas firing.

Test results indicated NO_x emission rates for the GTs of 0.82 and 0.43 lb/10^6 Btu for oil and gas firing, respectively (see Technical Support Document). The NO_x emission rate from the FPL GTs when firing oil is higher than the AP-42 emission factor of 0.698 lb/10^6 Btu. When firing natural gas, the GTs emission rate is about the same as the AP-42 emission factor of 0.44 lb/10^6 Btu.

Based on the 1990 actual fuel use data, the Lauderdale Plant had NO_x emissions of 2,127.9 tons which is about 6 percent of the total NO_x emissions for all of FPL's facilities located in Dade, Broward, and Palm Beach counties. Units 4 and 5 NO_x emissions totaled 1,375.1 tons or about 65 percent of the plant's total emissions. About 35 percent of the plant's 1990 NO_x emissions is attributable to the gas turbines.

Table 1 presents a summary of the characteristics and emissions for each unit at the Lauderdale Plant. Refer to Technical Support Document for additional information.

VOC Emissions

VOC emission rates were determined through source testing of the gas turbine units. The VOC emissions for the steam units were calculated using AP-42. Emissions from the GTs were determined as part of the licensing activities associated with the Lauderdale Repowering Project. EPA AP-42 steam generator emission factors are 0.005 and 0.0013 lb/10^6 Btu for oil and gas firing, respectively. For the GTs, the emission rates determined through testing were 0.0013 and 0.0034 lb/10^6 Btu for oil and gas firing, respectively. The AP-42 emission factors for GTs are 0.017 and 0.024 lb/10^6 Btu for oil and gas firing, respectively. VOC source test data are presented in Appendix B.

With the repowered units, maximum allowed VOC emission rates for the combustion turbines will be 0.0008 lb/10^6 Btu when firing natural gas and 0.0047 lb/10^6 Btu when firing light distillate oil. The maximum permitted emission rates are lower than the AP-42 emission factors as well as the emission rates determined for GTs 1-24.

The Lauderdale Plant also has tanks for storing and handling fuels. A total of five tanks are used for this purpose, and small amounts of VOCs are emitted through breathing and handling losses. Of the five tanks, three are or will be used for handling and storing light distillate (No. 2 or jet kerosene) fuel oil which has a minimum of VOC emissions. The light distillate fuel oil tanks have capacities of 75,000, 80,000, and 150,000 barrels.

A 4,000-gallon unleaded gasoline tank and a 1,000-gallon diesel fuel tank are also located onsite. Solvents (mineral spirits) are also used for parts cleaning and painting.

Table 2 presents actual 1990 and potential VOC emissions as well as actual estimated emissions after repowering for the Lauderdale Plant. Although the facility is a "major facility" for VOC emissions by virtue of its potential emissions, both historical and projected emissions are expected to be much less than 100 tons per year. (See Appendix A for VOC calculations; Note: Jet A or kerosene was used to estimate emissions for the Lauderdale plant since this fuel may be used by FPL in the advanced combustion turbines. Jet A has slightly higher volatility than No. 2 distillate fuel oil and produces slightly higher VOC emissions.)

NO_x RACT CONTROL ALTERNATIVES

Regulatory Guidance

For NO_x emissions from gas turbines, EPA will not issue Control Technology Guidance (CTG) documents. EPA has issued, in a supplement to the general preamble to the regulations related to the implementation of Title I of the Clean Air Act Amendments of 1990 for state implementation plans, some guidance for certain electric utility boilers [57 Federal Register (FR) 55620, November 25, 1992]. No guidance for gas turbines was provided by EPA in the preamble to Title I regulations.

For the advanced combustion turbines and simple cycle gas turbines, EPA has not provided guidance on RACT. The recognized control technique for reducing NO_x emissions from simple cycle gas turbines is combustion modifications primarily involving water injection for the type of gas turbine at the Lauderdale Plant. Combustion modifications involving staged combustion is not currently available for the FPL gas turbines.

Simple Cycle Gas Turbines--NO_x emissions can be reduced through water injection in the combustion zone of gas turbines. Water injection reduces the flame temperature and the thermal NO_x that is formed. Water injection equipment is available for the type of turbine at the Lauderdale Plant to reduce NO_x emissions by 60 percent or to 42 parts per million volume dry (ppmvd) corrected to 15 percent oxygen. Current NO_x emissions are about 100 ppmvd corrected to 15 percent oxygen. The amount of water injection required to reduced NO_x emissions at full load is about 25 gallons per minute per turbine which is about 0.75 lb water per lb of fuel.

The annualized cost to install and operate water injection is estimated to be about $130,000 per turbine or $3,120,000 per year for the 24 Lauderdale gas turbines. The cost effectiveness for the gas turbines is calculated to be over $10,000 per ton of NO_x removed. This is a result of the limited operation of the gas turbines which were operated at less than 2 percent capacity factor in 1990.

Although water injection would reduce NO_x concentrations, it would also increase emissions of carbon monoxide and VOCs. Testing performed on similar units with water injection indicate that carbon monoxide emission would increase by about 84 percent and VOC emissions would increase by over 100 percent.

POST-COMBUSTION TECHNOLOGIES

The post-combustion technologies such as selective catalytic combustion (SCR) are not applicable to the existing GTs.

VOC RACT CONTROL ALTERNATIVES

Sources of VOC emissions at the Lauderdale Plant include the advanced combustion turbines, gas turbines, and evaporative losses from tanks and solvent (mineral spirits) usage. EPA has not established CTG documents for VOC controls on combustion or gas turbines. Typically, VOCs from these sources are controlled by good combustion practices. FPL's combustion control systems are sufficiently sophisticated to ensure maximum unit efficiency. This results in actual VOC emissions that are lower than those expected using AP-42 emission factors (see discussion above). Such combustion systems also reduce particulate emissions and carbon monoxide emissions.

CTG's have been established for evaporative losses from tanks storing and handling highly volatile compounds with high vapor pressures. However, the volatility of light distillate oil is low, resulting in very little VOC emissions. Current FDER RACT rules for petroleum liquid storage tanks only regulate petroleum liquids with a true vapor pressure of greater than 1.5 pounds per square inch (psia) [see FDER Rule 17-2.650(1)(f)17 F.A.C.]. The true vapor pressure of light distillate fuel oil is 0.013 psia. With such a low true vapor pressure, the VOC emissions from tanks storing and handling light distillate oil are several orders of magnitude lower than petroleum products that are regulated. Indeed, VOC emissions for all tanks with the exception of the mineral spirits usage are less than 10 tons per year.

PROPOSED RACT AND RATIONALE

The current emission rates for gas and oil are proposed as NO_x RACT for the simple cycle gas turbines since the application of water injection is not cost effective based on the limited operation of these units (i.e., cost effectiveness of water injection is estimated to exceed $10,000 per ton of NO_x). The proposed RACT is to limit the cumulative capacity factor of these units to less than or equal to 10 percent; if capacity factors exceed this rate water injection may be required.

While the RACT rules do not apply to the repowered units, these operations will have an overall benefit in reducing emission rates and total emission in the tri-county nonattainment area. Based on the projected maximum fuel mix operation of the repowered units, the overall NO_x emission rate is 0.17 lb/10^6 Btu (0.16 lb/10^6 Btu at 80 percent capacity factor for natural gas firing and 0.26 lb/10^6 Btu at 7 percent capacity factor for oil firing). The maximum permitted (i.e., Best Available Control Technology; BACT) emission rates are the lowest currently achievable with combustion controls. Moreover, because of their efficiency, the repowered units will lower the total NO_x emissions in the tri-county area. The units are more efficient than the fossil fuel steam electric units and will have priority in their operation. On an energy equivalent basis (lb NO_x/MW) and assuming the same emission rate, the overall emission rate of the repowered units will be more than 20 percent lower than a fossil fuel steam unit. Taking together the actual emission rate of the repowered units and energy efficiency, the repowered units will emit 3 times less NO_x for each MW generated. Thus, the priority of operation and lower NO_x emission rate for the repowered units will contribute substantially to lowering the 3-county system wide emission rate by 38 percent; from 0.6 lb/10^6 Btu to 0.37 lb/10^6 Btu.

The proposed RACT for VOC sources at the Lauderdale Plant is the current emission rates. Actual emissions from the facility are estimated to be substantially less than 100 tons per year suggesting that any control would have limited value. Moreover, there are no additional control technologies for limiting VOC emissions from combustion sources or oil tanks that are reasonably available for these sources.

Certification by Professional Engineer Registered in Florida

This is to certify that the engineering features of this reasonably available control technology (RACT) application have been prepared or examined by me and found to be in conformity with modern engineering principles applicable to the treatment and disposal of pollutants characterized in the application.

Signed: Kennard F. Kosky

Date: 2/2/93

Kennard F. Kosky
KBN Engineering and Applied Sciences, Inc.
1034 NW 57th Street
Gainesville FL 32605
(904) 331-9000
Florida Registration No. 14996

SEAL
KFK

Table 1. Summary of NO_x Emission Rates and 1990 Emissions for FPL Lauderdale Plant

Unit[a]	Nominal Size (MW)	NO_x Emission Rate ($lb/10^6$ Btu) Oil	Gas	1990 NO_x Emissions (tons)	Percent of Total Plant Emissions
PFL 4	160	0.45	0.55	245.3	11.5
PFL 5	160	0.45	0.55	1,129.8	53.1
PFLGT 1-24	40.5 (each)[b]	0.82	0.43	752.8	35.4
			Total:	2,127.9	

Repowered under SCA

Note: See Tables 2-1, 2-2 and 2-3 in Technical Support Document.

[a] PFL = Fort Lauderdale.
GT = Gas Turbine
[b] Total of 972 MW for all gas turbine units.

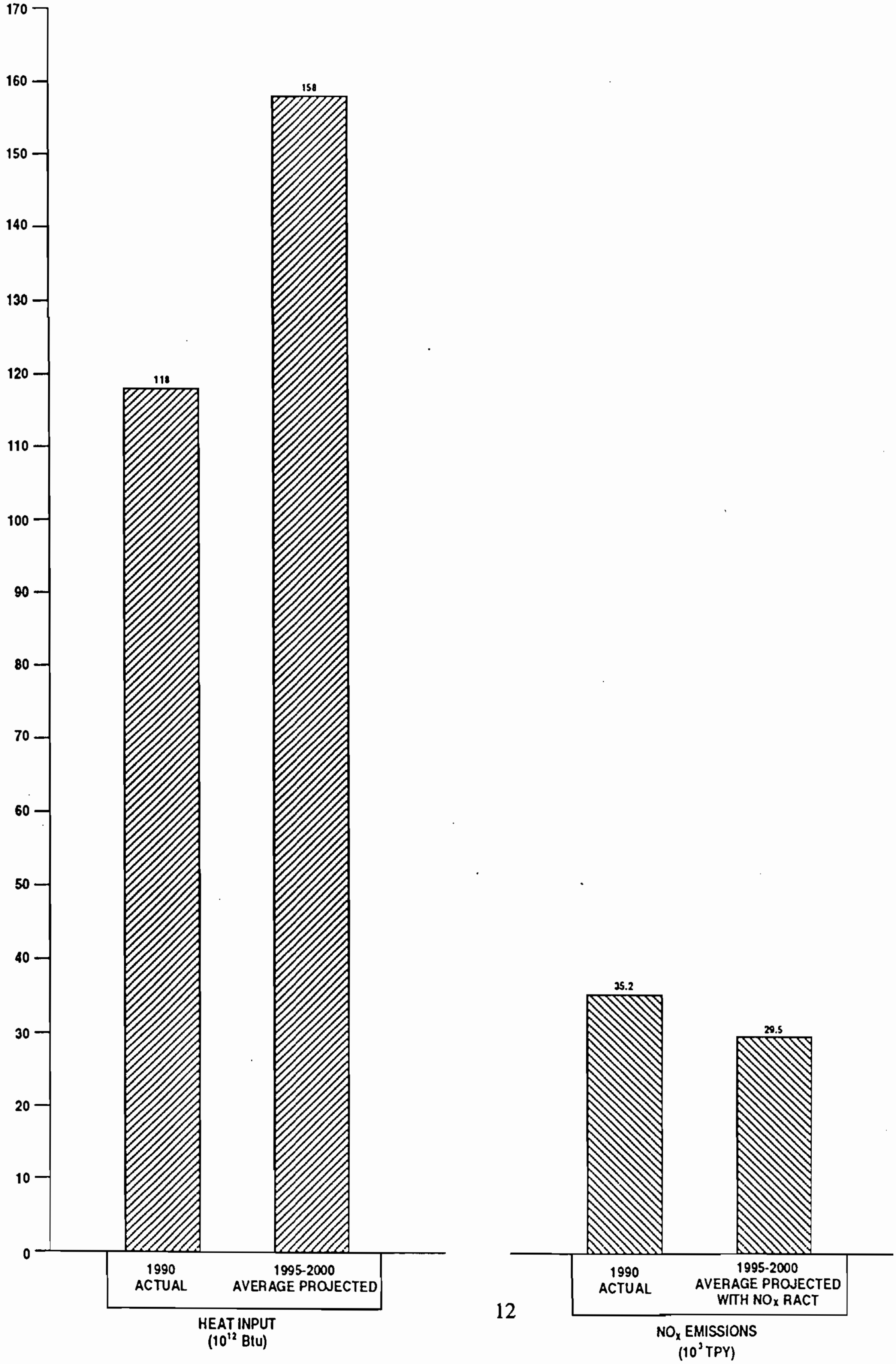
Table 2. Actual and Potential VOC Emissions for the FPL Lauderdale Plant Using Emission Rates Based on Test Results and AP-42 Factors

Unit Name	Heat Input (10^9 Btu) Oil	Heat Input (10^9 Btu) Gas	VOC Emission Rate ($lb/10^6$ Btu)[b] Oil	VOC Emission Rate ($lb/10^6$ Btu)[b] Gas	VOC Emissions (TPY)
Actual Emissions (1991)					
PFL4	248.5	4,522.8	0.0050[a]	0.0013[a]	3.6
PFL5	425.5	3,959.7	0.0050[a]	0.0013[a]	3.6
PFLGT1-24	292.6	2,940.4	0.0013[b]	0.0034[b]	5.2
Tanks	NA	NA	NA	NA	2.7[c]
Solvents	NA	NA	NA	NA	0.4[c]
				Plant Total	15.5
Estimated Actual Emissions After Repowering[d]					
PFL4	163.2	26,135.5	0.0047[e]	0.00077[e]	10.4
PFL5	711.9	23,104.2	0.0047[e]	0.00077[e]	10.6
PFLGT	88.6	2,226.5	0.0013	0.0034	3.8
Tanks[g]	NA		NA	NA	4.9[f]
Solvents	NA		NA	NA	0.9[c]
				Plant Total	30.6
Potential Emissions					
PFL4	NA	NA	NA	NA	39.4[f]
PFL5	NA	NA	NA	NA	39.4[f]
PFLGT	NA	NA	NA	NA	85.7[e]
Tanks[i]	NA	NA	NA	NA	13.3[g]
Solvent	NA	NA	NA	NA	0.9[c]
				Plant Total	178.7

Note: NA = not applicable.

[a] AP-42 emission factors.
[b] Emission factors based on gas turbine test data.
[c] From 1991 annual operating report.
[d] Heat input based on an average of 1995-2000 projected rates.
[e] Permitted rates (FDER permit AC 06-179848).
[f] Permitted rates (FDER permit No. PSD-FL-145; March, 1991).
[g] Based on jet kerosene per previous discussions with FPL.
[h] See Table A-1 in Appendix A for detailed calculations.
[i] See Table A-2 in Appendix A for detailed calculations.

Figure 1
COMPARISON OF HEAT INPUT AND NO_x EMISSION RATES FOR FPL PLANTS IN DADE, BROWARD, AND PALM BEACH COUNTIES



Attachments:

1. Appendix A--VOC Emission Calculations.
2. Appendix B--VOC Test Results.
3. FDER Renewal Application Form.
4. Technical Support Document.

APPENDIX A

VOC CALCULATIONS FOR TANKS

Table A1. Potential VOC Emission Calculations for Fixed Roof Storage Tanks at the FPL Lauderdale Plant Based on 1995-2000 Average Heat Input Rates

	Tank No. 2B Jet A	Tank No. 3B Jet A	Tank No. 5D Jet A
BREATHING LOSS			
Mv = Molecular wt of vapor[a]	130	130	130
Pa = Avg. atmospheric pressure (psia)	14.7	14.7	14.7
P = True vapor pressure (psia)[b]	0.013	0.013	0.013
D = Tank diameter (ft)	120	150	120
H = Avg. vapor space height (ft)[c]	20.0	24.0	19.0
T = Avg. ambient diurnal temp. chg. (°F)	20.0	20.0	20.0
Fp = Paint factor	1.33	1.33	1.33
C = Adj. factor sm. diameter tanks	1.0	1.0	1.0
Kc = Product factor	1.0	1.0	1.0
Lb = Fixed roof breathing loss (TPY)			
$Lb = 2.26x10^{-2}xMvP/Pa\text{-}P^{.68}D^{1.73}H^{.51}T^{.50}FpCKc/2000$	1.34	2.16	1.30
WORKING LOSS			
Mv = Molecular wt. of vapor[a]	130	130	130
P = True vapor pressure (psia)[b]	0.013	0.013	0.013
V = Tank capacity (gal)	3,360,000	6,300,000	3,150,000
Qb = Throughput (barrels)	41,647	83,294	41,647
Qg = Throughput (gallons)	1,749,180	3,498,359	1,749,180
N = Total thruput per yr (gal) / Tank capacity (gal)	1	1	1
Kn = Turnover factor	1.0	1.0	1.0
Kc = Product factor	1.0	1.0	1.0
Lw = Fixed roof working loss (TPY)			
$Lw = 2.40x10^{-5}xMvPVNKnKc/2000$	0.04	0.07	0.04
TOTAL LOSS (Lt) Lb + Lw = Lt (TPY)	1.37	2.23	1.34
Total Emissions for Fixed Roof Tanks (TPY):	4.94		

Note: All calculations based on AP-42 methodologies.

[a] Based on 60°F.
[b] Based on 75°F.
[c] Taken as half the tank height.

Table A2. Potential VOC Emission Calculations for Fixed Roof Storage Tanks at the FPL Lauderdale Plant

	Tank No. 2B Jet A	Tank No. 3B Jet A	Tank No. 5D Jet A
BREATHING LOSS			
Mv = Molecular wt of vapor[a]	130	130	130
Pa = Avg. atmospheric pressure (psia)	14.7	14.7	14.7
P = True vapor pressure (psia)[b]	0.013	0.013	0.013
D = Tank diameter (ft)	120	150	120
H = Avg. vapor space height (ft)[c]	20.0	24.0	19.0
T = Avg. ambient diurnal temp. chg. (°F)	20.0	20.0	20.0
Fp = Paint factor	1.33	1.33	1.33
C = Adj. factor sm. diameter tanks	1.0	1.0	1.0
Kc = Product factor	1.0	1.0	1.0
Lb = Fixed roof breathing loss (TPY)			
Lb = $2.26 \times 10^{-2} \times MvP/Pa\text{-}P^{.68}\ D^{1.73}\ H^{.51}\ T^{.50}\ FpCKc/2000$	1.34	2.16	1.30
WORKING LOSS			
Mv = Molecular wt. of vapor[a]	130	130	130
P = True vapor pressure (psia)[b]	0.013	0.013	0.013
V = Tank capacity (gal)	3,360,000	6,300,000	3,150,000
Qb = Throughput (barrels)	2,493,874	4,987,749	2,493,874
Qg = Throughput (gallons)	104,742,725	209,485,450	104,742,725
N = Total thruput per yr (gal) / Tank capacity (gal)	31	33	33
Kn = Turnover factor	1.0	1.0	1.0
Kc = Product factor	1.0	1.0	1.0
Lw = Fixed roof working loss (TPY)			
Lw = $2.40 \times 10^{-5} \times MvPVNKnKc/2000$	2.12	4.25	2.12
TOTAL LOSS (Lt)			
Lb + Lw = Lt (TPY)	3.46	6.41	3.43
Total Emissions for Fixed Roof Tanks (TPY):	13.29		

Note: All calculations based on AP-42 methodologies.
Emissions based on maximum potential throughput.

[a] Based on 60°F.
[b] Based on 75°F.
[c] Taken as half the tank height.

APPENDIX B

VOC TEST RESULTS

ACE
AIR CONSULTING
& ENGINEERING, INC.
2106 N.W. 67th Place • Suite 4 • Gainesville, Florida • 32606
(904) 335-1889 FAX (904) 335-1891

April 28, 1992

Mr. Michael J. Taylor
Emission Test Group
Florida Power & Light Company
Post Office Box 4830
Princeton, Florida 33092-4830

Dear Mr. Taylor:

Enclosed is an emission summary of testing performed April 9, 10, and 14, 1992 at the Port Everglades and Riviera Plants.

The Riviera Plant was unable to obtain clearance for a gas firing so only oil testing was performed.

Total hydrocarbons as propane testing was conducted using a Ratfisch RS55 FID analyzer with heated components. CO emissions were measured with a Thermo Environmental Model 48 gas correlation NDIR.

All sampling was conducted using a moisture knockout trap prior to analysis (dry basis). The Riviera Plant testing for VOC's was conducted using both a dry system and a wet system to demonstrate that no VOC's were condensing in the dry system. The wet system used heat trace line at 300°F from the point of sample.

All instruments were calibrated and operated using EPA Method 25A and 10 methodology using NBS Traceable Protocol 1 calibration gases.

If you wish a formal test report for these tests please contact me.

Thank you for allowing Air Consulting and Engineering, Inc. (ACE) to perform this valued work.

Respectfully,

AIR CONSULTING AND ENGINEERING, INC.

Stephen L. Neck

Stephen L. Neck, P.E.

SLN/cvt

cc: Ken Kosky, KBN Engineering & Applied Sciences, Inc.

ACE File: 169 92 01

Emission Sumary
FPL - Riviera Plant
Unit 4 - 4/14/92

"F" Factor Gas = 8710
"F" Factor Oil = 9190

Test Description	O2%	CO ppm	CO lbs/MMBTU	C_3H_8 ppm	C_3H_8 lbs/MMBTU
Oil firing all sampling on dry basis 10170-1117	5.16	5038	4.47	0.27	0.0004
Oil firing VOC sampled on wet basis 1148-1248	5.20	4256	3.78	0.30	0.0004

Emission Sumary
FPL - Port Everglades
Units 2 and 4 - 4/9-10/92

"F" Factor Gas = 8710
"F" Factor Oil = 9190

Test Description	O2%	CO ppm	CO lbs/MMBTU	C_3H_8 ppm	C_3H_8 lbs/MMBTU
Unit 4 - 4/9/92					
Gas Firing East 0850-0926	2.57	0.00	0.0000	0.00	0.0000
Gas Firing West 0940-1000	2.81	0.00	0.0000	0.00	0.0000
Oil Firing West 1100-1130	2.64	7.63	0.0058	0.00	0.0000
Oil Firing East 1220-1300	2.51	3.00	0.0023	0.00	0.0000
Unit 2 - 4/10/92					
Gas Firing 0815-0916	5.92	0.71	0.0006	0.14	0.0002
Oil Firing 1032-1132	5.58	0.48	0.0004	0.00	0.0000

VOC EMISSION ESTIMATES FOR GAS TURBINES 1-24

Emission estimates for VOCs from gas turbines contained in EPA Air Pollutant Emission Factors ,i.e., AP-42 are for unburned hydrocarbons. Investigations into the possible VOC emissions for the type of gas turbine unit at the Lauderdale Plant were unsuccessful in determining the amount of unreactive hydrocarbons, i.e., methane and ethane, that may be in the amount of unburned hydrocarbons. As a result, source testing which excluded these nonreactive hydrocarbons was performed as allowed by FDER Rule 17-2.100(223) F.A.C. The results of these tests are presented in the following report.

The emissions from the tests were evaluated statistically to determine an upper limit that would be applicable to all 24 gas turbines. The results of this evaluation indicated an upper bound for the emissions as follows:

Natural Gas - 0.0034 lb VOC per million Btu heat input
No. 2 Fuel Oil - 0.0013 lb VOC per million Btu heat input

The natural gas emission factor reflects an upper confidence limit of 95 percent. This confidence limit was chosen to account the generally higher VOC emissions on natural gas relative to fuel oil and the greater operating usage on natural gas. In addition, natural gas can contain minute quantities of ethylene, propane, butane and, hexane and higher molecular weight gases that are considered VOCs. The fuel oil emission factor was based on a 90 percent confidence limit. All statistics were based on the t distribution.

SOURCE TEST REPORT

VOLATILE ORGANIC COMPOUND EMISSIONS
EXCLUDING METHANE AND ETHANE

FLORIDA POWER AND LIGHT COMPANY
LAUDERDALE POWER PLANT
GAS TURBINE PEAKING UNITS 8 AND 23

NOVEMBER 8 AND 10, 1989

Prepared for:

KBN ENGINEERING AND APPLIED SCIENCES, INC.
1034 N.W. 57th STREET
GAINESVILLE, FLORIDA 32605

Prepared by:

AIR CONSULTING AND ENGINEERING, INC.
2106 N.W. 67th PLACE, SUITE 4
GAINESVILLE, FLORIDA 32606
(904) 335-1889

163-89-05

Table 1 Emission Summary
Florida Power and Light Company
Ft. Lauderdale Power Plant
November 8 and 10, 1989

Date	Fuel	Load MW	C_3H_8 ppm	O_2 %	Fuel Factor	Emission Rate* lb/MMBTU Carbon
Unit 8						
11/8/89	Natural gas	32.5	0.41	16.82	8710	0.0017
11/8/89	Distillate	32.5	0.20	16.51	9190	0.0008
Unit 23						
11/10/89	Distillate	33.0	0.46	16.90	8710	0.0020
11/10/89	Oil	32.5	0.11	16.75	9190	0.0005

* $E = (\text{ppm } C_3H_8)\,(2.595 \times 10^{-9})\,(\text{Fuel Factor})\left(\frac{20.9}{20.9 - \%O_2}\right)(36)$

Where 36 = molecular weight of carbon in C_3H_8

SECTION #3

APPLICATION FOR PERMIT
PROPOSED RACT FOR AIR POLLUTION SOURCES

CUTLER POWER PLANT

1. Application - Unit No. 5 Oil & Gas Fired, 75 MW Class (85 MW Gross Capacity)

2. Application - Unit No. 6 Oil & Gas Fired, 160 MW Class (160 MW Gross Capacity)

3. Proposed Reasonably Available Control Technology (RACT) for Florida Power & Light Company (FPL) Cutler Plant

Florida Department of Environmental Regulation

APPLICATION FOR PERMIT OF
PROPOSED RACT FOR AIR POLLUTION SOURCES(s)

If major alterations have occurred, the applicant should complete the Standard Air Permit Application Form.

Source Type: Fossil Fuel Steam Generator   Renewal of DER Permit No. AO-13-173751

Company Name: Florida Power & Light Company County: Dade

Identify the specific emission point source(s) addressed in this application (i.e., Lime Kiln No. 4 with Venturi Scrubber; Peaking Unit No. 2, Gas Fired):

Cutler Power Plant, Unit No. 5 Oil & Gas Fired, 75 MW Class (85 MW Gross Capacity)

Source Location: Street: 14925 S W 67 Avenue   City: Miami

UTM: East 570.4 Km Zone 17   North 2834.9 Km

Latitude: 25° 37' 52"N   Longitude: 80° 17' 56"W

---

1. Attach a check made payable to the Department of Environmental Regulation in accordance with operation permit fee schedule set forth in Florida Administrative Code Rule 17-4.05.

2. Have there been any alterations to the plant since last permitted? [ ] Yes [X] No If minor alterations have occurred, describe on a separate sheet and attach.

3. Attach the last compliance test report required per permit conditions if not submitted previously. **All compliance test reports have been submitted**

4. Have previous permit conditions been adhered to? [X] Yes [ ] No If no, explain on a separate sheet and attach.

5. Has there been any malfunction of the pollution control equipment during tenure of current permit? [ ] Yes [X] No If yes, and not previously reported, give brief details and what action was taken on a separate sheet and attach.

6. Has the pollution control equipment been maintained to preserve the collection efficiency last permitted by the Department? [X] Yes [ ] No

7. Has the annual operating report for the last calendar year been submitted? [X] Yes [ ] No If no, please attach.

8. Please provide the following information if applicable:

A. Raw Materials and Chemical Used in Your Process:

Description	Contaminant Type	%Wt	Utilization Rate lbs/hr
Magnesium Oxide is no longer Utilized			

B. Product Weight (lbs/hr): Not applicable

C. Fuels:

Type (Be Specific)	Consumption* Avg/hr*	Max/hr**	Maximum Heat Input(MMBTU/hr)
Fuel Oil No. 2 0.5% max. S (Start-up Only)	N/A	29.8	170
Residual Fuel Oil No. 6 0.5% max. S (Start-up Only)	N/A	27.0	170
Natural Gas	Variable	0.94	940

D. Potential Equipment Operating Time Up To: hrs/day 24; days/wk 7; wks/yr 52; hrs/yr (power plants only); 2657 hours of operation during 1992, all on natural gas. More operating time is typical when ambient temperature is either unusually high or low, or during other unusual system demands.

The undersigned owner or authorized representative*** of **Florida Power & Light Company** is fully aware that the statements made in this application for a renewal of a permit to operate an air pollution source are true, correct and complete to the best of his knowledge and belief. Further, the undersigned agrees to maintain and operate the pollution source and pollution control facilities in such a manner as to comply with the provisions of Chapter 403, Florida Statutes, and all the rules and regulations of the Department. He also understands that a permit, if granted by the Department, will be non-transferable and he will promptly notify the Department upon sale or legal transfer of the permitted facility. **This certification pertains solely to air pollution related requirements.**

Elsa A. Bishop

Signature, Owner or Authorized Representative
(Notarization is mandatory)

*During actual time of operation.
**Units: Natural Gas-MMCF/hr; Fuel Oils-barrels/hr; Coal-
***Attach letter of authorization if not previsouly submitted.

E. A. Bishop, Supervisor
Air Permitting and Programs
Typed Name and Title

P. O. Box 088801
Address

North Palm Beach
City

Florida 33408
State Zip

2/1/93
Date

(407) 625-7607
Telephone No.

Florida Department of Environmental Regulation

APPLICATION FOR PERMIT OF
PROPOSED RACT FOR AIR POLLUTION SOURCE(S)

If major alterations have occurred, the applicant should complete the Standard Air Permit Application Form.

Source Type: Fossil Fuel Steam Generator   Renewal of DER Permit No. AO-13-173753

Company Name: Florida Power & Light Company County: Dade

Identify the specific emission point source(s) addressed in this application (i.e., Lime Kiln No. 4 with Venturi Scrubber; Peaking Unit No. 2, Gas Fired):

Cutler Power Plant, Unit No. 6 Oil & Gas Fired, 160 MW Class (160 MW Gross Capacity)

Source Location: Street: 14925 S W 67 Avenue   City: Miami

UTM: East 570.4 Km Zone 17   North 2834.9 Km

Latitude: 25° 37' 52"N   Longitude: 80° 17' 56"W

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1. Attach a check made payable to the Department of Environmental Regulation in accordance with operation permit fee schedule set forth in Florida Administrative Code Rule 17-4.05.

2. Have there been any alterations to the plant since last permitted? [ ] Yes [X] No If minor alterations have occurred, describe on a separate sheet and attach.

3. Attach the last compliance test report required per permit conditions if not submitted previously. **All compliance test reports have been submitted**

4. Have previous permit conditions been adhered to? [X] Yes [ ] No If no, explain on a separate sheet and attach.

5. Has there been any malfunction of the pollution control equipment during tenure of current permit? [ ] Yes [ ] No If yes, and not previously reported, give brief details and what action was taken on a separate sheet and attach. **N/A**

6. Has the pollution control equipment been maintained to preserve the collection efficiency last permitted by the Department? [ ] Yes [ ] No **N/A**

7. Has the annual operating report for the last calendar year been submitted? [X] Yes [ ] No If no, please attach.

8. Please provide the following information if applicable:

A. Raw Materials and Chemical Used in Your Process:

Description	Contaminant Type	%Wt	Utilization Rate	lbs/hr
Magnesium Oxide is no longer Utilized				

B. Product Weight (lbs/hr): Not applicable

C. Fuels:

Type (Be Specific)	Consumption* Avg/hr*	Max/hr**	Maximum Heat Input(MMBTU/hr)
Fuel Oil No. 2 0.5% max. S (Start-up Only)	N/A	50.9	290
Residual Fuel Oil No. 6 0.5 % max. S (Start-up Only)	N/A	46.0	290
Natural Gas	Variable	1.6	1620

D. Potential Equipment Operating Time Up To: hrs/day 24; days/wk 7; wks/yr 52; hrs/yr (power plants only); 3274 hours of operation during 1992, all on natural gas. More operating time is typical when ambient temperature is either unusually high or low, or during other unusual system demands.

The undersigned owner or authorized representative*** of **Florida Power & Light Company** is fully aware that the statements made in this application for a renewal of a permit to operate an air pollution source are true, correct and complete to the best of his knowledge and belief. Further, the undersigned agrees to maintain and operate the pollution source and pollution control facilities in such a manner as to comply with the provisions of Chapter 403, Florida Statutes, and all the rules and regulations of the Department. He also understands that a permit, if granted by the Department, will be non-transferable and he will promptly notify the Department upon sale or legal transfer of the permitted facility. **This certification pertains solely to air pollution related requirements.**

Elsa A. Bishop

Signature, Owner or Authorized Representative
(Notarization is mandatory)

E. A. Bishop, Supervisor
Air Permitting and Programs
Typed Name and Title

P. O. Box 088801
Address

North Palm Beach
City

Florida 33408
State Zip

2/1/93
Date

(407) 625-7607
Telephone No.

*During actual time of operation.
**Units: Natural Gas-MMCF/hr; Fuel Oils-barrels/hr; Coal-
***Attach letter of authorization if not previsouly submitted.

PROPOSED
REASONABLY AVAILABLE CONTROL TECHNOLOGY (RACT)
FOR
FLORIDA POWER & LIGHT COMPANY (FPL)
CUTLER PLANT

PERSPECTIVE

The information contained in this application and the supporting documents provides FPL's recommended RACT emission limit for the Cutler plant. The basis of this recommendation is a comprehensive assessment of all of FPL's facilities in the moderate nonattainment area. This involved an evaluation of the 12 fossil fuel fired steam electric units and 36 gas turbines at five plants in the nonattainment area. The proposed RACT strategy would provide the Florida Department of Environmental Regulation (FDER):

1. A technically feasible, demonstrated, and cost effective control strategy based on FPL specific units which is consistent with guidance provided by the U.S. Environmental Protection Agency (EPA);
2. A 16 percent reduction in nitrogen oxides (NO_x) emissions from all of FPL facilities in the nonattainment area between the 1990 baseline year and the period 1995-2000, despite a 34 percent increase in energy used to serve customer demand (see Figure 1);
3. A 38 percent reduction in the weighted average emission rate from all of FPL facilities in the nonattainment area (i.e., a reduction in weighted average emission rate of 0.6 lb/10^6 Btu in 1990 to 0.38 lb/10^6 Btu in 1995-2000); and
4. Assurance that these significant NO_x emission reductions would be achieved by May 31, 1995.

The application consists of four sections including an introduction, description of existing sources, RACT assessment, and proposed RACT and rationale, along with supporting attachments.

INTRODUCTION

Purpose

The Cutler plant is located in Dade County which has been classified as a moderate ozone nonattainment area. Major facilities emitting NO_x and volatile organic compounds (VOCs) which are located in nonattainment areas classified as moderate or higher must apply for a new or revised operation permit by March 1, 1993 [pursuant to Rule 17-296.570 Florida Administrative Code (F.A.C.)]. The application will be reviewed by FDER for the purpose of establishing RACT emission limits for NO_x and VOCs on a case-by-case basis. The Cutler plant is a major emitting facility for NO_x subject to the RACT Determination procedure of FDER Rule 17-296.570 (4) F.A.C. This application and the attached technical support document titled "Reasonably Available Control Technology (RACT) Assessment of Florida Power & Light Company's Facilities Located in the Dade, Broward and Palm Beach Ozone Nonattainment Area" provides information required by FDER Rules, including FPL's recommended RACT determination for the Cutler plant sources.

RACT Requirements

The term "RACT" is defined in FDER rules as follows:

> RACT is the lowest emission limit that a particular source is capable of meeting by the application of control technology that is reasonably available considering technological and economic feasibility. [FDER Rule 17-2.100 (163) F.A.C.]

This longstanding regulatory definition, which EPA originally promulgated to guide states in establishing RACT emission limits for existing sources in nonattainment areas, clearly reflects the case-by-case, fact-specific nature of RACT determinations. Indeed, FDER's RACT Determination Procedure clearly states that RACT is to be established by the Department on a case-by-case basis. Consideration is given to RACT emission limiting standards established by other states, information available from EPA guidance documents, technological and economic feasibility, and all other relevant information [see FDER Rule 17-296.570 (4)(b) F.A.C.].

FACILITY DESCRIPTION

General

The Cutler plant consists of two fossil fuel steam electric units, Units 5 and 6, which have a nominal generating capability of 75 MW and 160 MW each. Units 5 and 6 have in-service dates of 1954 and 1958, respectively. The fossil fuel steam units are fired with natural gas only. All

~~of 1954 and 1958, respectively. The fossil fuel steam units are fired with natural gas only. All~~ units have large furnaces and are fired tangentially with high heat release rates, i.e., greater than 80,000 Btu/hr-ft^3.

A 0.3-MW emergency diesel generator also exists at the Cutler plant. This unit is not permitted and therefore is not subject to RACT.

NO_x Emissions

FPL conducted emission tests in 1991 and 1992 to "benchmark" NO_x emission rates for the affected units. Where units were substantially identical, only one unit was tested. The benchmarking tests are representative of the normal operation of the units and provide representative emission estimates for developing control options (refer to Technical Support Document for test results).

Test results indicated NO_x emissions rates for Units 5 and 6 fired on natural gas of 0.14 and 0.16 lb/10^6 Btu, respectively. The NO_x emission rates when firing natural gas were much lower than the AP-42 emission factor, i.e., 0.14 and 0.16 lb/10^6 Btu compared to 0.55 lb/10^6 Btu.

The NO_x emission rates determined from the benchmarking tests were used to estimate 1990 NO_x emissions. Based on the 1990 actual fuel use data, the Cutler plant had NO_x emissions of 133.1 tons which is less than 1 percent of the total NO_x emissions from FPL's facilities located in Dade, Broward, and Palm Beach counties.

Table 1 presents a summary of the characteristics and emissions for each unit at the Cutler plant. Refer to Technical Support Document for additional information.

VOC Emissions

VOC emission rates were determined through source testing of both the fossil fuel fired steam electric units and gas turbine units at the Port Everglades and Riviera plants. The VOC emissions for the steam units were determined in 1992 using EPA Method 25A. Table 2 presents the VOC emission rates used for the sources at the Cutler plant. The emission rates determined using EPA test methods are lower than the AP-42 emission factors for these sources. For the steam electric units, the maximum emission rates determined through testing were 0.0004 and 0.0002 $lb/10^6$ Btu for oil and gas firing, respectively. In contrast, EPA AP-42 emissions factors are 0.005 and 0.0013 $lb/10^6$ Btu, respectively. VOC source test data are presented in Appendix B.

The Cutler plant also has tanks for storing and handling fuels and solvents. A total of three tanks are used for this purpose, and small amounts of VOCs are emitted through breathing and handling losses. The three tanks include one tank each for storage and handling of gasoline, diesel fuel, and mineral spirits. The gasoline and diesel tanks have a capacity of 550 gallons each. The mineral spirits tank has a capacity of 250 gallons. The mineral spirits tank is now out of use.

VOC emissions due to tank breathing and working losses are presented in Appendix A, Table A1.

The Cutler plant also has VOC emissions due to paint and solvent use. The products used in 1991 and the estimated VOC emissions are presented in Table A2 of Appendix A.

Table 2 presents actual 1990 and potential VOC emissions for the Cutler plant. The facility is not considered to be a "major facility" for VOC emissions because its potential and actual emissions are less than 100 TPY.

Because VOC emissions are less than 100 TPY, RACT for VOC would not apply for these units.

NO_x AND VOC RACT CONTROL ALTERNATIVES

Regulatory Guidance

For NO_x emissions from fossil fuel fired steam generators and gas turbines, EPA will not issue Control Technology Guidance (CTG) documents. EPA has issued, in a supplement to the general preamble to the regulations related to the implementation of Title I of the Clean Air Act Amendments of 1990 for state implementation plans, some guidance for certain electric utility boilers [57 Federal Register (FR) 55620, November 25, 1992].

EPA's guidance concluded that RACT for utility generators should reflect " the most effective level of combustion modification reasonably available to an individual unit". EPA specified by reference the application of low NO_x burners but recognized that in some cases overfire air and flue gas recirculation may be appropriate while in other cases RACT would require no additional control.

Control Alternatives

The Cutler units, because of their design, have inherently low NO_x emissions. When firing natural gas, the emission rates were determined to be less than the new source performance standards (NSPS) for new units (i.e., 0.2 lb/10^6 Btu; see 40 CFR Part 60 Subpart Db). While these units are more than 30 years old, their specific design reflects the facility-specific factors related to NO_x emissions. Additional combustion controls are unwarranted since these units are lower than the EPA suggested control level as well as NSPS.

PROPOSED RACT AND RATIONALE

The very low NO_x emission rates for Cutler Units 5 and 6, combined with their low capacity factors and use of natural gas only, indicate that these units already meet the RACT requirements.

Certification by Professional Engineer Registered in Florida

This is to certify that the engineering features of this reasonably available control technology (RACT) application have been prepared or examined by me and found to be in conformity with modern engineering principles applicable to the treatment and disposal of pollutants characterized in the application.

Signed: Kennard F. Kosky   Date: 2/2/93

Kennard F. Kosky
KBN Engineering and Applied Sciences, Inc.
1034 NW 57th Street
Gainesville FL 32605
(904) 331-9000
Florida Registration No. 14996

SEAL
/KS

Table 1. Summary of NO_x Emission Rates and 1990 Emissions for FPL Cutler Plant

Unit[a]	Nominal Size (MW)	NO_x Emission Rate ($lb/10^6$ Btu) Oil	Gas	1990 NO_x Emissions (tons)	Percent of Total Plant Emissions
PCU 5	75	NA	0.14	79.2	59.5
PCU 6	160	NA	0.16	53.9	40.5
			Total:	133.1	

Note: See Tables 2-1, 2-2 and 2-3 in Technical Support Document.
NA = not applicable.

[a] PCU = Cutler plant.

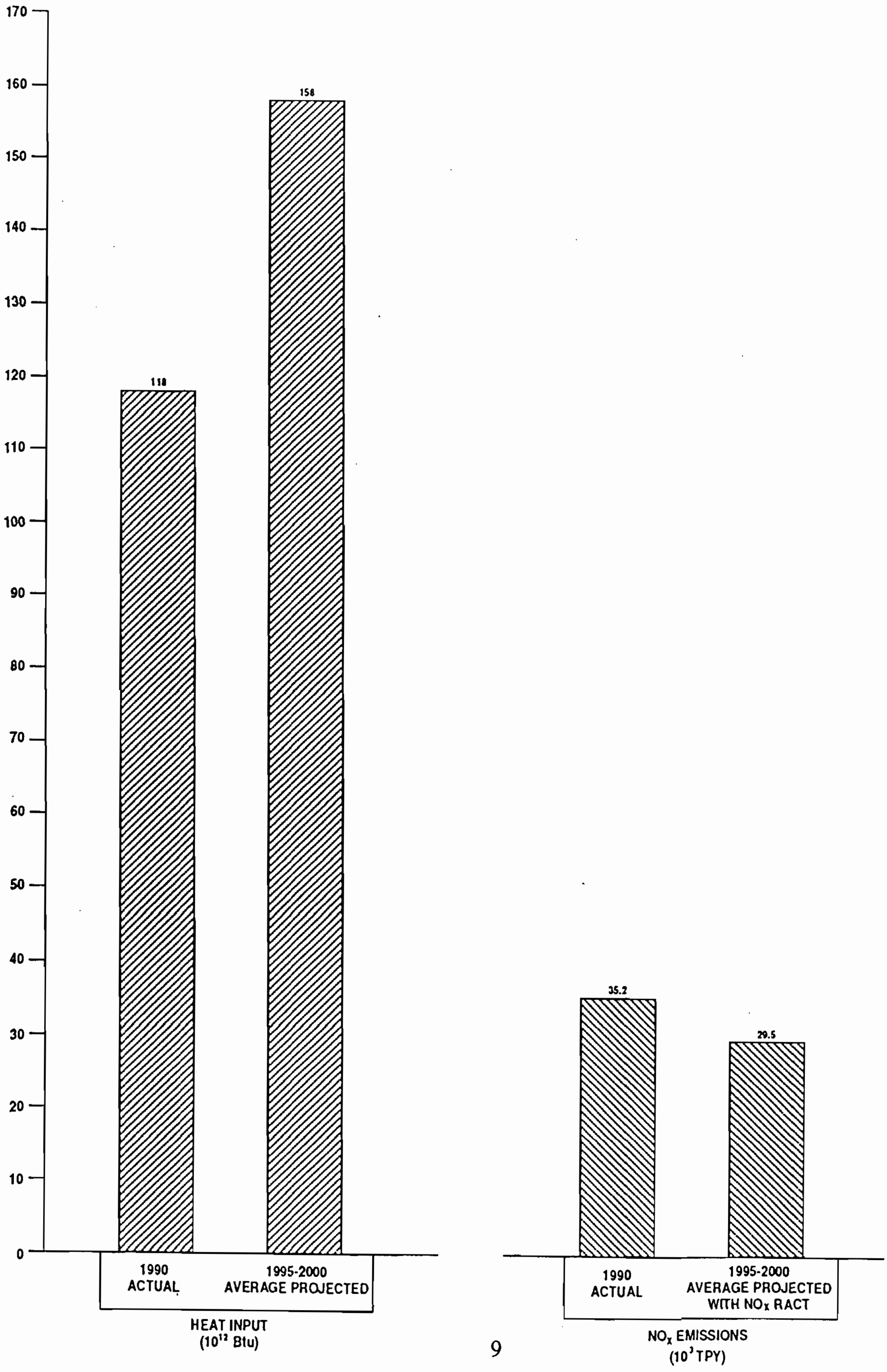
Table 2. Actual and Potential VOC Emissions for the FPL Cutler Plant Using Emission Rates Based on Test Results

Unit Name	Heat Input (10^9 Btu)[a] Oil	Heat Input (10^9 Btu)[a] Gas	VOC Emission Rate ($lb/10^6$ Btu)[b] Oil	VOC Emission Rate ($lb/10^6$ Btu)[b] Gas	VOC Emissions (TPY)
Actual Emissions					
PCU-5	0.0	1,131.8	0.0	0.0002	0.1
PCU-6	0.0	673.7	0.0	0.0002	0.1
Tanks[c]	NA	NA	NA	NA	0.2
Solvents[d]	NA	NA	NA	NA	3.1
				Plant Total	3.5
Potential Emissions					
PCU-5	0.0	8,234.4	0.0	0.0002	0.8
PCU-6	0.0	14,191.2	0.0	0.0002	1.4
Tanks[c]	NA	NA	NA	NA	0.2
Solvents[d]	NA	NA	NA	NA	3.1
				Plant Total	5.5

Note: NA = not applicable.

[a] 1990 heat input values as provided by FPL.
[b] Boiler emission rates based on tests conducted at the Riviera and Port Everglades plants.
[c] Refer to Table A1 in Appendix A for detailed calculations.
[d] Refer to Table A2 in Appendix A for detailed calculations.

Figure 1
COMPARISON OF HEAT INPUT AND NO_x EMISSION RATES FOR FPL PLANTS IN DADE, BROWARD, AND PALM BEACH COUNTIES



Attachments:

1. Appendix A--VOC Emission Calculations.

2. Appendix B--VOC Test Results.

3. FDER Renewal Application Form.

4. Technical Support Document.

APPENDIX A

VOC CALCULATIONS FOR TANKS AND SOLVENTS

Table A1. VOC Emission Calculations for Storage Tanks at the FPL Cutler Plant

	Gasoline Tank	#2 Diesel Tank	Mineral Spirits (Empty)
BREATHING LOSS			
Mv = Molecular wt of vapor[a]	64	130	0.0
Pa = Avg. atmospheric pressure (psia)	14.7	14.7	0.0
P = True vapor pressure (psia)[b]	7.4	0.012	0.0
D = Tank diameter (ft)	5.97	5.97	0.0
H = Avg. vapor space height (ft)[c]	1.75	1.75	0.0
T = Avg. ambient diurnal temp. chg. (°F)	14.8	14.8	0.0
Fp = Paint factor[d]	1.40	1.40	0.0
C = Adj. factor sm. diameter tanks	1.0	0.64	0.0
Kc = Product factor	1.0	1.0	0.0
Lb = Fixed roof breathing loss (TPY)			
Lb = $2.26\text{x}10^{-2}\text{xMvP/Pa-P}^{.68}\text{D}^{1.73}\text{H}^{.51}\text{T}^{.50}\text{FpCKc/2000}$	0.12	0.001	0.0
WORKING LOSS			
Mv = Molecular wt. of vapor[a]	64	130	0.0
P = True vapor pressure (psia)[b]	7.4	0.012	0.0
V = Tank capacity (gal)	550	550	0.0
Qb = Throughput (barrels)	150	107	0.0
Qg = Throughput (gallons)	6,300	4,500	0.0
N = Total thruput per yr (gal) / Tank capacity (gal)	11	8	0.0
Kn = Turnover factor	1.0	1.0	0.0
Kc = Product factor	1.0	1.0	0.0
Lw = Fixed roof working loss (TPY)			
Lw = $2.40\text{x}10^{-5}\text{xMvPVNKnKc/2000}$	0.036	0.000084	0.0
TOTAL LOSS (Lt)			
Lb + Lw = Lt (TPY)	0.15	0.001	0.0
Total Emissions for Fixed Roof Tanks (TPY):	0.15		

Note: All calculations based on AP42 methodologies.
Emissions based on 1991 throughputs.
All tanks are horizontal and are of unknown dimensions. Assume a tank diameter and length of 3.5 and 8 feet, respectively. Effective tank diameter is 5.97 feet based on the liquid surface area in a half-full tank.

[a] Based on 60 degrees F.
[b] Based on 80 degrees F.
[c] Taken as half the tank height.
[d] Tank color unknown. Use paint factor for light gray.

Table A2. Estimated VOC Emission Due to Paint and Solvent Usage at the FPL Cutler Plant

Product Name	Estimated Annual Usage (gal)[a]	Solvent Density (lb/gal)[b]	Percent VOC[b]	Estimated VOC Emissions (lb/yr)	(TPY)
No. 1 Thinner	165	7.23	100	1,193.0	0.60
No. 4 Thinner	55	7.50	100	412.5	0.21
Acrylic Enamel	100	8.50	75	637.5	0.32
Universal Primer	200	8.50	75	1,275.0	0.64
Acrylic Latex	200	8.50	75	1,275.0	0.64
No. 2 Thinner	30	7.10	100	213.0	0.11
No. 76 Thinner	10	7.50	100	75.0	0.04
Carboline 834 Pt. A	45	8.50	75	286.9	0.14
Urethane Converter 811	45	8.50	75	286.9	0.14
Carboline 893 Pt. B	45	8.50	75	286.9	0.14
Carboline 893 Pt. A	45	8.50	75	286.9	0.14
			TOTAL:	6,228.5	3.11

[a] Based on 1991 annual purchases.
[b] If unknown, a conservative density and VOC content of 8.5 lb/gal and 75 percent was used.

APPENDIX B

VOC TEST RESULTS

ACE
AIR CONSULTING
& ENGINEERING, INC.

2106 N.W. 67th Place • Suite 4 • Gainesville, Florida • 32606
(904) 335-1889 FAX (904) 335-1891

April 28, 1992

Mr. Michael J. Taylor
Emission Test Group
Florida Power & Light Company
Post Office Box 4830
Princeton, Florida 33092-4830

Dear Mr. Taylor:

Enclosed is an emission summary of testing performed April 9, 10, and 14, 1992 at the Port Everglades and Riviera Plants.

The Riviera Plant was unable to obtain clearance for a gas firing so only oil testing was performed.

Total hydrocarbons as propane testing was conducted using a Ratfisch RS55 FID analyzer with heated components. CO emissions were measured with a Thermo Environmental Model 48 gas correlation NDIR.

All sampling was conducted using a moisture knockout trap prior to analysis (dry basis). The Riviera Plant testing for VOC's was conducted using both a dry system and a wet system to demonstrate that no VOC's were condensing in the dry system. The wet system used heat trace line at 300°F from the point of sample.

All instruments were calibrated and operated using EPA Method 25A and 10 methodology using NBS Traceable Protocol 1 calibration gases.

If you wish a formal test report for these tests please contact me.

Thank you for allowing Air Consulting and Engineering, Inc. (ACE) to perform this valued work.

Respectfully,

AIR CONSULTING AND ENGINEERING, INC.

Stephen L. Neck

Stephen L. Neck, P.E.

SLN/cvt

cc: Ken Kosky, KBN Engineering & Applied Sciences, Inc.

ACE File: 169 92 01

Emission Sumary
FPL - Riviera Plant
Unit 4 - 4/14/92

"F" Factor Gas = 8710
"F" Factor Oil = 9190

Test Description	O2%	CO ppm	CO lbs/MMBTU	C_3H_8 ppm	C_3H_8 lbs/MMBTU
Oil firing all sampling on dry basis 10170-1117	5.16	5038	4.47	0.27	0.0004
Oil firing VOC sampled on wet basis 1148-1248	5.20	4256	3.78	0.30	0.0004

Emission Sumary
FPL - Port Everglades
Units 2 and 4 - 4/9-10/92

"F" Factor Gas = 8710
"F" Factor Oil = 9190

Test Description	O2%	CO ppm	CO lbs/MMBTU	C_3H_8 ppm	C_3H_8 lbs/MMBTU
Unit 4 - 4/9/92					
Gas Firing East 0850-0926	2.57	0.00	0.0000	0.00	0.0000
Gas Firing West 0940-1000	2.81	0.00	0.0000	0.00	0.0000
Oil Firing West 1100-1130	2.64	7.63	0.0058	0.00	0.0000
Oil Firing East 1220-1300	2.51	3.00	0.0023	0.00	0.0000
Unit 2 - 4/10/92					
Gas Firing 0815-0916	5.92	0.71	0.0006	0.14	0.0002
Oil Firing 1032-1132	5.58	0.48	0.0004	0.00	0.0000

SECTION #4

APPLICATION FOR PERMIT
PROPOSED RACT FOR AIR POLLUTION SOURCES

TURKEY POINT POWER PLANT

1. Application - Unit No. 1 Oil & Gas Fired, 400 MW Class (440 MW Gross Capacity)

2. Application - Unit No. 2 Oil & Gas Fired, 400 MW Class (440 MW Gross Capacity)

3. Proposed Reasonably Available Control Technology (RACT) for Florida Power & Light Company (FPL) Turkey Point Plant

Florida Department of Environmental Regulation

APPLICATION FOR PERMIT OF
PROPOSED RACT FOR AIR POLLUTION SOURCE(S)

If major alterations have occurred, the applicant should complete the Standard Air Permit Application Form.

Source Type: Fossil Fuel Steam Generator   Renewal of DER Permit No. AO-13-155469

Company Name: Florida Power & Light Company County: Dade

Identify the specific emission point source(s) addressed in this application (i.e., Lime Kiln No. 4 with Venturi Scrubber; Peaking Unit No. 2, Gas Fired):

Turkey Point Power Plant, Unit No. 1 Oil & Gas Fired, 400 MW Class (440 MW Gross Capacity)

Source Location: Street: Palm Drive 9 1/2 miles East of   City: Florida City

UTM: East 567.2 Km Zone 17   North 2813.2 Km

Latitude: 25° 26' 09"N   Longitude: 80° 19' 52"W

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1. Attach a check made payable to the Department of Environmental Regulation in accordance with operation permit fee schedule set forth in Florida Administrative Code Rule 17-4.05.

2. Have there been any alterations to the plant since last permitted? [ ] Yes [X] No If minor alterations have occurred, describe on a separate sheet and attach.

3. Attach the last compliance test report required per permit conditions if not submitted previously. **All compliance test reports have been submitted**

4. Have previous permit conditions been adhered to? [X] Yes [ ] No If no, explain on a separate sheet and attach.

5. Has there been any malfunction of the pollution control equipment during tenure of current permit? [ ] Yes [X] No If yes, and not previously reported, give brief details and what action was taken on a separate sheet and attach.

6. Has the pollution control equipment been maintained to preserve the collection efficiency last permitted by the Department? [X] Yes [ ] No

7. Has the annual operating report for the last calendar year been submitted? [X] Yes [ ] No If no, please attach.

8. Please provide the following information if applicable:

A. Raw Materials and Chemical Used in Your Process:

Description	Contaminant Type	%Wt	Utilization Rate lbs/hr
MgO or $Mg(OH)_2$ Additive	Particulate	100	40 lb/day average estimated for 1991
Evaporation of boiler cleaning water with approximately 3% of monoammonium citrate solution	Particulate	100	Approximately 75,000 gallons of water every 3 years

B. Product Weight (lbs/hr): Not applicable

C. Fuels: In order to improve start-up combustion, propane gas may be used for stabilizing ignition, small amounts of light oil (No. 2 fuel oil), or natural gas if that is available, are sometimes fired to preheat the boiler prior to ignition of residual fuel oil. Very small quantities of on-specification used oil, entirely from FPL operations, may be consumed while burning residual oil.

Type (Be Specific)	Consumption* Avg/hr*	Max/hr**	Maximum Heat Input (MMBTU/hr)
Residual Fuel Oil	Variable	631	3850
Natural Gas	Variable	4.02	4025

D. Potential Equipment Operating Time Up To: hrs/day 24; days/wk 7; wks/yr 52; hrs/yr (power plants only) ; 3378 hours of operation during 1992. More operating time is typical when ambient temperature is either unusually high or low, or during other unusual system demands.

The undersigned owner or authorized representative*** of Florida Power & Light Company is fully aware that the statements made in this application for a renewal of a permit to operate an air pollution source are true, correct and complete to the best of his knowledge and belief. Further, the undersigned agrees to maintain and operate the pollution source and pollution control facilities in such a manner as to comply with the provisions of Chapter 403, Florida Statutes, and all the rules and regulations of the Department. He also understands that a permit, if granted by the Department, will be non-transferable and he will promptly notify the Department upon sale or legal transfer of the permitted facility. **This certification pertains solely to air pollution related requirements.**

Elsa A. Bishop

Signature, Owner or Authorized Representative
(Notarization is mandatory)

E. A. Bishop, Supervisor
Air Permitting and Programs

Typed Name and Title

P. O. Box 088801
Address

North Palm Beach
City

Florida 33408
State Zip

2/1/93

(407) 625-7607

*During actual time of operation.
**Units: Natural Gas-MMCF/hr; Fuel Oils-barrels/hr; Coal-
***Attach letter of authorization if not previsouly submitted.

Florida Department of Environmental Regulation

APPLICATION FOR PERMIT OF
PROPOSED RACT FOR AIR POLLUTION SOURCE(S)

If major alterations have occurred, the applicant should complete the Standard Air Permit Application Form.

Source Type: Fossil Fuel Steam Generator   Renewal of DER Permit No. AO-13-155471

Company Name: Florida Power & Light Company County: Dade

Identify the specific emission point source(s) addressed in this application (i.e., Lime Kiln No. 4 with Venturi Scrubber; Peaking Unit No. 2, Gas Fired):

Turkey Point Power Plant, Unit No. 2 Oil & Gas Fired, 400 MW Class (440 MW Gross Capacity)

Source Location: Street: Palm Drive 9 1/2 miles East of   City: Florida City

UTM: East 567.2 Km Zone 17   North 2813.2 Km

Latitude: 25° 26′ 09"N   Longitude: 80° 19′ 52"W

---

1. Attach a check made payable to the Department of Environmental Regulation in accordance with operation permit fee schedule set forth in Florida Administrative Code Rule 17-4.05.

2. Have there been any alterations to the plant since last permitted? [ ] Yes [X] No If minor alterations have occurred, describe on a separate sheet and attach.

3. Attach the last compliance test report required per permit conditions if not submitted previously. **All compliance test reports have been submitted**

4. Have previous permit conditions been adhered to? [X] Yes [ ] No If no, explain on a separate sheet and attach.

5. Has there been any malfunction of the pollution control equipment during tenure of current permit? [ ] Yes [X] No If yes, and not previously reported, give brief details and what action was taken on a separate sheet and attach.

6. Has the pollution control equipment been maintained to preserve the collection efficiency last permitted by the Department? [X] Yes [ ] No

7. Has the annual operating report for the last calendar year been submitted? [X] Yes [ ] No If no, please attach.

8. Please provide the following information if applicable:

A. Raw Materials and Chemical Used in Your Process:

Description	Contaminant Type	%Wt	Utilization Rate lbs/hr
MgO or $Mg(OH)_2$ Additive	Particulate	100	40 lb/day average estimated for 1991
Evaporation of boiler cleaning water with approximately 3% of monoammonium citrate solution	Particulate	100	Approximately 75,000 gallons of water every 3 years

B. Product Weight (lbs/hr): Not applicable

C. Fuels: In order to improve start-up combustion, propane gas may be used for stabilizing ignition, small amounts of light oil (No. 2 fuel oil), or natural gas if that is available, are sometimes fired to preheat the boiler prior to ignition of residual fuel oil. Very small quantities of on-specification used oil, entirely from FPL operations, may be consumed while burning residual oil.

Type (Be Specific)	Consumption* Avg/hr*	Max/hr**	Maximum Heat Input(MMBTU/hr)
Residual Fuel Oil	Variable	631	3850
Natural Gas	Variable	4.02	4025

D. Potential Equipment Operating Time Up To: hrs/day 24; days/wk 7; wks/yr 52; hrs/yr (power plants only) ; 6146 hours of operation during 1992. More operating time is typical when ambient temperature is either unusually high or low, or during other unusual system demands.

The undersigned owner or authorized representative*** of Florida Power & Light Company is fully aware that the statements made in this application for a renewal of a permit to operate an air pollution source are true, correct and complete to the best of his knowledge and belief. Further, the undersigned agrees to maintain and operate the pollution source and pollution control facilities in such a manner as to comply with the provisions of Chapter 403, Florida Statutes, and all the rules and regulations of the Department. He also understands that a permit, if granted by the Department, will be non-transferable and he will promptly notify the Department upon sale or legal transfer of the permitted facility. **This certification pertains solely to air pollution related requirements.**

*During actual time of operation.
**Units: Natural Gas-MMCF/hr; Fuel Oils-barrels/hr; Coal-
***Attach letter of authorization if not previsouly submitted.

Elsa A. Bishop
Signature, Owner or Authorized Representative
(Notarization is mandatory)

E. A. Bishop, Supervisor
Air Permitting and Programs
Typed Name and Title

P. O. Box 088801
Address

North Palm Beach
City

Florida 33408
State Zip

2/1/93
Date

(407) 625-7607
Telephone No.

PROPOSED
REASONABLY AVAILABLE CONTROL TECHNOLOGY (RACT)
FOR
FLORIDA POWER & LIGHT COMPANY (FPL)
TURKEY POINT PLANT

PERSPECTIVE

The information contained in this application and the supporting documents provides FPL's recommended RACT emission limit for the Turkey Point plant. The basis of this recommendation is a comprehensive assessment of all of FPL's facilities in the moderate nonattainment area. This involved an evaluation of the 12 fossil fuel fired steam electric units and 36 gas turbines at five plants in the nonattainment area. The proposed RACT strategy would provide the Florida Department of Environmental Regulation (FDER):

1. Technically feasible, demonstrated, and cost effective control strategy based on FPL specific units which is consistent with guidance provided by the U.S. Environmental Protection Agency (EPA);
2. A 16 percent reduction in nitrogen oxides (NO_x) emissions from all of FPL facilities in the nonattainment area between the 1990 baseline year and the period 1995-2000, despite a 34 percent increase in energy used to serve customer demand (see Figure 1);
3. A 38 percent reduction in the weighted average emission rate from all of FPL facilities in the nonattainment area (i.e., a reduction in weighted average emission rate of 0.6 lb/10^6 Btu in 1990 to 0.38 lb/10^6 Btu in 1995-2000); and
4. Assurance that these significant NO_x emission reductions would be achieved by May 31, 1995.

The application consists of four sections including an introduction, description of existing sources, RACT assessment, and proposed RACT and rationale, along with supporting attachments.

INTRODUCTION

Purpose

The Turkey Point plant is located in Dade County which has been classified as a moderate ozone nonattainment area. Major facilities emitting NO_x and volatile organic compounds (VOCs) which are located in nonattainment areas classified as moderate or higher must apply for a new or revised operation permit by March 1, 1993 [pursuant to Rule 17-296.570 Florida Administrative Code (F.A.C.)]. The application will be reviewed by FDER for the purpose of establishing RACT emission limits for NO_x and VOCs on a case-by-case basis. The Turkey Point plant is a major emitting facility for NO_x subject to the RACT Determination procedure of FDER Rule 17-296.570 (4) F.A.C. This application and the attached technical support document titled "Reasonably Available Control Technology (RACT) Assessment of Florida Power & Light Company's Facilities Located in the Dade, Broward and Palm Beach Ozone Nonattainment Area" provide information required by FDER rules, including FPL's recommended RACT determination for the Turkey Point plant sources.

RACT Requirements

The term "RACT" is defined in FDER rules as follows:

> RACT is the lowest emission limit that a particular source is capable of meeting by the application of control technology that is reasonably available considering technological and economic feasibility. [FDER Rule 17-2.100 (163) F.A.C.]

This longstanding regulatory definition, which the U.S. Environmental Protection Agency (EPA) originally promulgated to guide states in establishing RACT emission limits for existing sources in nonattainment areas, clearly reflects the case-by-case, fact-specific nature of RACT determinations. Indeed, FDER's RACT Determination Procedure clearly states that RACT is to be established by the Department on a case-by-case basis. Consideration is given to RACT emission limiting standards established by other states, information available from EPA guidance documents, technological and economic feasibility, and all other relevant information [see FDER Rule 17-296.570 (4)(b) F.A.C.].

FACILITY DESCRIPTION

General

The Turkey Point plant consists of two fossil steam electric units. The two fossil fuel steam electric units, Units 1 and 2, have a nominal generating capability of 400 MW each. The fossil fuel steam units are fired with natural gas and/or residual oil. All units are single-wall fired with high heat release rates, i.e., greater than 80,000 Btu/hr-ft^3.

Also located at the Turkey Point plant are nine emergency diesel generators, each having a generating capability of 3.5 MW. These units are not permitted and therefore are not subject to RACT.

NO_x Emissions

FPL conducted emission tests in 1991 and 1992 to "benchmark" NO_x emission rates for the affected units. Where units were substantially identical, only one unit was tested. The benchmarking tests are representative of the normal operation of the units and provide representative emission estimates for developing control options (refer to Technical Support Document for test results).

Test results indicated NO_x emission rates for Units 1 and 2 of 0.78 and 0.56 lb/10^6 Btu for oil and natural gas firing, respectively. The NO_x emission rate when firing oil in Units 1 and 2 was almost 75 percent higher than EPA's AP-42 emission factor, i.e., 0.78 lb/10^6 Btu compared to 0.45 lb/10^6 Btu, while the NO_x emission rate for natural gas firing was almost equal to the AP-42 emission factor.

The NO_x emission rates determined from the benchmarking tests were used to estimate 1990 NO_x emissions. Based on the 1990 actual fuel use data, the Turkey Point plant had NO_x emissions of 9,790.5 tons which is about 28 percent of the total NO_x emissions for FPL's facilities located in Dade, Broward, and Palm Beach counties.

Table 1 presents a summary of the characteristics and emissions for each unit at the Turkey Point plant. Refer to Technical Support Document for additional information.

VOC Emissions

VOC emission rates were determined through source testing of both the fossil fuel fired steam electric units and gas turbine units at the Port Everglades and Riviera plants. The VOC emissions for the steam units were determined in 1992 using EPA Method 25A. Table 2 presents the VOC emission rates used for the sources at the Turkey Point Plant. The emission rates determined using EPA test methods are lower than the AP-42 emission factors for these sources. For the steam electric units, the maximum emission rates determined through testing were 0.0004 and 0.0002 lb/10^6 Btu for oil and gas firing, respectively. In contrast, EPA AP-42 emissions factors are 0.005 and 0.0013 lb/10^6 Btu, respectively. VOC source test data are presented in Appendix B.

The Turkey Point plant also has tanks for storing and handling fuels and solvents. A total of 29 tanks are used for this purpose and small amounts of VOCs are emitted through breathing and handling losses. Of the 29 tanks, 8 tanks are located at the fossil plant, 16 tanks are located at the nuclear plant, and an additional 5 tanks are dedicated to land utilization. Tank capacities range from 5 bbls to 268,000 bbls, with the larger tanks utilized for No. 6 fuel oil. Most other tanks handle either No. 2 diesel fuel or gasoline. Of the 29 tanks, only 12 have capacities greater than 5,000 gallons. Four tanks are no longer in service or are usually empty except for emergency situations. These include a 200-gallon mineral spirits tank, a 15,000-gallon lube oil tank, a 350-gallon fire pump tank, and a 550-gallon aviation fuel tank. VOC emissions have been developed for each in-use tank and are presented in Table A1 of Appendix A.

The Turkey Point plant also has VOC emissions due to paint and solvent use. The products utilized in 1991 along with estimated VOC emissions are presented in Table A2 of Appendix A.

Table 2 presents actual 1990 and potential VOC emissions for the Turkey Point plant. The facility is not considered to be a "major facility" for VOC emissions because of its potential and actual emissions are less than 100 tons per year. (See Appendix A for VOC calculations.)

NO_x RACT CONTROL ALTERNATIVES

Regulatory Guidance

For NO_x emissions from fossil fuel fired steam generators and gas turbines, EPA will not issue Control Technology Guidance (CTG) documents. EPA has issued, in a supplement to the general preamble to the regulations related to the implementation of Title I of the Clean Air Act

Amendments of 1990 for state implementation plans, some guidance for certain electric utility boilers [57 Federal Register (FR) 55620, November 25, 1992].

EPA's guidance concluded that RACT for utility generators should reflect " the most effective level of combustion modification reasonably available to an individual unit". EPA specified by reference the application of low-NO_x burners but recognized that in some cases overfire air and flue gas recirculation may be appropriate while in other cases RACT would require no additional control.

For oil/gas wall-fired units, EPA indicated that in the majority of cases, RACT should result in an overall level of control equivalent to 0.3 lb/10^6 Btu with compliance based on a 30-day rolling average. EPA encourages the states to adopt emission averaging concepts including averaging within the same transport region. However, EPA states that: "The actual NO_x emission reduction that can be achieved on a specific boiler depends on a number of site-specific factors including, but not limited to, furnace dimensions and operating characteristics, design and condition of burner controls, design and condition of stream control systems, and fan capacity. The combustion modification technology must be custom-designed for each boiler application."

The approach taken by FPL to identify RACT for each unit is consistent with EPA guidance and is based on a unit-specific analysis of NO_x control options that realistically considered the technological and economic feasibility for each unit.

Combustion Modifications--Boilers

Combustion modifications, which EPA suggests as the control technology that would achieve RACT, was evaluated for Turkey Point Units 1 and 2 (see Technical Support Document). Four major types of combustion modifications were evaluated, including low-NO_x burner (LNB) technology, off-stoichiometric combustion (OSC), over-fire air (OFA), and flue gas recirculation (FGR). The results of the evaluation, which are summarized in Table 3, suggest that LNB technology is the most cost effective for these units. The cost effectiveness for LNB technology is about $600 per ton of NO_x reduced for both units. In contrast, the cost effectiveness of OFA and FGR is about $3,100 and $2,500 per ton of NO_x reduced, respectively.

For Units 1 and 2, LNB technology can achieve a minimum of 25 percent NO_x reduction which would be equivalent to a proposed RACT emission rate of 0.42 and 0.59 lb/10^6 Btu for natural gas and oil firing, respectively. LNB technology is feasible for these units and the amount of reduction proposed is viable. Application of OFA and FGR on these units requires extensive modifications which cannot be completed by the required May 31, 1995 date. The cost of OFA and FGR is more than four times higher per ton of NO_x removed than LNB technology, suggesting the latter is the most appropriate for these units.

Post-Combustion Technologies--Boilers

The post-combustion technologies evaluated included selective non-catalytic reduction (SNCR) and selective catalytic reduction (SCR). Although EPA has not considered these technologies to be appropriate or necessary for fossil fuel steam units in its RACT guidance, SNCR and SCR were evaluated as alternatives to combustion modifications. The evaluation found that SNCR was not feasible since the temperature and residence times required for the reaction of ammonia and NO_x are not available in Units 1 and 2. The cost of SCR would make this technology economically infeasible. For both SNCR and SCR, achieving the RACT compliance date for all units would not be possible. Table 4 summarizes the economic and technical attributes of the post-combustion technologies evaluated.

VOC RACT CONTROL ALTERNATIVES

Because the Turkey Point plant is not considered a major facility for VOC emissions, VOC RACT control alternatives do not apply.

PROPOSED RACT AND RATIONALE

EPA's guidance, while suggesting NO_x emission rates as RACT for certain utility boilers, clearly provides for the evaluation of design-specific factors when establishing RACT. Units 1 and 2 are unique in those design features that affect NO_x emissions and the ability to apply combustion control technology. The specific design factors unique to these units are the single-wall fired configuration and small furnace design with associated high heat release rates (as indicated by Btu/hr-ft^3). These design features are illustrated in Figure 2.

Of the 59,000-MW oil/gas-fired utility steam generators nationwide, about 41 percent are single-wall fired units. In contrast to units designed as single-wall fired, tangentially and opposed-wall fired units have inherently lower NO_x emissions and can generally meet 0.3 lb $NO_x/10^6$ Btu heat input. Units 1 and 2 were designed and fabricated by Foster-Wheeler (FW). FW-designed oil/gas-fired boilers make up about 49 percent of all U.S. single-wall fired designs; the other major manufacturer, Babcock and Wilcox (B&W), makes up the remainder (i.e., 51 percent). In general, B&W designs have larger furnace volumes and lower NO_x emission rates. As shown in Figure 2, about 66 percent of FW designs are pre-New Source Performance Standards (NSPS); the post-NSPS designs meet a 0.3 lb $NO_x/10^6$ Btu limit. Of the pre-NSPS designs, 57 percent are high heat release rate ($>$80,000 Btu/hr-ft^3) units. Low ($<$45,000 Btu/hr-ft^3) and medium (45,000 to 80,000 Btu/hr-ft^3) heat release units make up 10 and 33 percent, respectively, of the pre-NSPS units. Fifty percent of the high heat release units are located in non-attainment areas; all these units are owned by FPL and located in Dade, Broward, and Palm Beach counties (see Figure 2).

In contrast to the FPL single-wall fired oil/gas units, NO_x emission rates from many other oil/gas-fired units are inherently lower due to larger furnace volume for a similarly sized unit. This is particularly true of units originally designed to burn coal and converted to oil/gas firing to meet particulate and sulfur dioxide emission limits. Such units, many of which are in the northeast United States (e.g., Con Edison), have large furnace volumes and low heat release rates resulting in inherently lower NO_x emission rates. These units generally can meet the EPA-suggested guidance levels without additional controls.

Boilers with high heat release rates have inherently higher NO_x emission rates, and options for reasonably available controls are limited. The application of LNB technology is the most readily adaptable to these units and the most cost-effective.

Considerable experience in low-NO_x burner technology was gained through the installation of low-NO_x burners in Port Everglades Units 3 and 4. This experience is relatively unique in that there have been very few utility-sized retrofits of low-NO_x oil/gas burners in the U.S. FPL's operational experience with LNB technology, while demonstrated to achieve required NO_x

reduction requirements, was not without design, startup, and operational problems (e.g., oil safety shutoff valve system seal failures, burner management system interface logic design issues, et.al). Considerable time, effort, and funds were spent on plant components having no influence on the burner's combustion/emission performance. Lessons learned from this project therefore indicate that substantial cost savings are possible by concentrating on design changes to only those components which effect combustion/emissions performance. Toward a goal of achieving maximum NO_x reductions using the most cost effective approach, FPL has undertaken a program, with contract support from the existing burner manufacturer, International Combustion Limited (ICL), to develop optimized designs for converting the existing burners to a low-NO_x configuration. This program consists of design development of combustion/emission related burner components and prototype testing to compare design alternatives and select the optimum design prior to actual implementation. It is currently anticipated that these efforts will result in a low-NO_x burner configuration consisting of an axial flow, single register, fuel staged design.

LNB technology is proposed as NO_x RACT for Turkey Point Units 1 and 2. The advantages of this technology are:

1. Technologically Feasible--Unlike other technologies, LNB technology has been retrofitted on Units 3 and 4 at the Port Everglades plant with a demonstrated NO_x reduction of 25 percent. This technology can be installed on Turkey Point Units 1 and 2. EPA has also suggested this technology as being the most appropriate for RACT.
2. Cost Effectiveness--LNB technology represents a cost effective approach. The $/ton of NO_x removed is $565, in contrast to EPA's recommendation for the NO_x reductions required under the acid rain provisions (Title IV) of the Clean Air Act (57FR55620), which was approximately $300 per ton of NO_x removed.
3. Achievement of Compliance Date--Installation of LNB technology can be achieved by May 31, 1995, for Turkey Point Units 1 and 2. It may not be possible to convert both units with other control alternatives.

The proposed RACT emission rate is based on a 25 percent reduction in maximum uncontrolled NO_x emissions for Units 1 and 2. Maximum uncontrolled emission rates are those rates determined from the benchmarking tests (or subsequent tests determined by FDER). The proposed RACT limits are:

PTF Units 1 and 2--0.42 lb/10^6 Btu gas; 0.59 lb/10^6 Btu oil

Certification by Professional Engineer Registered in Florida

This is to certify that the engineering features of this reasonably available control technology (RACT) application have been prepared or examined by me and found to be in conformity with modern engineering principles applicable to the treatment and disposal of pollutants characterized in the application.

Signed: Kennard F. Kosky

Date: 2/2/93

Kennard F. Kosky
KBN Engineering and Applied Sciences, Inc.
1034 NW 57th Street
Gainesville FL 32605
(904) 331-9000
Florida Registration No. 14996

SEAL

KFK

Table 1. Summary of NO_x Emission Rates and 1990 Emissions for FPL Turkey Point Plant

Unit[a]	Nominal Size (MW)	NO_x Emission Rate ($lb/10^6$ Btu) Oil	Gas	1990 NO_x Emissions (tons)	Percent of Total Plant Emissions
PTF 1	400	0.78	0.56	3,580.7	36.6
PTF 2	400	0.78	0.56	6,209.8	63.4
			Total:	9,790.5	

Note: See Tables 2-1, 2-2 and 2-3 in Technical Support Document.

[a] PTF = Turkey Point.

Table 2. Actual and Potential VOC Emissions for the FPL Turkey Point Plant Using Emission Rates Based on Test Results

Unit Name	Heat Input (10^9 Btu)[a] Oil	Heat Input (10^9 Btu)[a] Gas	VOC Emission Rate ($lb/10^6$ Btu)[b] Oil	VOC Emission Rate ($lb/10^6$ Btu)[b] Gas	VOC Emissions (TPY)
Actual Emissions					
PTF-1	4,892.8	5,973.4	0.0004	0.0002	1.6
PTF-2	7,597.3	11,596.0	0.0004	0.0002	2.7
Tanks[c]	NA	NA	NA	NA	1.3
Solvents[d]	NA	NA	NA	NA	18.9
				Plant Total	24.5
Potential Emissions					
PTF-1	33,726.0	35,259.0	0.0004	0.0002	10.3
PTF-2	33,726.0	35,259.0	0.0004	0.0002	10.3
Tanks[c]	NA	NA	NA	NA	1.3
Solvents[d]	NA	NA	NA	NA	18.9
				Plant Total	40.8

Note: NA = not applicable.

[a] 1990 heat input values as provided by FPL.
[b] Boiler emission rates based on tests conducted at the Riviera and Port Everglades plants.
[c] Refer to Table A1 in Appendix A for detailed calculations.
[d] Refer to Table A2 in Appendix A for detailed calculations.

Table 3. Summary of RACT Factors for Combustion Modifications FPL Turkey Point Plant

Factor	Unit	Alternative Control Technology[a] LNBT	OSC	OFA	FGR
NO_x Reduction		25%	≤20%[b]	10%	45%
Capital Cost	PTF 1	$ 3,798,000	NA	$ 4,956,000	$ 20,981,000
	PTF 2	3,798,000	NA	4,956,000	20,981,000
	Plant Total:	7,596,000	NA	9,912,000	41,962,000
Annualized Cost	PTF 1	691,000	NA	1,126,000	4,153,000
	PTF 2	691,000	NA	1,126,000	4,153,000
	Plant Total:	1,382,000	NA	2,252,000	8,306,000
Cost Effective-ness ($/ton)	PTF 1&2	565	NA	3,067	2,514
	Plant Total:	565	NA	3,067	2,514
Schedule Requirements:					
Duration of Outage		6 Weeks	Variable	3 Months	6 Months
Total Duration per Unit:		9 Months	Variable	12-14 Months	24 Months
Achieve Compliance Date?		Yes	Unknown	No	No
Technical Feasibility		Yes	Possible	Possible	Possible
Energy Penalties		Minor	Minor	Moderate	Major
Other Environmental Impacts		Minor	Minor	Yes	Yes

Note: NA = not available or unknown at this time.

[a] See Tables 3-1, 3-2, 4-1, B-1, B-2, and B-3 in Technical Support Document.
[b] OSC would not likely achieve the desired NO_x reduction. Refer to Sections 3.2.2 in Technical Support Document.

Table 4. Summary of RACT Factors for Post-Combustion Technologies FPL Turkey Point Plant

Factor	Unit	Alternative Control Technology[a] SNCR	SCR
NO_x Reduction		35%	55%
Capital Cost	PTF 1	$ 13,206,961	$ 29,049,296
	PTF 2	13,206,961	29,049,296
	Plant Total:	26,413,922	58,098,592
Annualized Cost	PTF 1	4,479,712	11,220,972
	PTF 2	4,479,712	11,220,972
	Plant Total:	8,959,424	22,441,944
Cost Effectiveness ($/ton)	PTF 1&2	3,486	5,557
	Plant Total:	3,486	5,557
Schedule Requirements:			
Duration of Outage		2 Months	6 Months
Total Duration per Unit:		12-14 Months	24 Months
Achieve Compliance Date?		No	No
Technical Feasibility		Questionable	Possible
Energy Penalties		Minor	Major
Other Environmental Impacts		Yes	Yes

[a] See Tables 3-1, 3-2, 4-1, B-4, and B-5 in Technical Support Document.

Figure 1
COMPARISON OF HEAT INPUT AND NO_x EMISSION RATES FOR FPL PLANTS IN DADE, BROWARD, AND PALM BEACH COUNTIES

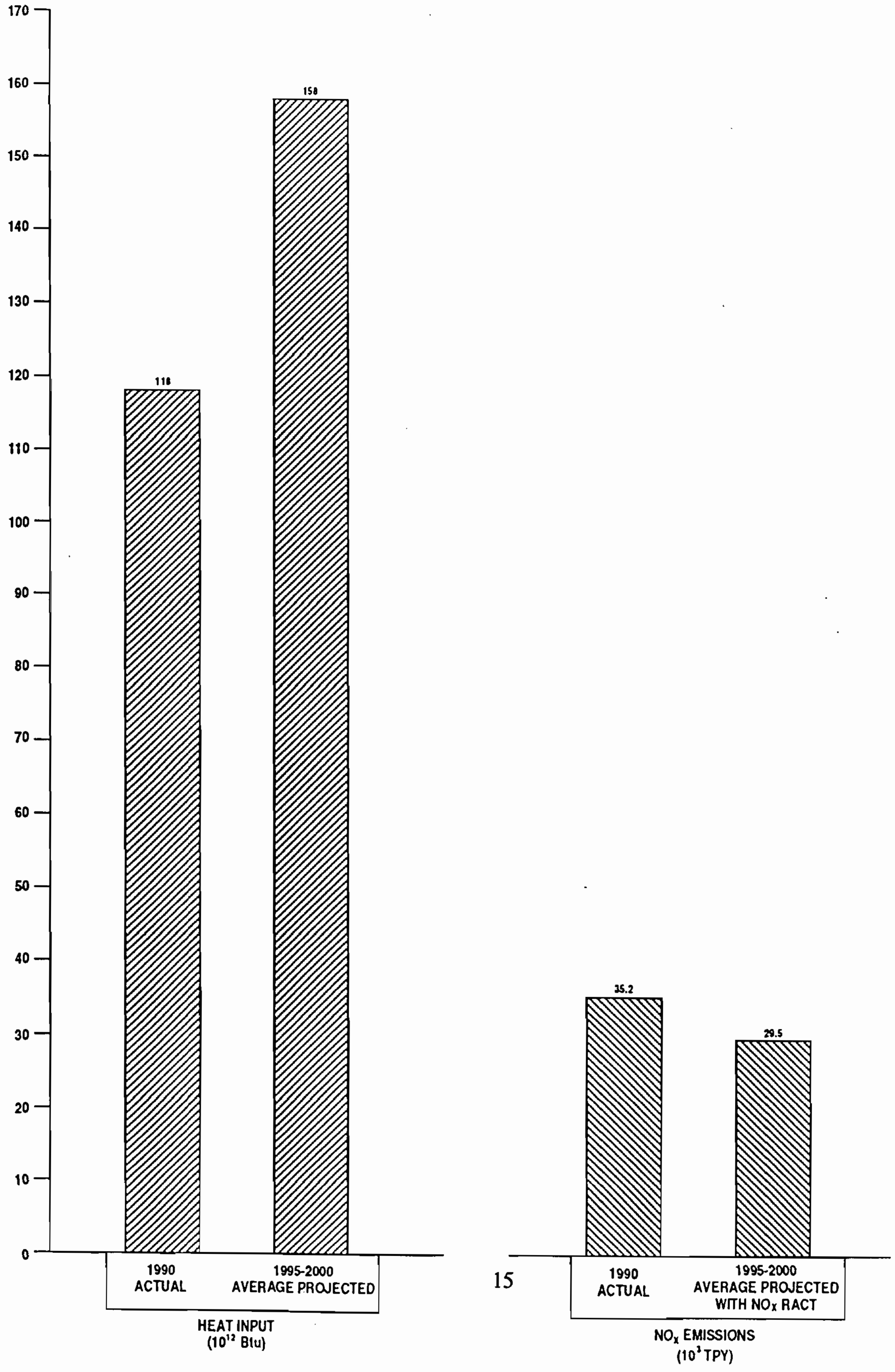
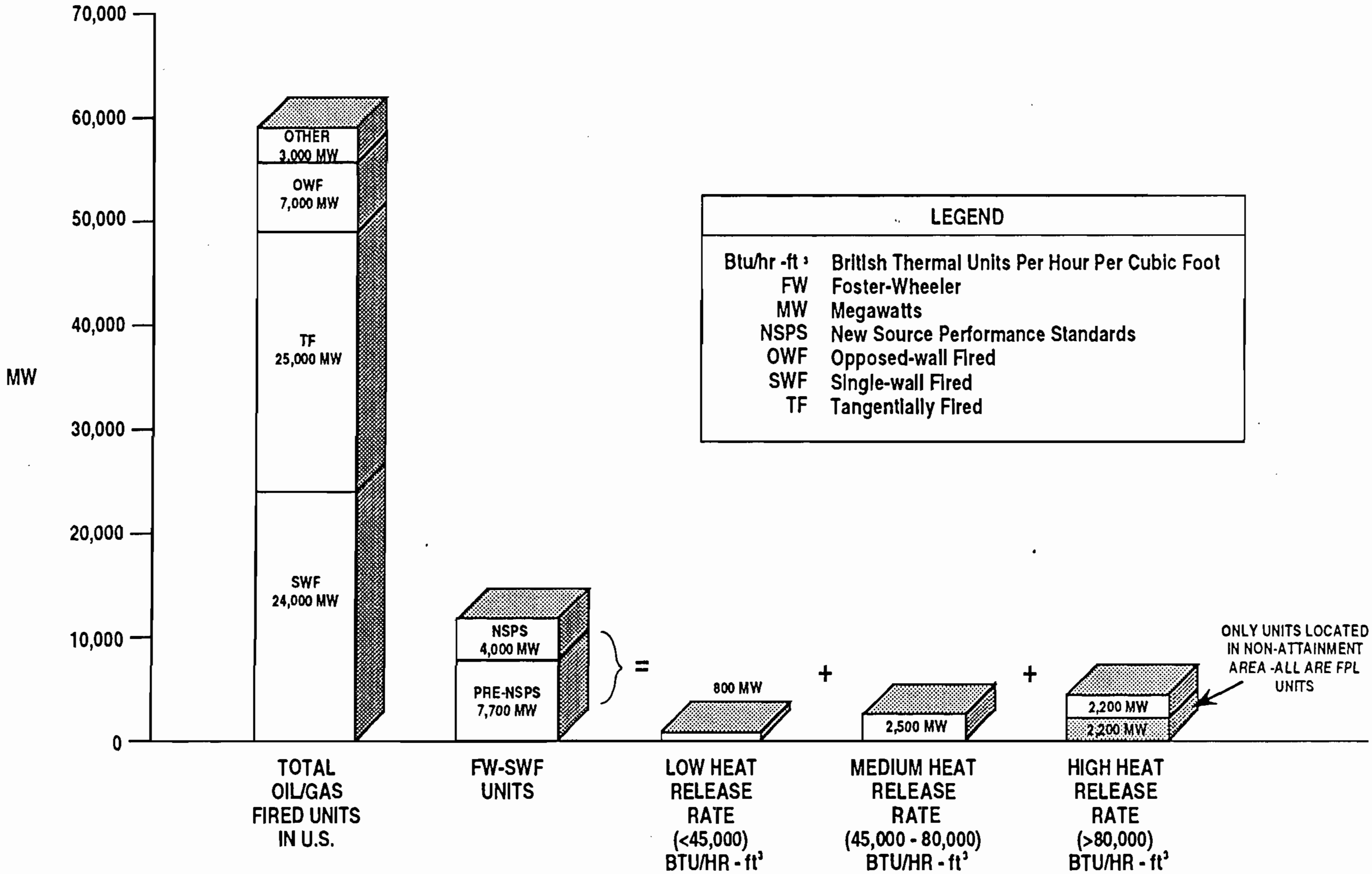


Figure 2
OIL/GAS-FIRED UTILITY STEAM GENERATORS



Attachments:

1. Appendix A--VOC Emission Calculations.
2. Appendix B--VOC Test Results.
3. FDER Renewal Application Form.
4. Technical Support Document.

APPENDIX A

VOC CALCULATIONS FOR TANKS AND SOLVENTS

Table A1. VOC Emission Calculations for Fixed Roof Storage Tanks at the FPL Turkey Point Plant (Page 1 of 3)

	Tank No. PTF 1B #6 Fuel	Tank No. PTF 2B #6 Fuel	Tank No. PTF 1M #6 Fuel	Tank No. PTF 2M #6 Fuel	Tank No. PTF E-LO #2 Diesel	Tank No. PTF W-LO #2 Diesel	Tank No. PTF Gasoline	Tank No. PTF Diesel	Tank No. PTN D #2 Diesel
BREATHING LOSS									
Mv = Molecular wt of vapor[a]	190	190	190	190	130	130	66	130	130
Pa = Avg. atmospheric pressure (psia)	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7
P = True vapor pressure (psia)[b]	0.00009	0.00009	0.00009	0.00009	0.012	0.012	7.4	0.012	0.012
D = Tank diameter (ft)	200.0	200.0	35.0	35.0	12.0	16.7	10.0	10.0	20.0
H = Avg. vapor space height (ft)[c]	24.0	24.0	35.0	35.0	12.0	8.0	1.7	1.7	14.8
T = Avg. ambient diurnal temp. chg. (#F)	14.8	14.8	14.8	14.8	14.8	14.8	14.8	14.8	14.8
Fp = Paint factor	1.40	1.40	1.40	1.40	1.40	1.40	1.00	1.00	1.40
C = Adj. factor sm. diameter tanks	1.0	1.0	1.0	1.0	0.64	0.8	0.54	0.54	0.9
Kc = Product factor	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Lb = Fixed roof breathing loss (TPY)									
Lb = $2.26 \times 10^{-2} \times MvP/Pa-P^{.68} D^{1.73} H^{.51} T^{.50}$ FpCKc/2000	0.16	0.16	0.0095	0.0095	0.011	0.019	0.11	0.0017	0.040
WORKING LOSS									
Mv = Molecular wt. of vapor[a]	190	190	190	190	130	130	66	130	130
P = True vapor pressure (psia)[b]	0.00009	0.00009	0.00009	0.00009	0.012	0.012	7.4	0.012	0.012
V = Tank capacity (gal)	11,256,000	11,256,000	504,000	504,000	19,992	24,990	2,000	2,000	70,000
Qb = Throughput (barrels)	1,494,359	1,494,359	66,912	66,912	1,378	1,378	179	64	1,378
Qg = Throughput (gallons)	62,763,074	62,763,074	2,810,287	2,810,287	57,887	57,887	7,500	2,700	57,887
N = Total thruput per yr (gal) / Tank capacity (gal)	6	6	6	6	3	2	4	1	1
Kn = Turnover factor	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Kc = Product factor	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Lw = Fixed roof working loss (TPY)									
Lw = $2.40 \times 10^{-5} \times$ MvPVNKnKc/2000	0.013	0.013	0.00058	0.00058	0.0011	0.0011	0.044	0.0001	0.0011
TOTAL LOSS (Lt)									
Lb + Lw = Lt (TPY)	0.17	0.17	0.010	0.010	0.012	0.020	0.15	0.0017	0.041

Table A1. VOC Emission Calculations for Fixed Roof Storage Tanks at the FPL Turkey Point Plant (Page 2 of 3)

	Tank No. PTN TA #2 Diesel	Tank No. PTN TB #2 Diesel	Tank No. PTN CT-1 Gasoline	Tank No. PTN CT-2 Gasoline	Tank No. PTN DT-A #2 Diesel	Tank No. PTN DT-B #2 Diesel	Tank No. PTN DT-C #2 Diesel	Tank No. PTN DT-D #2 Diesel	Tank No. PTN A #2 Diesel
BREATHING LOSS									
Mv = Molecular wt of vapor[a]	130	130	66	66	130	130	130	130	130
Pa = Avg. atmospheric pressure (psia)	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7
P = True vapor pressure (psia)[b]	0.012	0.012	7.4	7.4	0.012	0.012	0.012	0.012	0.012
D = Tank diameter (ft)	11.1	11.1	7.1	7.1	7.1	7.1	7.1	7.1	19.8
H = Avg. vapor space height (ft)[c]	3.5	3.5	1.7	1.7	1.7	1.7	1.7	1.7	8.8
T = Avg. ambient diurnal temp. chg. (#F)	14.8	14.8	14.8	14.8	14.8	14.8	14.8	14.8	14.8
Fp = Paint factor	1.40	1.40	1.40	1.40	1.40	1.40	1.40	1.40	1.39
C = Adj. factor sm. diameter tanks	0.58	0.58	0.36	0.36	0.36	0.36	0.36	0.36	0.90
Kc = Product factor	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Lb = Fixed roof breathing loss (TPY)									
Lb = $2.26\times10^{-2} x Mv P/Pa-P^{.68} D^{1.73} H^{.51} T^{.50} Fp C Kc/2000$	0.0044	0.0044	0.056	0.056	0.001	0.00087	0.00087	0.00087	0.030
WORKING LOSS									
Mv = Molecular wt. of vapor[a]	130	130	66	66	130	130	130	130	130
P = True vapor pressure (psia)[b]	0.012	0.012	7.4	7.4	0.012	0.012	0.012	0.012	0.012
V = Tank capacity (gal)	4,000	4,000	1,000	1,000	1,000	1,000	1,000	1,000	40,400
Qb = Throughput (barrels)	689	689	460	460	2,874	2,874	2,874	2,874	1,378
Qg = Throughput (gallons)	28,944	28,944	19,317	19,317	120,726	120,726	120,726	120,726	57,887
N = Total thruput per yr (gal) / Tank capacity (gal)	7	7	19	19	121	121	121	121	1
Kn = Turnover factor	1.0	1.0	1.0	1.0	0.4	0.4	0.4	0.4	1.0
Kc = Product factor	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Lw = Fixed roof working loss (TPY)									
Lw = $2.40\times10^{-5} x Mv P V N Kn Kc/2000$	0.0005	0.0005	0.11	0.11	0.0009	0.00090	0.00090	0.00090	0.0011
TOTAL LOSS (Lt)									
Lb + Lw = Lt (TPY)	0.0050	0.0050	0.17	0.17	0.0018	0.0018	0.0018	0.0018	0.031

Table A1. VOC Emission Calculations for Fixed Roof Storage Tanks at the FPL Turkey Point Plant (Page 3 of 3)

	Tank No. PTN B #2 Diesel	Tank No. PTN ADT #2 Diesel	Tank No. PTN BDT #2 Diesel	Tank No. LU Gas Gasoline^d	Tank No. LU Diesel #2 Diesel^d	Tank No. LU Diesel #2 Diesel	Tank No. LU Diesel #2 Diesel
BREATHING LOSS							
Mv = Molecular wt of vapor[a]	130	130	130	66	130	130	130
Pa = Avg. atmospheric pressure (psia)	14.7	14.7	14.7	14.7	14.7	14.7	14.7
P = True vapor pressure (psia)[b]	0.012	0.012	0.012	7.4	0.012	0.012	0.012
D = Tank diameter (ft)	19.8	6.1	6.1	13.3	13.3	5.8	5.8
H = Avg. vapor space height (ft)[c]	8.8	1.8	1.8	3.2	3.2	2.5	2.5
T = Avg. ambient diurnal temp. chg. (#F)	14.8	14.8	14.8	14.8	14.8	14.8	14.8
Fp = Paint factor	1.39	1.39	1.39	1.40	1.40	1.40	1.40
C = Adj. factor sm. diameter tanks	0.9	0.3	0.3	0.7	0.7	0.5	0.5
Kc = Product factor	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Lb = Fixed roof breathing loss (TPY)							
Lb = $2.26 \times 10^{-2} \times Mv P/Pa-P^{.68} D^{1.73} H^{.51} T^{.50} Fp C Kc/2000$	0.030	0.00058	0.00058	0.00	0.00	0.0011	0.0011
WORKING LOSS							
Mv = Molecular wt. of vapor[a]	130	130	130	66	130	130	130
P = True vapor pressure (psia)[b]	0.012	0.012	0.012	7.4	0.012	0.012	0.012
V = Tank capacity (gal)	40,400	650	650	4,000	4,000	1,000	1,000
Qb = Throughput (barrels)	1,378	689	689	1,007	1,151	288	288
Qg = Throughput (gallons)	57,887	28,944	28,944	42,310	48,360	12,090	12,090
N = Total thruput per yr (gal) / Tank capacity (gal)	1	45	45	11	12	12	12
Kn = Turnover factor	1.0	0.8	0.8	1.0	1.0	1.0	1.0
Kc = Product factor	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Lw = Fixed roof working loss (TPY)							
Lw = $2.40 \times 10^{-5} \times Mv P V N Kn Kc/2000$	0.0011	0.00043	0.00043	0.25	0.00091	0.00023	0.00023
TOTAL LOSS (Lt)							
Lb + Lw = Lt (TPY)	0.031	0.0010	0.0010	0.25	0.00091	0.0013	0.0013

Total Emissions for Fixed Roof Tanks (TPY): 1.26

Note: All calculations based on AP42 methodologies.
PTF = Turkey Point fossil facility.
PTN = Turkey Point nuclear facility.
LU = land utilization.

[a] Based on 60 degrees F.
[b] Based on 80 degrees F.
[c] Taken as half the tank height.
[d] Tanks are underground. Only emissions due to working loss apply.

Table A2. Estimated VOC Emission Due to Paint and Solvent Usage at the FPL Turkey Point Plant

Product Name	Estimated Annual Usage (gal)[a]	Solvent Density (lb/gal)[b]	Percent VOC[b]	Estimated VOC Emissions (lb/yr)	(TPY)
Fossil Fuel Facility					
Metalite SV-7	220	6.70	100	1,474.0	0.74
Thinner No. 1	400	7.20	100	2,880.0	1.44
Thinner No. 4	220	7.30	100	1,606.0	0.80
Uniprime	700	13.60	85	8,092.0	4.05
Acrylic Enamel	800	9.20	66	4,857.6	2.43
High Temperature Primer	400	10.50	72	3,024.0	1.51
Acrylic Latex	50	10.80	0	0.0	0.00
High Temperature Coating	400	8.50	75	2,550.0	1.28
Subflex Coating	500	8.50	75	3,187.5	1.59
Nuclear Facility					
Korchem 1100	168	8.50	75	1,071.0	0.54
Korchem 1200	138	8.50	75	879.8	0.44
Subox Antrex 1500	10	8.50	75	63.8	0.03
Subox SA-338	10	8.50	75	63.8	0.03
Subox 335	10	8.50	75	63.8	0.03
Carbomastic 15	180	8.50	75	1,147.5	0.57
Capox A-HB	100	8.50	75	637.5	0.32
Capox A-8000	23	8.50	75	146.6	0.07
Subthane 3000	14	10.72	50	75.0	0.04
Carboline 134	10	8.50	75	63.8	0.03
Carboline 870	100	8.50	75	637.5	0.32
Carbozinc 11	700	20.50	18	2,583.0	1.29
Amerlock 400	200	8.50	75	1,275.0	0.64
Subox 2000	105	8.50	75	669.4	0.33
Subox 500	25	8.50	75	159.4	0.08
Capox A	10	8.50	75	63.8	0.03
Subox 207	10	8.50	75	63.8	0.03
Carboline 82	5	8.50	75	31.9	0.02
Carboline 25	5	8.50	75	31.9	0.02
Carboline 2	6	8.50	75	38.3	0.02
Thinner No. 1	44	7.23	100	318.1	0.16
			TOTAL:	37,755.4	18.9

[a] Based on annual purchases.
[b] If unknown, a conservative density and VOC content of 8.5 lb/gal and 75 percent, respectively, were used.

APPENDIX B

VOC TEST RESULTS

ACE
AIR CONSULTING
& ENGINEERING, INC.
2106 N.W. 67th Place • Suite 4 • Gainesville, Florida • 32606
(904) 335-1889 FAX (904) 335-1891

April 28, 1992

Mr. Michael J. Taylor
Emission Test Group
Florida Power & Light Company
Post Office Box 4830
Princeton, Florida 33092-4830

Dear Mr. Taylor:

Enclosed is an emission summary of testing performed April 9, 10, and 14, 1992 at the Port Everglades and Riviera Plants.

The Riviera Plant was unable to obtain clearance for a gas firing so only oil testing was performed.

Total hydrocarbons as propane testing was conducted using a Ratfisch RS55 FID analyzer with heated components. CO emissions were measured with a Thermo Environmental Model 48 gas correlation NDIR.

All sampling was conducted using a moisture knockout trap prior to analysis (dry basis). The Riviera Plant testing for VOC's was conducted using both a dry system and a wet system to demonstrate that no VOC's were condensing in the dry system. The wet system used heat trace line at 300°F from the point of sample.

All instruments were calibrated and operated using EPA Method 25A and 10 methodology using NBS Traceable Protocol 1 calibration gases.

If you wish a formal test report for these tests please contact me.

Thank you for allowing Air Consulting and Engineering, Inc. (ACE) to perform this valued work.

Respectfully,

AIR CONSULTING AND ENGINEERING, INC.

Stephen L. Neck

Stephen L. Neck, P.E.

SLN/cvt

cc: Ken Kosky, KBN Engineering & Applied Sciences, Inc.

ACE File: 169 92 01

Emission Sumary
FPL - Riviera Plant
Unit 4 - 4/14/92

"F" Factor Gas = 8710
"F" Factor Oil = 9190

Test Description	O2%	CO ppm	CO lbs/MMBTU	C_3H_8 ppm	C_3H_8 lbs/MMBTU
Oil firing all sampling on dry basis 10170-1117	5.16	5038	4.47	0.27	0.0004
Oil firing VOC sampled on wet basis 1148-1248	5.20	4256	3.78	0.30	0.0004

Emission Sumary
FPL - Port Everglades
Units 2 and 4 - 4/9-10/92

"F" Factor Gas = 8710
"F" Factor Oil = 9190

Test Description	O2%	CO ppm	CO lbs/MMBTU	C_3H_8 ppm	C_3H_8 lbs/MMBTU
Unit 4 - 4/9/92					
Gas Firing East 0850-0926	2.57	0.00	0.0000	0.00	0.0000
Gas Firing West 0940-1000	2.81	0.00	0.0000	0.00	0.0000
Oil Firing West 1100-1130	2.64	7.63	0.0058	0.00	0.0000
Oil Firing East 1220-1300	2.51	3.00	0.0023	0.00	0.0000
Unit 2 - 4/10/92					
Gas Firing 0815-0916	5.92	0.71	0.0006	0.14	0.0002
Oil Firing 1032-1132	5.58	0.48	0.0004	0.00	0.0000

SECTION #5

APPLICATION FOR PERMIT
PROPOSED RACT FOR AIR POLLUTION SOURCES

RIVIERA POWER PLANT

1. Application - Unit No. 3 Oil & Gas Fired, 300 MW Class (315 MW Gross Capacity)

2. Application - Unit No. 4 Oil & Gas Fired, 300 MW Class (315 MW Gross Capacity)

3. Proposed Reasonably Available Control Technology (RACT) for Florida Power & Light Company (FPL) Riviera Plant

Florida Department of Environmental Regulation

APPLICATION FOR PERMIT OF
PROPOSED RACT FOR AIR POLLUTION SOURCE(S)

If major alterations have occurred, the applicant should complete the Standard Air Permit Application Form.

Source Type: Fossil Fuel Steam Generator Renewal of DER Permit No. AO-50-206721

Company Name: Florida Power & Light Company County: Palm Beach

Identify the specific emission point source(s) addressed in this application (i.e., Lime Kiln No. 4 with Venturi Scrubber; Peaking Unit No. 2, Gas Fired):

Riviera Power Plant, Unit No. 3 Oil & Gas Fired, 300 MW Class (315 MW Gross Capacity)

Source Location: Street: 200-300 Broadway City: Riviera Beach

UTM: East 594249 Zone 17 North 2960632

Latitude: 26° 45′ 55"N Longitude: 80° 03′ 09"W

---

1. Attach a check made payable to the Department of Environmental Regulation in accordance with operation permit fee schedule set forth in Florida Administrative Code Rule 17-4.05.

2. Have there been any alterations to the plant since last permitted? [ ] Yes [X] No If minor alterations have occurred, describe on a separate sheet and attach.

3. Attach the last compliance test report required per permit conditions if not submitted previously. **All compliance test reports have been submitted**

4. Have previous permit conditions been adhered to? [X] Yes [ ] No If no, explain on a separate sheet and attach.

5. Has there been any malfunction of the pollution control equipment during tenure of current permit? [ ] Yes [X] No If yes, and not previously reported, give brief details and what action was taken on a separate sheet and attach.

6. Has the pollution control equipment been maintained to preserve the collection efficiency last permitted by the Department? [X] Yes [ ] No

7. Has the annual operating report for the last calendar year been submitted? [X] Yes [ ] No If no, please attach.

8. Please provide the following information if applicable:

A. Raw Materials and Chemical Used in Your Process:

Description	Contaminant Type	%Wt	Utilization Rate lbs/hr
MgO or $Mg(OH)_2$ Additive	Particulate	100	150 lb/day average estimated for 1991
Evaporation of boiler cleaning water with approximately 3% of monoammonium citrate solution	Particulate	100	Approximately 50,000 gallons of water every 3 years

B. Product Weight (lbs/hr): **Not applicable**

C. Fuels: In order to improve start-up combustion, propane gas may be used for stabilizing ignition and small amounts of light oil (No. 2 fuel oil), or natural gas if that is available, are sometimes fired to preheat the boiler prior to ignition of residual fuel oil. Very small quantities of on-specification used oil, entirely from FPL operations, may be consumed while burning residual oil.

Type (Be Specific)	Consumption* Avg/hr*	Max/hr**	Maximum Heat Input (MMBTU/hr)
Residual Fuel Oil	Variable	500	3050
Natural Gas	Variable	3.3	3260

D. Potential Equipment Operating Time Up To: hrs/day 24; days/wk 7; wks/yr 52; hrs/yr (power plants only) ; 7609 hours of operation during 1992. More operating time is typical when ambient temperature is either unusually high or low, or during other unusual system demands.

The undersigned owner or authorized representative*** of **Florida Power & Light Company** is fully aware that the statements made in this application for a renewal of a permit to operate an air pollution source are true, correct and complete to the best of his knowledge and belief. Further, the undersigned agrees to maintain and operate the pollution source and pollution control facilities in such a manner as to comply with the provisions of Chapter 403, Florida Statutes, and all the rules and regulations of the Department. He also understands that a permit, if granted by the Department, will be non-transferable and he will promptly notify the Department upon sale or legal transfer of the permitted facility. **This certification pertains solely to air pollution related requirements.**

*During actual time of operation.
**Units: Natural Gas-MMCF/hr; Fuel Oils-barrels/hr; Coal-
***Attach letter of authorization if not previsouly submitted.

Elsa A. Bishop
Signature, Owner or Authorized Representative
(Notarization is mandatory)

E. A. Bishop, Supervisor
Air Permitting and Programs
Typed Name and Title

P. O. Box 088801
Address

North Palm Beach
City

Florida 33408
State Zip

2/1/93
Date

(407) 625-7607
Telephone No.

Florida Department of Environmental Regulation

**APPLICATION FOR PERMIT OF
PROPOSED RACT FOR AIR POLLUTION SOURCE(S)**

If major alterations have occurred, the applicant should complete the Standard Air Permit Application Form.

Source Type: Fossil Fuel Steam Generator   Renewal of DER Permit No. AO-50-206722

Company Name: Florida Power & Light Company County: Palm Beach

Identify the specific emission point source(s) addressed in this application (i.e., Lime Kiln No. 4 with Venturi Scrubber; Peaking Unit No. 2, Gas Fired):

Riviera Power Plant, Unit No. 4 Oil & Gas Fired, 300 MW Class (315 MW Gross Capacity)

Source Location: Street: 200-300 Broadway   City: Riviera Beach

UTM: East 594249 Zone 17   North 2960632

Latitude: 26° 45' 55"N   Longitude: 80° 03' 09"W

---

1. Attach a check made payable to the Department of Environmental Regulation in accordance with operation permit fee schedule set forth in Florida Administrative Code Rule 17-4.05.

2. Have there been any alterations to the plant since last permitted? [ ] Yes [X] No If minor alterations have occurred, describe on a separate sheet and attach.

3. Attach the last compliance test report required per permit conditions if not submitted previously. **All compliance test reports have been submitted**

4. Have previous permit conditions been adhered to? [X] Yes [ ] No If no, explain on a separate sheet and attach.

5. Has there been any malfunction of the pollution control equipment during tenure of current permit? [ ] Yes [X] No If yes, and not previously reported, give brief details and what action was taken on a separate sheet and attach.

6. Has the pollution control equipment been maintained to preserve the collection efficiency last permitted by the Department? [X] Yes [ ] No

7. Has the annual operating report for the last calendar year been submitted? [X] Yes [ ] No If no, please attach.

8. Please provide the following information if applicable:

A. Raw Materials and Chemical Used in Your Process:

Description	Contaminant Type	%Wt	Utilization Rate	lbs/hr
MgO or $Mg(OH)_2$ Additive	Particulate	100	150 lb/day average estimated for 1991	
Evaporation of boiler cleaning water with approximately 3% of monoammonium citrate solution	Particulate	100	Approximately 50,000 gallons of water every 3 years	

B. Product Weight (lbs/hr): Not applicable

C. Fuels: In order to improve start-up combustion, propane gas may be used for stabilizing ignition and small amounts of light oil (No. 2 fuel oil), or natural gas if that is available, are sometimes fired to preheat the boiler prior to ignition of residual fuel oil. Very small quantities of on-specification used oil, entirely from FPL operations, may be consumed while burning residual oil.

Type (Be Specific)	Consumption* Avg/hr*	Max/hr**	Maximum Heat Input(MMBTU/hr)
Residual Fuel Oil	Variable	500	3050
Natural Gas	Variable	3.3	3260

D. Potential Equipment Operating Time Up To: hrs/day 24; days/wk 7; wks/yr 52; hrs/yr (power plants only) ; 7228 hours of operation during 1992. More operating time is typical when ambient temperature is either unusually high or low, or during other unusual system demands.

The undersigned owner or authorized representative*** of Florida Power & Light Company is fully aware that the statements made in this application for a renewal of a permit to operate an air pollution source are true, correct and complete to the best of his knowledge and belief. Further, the undersigned agrees to maintain and operate the pollution source and pollution control facilities in such a manner as to comply with the provisions of Chapter 403, Florida Statutes, and all the rules and regulations of the Department. He also understands that a permit, if granted by the Department, will be non-transferable and he will promptly notify the Department upon sale or legal transfer of the permitted facility. **This certification pertains solely to air pollution related requirements.**

Elsa A. Bishop
Signature, Owner or Authorized Representative
(Notarization is mandatory)

*During actual time of operation.
**Units: Natural Gas-MMCF/hr; Fuel Oils-barrels/hr; Coal-
***Attach letter of authorization if not previsouly submitted.

E. A. Bishop, Supervisor
Air Permitting and Programs
Typed Name and Title

P. O. Box 088801
Address

North Palm Beach
City

Florida 33408
State Zip

2/1/93
Date

(407) 625-7607
Telephone No.

PROPOSED
REASONABLY AVAILABLE CONTROL TECHNOLOGY (RACT)
FOR
FLORIDA POWER & LIGHT COMPANY (FPL)
RIVIERA PLANT

PERSPECTIVE

The information contained in this application and the supporting documents provides FPL's recommended RACT emission limit for the Riviera plant. The basis of this recommendation is a comprehensive assessment of all of FPL's facilities in the moderate nonattainment area. This involved an evaluation of the 12 fossil fuel fired steam electric units and 36 gas turbines at five plants in the nonattainment area. The proposed RACT strategy would provide the Florida Department of Environmental Regulation (FDER):

1. Technically feasible, demonstrated, and cost effective control strategy based on FPL specific units which is consistent with guidance provided by the U.S. Environmental Protection Agency (EPA);
2. A 16 percent reduction in nitrogen oxides (NO_x) emissions from all of FPL facilities in the nonattainment area between the 1990 baseline year and the period 1995-2000, despite a 34 percent increase in energy used to serve customer demand (see Figure 1);
3. A 38 percent reduction in the weighted average emission rate from all of FPL facilities in the nonattainment area (i.e., a reduction in weighted average emission rate of 0.6 lb/10^6 Btu in 1990 to 0.38 lb/10^6 Btu in 1995-2000); and
4. Assurance that these significant NO_x emission reductions would be achieved by May 31, 1995.

The application consists of four sections including an introduction, description of existing sources, RACT assessment, and proposed RACT and rationale, along with supporting attachments.

are located in nonattainment areas classified as moderate or higher must apply for a new or revised operation permit by March 1, 1993 [pursuant to Rule 17-296.570 Florida Administrative Code (F.A.C.)]. The application will be reviewed by FDER for the purpose of establishing RACT emission limits for NO_x and VOCs on a case-by-case basis. The Riviera plant is a major emitting facility for NO_x and is subject to the RACT Determination procedure of FDER Rule 17-296.570 (4) F.A.C. This application and the attached technical support document titled "Reasonably Available Control Technology (RACT) Assessment of Florida Power & Light Company's Facilities Located in the Dade, Broward and Palm Beach Ozone Nonattainment Area" provides information required by FDER Rules, including FPL's recommended RACT determination for the Riviera plant sources.

RACT Requirements

The term "RACT" is defined in FDER rules as follows:

> RACT is the lowest emission limit that a particular source is capable of meeting by the application of control technology that is reasonably available considering technological and economic feasibility. [FDER Rule 17-2.100 (163) F.A.C.]

This longstanding regulatory definition, which EPA originally promulgated to guide states in establishing RACT emission limits for existing sources in nonattainment areas, clearly reflects the case-by-case, fact-specific nature of RACT determinations. Indeed, FDER's RACT Determination Procedure clearly states that RACT is to be established by the Department on a case-by-case basis. Consideration is given to RACT emission limiting standards established by other states, information available from EPA guidance documents, technological and economic feasibility, and all other relevant information [see FDER Rule 17-296.570 (4)(b) F.A.C.].

FACILITY DESCRIPTION

General

The Riviera plant consists of two fossil fuel steam electric units. The two fossil fuel steam electric units, Units 3 and 4, have a nominal generating capability of 300 MW each and were in commercial service beginning in June 1962 and March 1963, respectively. The fossil fuel steam units are fired with natural gas and/or residual oil. All units are single-wall fired with high heat release rates, i.e., greater than 80,000 Btu/hr-ft^3.

NO_x Emissions

FPL conducted emission tests in 1991 and 1992 to "benchmark" NO_x emission rates for the affected units. Where units were substantially identical, only one unit was tested. The benchmarking tests are representative of the normal operation of the units and provide representative emission estimates for developing control options (refer to Technical Support Document for test results).

Test results indicated NO_x emission rates for Units 3 and 4 of 0.92 and 0.72 lb/10^6 Btu for oil and natural gas firing, respectively. The NO_x emission rate when firing oil in Units 3 and 4 was more than two times higher than EPA's AP-42 emission factor, i.e., 0.92 lb/10^6 Btu compared to 0.45 lb/10^6 Btu, while the NO_x emission rate for natural gas firing was approximately 30 percent higher than the AP-42 emission factor, i.e., 0.72 lb/10^6 Btu compared to 0.55 lb/10^6 Btu.

The NO_x emission rates determined from the benchmarking tests were used to estimate 1990 NO_x emissions. Based on the 1990 actual fuel use data, the Riviera plant had NO_x emissions of 8,344.0 tons which is about 24 percent of the total NO_x emissions from FPL's facilities located in Dade, Broward, and Palm Beach counties.

Table 1 presents a summary of the characteristics and emissions for each unit at the Riviera plant. Refer to Technical Support Document for additional information.

VOC Emissions

VOC emission rates were determined through source testing of the fossil fuel fired steam electric units fired on oil. The VOC emissions for the steam units were determined in 1992 using EPA Method 25A. Table 2 presents the VOC emission rates determined for the sources at the Riviera plant. Because VOC emissions at Riviera were not determined for gas firing, these emission rates were taken from tests conducted at the Port Everglades plant. The emission rates determined for Units 3 and 4 using EPA test methods are lower than the AP-42 emission factors for these sources. For the steam electric units, the maximum emission rates determined through testing were 0.0004 and 0.0002 $lb/10^6$ Btu for oil and gas firing, respectively. In contrast, EPA AP-42 emissions factors are 0.005 and 0.0013 $lb/10^6$ Btu, respectively. VOC source test data are presented in Appendix B.

The Riviera plant also has tanks for storing and handling fuels. A total of 6 tanks are used for this purpose and small amounts of VOCs are emitted through breathing and handling losses. Of the six tanks, five are used for handling and storing No. 6 fuel oil which has a minimum of VOC emissions. The No. 6 fuel oil tanks include:

1. Four storage tanks which range in capacity from 55,000 to 268,000 barrels (bbl), with a total capacity of 528,000 bbl; and
2. One metering tank used for special testing with a capacity of 4,500 bbl.

The plant also has a 240 bbl tank for storing No. 2 distillate fuel oil. Solvents and cleaners used at the facility are also a source of VOC emissions.

Table 2 presents actual 1990 and potential VOC emissions for the Riviera plant. Because actual and potential VOC emissions are less than 100 tons per year, this facility is not classified as a "major facility" for VOC emissions. (See Appendix A for VOC calculations.)

NO_x RACT CONTROL ALTERNATIVES

Regulatory Guidance

For NO_x emissions from fossil fuel fired steam generators and gas turbines, EPA will not issue Control Technology Guidance (CTG) documents. EPA has issued, in a supplement to the general preamble to the regulations related to the implementation of Title I of the Clean Air Act Amendments of 1990 for state implementation plans, some guidance for certain electric utility boilers [57 Federal Register (FR) 55620, November 25, 1990].

EPA's guidance concluded that RACT for utility generators should reflect " the most effective level of combustion modification reasonably available to an individual unit". EPA specified by reference the application of low NO_x burners but recognized that in some cases overfire air and flue gas recirculation may be appropriate while in other cases RACT would require no additional control.

For oil/gas wall-fired units, EPA indicated that in the majority of cases, RACT should result in an overall level of control equivalent to 0.3 lb/10^6 Btu with compliance based on a 30 day rolling average. EPA encourages the states to adopt emission averaging concepts including averaging within the same transport region. However, EPA states that: "The actual NO_x emission reduction that can be achieved on a specific boiler depends on a number of site-specific factors including, but not limited to, furnace dimensions and operating characteristics, design and condition of burner controls, design and condition of stream control systems, and fan capacity. The combustion modification technology must be custom-designed for each boiler application."

The approach taken by FPL to identify RACT for each unit is consistent with EPA guidance and is based on a unit-specific analysis of NO_x control options that realistically considered the technological and economic feasibility for each unit.

Combustion Modifications--Boilers

Combustion modifications, which EPA suggests as the control technology that would achieve RACT, was evaluated for Riviera Units 3 and 4 (see Technical Support Document). Four major types of combustion modifications were evaluated, including low-NO_x burner (LNB) technology, off-stoichiometric combustion (OSC), over-fire air (OFA) and flue gas recirculation (FGR). The results of the evaluation, which are summarized in Table 3, suggest that LNB technology is the most cost effective for these units. The cost effectiveness for LNB technology is about $800 per ton of NO_x reduced for both units. In contrast, the cost effectiveness of OFA and FGR is about $3,400 and $3,000 per ton of NO_x reduced, respectively.

For Units 3 and 4, LNB technology can achieve a minimum of 25 percent NO_x reduction which would be equivalent to a proposed RACT emission rate of 0.54 and 0.69 lb/10^6 Btu for natural gas and oil firing, respectively. LNB technology is feasible for these units and the amount of reduction proposed is viable. Application of OFA and FGR on these units requires extensive modifications, and completing needed modifications would not be possible by May 31, 1995. The cost of OFA and FGR is over four times higher per ton of NO_x removed than LNB technology, suggesting the latter is the most appropriate for these units.

Post-Combustion Technologies--Boilers

The post-combustion technologies evaluated included selective non-catalytic reduction (SNCR) and selective catalytic reduction (SCR). Although EPA has not considered these technologies to be appropriate or necessary for fossil fuel steam units in its RACT guidance, SNCR and SCR were evaluated as alternatives to combustion modifications. The evaluation found that SNCR was not feasible since the temperature and residence times required for the reaction of ammonia and NO_x are not available in Units 3 and 4. The cost of SCR would make this technology economically infeasible. For both SNCR and SCR, achieving the RACT compliance date for all units would not be possible. Table 4 summarizes the economic and technical attributes of the post-combustion technologies evaluated.

VOC RACT CONTROL ALTERNATIVES

Because the Riviera plant is not considered a major facility for VOC emissions, VOC RACT control alternatives do not apply.

PROPOSED RACT AND RATIONALE

EPA's guidance, while suggesting NO_x emission rates as RACT for certain utility boilers, clearly provides for the evaluation of design-specific factors when establishing RACT. Units 3 and 4 are unique in those design features that affect NO_x emissions and the ability to apply combustion control technology. The specific design factors unique to these units are the single-wall fired configuration and small furnace design with associated high heat release rates (as indicated by Btu/hr-ft^3). These design features are illustrated in Figure 2.

Of the 59,000-MW oil/gas fired utility steam generators, about 41 percent are single-wall fired units. In contrast to units designed as single-wall fired, tangentially and opposed-wall fired units have inherently lower NO_x emissions and can generally meet 0.3 lb $NO_x/10^6$ Btu heat input. Units 3 and 4 were designed and fabricated by Foster-Wheeler (FW). FW-designed oil/gas-fired boilers make up about 49 percent of all U.S. single-wall fired designs; the other major manufacturer, Babcock and Wilcox (B&W), makes up the remainder (i.e., 51 percent). In general, B&W designs have larger furnace volumes and lower NO_x emission rates. As shown in Figure 2, about 66 percent of FW designs are pre-New Source Performance Standards (NSPS); the post-NSPS designs meet a 0.3 lb $NO_x/10^6$ Btu limit. Of the pre-NSPS designs, 57 percent are high heat release rate (>80,000 Btu/hr-ft^3) units. Low (<45,000 Btu/hr-ft^3) and medium (45,000 to 80,000 Btu/hr-ft^3) heat release units make up 10 and 33 percent, respectively, of the pre-NSPS units. Fifty percent of the high heat release units are located in non-attainment areas; all these units are owned by FPL and located in Dade, Broward, and Palm Beach counties (see Figure 2).

In contrast to the FPL single-wall fired oil/gas units, NO_x emission rates from many other oil/gas-fired units are inherently lower due to larger furnace volume for a similarly sized unit. This is particularly true of units originally designed to burn coal and converted to oil/gas firing to meet particulate and sulfur dioxide emission limits. Such units, many of which are in the northeast United States (e.g., Con Edison), have large furnace volumes and low heat release rates resulting in inherently lower NO_x emission rates. These units generally can meet the EPA-suggested guidance levels without additional controls.

Boilers with high heat release rates have inherently higher NO_x emission rates, and options for reasonably available controls are limited. The application of LNB technology is the most readily adaptable to these units and the most cost-effective.

Considerable experience in LNB technology was gained through the installation of low-NO_x burners in Port Everglades Units 3 and 4. Indeed, FPL's experience is unique in this regard, since low-NO_x combustion technology was integrated into the performance requirements for existing operating units. FPL's operational experience with LNB technology, while demonstrated to achieve required NO_x reduction requirements, was not without operating difficulties (e.g., flame impingement on boiler side and far walls). This experience suggests that LNB technology may developed more synergistically with existing units by using some existing burner components. Toward a goal of achieving a desired NO_x reduction while minimizing operating problems, FPL has undertaken a program, with contract support from the existing burner

Considerable experience in low-NO_x burner technology was gained through the installation of low-NO_x burners in Port Everglades Units 3 and 4. This experience is relatively unique in that there have been very few utility-sized retrofits of low-NO_x oil/gas burners in the U.S. FPL's operational experience with LNB technology, while demonstrated to achieve required NO_x reduction requirements, was not without design, startup, and operational problems (e.g., oil safety shutoff valve system seal failures, burner management system interface logic design issues, et.al). Considerable time, effort, and funds were spent on plant components having no influence on the burner's combustion/emission performance. Lessons learned from this project therefore indicate that substantial cost savings are possible by concentrating on design changes to only those components which effect combustion/emissions performance. Toward a goal of achieving maximum NO_x reductions using the most cost effective approach, FPL has undertaken a program, with contract support from the existing burner manufacturer, International Combustion Limited (ICL), to develop optimized designs for converting the existing burners to a low-NO_x configuration. This program consists of design development of combustion/emission related burner components and prototype testing to compare design alternatives and select the optimum design prior to actual implementation. It is currently anticipated that these efforts will result in a low-NO_x burner configuration consisting of an axial flow, single register, fuel staged design.

LNB technology is proposed as RACT for Riviera Units 3 and 4. The advantages of this technology are:

1. Technologically Feasible--Unlike other technologies, LNB technology has been retrofitted on Units 3 and 4 at the Port Everglades plant with a demonstrated NO_x reduction of 25 percent. This technology can be installed on Riviera Units 3 and 4. EPA has also suggested this technology as being the most appropriate for RACT.
2. Cost Effectiveness--LNB technology represents a cost effective approach. The $/ton of NO_x removed is $796, in contrast to EPA's recommendation for the NO_x reductions required under the acid rain provisions (Title IV) of the Clean Air Act (57FR55620), which was approximately $300 per ton of NO_x removed.
3. Achievement of Compliance Date--Installation of LNB technology can be achieved by May 31, 1995, for Riviera Units 3 and 4. It may not be possible to convert both units with other control alternatives.

The proposed RACT emission rate is based on a 25 percent reduction in maximum uncontrolled NO_x emissions for Units 3 and 4. Maximum uncontrolled emission rates are those rates determined from the benchmarking tests (or subsequent tests determined by FDER). The proposed RACT limits are:

PRV Units 3 and 4--0.54 lb/10^6 Btu gas; 0.69 lb/10^6 Btu oil

Certification by Professional Engineer Registered in Florida

This is to certify that the engineering features of this reasonably available control technology (RACT) application have been prepared or examined by me and found to be in conformity with modern engineering principles applicable to the treatment and disposal of pollutants characterized in the application.

Signed: Kennard F. Kosky   Date: 2/2/93

Kennard F. Kosky
KBN Engineering and Applied Sciences, Inc.
1034 NW 57th Street
Gainesville FL 32605
(904) 331-9000
Florida Registration No. 14996

SEAL
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Table 1. Summary of NO_x Emission Rates and 1990 Emissions for FPL Riviera Plant

Unit[a]	Nominal Size (MW)	NO_x Emission Rate ($lb/10^6$ Btu)		1990 NO_x Emissions (tons)	Percent of Total Plant Emissions
		Oil	Gas		
PRV 3	300	0.92	0.72	4,870.9	58.4%
PRV 4	300	0.92	0.72	3,473.1	41.6%
			Total:	8,344.0	

Note: See Tables 2-1, 2-2 and 2-3 in Technical Support Document.

[a] PRV = Riviera.

Table 2. Actual and Potential VOC Emissions for the FPL Riviera Plant Using Emission Rates Based on Test Results

Unit Name	Heat Input (10^9 Btu)[a] Oil	Heat Input (10^9 Btu)[a] Gas	VOC Emission Rate (lb/10^6 Btu)[b] Oil	VOC Emission Rate (lb/10^6 Btu)[b] Gas	VOC Emissions (TPY)
Actual Emissions					
PRV-3	3,540.6	9,006.2	0.0004	0.0002	1.6
PRV-4	3,012.0	5,798.9	0.0004	0.0002	1.2
Tanks[c]	NA	NA	NA	NA	0.4
Solvents[d]	NA	NA	NA	NA	1.9
				Plant Total	5.1
Potential Emissions					
PRV-3	26,718.0	27,944.4	0.0004	0.0002	8.1
PRV-4	26,718.0	27,944.4	0.0004	0.0002	8.1
Tanks[c]	NA	NA	NA	NA	0.4
Solvents[d]	NA	NA	NA	NA	1.9
				Plant Total	18.5

Note: NA = not applicable.

[a] 1990 heat input values as provided by FPL.
[b] Boiler emission rates based on tests conducted at the Riviera and Port Everglades plants.
[c] Refer to Table A1 in Appendix A for detailed calculations.
[d] Refer to Table A2 in Appendix A for detailed calculations.

Table 3. Summary of RACT Factors for Combustion Modifications FPL Riviera Plant

Factor	Unit	Alternative Control Technology[a] LNBT	OSC	OFA	FGR
NO_x Reduction		25%	≤20%[b]	10%	45%
Capital Cost	PRV 3	$ 4,733,000	NA	$ 7,447,000	$ 23,743,000
	PRV 4	4,733,000	NA	7,447,000	23,743,000
	Plant Total:	9,466,000	NA	14,894,000	47,486,000
Annualized Cost	PRV 3	830,000	NA	1,433,000	4,451,000
	PRV 4	830,000	NA	1,433,000	4,451,000
	Plant Total:	1,660,000	NA	2,866,000	8,902,000
Cost Effectiveness ($/ton)	PRV 3&4	796	NA	4,580	3,161
	Plant Total:	796	NA	4,580	3,161
Schedule Requirements:					
Duration of Outage		6 Weeks	Variable	3 Months	6 Months
Total Duration per Unit:		9 Months	Variable	12-14 Months	24 Months
Achieve Compliance Date?		Yes	Unknown	No	No
Technical Feasibility		Yes	Possible	Possible	Possible
Energy Penalties		Minor	Minor	Moderate	Major
Other Environmental Impacts		Minor	Minor	Yes	Yes

Note: NA = not available or unknown at this time.

[a] See Tables 3-1, 3-2, 4-1, B-1, B-2, and B-3 in Technical Support Document.
[b] OSC would not likely achieve the desired NO_x reduction. Refer to Section 3.2.2 in Technical Support Document.

Table 4. Summary of RACT Factors for Post-Combustion Technologies FPL Riviera Plant

Factor	Unit	Alternative Control Technology[a] SNCR	SCR
NO_x Reduction		35%	55%
Capital Cost	PRV 3	$ 9,932,721	$ 23,417,192
	PRV 4	9,932,721	23,417,192
	Plant Total:	19,865,442	46,834,384
Annualized Cost	PRV 3	3,419,052	8,870,936
	PRV 4	3,419,052	8,870,936
	Plant Total:	6,838,104	17,741,872
Cost Effectiveness ($/ton)	PRV 3&4	3,122	5,155
	Plant Total:	3,122	5,155
Schedule Requirements:			
Duration of Outage		2 Months	6 Months
Total Duration per Unit:		12-14 Months	24 Months
Achieve Compliance Date?		No	No
Technical Feasibility		Questionable	Possible
Energy Penalties		Minor	Major
Other Environmental Impacts		Yes	Yes

[a] See Tables 3-1, 3-2, 4-1, B-4, and B-5 in Technical Support Document.

Figure 1
COMPARISON OF HEAT INPUT AND NO_x EMISSION RATES FOR FPL PLANTS IN DADE, BROWARD, AND PALM BEACH COUNTIES

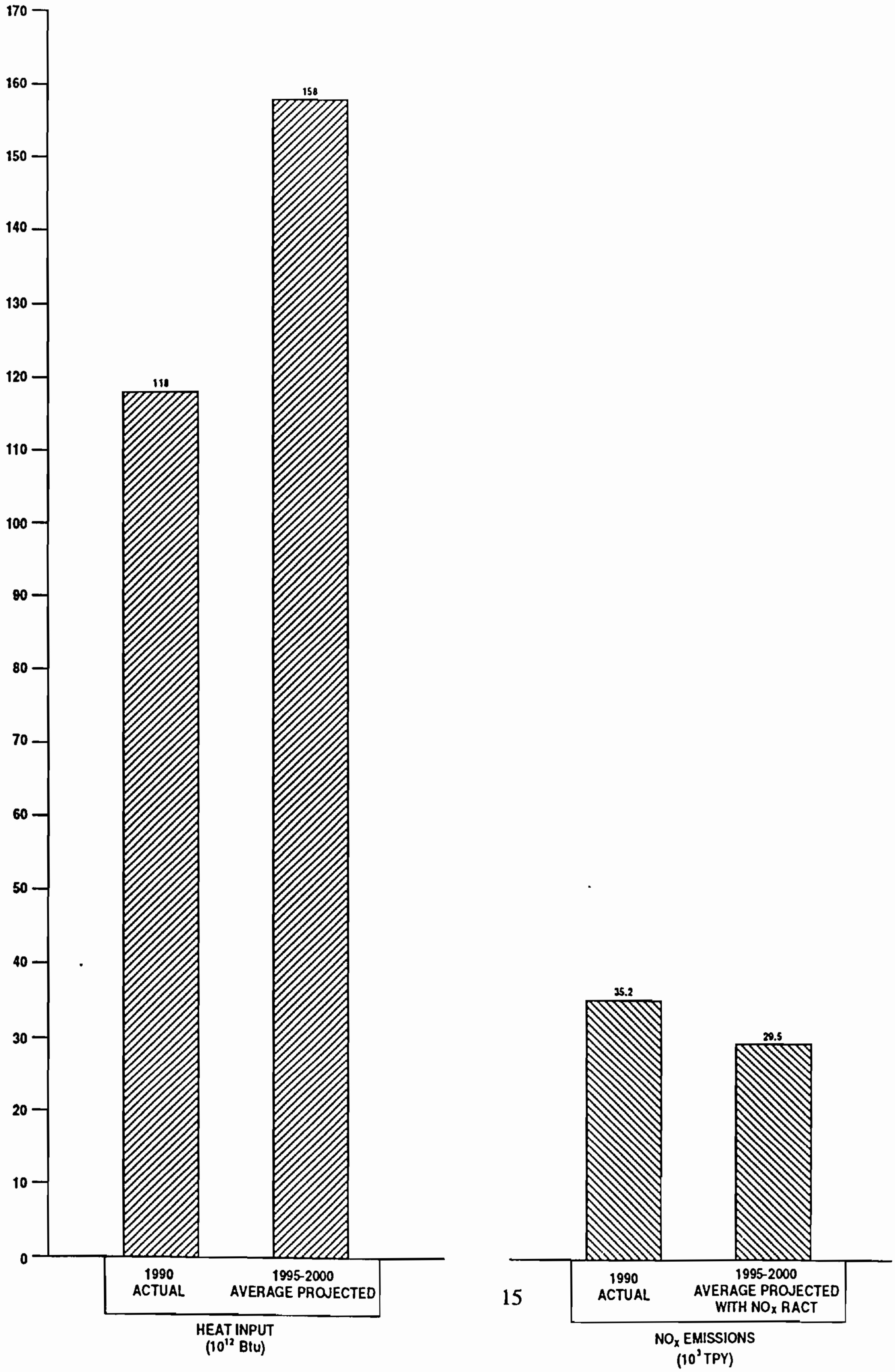
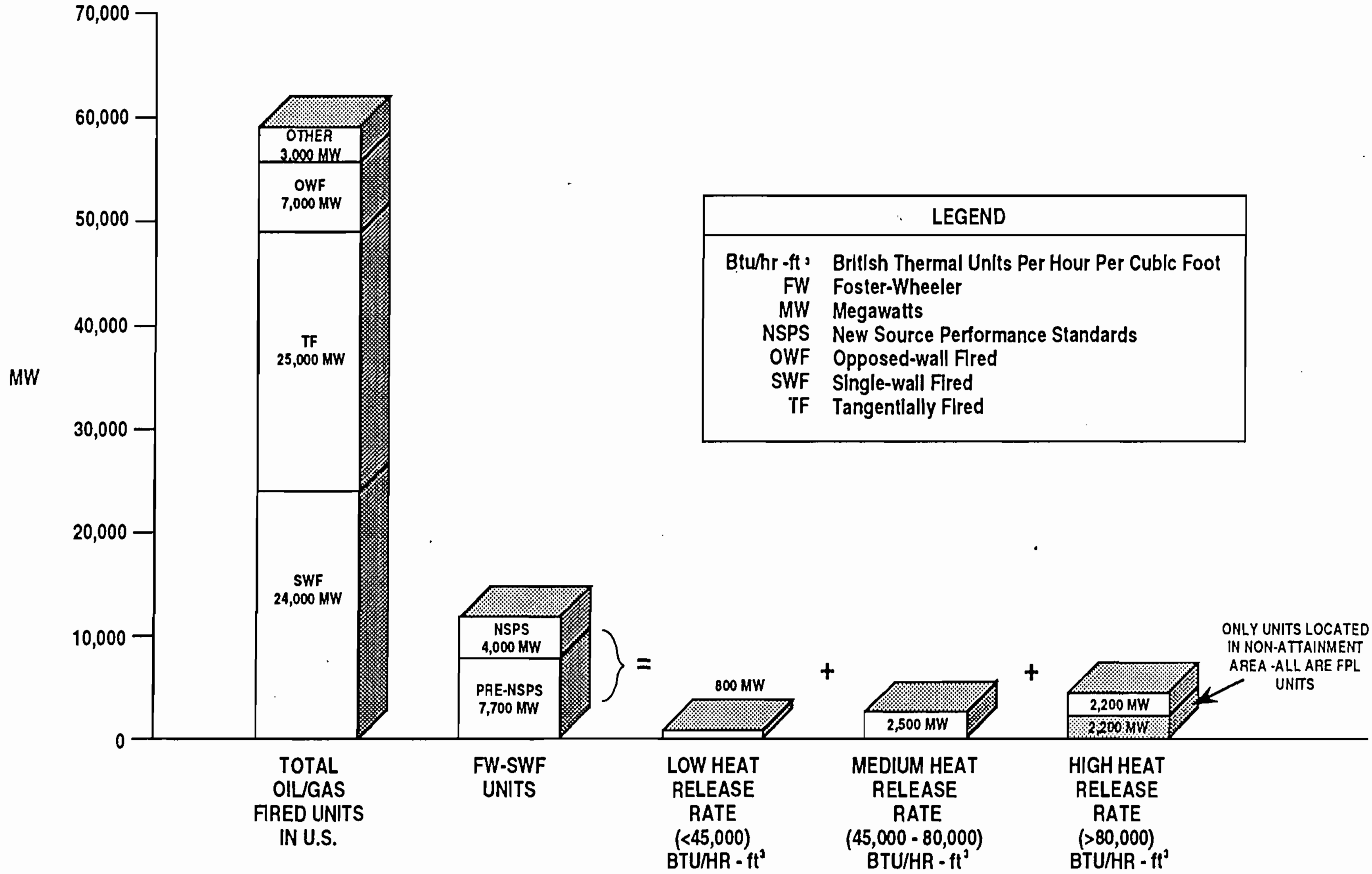


Figure 2
OIL/GAS-FIRED UTILITY STEAM GENERATORS



Attachments:

1. Appendix A--VOC Emission Calculations.
2. Appendix B--VOC Test Results.
3. FDER Renewal Application Form.
4. Technical Support Document.

APPENDIX A

VOC CALCULATIONS FOR TANKS AND SOLVENTS

Table A1. VOC Emission Calculations for Fixed Roof Storage Tanks at the FPL Riviera Plant

	Tank No. A #6 Fuel	Tank No. B #6 Fuel	Tank No. C #6 Fuel	Tank No. D #6 Fuel	Tank No. M #6 Fuel	Tank No. W-LO #2 Diesel[e]
BREATHING LOSS						
Mv = Molecular wt of vapor[a]	190	190	190	190	190	130
Pa = Avg. atmospheric pressure (psia)	14.7	14.7	14.7	14.7	14.7	14.7
P = True vapor pressure (psia)[b]	0.00009	0.00009	0.00009	0.00009	0.00009	0.012
D = Tank diameter (ft)	120	120	150	200	24	17.34[f]
H = Avg. vapor space height (ft)[c]	14.0	14.0	24.0	29.0	29.0	3.69
T = Avg. ambient diurnal temp. chg. (°F)	16.0	16.0	16.0	16.0	16.0	16.0
Fp = Paint factor[d]	1.40	1.40	1.40	1.40	1.40	1.40
C = Adj. factor sm. diameter tanks	1.0	1.0	1.0	1.0	1.0	0.4
Kc = Product factor	1.0	1.0	1.0	1.0	1.0	1.0
Lb = Fixed roof breathing loss (TPY) $= 2.26\times10^{-2} x MvP/Pa\text{-}P^{.68}D^{1.73}H^{.51}T^{.50}FpCKc/2000$	0.052	0.052	0.10	0.18	0.0047	0.0071
WORKING LOSS						
Mv = Molecular wt. of vapor[a]	190	190	190	190	190	130
P = True vapor pressure (psia)[b]	0.00009	0.00009	0.00009	0.00009	0.00009	0.012
V = Tank capacity (gal)	2,284,800	2,284,800	6,064,800	10,558,800	186,900	10,124
Qb = Throughput (barrels)	250,000	250,000	1,000,000	1,500,000	35,000	343
Qg = Throughput (gallons)	10,500,000	10,500,000	42,000,000	63,000,000	1,470,000	14,400
N = Total thruput per yr (gal) / Tank capacity (gal)	5	5	7	6	8	1
Kn = Turnover factor	1.0	1.0	1.0	1.0	1.0	1.0
Kc = Product factor	1.0	1.0	1.0	1.0	1.0	1.0
Lw = Fixed roof working loss (TPY) $= 2.40\times10^{-5} x MvPVNKnKc/2000$	0.0022	0.0022	0.0086	0.013	0.00030	0.00027
TOTAL LOSS (Lt)						
Lb + Lw = Lt (TPY)	0.054	0.054	0.11	0.20	0.0050	0.0074
Total Emissions for Fixed Roof Tanks (TPY):	0.43					

Note: All calculations based on AP42 methodologies.
Emissions based on 1991 throughputs.

[a] Based on 60 degrees F.
[b] Based on 80 degrees F.
[c] Taken as half the tank height.
[d] All tanks are green.Use paint factor for medium gray.
[e] Tank is a horizontal tank with a diameter and length of 7 ft-4.5 inches and 32 ft, respectively.
[f] Effective diameter based on the liquid surface area of a half-full tank.

Table A2. Estimated VOC Emission Due to Solvent Usage at the FPL Riviera Plant

Solvent Name	Estimated Annual Usage (gal)	Solvent Density (lb/gal)	Percent VOC	Estimated VOC Emissions (lb/yr)	(TPY)
Thinner No. 1	110	7.23	100	795.3	0.40
Thinner No. 2	110	7.10	100	781.0	0.39
Thinner No. 3	110	7.43	100	817.3	0.41
Thinner No. 4	110	7.50	100	825.0	0.41
CRC Lectra-Clean	50	11.47	100	573.5	0.29
			TOTAL:	3,792.1	1.90

APPENDIX B

VOC TEST RESULTS

AIR CONSULTING
& ENGINEERING, INC.

2106 N.W. 67th Place • Suite 4 • Gainesville, Florida • 32606
(904) 335-1889 FAX (904) 335-1891

April 28, 1992

Mr. Michael J. Taylor
Emission Test Group
Florida Power & Light Company
Post Office Box 4830
Princeton, Florida 33092-4830

Dear Mr. Taylor:

Enclosed is an emission summary of testing performed April 9, 10, and 14, 1992 at the Port Everglades and Riviera Plants.

The Riviera Plant was unable to obtain clearance for a gas firing so only oil testing was performed.

Total hydrocarbons as propane testing was conducted using a Ratfisch RS55 FID analyzer with heated components. CO emissions were measured with a Thermo Environmental Model 48 gas correlation NDIR.

All sampling was conducted using a moisture knockout trap prior to analysis (dry basis). The Riviera Plant testing for VOC's was conducted using both a dry system and a wet system to demonstrate that no VOC's were condensing in the dry system. The wet system used heat trace line at 300°F from the point of sample.

All instruments were calibrated and operated using EPA Method 25A and 10 methodology using NBS Traceable Protocol 1 calibration gases.

If you wish a formal test report for these tests please contact me.

Thank you for allowing Air Consulting and Engineering, Inc. (ACE) to perform this valued work.

Respectfully,

AIR CONSULTING AND ENGINEERING, INC.

Stephen L. Neck

Stephen L. Neck, P.E.

SLN/cvt

cc: Ken Kosky, KBN Engineering & Applied Sciences, Inc.

ACE File: 169 92 01

Emission Sumary
FPL - Riviera Plant
Unit 4 - 4/14/92

"F" Factor Gas = 8710
"F" Factor Oil = 9190

Test Description	O2%	CO ppm	CO lbs/MMBTU	C_3H_8 ppm	C_3H_8 lbs/MMBTU
Oil firing all sampling on dry basis 10170-1117	5.16	5038	4.47	0.27	0.0004
Oil firing VOC sampled on wet basis 1148-1248	5.20	4256	3.78	0.30	0.0004

Emission Sumary
FPL - Port Everglades
Units 2 and 4 - 4/9-10/92

"F" Factor Gas = 8710
"F" Factor Oil = 9190

Test Description	O2%	CO ppm	CO lbs/MMBTU	C_3H_8 ppm	C_3H_8 lbs/MMBTU
Unit 4 - 4/9/92					
Gas Firing East 0850-0926	2.57	0.00	0.0000	0.00	0.0000
Gas Firing West 0940-1000	2.81	0.00	0.0000	0.00	0.0000
Oil Firing West 1100-1130	2.64	7.63	0.0058	0.00	0.0000
Oil Firing East 1220-1300	2.51	3.00	0.0023	0.00	0.0000
Unit 2 - 4/10/92					
Gas Firing 0815-0916	5.92	0.71	0.0006	0.14	0.0002
Oil Firing 1032-1132	5.58	0.48	0.0004	0.00	0.0000

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FEB 4 - 1993

Division of Air
Resources Management

REASONABLY AVAILABLE CONTROL TECHNOLOGY (RACT) ASSESSMENT FOR
FLORIDA POWER & LIGHT COMPANY'S FACILITIES
LOCATED IN THE
DADE, BROWARD, AND PALM BEACH OZONE NON-ATTAINMENT AREA

Technical Support Document submitted with Applications for Determination of Reasonably Available Control Technology

August 1992

12150C1

PREFACE

INTRODUCTION

Florida Power & Light Company (FPL) owns and operates eight oil and/or gas fired steam electric generating units with greater than 200 megawatts of capacity in Dade, Broward and Palm Beach Counties. As these three counties have been classified as a "moderate" ozone nonattainment area, FPL has recently conducted an assessment designed to assist in establishing Reasonably Available Control Technology (RACT) requirements for emissions of nitrogen oxides (NO_x) from these units. FPL has also reviewed NO_x RACT approaches proposed by various regional and national organizations. In particular, FPL has considered certain suggestions offered by U. S. EPA staff in recent months, including presumptive NO_x RACT limits of 0.3 pounds per million Btu heat input for "wall-fired" oil/gas units and 0.55 pounds per million Btu heat input for "other" oil/gas units.

As discussed below, evaluation of data from FPL's units demonstrates the need for more detailed analysis of furnace design features in considering RACT limits. Simply stated, all "wall-fired" units are not the same when it comes to NO_x emissions. Any U. S. EPA guidance on this subject should recognize that certain furnace design features (including single wall burner configuration, small furnace volume, and high heat release rate) are critical factors affecting NO_x emission rates for oil/gas units.

FPL DATA AND ANALYSIS

Unit Design

Each of the eight FPL units with greater than 200 megawatt capacity located in the tri-county ozone nonattainment area was constructed in the late 1950s or 1960s. All of the units were originally designed to fire fuel oil and natural gas. Consequently, their furnace volume is relatively smaller than many oil/gas units in the northeast that were originally designed to fire coal. A common furnace design feature of the FPL units is their single wall burner configuration. Furnace design data for the FPL units are presented in Table A, along with data for an "NSPS-design" unit for comparison. As is apparent from the Table, FPL's units were not designed with NO_x emission control features nor is their design conducive to retrofit of certain control technology.

NO_x Data

FPL has conducted short-term NO_x stack tests, using EPA Reference Method 7E, on a number of the units that will be subject to RACT. A summary of the results of this recent testing is presented in Table B. These results reflect normal excess air and high load (i.e., 90 percent load or greater) conditions. Both the wide range of NO_x emission rates (0.40 to 0.92 on oil, 0.22 to 0.72 on gas), and the consistently higher rates for oil as compared to gas, are noteworthy.

Evaluation

Based on the emissions test data, FPL has concluded that both the single wall burner configuration and the furnace volume heat release rate are critical factors influencing NO_x emission rates.

The single wall burner arrangement (in combination with relatively shallow furnace depth) requires the fuel to be burned out quickly to avoid flame impingement on the rear wall. The resulting intense and rapid combustion tends to favor thermal NO_x production. In comparison, opposed wall-fired (and tangentially fired) furnaces are not subject to the risk of flame impingement and can have slower, less intense combustion due to the length-limiting nature of the opposed flames (or tangential swirl). Moreover, the single wall configuration uses fewer burners to deliver the necessary quantity of fuel for a given unit size than an opposed-wall furnace design (typically, one half the number for a unit of the same capacity with an opposed wall firing). Consequently, the heat release rate for individual burners in a single wall furnace is greater, with more intense combustion required to burn the requisite quantity of fuel.

The furnace design parameter that correlates with, and helps explain, the higher NO_x emission rates for FPL's 300 and 400 megawatt units is volume heat release rate (HRR). As shown in Table A, the volume HRR is about twice the rate for these units as for the NSPS design unit. In contrast, the volume HRR for FPL's 220 megawatt units (with lower NO_x emission rates) is approximately the same as for the NSPS design unit.

The higher NO_x emission rates for FPL's 300 megawatt units (compared even with the 400 megawatt units) may result from their compact flames, which are shaped to fit between the outer walls of the furnace and the internal division walls. In addition, refractory on the front walls of the 300 megawatt units reduces heat absorption in the flame zone, resulting in higher temperatures and more thermal NO_x production.

CONCLUSION

FPL's evaluation indicates that establishing one NO_x RACT emission limit for all "wall-fired" oil/gas units is not appropriate, as this is not a sufficiently detailed furnace design characteristic for distinguishing among oil/gas units. The critical effects of additional furnace design parameters (including single vs. opposed wall arrangements and volume heat release rate) on NO_x emission rates must be recognized in establishing RACT limits. Given the "uncontrolled" NO_x emission rates for FPL's single wall fired units and the reductions reasonably achievable with combustion modifications such as low NO_x burners, the 0.3 pound per million Btu limit suggested by U. S. EPA staff for "wall-fired" oil/gas units merits further study. A RACT limit in the 0.6 pound per million Btu range would be far more appropriate for units with single wall burner configuration and high volume heat release rates.

Table A. Furnace Design Features

WHAT ABOUT CUTLER 5 & 6 ?
(THESE ARE THE 8 WITH > 200MW CAPACITY)
THAT WERE CONSTRUCTED IN LATE 50's - 60's

Parameter	PPE1/2	PRV3/4	PPE3/4	PTF1/2	NSPS-Designed[c] OFA & FGR	
Nominal Size (MW)	220	300	400	400	600	1.5 OUTPUT FACTOR
Boiler OEM	CE	FW	FW	FW	FW	
Circulation	Controlled	Natural	Natural	Natural	Natural	
Draft	Balanced	Balanced	Forced	Forced	Balanced	
Furnace Size (DxWxHft) Total Height VOLUME (FT3)	25x48x95 114,000	24x77x62 114,576	28x70x114 223,440	28x70x114 223,440	42x65x167 455,910	2.0 TOTAL VOL. FACTOR
Refractory on Front Wall HRR BTU	No	Yes[b]	No	No	No	
Fuel	Oil/gas	Oil/gas	Oil/gas	Oil/gas	Oil/gas	
PER UNIT Heat Input/Unit (MMBtu/hr)	2300/2400	3050/3230	3850/4025	3850/4025	6255	1.5 HEAT INPUT FACTOR
Burner Zone Division Wall	Water	Water (3)	N/A	N/A	N/A	
Burner Configuration	Rear wall	Front wall	Front wall	Front wall	Opposed	
Burner OEM	ICL	ICL	ICL	ICL	---	
Number of Burners	16	24	18	18	30	
Columns x Row	4 x 4	8 x 3	6 x 3	6 x 3	2x(5x4)	
PER BURNER Heat Input/Burner[a] (MMBtu/hr)	144/150	127/135	214/224	214/224	209	
Burner Zone Cooling Area (ft^2)	8,543	7,352[b]	8,506	8,506	10,272	
Volume HRR[a] (MBtu/hr/ft^3)	50/53	84/90	84/88	84/88	48	
BTU/HR/FT3 VOL (FT3) HRR MW	0.24	0.30	0.22	0.22	.08	

Note: HRR = heat release rate.
MBtu/hr/ft^2 = thousand British thermal units per hour per square foot.
MMBtu/hr = million British thermal units per hour.
MW = megawatts.
NSPS = new source performance standard.
OEM = original equipment manufacturer.
PPE = Port Everglades.
PRV = Riviera Beach.
PTF = Turkey Point.

4

[a] Maximum HRR in the burner zone. Volume calculation based on furnace width multiplied by furnace depth and burner zone height.

[b] Front wall covered with refractory: 10 feet in from side wall, and from furnace floor to 5 feet above top row of burners (cooling area reduced to reflect refractory).

[c] This tower unit design includes air ports between upper and middle burner rows (OFA) and flue gas recirculation (FGR) [data provided by Foster Wheeler (FW)].

Table B. Present (1990) NO_x Emission Rates for Selected FPL Plants in Dade, Broward and Palm Beach Counties.

Unit Name	Unit Size[a] (MW)	NO_x Emission Rate ($lb/10^6$ Btu) Oil	Gas	Data Source
Turkey Point (PTF) 1 & 2	402	0.78	0.56	FPL test data, April 1992
Port Everglades (PPE) 1 & 2	225	0.40	0.22	FPL test data, April 1992
Port Everglades (PPE) 3 & 4	402	0.77	0.55	FPL test data, March, 1991
Riviera Beach (PRV) 3 & 4	310	0.92	0.72	FPL test data, March, 1992

[a] General maximum nameplate (FPL, 1992).

1.0 INTRODUCTION

1.1 PURPOSE OF REPORT

The Clean Air Act Amendments of 1990 call for a renewed effort to bring air quality within established standards. In Florida, this effort will involve measures designed to control ground-level ozone concentrations, including consideration of reasonably available control technology (RACT) for major sources of nitrogen oxides (NO_x) located in Dade, Broward, and Palm Beach Counties. Florida Power & Light Company (FPL) supports this effort, and its engineering staff, operating personnel, and environmental specialists have spent many hours analyzing the current situation and possible responses. Conclusions based on FPL's work to date are the objective of this report.

1.2 BACKGROUND

In its determination to achieve air quality standards, Congress recognized the importance of taking a deliberate, well-thought-out, and planned approach to the problem. First, our elected leaders recognized that individual areas differ in terms of the severity of their air pollution problems and that it will take time to implement improvements. (Florida's ozone non-attainment areas, for example, are classified as marginal or moderate, compared to areas in other parts of the country that are considered serious, severe, or even extreme in terms of their respective air pollution problems.) Second, Congress recognized that there remains large scientific uncertainty regarding the formation of smog conditions. Scientifically, it has proven difficult to determine the relative relationship between NO_x versus volatile organic compounds (VOCs) in ozone non-attainment areas; in fact, the new Clean Air Act itself specifically acknowledges that reducing NO_x emissions may not be beneficial in some cases. Recent scientific studies tend to confirm that different approaches regarding VOC and NO_x controls may be required depending upon the circumstances in specific areas. It is certainly conceivable, from a scientific viewpoint, that even a decision to totally shut down all power plants in southeast Florida would not measurably improve the ozone non-attainment situation. Finally, adding to the uncertainty, the "moderate" ozone levels in southeast Florida occur very sporadically according to air monitoring data. There may only be a few hours in a year when ozone levels exceed the standards. In fact, in 1990 and 1991 the ozone levels did not exceed the standard at any monitoring stations in Dade, Broward and Palm Beach Counties.

Understanding the variability and complexity of the ozone problem in different areas, Congress did not require all sources to immediately install very expensive advanced control technologies regardless of the cost-effectiveness or practicalities involved. Instead, states are required to develop new plans based on appropriate reduction targets and reasonably available control technologies. States are still given the primary role in this effort, with considerable discretion to fashion control strategies based on state- and region-specific factors.

The longstanding regulatory definition clearly reflects the case-by-case, fact-specific nature of RACT [FDER Rule 17-2.100 (163) F.A.C]:

> RACT is the lowest emission limit that a particular source is capable of meeting by the application of control technology that is reasonably available considering technological and economic feasibility.

Moreover, RACT requirements apply to existing sources and the technological and economic feasibility of any control option is usually greatly affected by original plant design factors and retrofit ramifications. In developing NO_x RACT rules, FPL encourages the Department to take into account three major considerations:

1. Equity--considering the relative contribution of various types of sources to the problem,
2. Efficiency--considering how to get the maximum benefit for the investment made, and
3. Effectiveness--phasing in reductions in a programmed approach that allows effectiveness of reductions to be evaluated prior to additional requirements.

1.3 FPL SOURCES

FPL owns and operates five power plants in Dade, Broward, and Palm Beach Counties--Turkey Point and Cutler in Dade County, Lauderdale and Port Everglades in Broward County, and Riviera in Palm Beach County.

A total of 10 fossil-fuel-fired steam electric generating units currently operate at the five FPL power plants, as follows:

Turkey Point (PTF - Units 1 and 2)
Port Everglades (PPE - Units 1 - 4)
Riviera (PRV - Units 3 and 4)
Cutler (PCU - Units 5 and 6)

In addition, one bank of 12 peaking gas turbines (GTs) operates at PPE, and two banks of 12 peaking GTs each operate at PFL. Units No. 4 and 5 at PFL are now undergoing "repowering," and they will return to operation in 1992 as larger, more efficient combined cycle units replacing the existing fossil-fuel-fired steam units. All of the generating units at these five plants are capable of burning natural gas or fuel oil (No. 6 residual oil in the fossil-fuel-fired steam units and No. 2 distillate oil in the GTs). The generating units at the Cutler plant currently burn only natural gas.

1.4 ORGANIZATION OF REPORT

This report presents a technological assessment of the availability, feasibility, and economics of various NO_x control options potentially applicable to the major FPL sources in the Dade, Broward and Palm Beach non-attainment area. Section 2.0 presents a description of the each unit and the results of testing performed by FPL. In addition, the 1990 NO_x emissions for the FPL plants in the non-attainment area are presented in this section. The RACT technological assessment of available control technologies is presented in Section 3.0. This section presents technical descriptions, feasibility assessments, environmental consequences, and economics of each available control technology. Section 4.0 presents the proposed RACT for each unit and the overall emissions reduction expected for all FPL plants located in the non-attainment area. The appendices contain technical information to support the report (Appendices A - D) and proposed RACT rule language (Appendix E).

2.0 EMISSIONS AND DESCRIPTION OF FPL NO_x SOURCES

2.1 NO_x EMISSIONS

FPL undertook a program of determining NO_x emissions from each unit by testing representative units at each plant. The similar units for which representative testing was performed are:

Turkey Point Units 1 and 2 (nominal 400-MW units)
Port Everglades Units 1 and 2 (nominal 220-MW units)
Port Everglades Units 3 and 4 (nominal 400-MW units)
Riviera Units 3 and 4 (nominal 300-MW units)
Cutler Unit 5 and Unit 6 (nominal 75/160-MW units)

In addition, FPL has three banks of 12 gas turbine units; two banks are located at the Lauderdale Plant and one bank is located at the Port Everglades Plant. Each GT unit has a nominal capacity of 34 MW.

FPL performed NO_x testing over the past year on representative units using U.S. Environmental Protection Agency (EPA) Method 7E. A summary of the results of this recent testing is presented in Table 2-1. These results present NO_x emissions under normal excess air and high load (i.e., 90 percent or greater of full load) conditions. Appendix A contains the specific source test information.

The results suggest that FPL units can be classified by unit design series and associated NO_x emissions. The NO_x emissions for the nominal 400-MW units (i.e., Port Everglades Units 3 and 4 and Turkey Point Units 1 and 2) were similar for gas and oil. Although the emissions for Turkey Point were slightly higher than emissions for Port Everglades, the difference is within the precision of the test method. The emissions for natural gas firing were similar to the EPA AP-42 emission factor for utility units, i.e., 0.55 pound per million British thermal units (lb/MMBtu) heat input. When firing residual oil, the NO_x emissions for these 400-MW units were about 70 percent higher than the AP-42 emissions factor of 0.45 lb/MMBtu heat input. Prior to these tests, FPL reported NO_x emissions on an annual basis using the EPA emission factors.

The emissions for the nominal 300-MW units (i.e., Riviera Units 3 and 4) were about 20 percent higher than the emissions for the 400-MW units when firing oil and about 30 percent higher when firing natural gas. The NO_x emissions from these units were twice the EPA emission factor for oil firing and about 30 percent higher for natural gas firing.

Table 2-1. Present (1990) NO_x Emission Rates for FPL Plants in Dade, Broward, and Palm Beach Counties

Unit Name	Unit Size[a] (MW)	NO_x Emission Rate ($lb/10^6$ Btu) Oil	Gas	Data Source
Turkey Point (PTF) 1 & 2	402	0.78	0.56	FPL test data, April 1992
Lauderdale (PFL) 4 & 5[b]	156	0.45	0.55	AP-42
Port Everglades (PPE) 1 & 2	225	0.40	0.22	FPL test data, April 1992
Port Everglades (PPE) 3 & 4	402	0.77	0.55	FPL test data, March 1991
Riviera Beach (PRV) 3 & 4	310	0.92	0.72	FPL test data, March 1992
Cutler (PCU) 5 & 6	75/162	NA	0.14/0.16	FPL test data, May 1992
Lauderdale Gas Turbines (PFLGT) 1-24	34.2	0.82	0.43	FPL test data, May 1992
Port Everglades Gas Turbines (PPEGT) 1-12	34.2	0.82	0.43	FPL test data, May 1992

[a] General maximum nameplate (FPL, 1992).
[b] NO_x emissions for 1990 were calculated using AP-42 emission factors for these units. These units are being repowered. NO_x emissions for these repowered units were determined to be best available control technology (BACT). The BACT emission limits are: 0.26 $lb/10^6$ Btu when firing distillate oil and 0.16 $lb/10^6$ Btu when firing natural gas.

Note: NA = not applicable.

The NO_x emissions for the nominal 220-MW units (i.e., Port Everglades Plant Units 1 and 2) were relatively low compared to FPL's larger units. For residual oil firing, the NO_x emissions were about 50 percent lower than the emissions observed for the 400-MW units and about 60 percent lower for natural gas firing. Indeed, for natural gas firing, the NO_x emissions from these units were within 10 percent of the new source performance standards (NSPS); see 40 CFR Part 60, Subpart Da. The NO_x emissions from Port Everglades Units 1 and 2 for both natural gas and oil firing were lower than the AP-42 emission factors.

The nominal 400 MW (PTF), 300 MW and 220 MW units are currently equipped with similar model burners. The observed NO_x emissions differences are therefore primarily attributable to the differences in the original furnace design of each unit. Table 2-2 presents a comparison of furnace design features for each of FPL units with a nominal capacity greater than 200 MW along with information for a typical oil/gas-fired unit that would meet NSPS. Each FPL unit is a single-wall fired unit. The parameter that suggests higher NO_x emissions for the nominal 400- and 300-MW units is the volume heat release rate (HRR). The volume HRR is about a factor of 2 higher for these units than for the NSPS design unit. In contrast, the volume HRR for the nominal 220-MW units is about the same as for the NSPS design unit. The higher NO_x emissions for the 300-MW units is believed to result from the more compact flames which are shaped to fit between the outer walls of the furnace and internal division walls. In addition, refractory on the front walls reduces heat absorption in the flame zone.

The NO_x emissions for the two Cutler units were below the NSPS for natural gas firing which would presumably be more stringent than RACT. Currently, only natural gas is fired in these units.

For the GTs, the NO_x emissions when firing distillate oil were about twice the emissions when firing natural gas. These units are early 1970s vintage aircraft-derivative machines (Pratt and Whitney GG7A Gas Generators). Each unit has a heat input of 675 MMBtu/hr when firing distillate oil and 705 MMBtu/hr when firing natural gas.

2.2 1990 NO_x EMISSIONS

Table 2-3 presents the 1990 NO_x emissions using the NO_x emission information developed for each unit. The estimated NO_x emissions were 35,226.4 tons which represents about one quarter of total NO_x emissions emitted in Dade, Broward, and Palm Beach Counties. Of the FPL sources, about

Table 2-2. Furnace Design Features

Parameter	PPE1/2	PRV3/4	PPE3/4	PTF1/2	NSPS-Designed[c]
Nominal Size (MW)	220	300	400	400	600
Boiler OEM	CE	FW	FW	FW	FW
Circulation	Controlled	Natural	Natural	Natural	Natural
Draft	Balanced	Balanced	Forced	Forced	Balanced
Furnace Size (DxWxHft)	25x48x95	24x77x62	28x70x114	28x70x114	42x65x167
Refractory on Front Wall	No	Yes[b]	No	No	No
Fuel	Oil/gas	Oil/gas	Oil/gas	Oil/gas	Oil/gas
Heat Input/Unit (MMBtu/hr)	2300/2400	3050/3230	3850/4025	3850/4025	6255
Burner Zone Division Wall	Water	Water (3)	N/A	N/A	N/A
Burner Configuration	Rear wall	Front wall	Front wall	Front wall	Opposed
Burner OEM	ICL	ICL	ICL	ICL	---
Number of Burners	16	24	18	18	30
Columns x Row	4 x 4	8 x 3	6 x 3	6 x 3	2x(5x4)
Heat Input/Burner[a] (MMBtu/hr)	144/150	127/135	214/224	214/224	209
Burner Zone Cooling Area (ft^2)	8,543	7,352[b]	8,506	8,506	10,272
Volume HRR[a] (MBtu/hr/ft^3)	50/53	84/90	84/88	84/88	48

Note: HRR = heat release rate.
MBtu/hr/ft^2 = thousand British thermal units per hour per square foot.
MMBtu/hr = million British thermal units per hour.
MW = megawatts.
NSPS = new source performance standard.
OEM = original equipment manufacturer.
PPE = Port Everglades.
PRV = Riviera Beach.
PTF = Turkey Point.

[a] Maximum HRR in the burner zone. Volume calculation based on furnace width multiplied by furnace depth and burner zone height.
[b] Front wall covered with refractory: 10 feet in from side wall, and from furnace floor to 5 feet above top row of burners (cooling area reduced to reflect refractory).
[c] This tower unit design includes air ports between upper and middle burner rows and flue gas recirculation [data provided by Foster Wheeler (FW)].

Table 2-3. 1990 NO_x Emissions from FPL Plants in Dade, Broward and Palm Beach Counties

Unit Name	Heat Input (10^9 Btu) Oil	Heat Input (10^9 Btu) Gas	NO_x Emission Rate (lb/10^6 Btu) Oil	NO_x Emission Rate (lb/10^6 Btu) Gas	NO_x Emissions (tons)
PTF-1	4,892.8	5,973.4	0.78	0.56	3,580.7
PTF-2	7,597.3	11,596.0	0.78	0.56	6,209.8
PFL-4	207.0	722.5	0.45	0.55	245.3
PFL-5	124.5	4,006.6	0.45	0.55	1,129.8
PPE-1	2,477.6	7,815.8	0.40	0.22	1,355.3
PPE-2	5,452.8	5,557.1	0.40	0.22	1,701.8
PPE-3	12,815.2	9,746.1	0.77	0.55	7,614.0
PPE-4	7,321.2	3,957.2	0.77	0.55	3,906.9
PRV-3	3,540.6	9,006.2	0.92	0.72	4,870.9
PRV-4	3,012.0	5,798.9	0.92	0.72	3,473.1
PCU-5	NA	1,131.8	NA	0.14	79.2
PCU-6	NA	673.7	NA	0.16	53.9
PFLGT (1-24)	193.3	3,132.6	0.82	0.43	752.8
PPEGT (1-12)	99.8	985.5	0.82	0.43	252.8
TOTAL					35,226.4

Note: NA = not applicable
PCU = Cutler.
PFL = Lauderdale.
PFLGT = Lauderdale Gas Turbine.
PPE = Port Everglades.
PPEGT = Port Everglades Gas Turbine.
PRV = Riviera Beach.
PTF = Turkey Point.

Table 2-4. Present (1990) NO_x Emissions from FPL Plants in Dade, Broward, and Palm Beach Counties

	Unit Name	NO_x Emissions (tons)	Percent of Total
Turkey Pt.	PTF-1	3,580.7	10.2
	PTF-2	6,209.8	17.6
Lauderdale	PFL-4	245.3	0.7
	PFL-5	1,129.8	3.2
Pt. Everglades	PPE-1	1,355.3	3.8
	PPE-2	1,701.8	4.8
	PPE-3	7,614.0	21.6
	PPE-4	3,906.9	11.1
Riviera Beach	PRV-3	4,870.9	13.8
	PRV-4	3,473.1	9.9
Cutler	PCU-5	79.2	0.2
	PCU-6	53.9	0.2
Lauderdale GT	PFLGT (1-24)	752.8	2.1
Pt. Everglades GT	PPEGT (1-12)	252.8	0.7
	TOTAL	35,226.4	100.0

Note:
PCU = Cutler.
PFL = Lauderdale.
PFLGT = Lauderdale Gas Turbine.
PPE = Port Everglades.
PPEGT = Port Everglades Gas Turbine.
PRV = Riviera Beach.
PTF = Turkey Point.

84 percent of emissions were from six units: Port Everglades Units 3 and 4, Turkey Point Units 1 and 2, and Riviera Units 3 and 4 (see Table 2-4). In contrast, the NO_x emissions from Port Everglades Units 1 and 2 were 8.6 percent of total FPL emissions, and the 36 GTs were only 2.8 percent of total FPL NO_x emissions. The Cutler units were less than 0.5 percent of total FPL NO_x emissions. This distribution of 1990 NO_x emissions by plant is historically representative of the operation of these units in the FPL system based on a review of fuel usage during previous years. This suggests that NO_x emissions reductions from the FPL plants in Dade, Broward, and Palm Beach Counties would be most effective through reductions from the nominal 400- and 300-MW units.

3.0 RACT (CONTROL TECHNOLOGY) ASSESSMENT

3.1 CONTROL ALTERNATIVES

NO_x emissions from combustion of fossil fuels consist of thermal NO_x and fuel-bound NO_x. Thermal NO_x is formed from the reaction of oxygen and nitrogen in the combustion air at combustion temperatures. Formation of thermal NO_x depends on the flame temperature, residence time, combustion pressure, and air-to-fuel ratios in the primary combustion zone. The design and operation of the combustion chamber dictates these conditions. Fuel-bound NO_x is created by the oxidation of volatilized nitrogen in the fuel. Nitrogen content in the fuel is the primary factor in its formation.

The control of NO_x emissions from fossil fuel steam generators can be accomplished through the application of combustion modifications and/or post-combustion technology (EPA, 1991). The combustion modifications include low-NO_x burner (LNB) technology, off-stoichiometric combustion (OSC; i.e. burners out of service in the context of this report), over-fire air (OFA), and flue gas recirculation (FGR). Post-combustion technology include selective non-catalytic reduction (SNCR) and selective catalytic reduction (SCR). The application of any of these control technologies as a retrofit option is highly dependent on the existing design of the facility.

A key factor in assessing control technology alternatives is the RACT compliance date mandated in the 1990 Clean Air Act Amendments, i.e., May 31, 1995 for moderate non-attainment areas. The time required for installing control equipment and the duration of unit outage are important in meeting the compliance date. The installation of any control technology will involve the selection of bidders, issuance of a request for proposal, evaluation of bids, contract negotiation, equipment design, manufacture and installation, and testing and adjustment activities. This cycle is required for each technology and will be required for each representative unit. Also important is the amount of time required for each unit to be out of service. These outages must be scheduled during the low power demand periods (i.e., spring and fall) and must ensure that sufficient units are available to provide power. It is desirable to limit the number of units taken out of service and limit the time required for equipment installation. Furthermore, there are distinct advantages when the installation of control equipment can be accommodated within the routine scheduled outages. The sections that follow present the schedule considerations, technical feasibility, and economics of the control alternatives for the FPL fossil steam units at PTF, PPE and PRV. The current NO_x emissions from the Cutler Plant are considered to meet a RACT emission level.

3.2 COMBUSTION MODIFICATIONS

3.2.1 LOW-NO_x BURNER TECHNOLOGY (LNB)

Technology description--LNB technology reduces NO_x emissions by inducing staged combustion from each burner of the steam generator. This is accomplished through the creation of fuel rich and lean zones in the central and outer portions of the flame, respectively. This limits the amount of thermal and fuel NO_x formed during combustion. The amount of reduction achievable is dependent upon the original boiler design, existing burner design and actual operating practices. Industry experience of retrofitting LNB technology is very limited on oil- and gas-fired units.

Availability and Feasibility--LNB technology is directly applicable to the FPL units based on the recent experience at the Port Everglades Units 3 and 4. LNBs were installed in these units in early 1992 and preliminary testing indicates that a 25 percent reduction in current NO_x emissions levels is achievable. The experience gained from these units is directly applicable to the other 400-MW units and the 300-MW units. This technology is particularly attractive due to the ability to retrofit the new/converted LNB equipment to FPL's nominal 400- and 300-MW units without major changes to the plant. A 25 percent NO_x reduction would be expected for these six units. For the nominal 220-MW units, the amount of reduction using LNB technology may be less due to inherently lower existing NO_x emissions. The existing NO_x emissions result from the boiler design and lower volume heat release rate.

$\frac{0.40-0.3}{0.40} = 25\%$

$\frac{0.40-.24}{0.40} = 40\%$

For LNB technology, the amount of time required for procurement through installation is at least 9 months. This was accomplished with the installation of LNB technology on Port Everglades Units 3 and 4. In addition, the installation of LNB equipment can be accomplished within about a 6-week period which is the general duration of routine boiler outages. These are scheduled every 3 years for each unit. See Table 3-1 for schedule requirements and implications of LNB technology and other control alternatives.

Environmental and Energy Considerations--This technology is truly pollution prevention, i.e., it reduces the formation of NO_x. There will be a small heat rate reduction of about 10 Btu/kWh or about 0.1 percent which will produce a minor amount of secondary emissions.

Economics--The capital and annual costs of LNB and other NO_x control technologies are presented in Table 3-2. Capital costs for LNB technology are based on the actual costs for the LNB installed for the Port Everglades Units 3 and 4. The total and incremental cost effectiveness of LNB and other NO_x control technologies are presented in Table 3-3.

The estimated average capital costs for retrofitting LNBT on eight FPL units is less than $11.95/kW. The total cost effectiveness is estimated to be less than $724/ton of NO_x removed. The feasibility of converting existing burners to a low NO_x burner configuration is currently being investigated. This approach could potentially reduce the total cost of this low NO_x burner technology option. Appendix B contains cost summaries of the various control technologies evaluated.

Need more discussion.

3.2.2 OFF-STOICHIOMETRIC COMBUSTION (BURNERS OUT OF SERVICE)

Technology Description--This control option involves staging combustion through operating with burners out of service. This method is low cost but can produce operational problems. Unit performance is degraded, and emissions of particulate matter, carbon monoxide, and opacity can increase.

Availability and Feasibility--Limited testing with existing burners out of service provided NO_x reductions of 20 to 25 percent on gas and oil firing. However, impingement of the flame on the rear wall was observed during this limited testing. Such a condition would have significant effects to the heat transfer surfaces and would result in increased maintenance costs and potentially forced outages. Preliminary testing with LNB suggests that no substantial reduction in NO_x emissions is achieved by using burners out of service.

(DUE TO FIRING AT OR ABOVE MAX CAPACITY)

A comprehensive test program would be required to determine the overall scope of plant modifications required and the associated capital and operating costs. Plant modifications will probably be required to avoid adverse equipment damage from flame impingement. The use of OSC at the 300 MW units would also require more extensive plant changes to preclude a loss of generating capacity.

3.2.3 OVER-FIRE AIR (OFA)

Technology Description--OFA involves firing the burners in a fuel-rich mode and supplying combustion air through ports above the burners. The use of OFA is so specific to boiler design that estimating NO_x control performance for a specific unit is extremely difficult. Moreover, OFA is generally not a preferred retrofit option because burners out of service provide a similar level of control and OFA involves major modifications to the boiler (EPA, 1992).

Table 3-1. Schedule Requirements and Implications of NO_x Control Technologies

Control Technology	Outage	Total Duration per Unit[a] (months)	Completion Period for all Units[b]
LNBT	6 Weeks	9	Spring 1995
Boos OSC	Variable	Variable	Unknown
OFA	3 Months	12-14	Spring 1996
FGR	6 Months	24	Fall 1997
SNCR	2 Months	12-14	Fall 1996
SCR	6 Months	24	Fall 1997

[a] Includes time for engineering, design, procurement, unit preparation and installation.
[b] Assumes, where possible, that no more than one unit would be taken out of service at one time and outages not scheduled during peak load periods. FGR and SCR will either require overlapping outages or outages scheduled during peak load periods.

Table 3-2. Summary of Capital and Annualized Cost for NO_x Control Technologies for PTF Units 1 and 2, PPE Units 1 - 4, and PRV Units 3 and 4

Control Technology	NO_x Reduction	Capital Cost	Annualized Cost
LNBT	25.0%[a]	$31,110,000	$5,590,866
OSC[b]	≤20	Unknown	Unknown
OFA[c]	10.0%	$42,534,000	$8,904,0000
FGR	45.0%	$169,160,000	$32,548,000
SNCR[d]	35.0%	$85,791,940	$28,993,400
SCR	70.0%	$199,951,756	$76,600,400

[a] 25% reduction on PTF 1 and 2, PPE 3 and 4 and PRV 3 and 4; 10% reduction for PPE 1 and 2.
[b] Refer to Section 3.2.2. OSC would not likely achieve the desired NO_x reduction.
[c] OFA would not likely achieve the desired NO_x reduction.
[d] SNCR is not considered viable NO_x control technology alternative for retrofit at FPL's units due to insufficient residence time for NO_x conversion and predicted ammonia slip concerns.

$\frac{.40-.26}{.40} = 35\%$

$\frac{.40-.12}{.40} = 70\%$

Table 3-3. Summary of Cost Effectiveness of NO_x Control Technologies for PTF Units 1 and 2, PPE Units 1 - 4 and PRV Units 3 and 4

Control Technology	Total		Incremental From LNBT	
	NO_x Removed (tons)[a]	Cost-Effectiveness ($/Ton NO_x Removed)	NO_x Removed (tons)[b]	Cost-Effectiveness ($/Ton NO_x Removed)
LNBT	7,720	724	--	--
OSC	NA	NA	NA	NA
OFA	2,983[c]	2,985	2,500	3,562
FGR	13,425[c]	2,424	11,247	2,894
SNCR	10,442[c]	2,777	8,747	3,315
SCR	20,884[c]	3,668	13,746[d]	5,573

[a] Based on 1990 NO_x emissions.
[b] NO_x reductions with all units installed with LNBT.
[c] Based on 1990 NO_x emissions adjusted for LNBT installed on PPE Units 3 and 4.
[d] Based on total removal of 70% which brings units to NSPS (Subpart Da) levels.

NA = Not available.

Availability and Feasibility--Data is not readily available to support a definitive NO_x reduction on FPL's oil and gas fired units with LNB. Potential NO_x reductions of between 5 and 15 percent may be feasible. The addition of OFA would require that less air be routed through the existing burners and that additional air be injected into the furnace above the burners. This would expand the volume of combustion, in that there would be a secondary burn zone in the vicinity of the OFA ports. An increased combustion volume results in lower combustion temperatures and, thus, lower NO_x emissions.

A preliminary study of FPL's 400-MW units indicates that the following design modifications would have to be made:

1. A new OFA system supply duct would have to be added to transport air directly from the forced draft fan discharge to the new OFA ports in the windbox. This new duct would have to be sized to minimize pressure drop, thereby maximizing the available pressure for injecting the OFA into the furnace. This is necessary to insure adequate mixing in the furnace and thus maximum NO_x reduction.
2. The OFA supply tie-in to the windbox would require a windbox/ductwork airflow modeling distribution study to preclude adverse effects on burner performance.
3. The windbox and ductwork would require revised baffle arrangements and reconfiguration at the interface area.
4. New OFA ports would have to be added with associated dampers/controls.
5. Pressure part modification of the front waterwall and radiant superheat would be required for each OFA port. The radiant superheat inlet header would have to be raised to an elevation above the top of the windbox. This approach would reduce the structural loading to the front wall hangers to partially accommodate the increased load from the weight of the OFA equipment.

A preliminary study of FPL's 300 MW and 220 MW units identified several factors making OFA more difficult than at the 400 MW units. This included asbestos insulation removal requirements, more extensive pressure part modifications and relatively longer OFA ducts.

The installation of OFA would require about 12 to 14 months per unit to complete with each unit outage requiring about 3 months (see Table 3-1). To install OFA on all eight units could be accomplished by spring 1996, or about 1 year later than LNB technology.

Environmental and Energy Considerations--This technology would cause some secondary emissions and increased heat rate.

Economic--The estimated costs of OFA for the FPL plants are presented in Table 3-2. The capital cost for retrofitting eight FPL units with OFA is estimated to be $15.88/kW. The total cost effectiveness is estimated to be $2,985/ton of NO_x removed; the incremental cost effectiveness over LNB is estimated to be $3,562/ton of NO_x removed (see Table 3-3).

3.2.4 FLUE GAS RECIRCULATION

Technology Description--FGR involves recycling a portion of the flue gases back into the primary combustion zone. NO_x emissions are reduced by lowering the peak flame temperature and lowering the oxygen concentration in the primary flame zone. FGR is effective in reducing NO_x emissions from natural gas and distillate oil firing; it is less effective with residual oil due to the nitrogen content of the fuel. Similar to OFA, this technology is not easily suited in retrofit applications due to the plant modifications required. FGR also substantially affects the unit heat rate through lowering fuel efficiency and increased fan power.

Availability and Feasibility--The application of FGR to FPL units would require major modifications to the plant and the addition of new equipment. Preliminary analysis of FPL's 400 MW units suggests that the following modifications would have to be made:

$\frac{0.40-0.22}{0.40}$, 45%

1. The static pressure capability of the forced draft (FD) fans, which supply combustion air to the boiler, would have to be increased. This would be required because FGR adds gas flow in addition to the normal air flow through the unit. The increased mass flow through the unit increases the pressure drop across all of the flow paths that the recirculated flue gas flows through and thus puts more load on the FD fans. For a 20 percent FGR flow, the static pressure of the FD fan would have to be increased by approximately 28 percent. Replacement of the FD fans has been considered necessary for FGR. One other option for increasing the static pressure required to compensate for the increase in draft loss is the addition of induced draft (ID) fans. This option would have to be studied further in order to determine which approach would be the most cost effective.
2. Replacement of the FD fans would require considerable new electrical equipment and upgrades of existing equipment. Each of the fans would require a new motor, drive assembly, switchgear, power cables, and controls and possible upgrade of the switchgear/breakers.

3. Since the static pressure of the FD fans would increase, the ducts between the FD fan and the windbox would require structural reinforcement. Structural support steel would also need to be modified accordingly.
4. The increase in operating pressure would continue into the windbox. The existing structure of the windbox would require structural reinforcement to accommodate the increase in pressure level.
5. The FGR duct tie-in would be upstream of the windbox. In order to insure that the injected flue gas is evenly distributed, flow distribution baffles going into the windbox would have to be modified. This would require a windbox/ductwork air flow distribution modeling study.
6. With the increase in air flow through the burners, modifications would have to be made in order to maintain the proper combustion characteristics and shape of the flames. This would include redesigned air swirlers, gas nozzles, and oil atomizers.
7. The overall steam generator and associated support system would have to be redesigned to ensure that the change in operating pressures could be handled (higher positive pressures and potential negative pressures). With the addition of an FGR fan, it is now possible that the pressure in the furnace could go negative should the FD fans or their dampers fail (this is a similar design scenario to a balanced draft unit). The new operating pressure conditions would require structural modifications to the buckstays, tension ties, structural steel, and pressure part support hangers in the penthouse.
8. With increased flue gas mass flow through the unit, there would be increased heat recovery area (HRA) heat absorption. Further study would be required to evaluate the extent of additional spray capacity and metal upgrades.
9. For the same reason as above, the economizer would require surface modifications.
10. The increased flow and resulting operating pressure through the flue ducts between the boiler exit and the FGR take-off point would require that these ducts be analyzed to determine if structural reinforcement of the ducts and/or their supports is necessary.
11. The new FGR system would consist of the following:
    a. Additional ducts to bring the recirculated flue gas from the flue after the air heater outlet to the duct upstream of the windbox.
    b. FGR fan(s) would have to be added. This would also require new foundation(s) and structural supports.

c. Expansion joints and necessary supports for the FGR ducts would have to be designed and added, as well as strengthening existing support steel or adding foundations.

d. In order to control the amount of FGR, dampers or a variable speed drive and related controls would have to be added. These would ensure that the proper amount of flue gas is fed to the windbox for NO_x reduction at all boiler loads.

e. Included with the addition of the FGR fans is all associated electrical equipment. This would include new motors, drives, power cables, grounding, controls (both local and additions to the control room), local lighting, and motor heaters. Each motor would require new breaker and switchgear facilities.

12. The upgraded fan equipment on the unit would consume substantially more power, thus increasing the auxiliary power requirements. This adds a constant increase in operating costs to the unit. Preliminary estimates indicate that an increase of 5.0 MW of auxiliary power would be required at full load. The scope of auxiliary equipment upgrades required is currently under evaluation. At ~~PTF~~ Turkey Pt., the auxiliary power system will require a new enlarged auxiliary power transformer, non-segregated bus, and an iso-phase bus.

A preliminary study of FPL's 300 MW and 220 MW units identified several factors making FGR retrofit more difficult than at the 400 MW units. This included asbestos insulation removal requirements, more fans and motors requiring upgrade, and relatively longer air ducts, gas flues and gas recirculation ducts.

The total time required for installation would be about 24 months per unit. The considerable amount of plant modifications would require an outage of about 6 months. Completion of FGR on all eight units would require until fall of 1997. To accomplish this schedule, at least two units each year would have overlapping outages scheduled.

Environmental and Energy--The major consequence of FGR is the loss of 5 MW per 400-MW unit. This is equivalent to a potential loss of 43,800 MW-hours per unit per year. Installation of FGR on any unit would potentially generate additional emissions of all regulated pollutants.

Economic--The estimated cost and cost-effectiveness of FGR are presented in Tables 3-2 and 3-3. The capital cost of retrofitting FGR on eight units is estimated at $63.17/kW. The total cost effectiveness is over ~~$2,424~~ 2894/ton of NO_x removed; the incremental cost effectiveness is $2,894/ton of NO_x removed.

3.3 POST-COMBUSTION TECHNOLOGIES

3.3.1 SELECTIVE NON-CATALYTIC COMBUSTION (SNCR)

Technology Description--SNCR describes post-combustion control technologies that remove NO_x by the addition of urea or ammonia into the flue gas and subsequent reduction of NO_x. Two available technologies are thermal De-NO_x and the NO_xOUT process.

MOST FLEXIBILITY

1. Thermal DeNO_x--Thermal DeNO_x is Exxon Research and Engineering Company's patented process for NO_x reduction. The process is a high temperature selective noncatalytic reduction (SNCR) of NO_x using ammonia as the reducing agent. Thermal DeNO_x requires the exhaust gas temperature to be above 1,800°F. However, use of ammonia plus hydrogen lowers the temperature requirement to about 1,000°F. For some applications, this must be achieved by additional firing in the exhaust stream before ammonia injection. The commercial applications of Thermal DeNO_x are on heavy industrial boilers, large furnaces, and incinerators that consistently produce exhaust gas temperatures above 1,800°F.

2. NO_xOUT Process--The NO_xOUT process originated from the initial research by the Electric Power Research Institute (EPRI) in 1976 on the use of urea to reduce NO_x. EPRI licensed the proprietary process to Fuel Tech, Inc., for commercialization. In the NO_xOUT process, aqueous urea is injected into the flue gas stream ideally within a temperature range of 1,600°F to 1,900°F. In the presence of oxygen, the following reaction results:

   $$CO(NH_2)_2 + 2NO + 1/2\ O_2 \dashrightarrow 2N_2 + CO_2 + 2H_2O$$

   The amount of urea required is most cost-effective when the treatment rate is 0.5 to 2 moles of urea per mole of NO_x. In addition to the original EPRI urea patents, Fuel Tech claims to have a number of proprietary catalysts capable of expanding the effective temperature range of the reaction to between 1,600°F and 1,950°F. Advantages of the system are as follows:

   a. Low capital and operating costs as a result of use of urea injection, and
   b. The proprietary catalysts used are nontoxic and nonhazardous, thus eliminating potential disposal problems.

Disadvantages of the system are as follows:

a. Formation of ammonia from excess urea treatment rates and/or improper use of reagent catalysts, and

b. Sulfur trioxide (SO_3), if present, will react with ammonia created from the urea to form ammonium bisulfate, potentially plugging the cold end equipment downstream.

Commercial application of the NO_xOUT system is limited to three reported cases:

a. Trial demonstration on a 62.5-ton-per-hour (TPH) stoker-fired wood waste boiler with 60 to 65 percent NO_x reduction,

b. A 600 x 10^6 Btu CE boiler with 60 to 70 percent NO_x reduction, and

c. A 75-MW pulverized coal-fired unit with 65 percent NO_x reduction.

For either SNCR process, the residence time is important. The suggested residence time for SNCR is about 0.5 to 1 second.

SUGGESTED VS. REQ'D ?

Availability and Feasibility--The design of the FPL facilities would generally preclude the installation of SNCR without major boiler modifications or re-build. The appropriate temperature zones in each boiler are particularly congested with boiler tubes which would therefore make installation of the injection system infeasible. Installation of SNCR would require inserting urea or ammonia injection nozzles in several areas of the boiler due to variations in temperature with fuel type and load. The existing boiler cavity residence times within the appropriate temperature zones are typically 0.2 second or less which is much lower than that required. Experience with SNCR on units with cavity retention times greater than that of the FPL units found unacceptably high ammonia slip rates (EPRI, 1992). Research sponsored by EPRI suggests that ammonia produces a greater amount of NO_x reduction than urea. This effect may be attributable to the temperature and residence times of the chemical reactions.

CHECK SCALED-DOWN VERSION OF NH_3 INJECTION IN COMB. w/ NEW LNBS ON PPE 3&4 (NO NH_3 SLIP)

COMPARE COST EFFECTIVENESS

SNCR would require from 12 to 14 months per unit to complete (see Table 3-1). The outage required for installation would be about 2 months. SNCR could be installed by the fall of 1996. Appendix C presents diagrams of the boiler cross sections and cavity temperature and residence time information for various load conditions and fuel types (i.e., gas and oil).

Environmental and Energy--SNCR has particular disadvantages in that urea or ammonia slip would occur. Typical designs on new facilities allow as much as 50 ppm slip which would be equivalent to 92 lb/hr for a 400-MW class unit. Emissions of N_2O have been reported to increase in SNCR applications (EPRI, 1992). N_2O, which is considered a greenhouse gas, is not normally emitted in significant quantities when combustion controls are utilized. In addition, on units firing moderate sulfur content (i.e., 1 percent or greater) fuels, the formation of corrosive ammonium salts such as ammonium sulfate and bisulfate has been observed. This is caused by the reaction of ammonia and sulfur oxides in the flue gas. The consequences of handling ammonia are presented in Appendix D.

Economic--For comparative purposes, the conceptual cost of SNCR was developed and is presented in Table 3-2; cost effectiveness is presented in Table 3-3. The capital cost for SNCR has been estimated to be about $33/kW. This estimated cost was developed from manufacturer information and is generally higher than that found in the industry. The potential for significant boiler modifications and specific guarantees would increase the cost. The estimated total cost effectiveness for SNCR is therefore over $2,800/ton of NO_x removed while the incremental cost effectiveness is over $3,300/ton of NO_x removed. These costs are about the same as that for FGR.

3.3.2 SELECTIVE CATALYTIC REDUCTION

Technology Description--SCR uses ammonia (NH_3) to react with NO_x in the gas stream in the presence of a catalyst. NH_3, which is diluted with air to about 5 percent by volume, is introduced into the gas stream at reaction temperatures between 600°F and 750°F. The reactions are as follows:

$$4NH_3 + 4NO + O_2 = 4N_2 + 6H_2O$$
$$4NH_3 + 2NO_2 + O_2 = 3N_2 + 6H_2O$$

The SCR in an oil/gas-fired boiler would have to be placed between the economizer and air preheater to achieve proper temperature conditions. This allows a relatively constant temperature for the reaction of NH_3 and NO_x on the catalyst surface.

While the operating experience on gas/oil-fired boilers is limited, certain cost, technical, and environmental considerations have surfaced. These considerations are summarized in Table 3-3. There have been no full scale retrofit applications of SCR on utility boilers.

As presented in Table 3-2, ammonium salts (ammonium sulfate and bisulfate) are formed by the reaction of NH_3 and sulfur combustion products. Ammonium bisulfate can be corrosive and could cause damage to the air preheater and flue surfaces that follow the catalyst, as well as to the stack. Corrosion protection for these areas would be required. Ammonium sulfate is emitted as particulate matter. While the formation of ammonium salts is primarily associated with oil firing, sulfur combustion products from natural gas also could form small amounts of ammonium salts.

Zeolite catalysts, which are reported to be capable of operating in temperature ranges from 600°F to 950°F, have been available commercially only recently. Optimum performance of an SCR system using a zeolite catalyst is reported to range from about 800°F to 900°F. At temperatures of 1,000°F and above, the zeolite catalyst will be irreparably damaged.

Availability and Feasibility--SCR has not been installed as a full scale retrofit on a utility boiler in the United States. Therefore, the availability of this technology for installation on the FPL units within a reasonable timeframe is unknown. Although the temperature zones for SCR appear available within the FPL boilers, major modifications would be necessary.

Procurement and installation of SCR would require about 24 months per unit (see Table 3-1). The outage would potentially require up to 6 months since plant modifications would be likely. Installation of SCR on all units could be completed by the fall of 1997. This is over 2.5 years later than LNB technology.

Environmental and Energy--SCR would have significant environmental and energy consequences such as ammonia slip and heat rate penalty. Ammonia slip at a rate of 20 ppm would be equivalent to 37 lb/hr for a 400-MW class unit. Conversion of sulfur dioxide to sulfite/sulfate aerosols has been reported to be as high as 4 percent in pilot tests. This would potentially cause increased formation of corrosive ammonium salts. The consequences of handling ammonia are presented in Appendix D.

Economic--Table 3-2 presents the costs of SCR. The estimated capital costs for SCR are the highest of any control technology evaluated and are $76.9/kW. The estimated total and incremental cost effectiveness of SCR are $3,668 and $5,573/ton of NO_x removed, respectively.

Table 3-4. Cost, Technical, and Environmental Considerations of SCR (Page 1 of 2)

Consideration	Description
COST:	
Catalyst Replacement	Catalyst life varies depending on the application. Cost ranges from 20 to 40 percent of total capital cost and is the dominant annual cost factor.
Ammonia	Ratio of at least 1:1 NH_3 to NO_x generally needed to obtain high removal efficiencies. Special storage and handling equipment required.
Space Requirements	Space in the catalyst is needed for replacement layers. Additional space is also required for catalyst maintenance and replacement.
Backup Equipment	Reliability requirements necessitate redundant systems, such as ammonia control and vaporization equipment.
Catalyst Back Pressure Heat Rate Reduction	Addition of catalyst creates backpressure which reduces overall heat rate.
Electrical	Additional usage of energy to operate ammonia pumps and dilution fans.
TECHNICAL:	
Ammonia Flow Distribution	NH_3 must be uniformly distributed in the exhaust stream to assure optimum mixing with NO_x before to reaching the catalyst.
Temperature	The narrow temperature range that SCR systems operate within (i.e., about 100°F) must be maintained even during load changes. Operational problems could occur if this range is not maintained.
Ammonia Control	Quantity of NH_3 introduced must be carefully controlled. With too little NH_3, the desired control efficiency is not reached; with too much NH_3, NH_3 emissions (referred to as slip) occur.
Flow Control	The velocity through the catalyst must be within a range to assure satisfactory residence time.

Table 3-4. Cost, Technical, and Environmental Considerations of SCR (Page 2 of 2)

Consideration	Description
ENVIRONMENTAL:	
Ammonia Slip	NH_3 slip (NH_3 that passes unreacted through the catalyst and into the atmosphere) can occur if 1) too much ammonia is added, 2) the flow distribution is not uniform, 3) the velocity is not within the optimum range, or 4) the proper temperature is not maintained.
Ammonium Salts	Ammonium salts (ammonium sulfate and bisulfate) can lead to increased corrosion. These salts can occur when firing natural gas. These compounds are emitted as particulates.
Ammonia Transportation and Storage	Storage and handling of anhydrous ammonia produces additional environmental risks. Appropriate controls and contingency plans in the event of a release is required.

4.0 PROPOSED RACT AND RATIONALE

Potential NO_x control strategies for the generating units located in Dade, Broward, and Palm Beach Counties have been carefully evaluated. Both combustion controls (LNB technology, OFA, FGR, and OSC, i.e, burners out-of-service) and post-combustion controls (SNCR and SCR) were considered for the fossil-fuel-fired steam units. Based on this evaluation, the appropriate control strategy for these units is LNB technology, which includes either conversion of existing burners to LNB configuration or installation of new burners. Other combustion controls evaluated would be difficult to implement on FPL's existing units or have questionable effectiveness in NO_x reduction. Post-combustion controls were determined to be either infeasible or cost prohibitive in retrofit application for these units. (See Table 4-1 for technology comparison matrix.)

Use of LNBT can achieve very significant reductions in NO_x emissions for most of the fossil-fuel-fired steam units subject to RACT requirements. Reductions of at least 25 percent are expected for the first six units with relatively higher baseline NO_x emission rates (PPE 3 and 4, PTF 1 and 2, PRV 3 and 4). Reductions of at least 10 percent are expected for PPE 1 and 2, which have considerably lower NO_x emissions at present. The very low NO_x emission rates for PCU 5 and 6, combined with their low capacity factors, and use of natural gas only, indicate these units already meet RACT.

Although FPL does not believe reductions in NO_x emissions for the GTs located at PPE and PFL are necessary or warranted based on their emission and utilization rates, evaluation of possible control technologies is continuing. If a technically and economically feasible technology is identified in this ongoing study, reductions in NO_x emissions for these units may also be pursued. No further controls for the repowered PFL 4 and 5 units are proposed in view of the fact that they are now subject to NO_x emissions limits based on FDER's BACT determination.

The RACT strategy outlined above will result in significant reductions in total NO_x emissions for FPL's generating units in Dade, Broward, and Palm Beach Counties. As shown in Table 4-2, average annual NO_x emissions (based on projected fuel use and RACT NO_x emissions

Table 4-1. Comparison of NO_x Control Technologies

Control Technology	Schedule [a]	Feasibility [b]	Energy Penalties [c]	Other Environmental Impacts [d]	Economics [e]
LNBT	Yes	Yes	Minor	Minor	Moderate
OSC[f]	Yes	Possible[g]	Minor	Minor	Low[h]
OFA[f]	No	Possible	Moderate	Yes	Moderate
FGR	No	Possible	Major	Yes	High
SNCR	No	Questionable	Minor	Yes	High
SCR	No	Possible	Major	Yes	High

[a] Ability to meet May 31, 1995, RACT compliance date for moderate nonattainment areas.
[b] Viability of technology to FPL units.
[c] Heat rate reduction or auxiliary power requirements.
[d] Secondary emissions or emissions of air pollutants not previously emitted.
[e] Based on capital and annualized costs.
[f] Would not likely achieve the desired NO_x reduction on larger units.
[g] A significant amount of testing would be required to determine actual feasibility.
[h] Assumes no affect on unit performance. Testing would be required to determine affect on unit performance.

Table 4-2. Projected RACT for FPL Plants in Dade, Broward and Palm Beach Counties Using 1995-2000 Average Heat Input Data for All Units

Unit Name	Projected 1995-2000 Average Heat Input (10^9 Btu)		Projected 1995-2000 NO_x Emissions (TPY)
	Oil	Gas	
PTF-1	7,253.4	600.2	2,247.7
PTF-2	10,476.8	781.2	3,228.5
PFL-4	163.2	26,135.5	2,072.5
PFL-5	711.9	23,104.2	1,904.8
PPE-1	4,578.7	3,261.5	1,147.1
PPE-2	4,938.3	3,715.8	1,256.8
PPE-3	5,409.4	15,277.4	4,712.9
PPE-4	5,188.1	14,677.8	4,525.4
PRV-3	2,661.6	10,471.2	3,745.5
PRV-4	2,820.5	10,395.4	3,779.8
PCU-5	0.0	421.3	29.5
PCU-6	0.0	2,188.8	175.1
PFLGT	88.6	2,226.5	515.0
PPEGT	0.0	606.3	130.4
TOTAL			29,470.8
Percent Reduction From Baseline (1990):			16.3 [a]

[a] (35,226.4 tons - 29,470.8 tons) ÷ 35,226.4 tons

Note:
PCU = Cutler.
PFL = Lauderdale.
PFLGT = Lauderdale Gas Turbine.
PPE = Port Everglades.
PPEGT = Port Everglades Gas Turbine.
PRV = Riviera Beach.
PTF = Turkey Point.

rates for 1995-2000) with this strategy will be more than 16 percent lower that the 1990 baseline emissions. This reduction is projected despite the growth in overall system load demand in future years requiring an increase of approximately 30 percent in total heat input for these units.

The RACT strategy proposed by FPL is the result of a unit-specific analysis of NO_x control options that realistically considered the technological and economic feasibility of each option as applied to FPL's existing generating units. The proposal also recognizes the "moderate" ozone non-attainment status of Dade, Broward, and Palm Beach Counties and reflects FPL's careful consideration of the three important factors previously identified--equity, efficiency, and effectiveness. FPL encourages FDER to include this approach in its evaluation of NO_x RACT options and welcomes the opportunity to discuss it further with all interested parties.

REFERENCES

Electric Power Research Institute (EPRI). 1992. NO_x Controls for Utility Boilers, Conference Papers. July 7-9, 1992, Cambridge, Massachusetts.

U.S. Environmental Protection Agency (EPA). 1991. Sourcebook: NO_x Control Technology Data. EPA-600/2-91-029.

U.S. EPA. 1992. Summary of NO_x Control Technologies and their Availability and Extent of Application. EPA-450/3-92-004.

APPENDIX A

TEST RESULTS

PTF 1 NO_X TEST DATA

UNIT #: 1 TEST #: 7 DATE: 4/22/92

TEST CONDITIONS: 100% OIL ~ 90% LOAD NORMAL O_2

NORTH DUCT

OPERATING PARAMETERS

FUEL OIL MW GROSS 390 NET 371

NUMBER OF BURNERS IN SERVICE 18 THROTTLE PRESSURE 2400 PSIG

F.O. (GAS) SUPPLY PRESSURE 710 PSIG F.O. RETURN PRESSURE 420 PSIG

F.O. ΔP 290 PSIG GAS BURNER PRESSURE — PSIG

F.O. TEMP 190 °F FUEL FLOW 79 % AIR FLOW 91 %

EXCESS O_2 NORTH 1.2 % SOUTH 1.2 %

WINDBOX PRESSURE EAST 27.5 " H_2O

FURNACE PRESSURE 19.3 " H_2O

FURNACE/WINDBOX PRESSURE Δ P 8.2 " H_2O

S.H. TEMP 1000 °F STEAM FLOW 2440 lbs/Hr x 1000

REHEAT TEMP 1000 °F F.W. FLOW 2460 lbs/Hr x 1000

F.D. FAN SPEED A 1102 RPM B 1026 RPM

F.D. FAN AMPS A 360 B 340

AIR FROM APH A 583 °F B 585 °F

GAS TO APH A 728 °F B 724 °F

OPACITY 6 %

NO_X NORTH OR SOUTH 600 PPM 0.785 #/BTU 6

LOWER SPRAY FLOW 94.4 lbs/HR x 1000 UPPER SPRAY FLOW 65.4 lbs/HR x 1000

R.H. SPRAY FLOW 1.04 lbs/HR x 1000

TEST VAN DATA: CO 49 PPM; CO_2 13.9 % O_2 3.4 %

COMMENTS: F.O. FAN DISCHARGE PRES 33.5 A 34.0 B

BURNER OIL FLOW = 10,533 #/HR.

JPS\OS3\KTW\PTF1TS7.DRW
UPDATED: 5/13/92

FLORIDA POWER AND LIGHT CO.
PLANT SERVICES OPERATIONS SUPPORT
NOx EMISSION RATE PTF UNIT 1

04/22/92

ANALYZER CALIBRATION RESPONSE

	TANK VALUE ppm	ANALYZER RESPONSE ppm	ABSOLUTE DIFF. ppm	% OF SPAN
ZERO	0	0	0	0
MID	554	554	0	0
HIGH	837	838	1	0.1

NORMAL 02 90% LOAD
NORTH DUCT

Year	Month	Day	Hour	Minute	Second	Average:
92	4	22	15	14	3	608.522
92	4	22	15	15	0	606.618
92	4	22	15	16	0	598.271
92	4	22	15	17	0	599.236
92	4	22	15	18	0	591.934
92	4	22	15	19	0	598.727
92	4	22	15	20	0	586.711
92	4	22	15	21	0	589.983
92	4	22	15	22	0	593.062
92	4	22	15	23	0	599.387
92	4	22	15	24	0	599.642
92	4	22	15	25	0	604.788
92	4	22	15	26	0	604.587
92	4	22	15	27	0	607.922
92	4	22	15	28	0	605.574
92	4	22	15	29	0	603.229

SYSTEM CALIBRATION BIAS AND DRIFT DATA

	ANALYZER RESPONSE ppm	INITIAL SYSTEM RESPONSE ppm	% OF SPAN	FINAL SYSTEM RESPONSE ppm	% OF SPAN	DRIFT % SPAN
ZERO	0	0	0	0	0	0
UPSCALE	554	555	0.1	552	-0.2	-0.3

RUN 7 PPM	599.887
RUN 7 CORRECTED	600.429
RUN 7 02	3.4
RUN 7 LB/MMBTU	0.785

02 / CO2/ CO
3.4/13.9/49

PTF 1 NO_X TEST DATA

UNIT #: 1 TEST #: 8 DATE: 4/22/92

TEST CONDITIONS: 100% OIL ~ 90% LOAD NORMAL O_2

SOUTH DUCT

OPERATING PARAMETERS

FUEL OIL MW GROSS 390 NET 371

NUMBER OF BURNERS IN SERVICE 18 THROTTLE PRESSURE 2400 PSIG

F.O. (GAS) SUPPLY PRESSURE 720 PSIG F.O. RETURN PRESSURE 420 PSIG

F.O. ΔP 300 PSIG GAS BURNER PRESSURE — PSIG

F.O. TEMP 190 °F FUEL FLOW 80 % AIR FLOW 90 %

EXCESS O_2 NORTH 1.2 % SOUTH 1.1 %

WINDBOX PRESSURE EAST 27.5 " H_2O

FURNACE PRESSURE 19.3 " H_2O

FURNACE/WINDBOX PRESSURE Δ P 8.2 " H_2O

S.H. TEMP 1000 °F STEAM FLOW 2440 lbs/Hr x 1000

REHEAT TEMP 1000 °F F.W. FLOW 2450 lbs/Hr x 1000

F.D. FAN SPEED A 1105 RPM B 1090 RPM

F.D. FAN AMPS A 360 B 350

AIR FROM APH A 584 °F B 584 °F

GAS TO APH A 728 °F B 725 °F

OPACITY 6 %

NO_X NORTH OR SOUTH 584 PPM 0.765 #/BTU ^{6}

LOWER SPRAY FLOW 94.4 lbs/HR x 1000 UPPER SPRAY FLOW 63 lbs/HR x 1000

R.H. SPRAY FLOW 0.99 lbs/HR x 1000

TEST VAN DATA: CO 52 PPM; CO_2 14.0 % O_2 3.4 %

COMMENTS: F.O. FAN DISCHARGE PRES 34 A 35 B

JPS\OS3\KTW\PPE34TS8.DRW
UPDATED: 5/26/92

FLORIDA POWER AND LIGHT CO.
PLANT SERVICES OPERATIONS SUPPORT
NOx EMISSION RATE PTF UNIT 1

04/22/92

ANALYZER CALIBRATION RESPONSE

	TANK VALUE ppm	ANALYZER RESPONSE ppm	ABSOLUTE DIFF. ppm	% OF SPAN
ZERO	0	0	0	0
MID	554	554	0	0
HIGH	837	838	1	0.1

NORMAL 02 90% LOAD
SOUTH DUCT

Year	Month	Day	Hour	Minute	Second	Average:
92	4	22	15	49	6	577.146
92	4	22	15	50	0	581.106
92	4	22	15	51	0	581.525
92	4	22	15	52	0	583.390
92	4	22	15	53	0	582.327
92	4	22	15	54	0	583.216
92	4	22	15	55	0	581.178
92	4	22	15	56	0	596.148
92	4	22	15	57	0	591.675
92	4	22	15	58	0	584.389
92	4	22	15	59	0	584.586
92	4	22	16	0	0	586.754
92	4	22	16	1	0	574.837
92	4	22	16	2	0	580.152
92	4	22	16	3	0	575.979
92	4	22	16	4	0	577.854

SYSTEM CALIBRATION BIAS AND DRIFT DATA

	ANALYZER RESPONSE ppm	INITIAL SYSTEM RESPONSE ppm	% OF SPAN	FINAL SYSTEM RESPONSE ppm	% OF SPAN	DRIFT % SPAN
ZERO	0	0	0	0	0	0
UPSCALE	554	552	-0.2	552	-0.2	0

RUN 8 PPM	582.641
RUN 8 CORRECTED	584.752
RUN 8 02	3.4
RUN 8 LB/MMBTU	0.765

02 / CO2/ CO
3.4/14.0/52

N + S (avg) - 0.78

PTF 1 NO_X TEST DATA

UNIT #: 1 TEST #: 8 DATE: 4/23/92

TEST CONDITIONS: 100% GAS ~ 90% LOAD HIGH O_2

NORTH DUCT

OPERATING PARAMETERS

FUEL GAS * MW GROSS 392 NET 373

NUMBER OF BURNERS IN SERVICE 18 THROTTLE PRESSURE 2400 PSIG

F.O. (GAS) SUPPLY PRESSURE 60 PSIG F.O. RETURN PRESSURE — PSIG

F.O. ΔP — PSIG GAS BURNER PRESSURE 26 PSIG

F.O. TEMP — °F FUEL FLOW 84 % AIR FLOW 96 %

EXCESS O_2 NORTH 0.9 % SOUTH 0.8 %

WINDBOX PRESSURE EAST 29.0 " H_2O

FURNACE PRESSURE 19.8 " H_2O

FURNACE/WINDBOX PRESSURE Δ P 9.2 " H_2O

S.H. TEMP 1000 °F STEAM FLOW 2440 lbs/Hr x 1000

REHEAT TEMP 1000 °F F.W. FLOW 2410 lbs/Hr x 1000

F.D. FAN SPEED A 1127 RPM B 1115 RPM

F.D. FAN AMPS A 380 B 370

AIR FROM APH A 603 °F B 605 °F

GAS TO APH A 740 °F B 737 °F

OPACITY 5 %

NO_X EAST OR WEST 451 PPM 0.56 #/BTU 6

LOWER SPRAY FLOW 156.8 lbs/HR x 1000 UPPER SPRAY FLOW 93.2 lbs/HR x 1000

R.H. SPRAY FLOW 16.56 lbs/HR x 1000

TEST VAN DATA: CO 138 PPM; CO_2 10.1 % O_2 3.4 %

COMMENTS: F.O. FAN DISCHARGE PRES 35 A 37 B

GAS FLOW = 3.721 MIL cu FT. 3 (206,722 FT3 / BURNER)

* REHEAT SPRAY INCREASED LOAD

JPS\OS3\KTW\PTF1\PPETS8G.DRW
UPDATED: 5/13/92

FLORIDA POWER AND LIGHT CO.
PLANT SERVICES OPERATIONS SUPPORT
NOx EMISSION RATE PTF UNIT 1

04/23/92

ANALYZER CALIBRATION RESPONSE

	TANK VALUE ppm	ANALYZER RESPONSE ppm	ABSOLUTE DIFF. ppm	% OF SPAN
ZERO	0	0	0	0
MID	554	554	0	0
HIGH	837	831	6	0.6

90% LOAD - 100% GAS
NORTH DUCT - HIGH O2

Year	Month	Day	Hour	Minute	Second	Average:
92	4	23	10	25	1	434.036
92	4	23	10	26	0	433.558
92	4	23	10	27	0	433.705
92	4	23	10	28	0	423.940
92	4	23	10	29	0	424.048
92	4	23	10	30	0	422.049
92	4	23	10	31	0	437.492
92	4	23	10	32	0	445.662
92	4	23	10	33	0	445.474
92	4	23	10	34	0	448.546
92	4	23	10	35	0	457.542
92	4	23	10	36	0	458.550
92	4	23	10	37	0	456.604
92	4	23	10	38	0	457.504
92	4	23	10	39	0	447.468
92	4	23	10	40	0	445.662

SYSTEM CALIBRATION BIAS AND DRIFT DATA

	ANALYZER RESPONSE ppm	INITIAL SYSTEM RESPONSE ppm	% OF SPAN	FINAL SYSTEM RESPONSE ppm	% OF SPAN	DRIFT % SPAN
ZERO	0	0	0	0	0	0
UPSCALE	554	542	-1.2	542	-1.2	0

RUN 8 PPM	441.990
RUN 8 CORRECTED	451.776
RUN 8 O2	3.4
RUN 8 LB/MMBTU	0.560

O2 / CO2/ CO
3.4/10.1/138

PPE 2 NOx TEST DATA

UNIT #: 2 TEST #: 11 DATE: 4/7/92

TEST CONDITIONS: VWO NORMAL GAS RECIRC
ABIS

OPERATING PARAMETERS

FUEL OIL MW GROSS 222 NET 210

NUMBER OF BURNERS IN SERVICE 16 THROTTLE PRESSURE 2000 PSIG

F.O. SUPPLY PRESSURE 780 PSIG F.O. RETURN PRESSURE 490 PSIG

F.O. ΔP 290 PSIG GAS BURNER PRESSURE 0 PSIG

F.O. TEMP 185 °F FUEL FLOW 78 % AIR FLOW 80 %

EXCESS O_2 EAST 0.75 %

WINDBOX PRESSURE EAST 6.3 " H_2O

FURNACE PRESSURE -0.3 2

FURNACE/WINDBOX PRESSURE ΔP 6.6 " H_2O

S.H. TEMP E 980 /L 1003 °F STEAM FLOW 150 lbs/Hr x 1000

REHEAT TEMP E 1000 /L 1000 °F F.W. FLOW 150 lbs/Hr x 1000

F.D. FAN AMPS EAST 85 WEST 85

I.D. FAN AMPS EAST 210 WEST 230 RPM 460 E 570 W

AIR FROM APH EAST 520 °F WEST 515 °F

GAS TO APH EAST 660 °F WEST 660 °F

OPACITY 8 %

NO_x EAST OR WEST 277.4 PPM .404 #/BTU 6

S.H. SPRAY FLOW 0 % VALVE POSITION 0 E 0 W % POSITION

R.H. SPRAY FLOW 0 % VALVE POSITION 0 E 0 W % POSITION

TEST VAN DATA: CO 396 PPM; CO_2 12.2 % O_2 5.2 %

COMMENTS:

GAS RECIRC	A	40	B	40
F O FAN DISCHARGE	A	9.5	B	9.5

BURNER OIL FLOW = 6825 #/HR.

JPS\OS3\KTW\PPE2OI11.DRW
UPDATED: 7/16/92

FLORIDA POWER & LIGHT CO. 04/07/92
PORT EVERGLADES PLANT UNIT NO. 2

CALIBRATION RESPONSE

TANK VALUE	ANALYZER VALUE	DIFF	% SPAN
0	0.0	0.0	0.0
554	556.0	2.0	0.2
837	837.0	0.0	0.0

WIDE OPEN VALVES O2 NORMAL
100% OIL

Year	Month	Day	Hour	Minute	Second	Average:
92	4	7	14	17	0	269.803
92	4	7	14	18	0	267.186
92	4	7	14	19	0	264.413
92	4	7	14	20	0	264.288
92	4	7	14	21	0	272.536
92	4	7	14	22	0	270.718
92	4	7	14	23	0	273.462
92	4	7	14	24	0	267.081
92	4	7	14	25	0	271.667
92	4	7	14	26	0	271.700
92	4	7	14	27	0	270.625
92	4	7	14	28	0	277.017
92	4	7	14	29	0	275.217
92	4	7	14	30	0	272.455
92	4	7	14	31	0	270.637
92	4	7	14	32	0	267.092

SYSTEM BIAS AND SYSTEM DRIFT DATA

ANALYZER VALUE	PRETEST CHECK	% SPAN	POSTTEST CHECK	% SPAN	% DRIFT
0.0	0.0	0.0	0.0	0.0	0.0
556.0	540.0	-1.6	540.0	-1.6	0.0

	RUN 4 PPM	270.37
	CORRECTED PPM	277.38
V.W.O.	RUN 4 % O2 NORMAL	5.2
	RUN 4 LB/MMBTU	0.404

PPE 2 NOx TEST DATA

UNIT #: 2 TEST #: 11 DATE: 4/8/92

TEST CONDITIONS: VWO

ABIS

NORMAL O_2

OPERATING PARAMETERS

FUEL GAS MW GROSS 222 NET 211

NUMBER OF BURNERS IN SERVICE 16 THROTTLE PRESSURE 2000 PSIG

F.O. SUPPLY PRESSURE 57 PSIG F.O. RETURN PRESSURE NA PSIG

F.O. ΔP NA PSIG GAS BURNER PRESSURE 24 PSIG

F.O. TEMP NA °F FUEL FLOW 80 % AIR FLOW 85 %

EXCESS O_2 EAST 0.60 %

WINDBOX PRESSURE EAST 8.0 " H_2O

FURNACE PRESSURE -0.35 2

FURNACE/WINDBOX PRESSURE ΔP 8.35 " H_2O

S.H. TEMP E 980 /L 1000 °F STEAM FLOW 145 lbs/Hr x 1000

REHEAT TEMP E 1020 /L 990 °F F.W. FLOW 148 lbs/Hr x 1000

F.D. FAN AMPS EAST 90 WEST 100

I.D. FAN AMPS EAST 210 WEST 245 RPM 485 E 545 W

AIR FROM APH EAST 510 °F WEST 510 °F

GAS TO APH EAST 670 °F WEST 670 °F

OPACITY 0 %

NO_X EAST OR WEST 151.8 PPM 0.215 #/BTU 6

S.H. SPRAY FLOW 16/16 % VALVE POSITION

R.H. SPRAY FLOW 0/3.5% VALVE POSITION

TEST VAN DATA: CO 133 PPM; CO_2 9.3 % O_2 5.6 %

COMMENTS: GAS RECIRC A 0 B 0

F O FAN DISCHARGE A 11.0 B 11.5

GAS FLOW = 2.084 MIL FT /HR

JPS\OS3\KTW\PPE2GS11.DRW
UPDATED: 7/16/92

FLORIDA POWER & LIGHT CO. 04/08/92
PORT EVERGLADES PLANT UNIT NO. 2

CALIBRATION RESPONSE

TANK VALUE	ANALYZER VALUE	DIFF	% SPAN
0	0.0	0.0	0.0
137.1	138.5	1.4	0.6
212	209.0	-3.0	-1.2

WIDE OPEN VALVES
100% GAS

Year	Month	Day	Hour	Minute	Second	Average:
92	4	8	13	31	0	153.519
92	4	8	13	32	0	154.939
92	4	8	13	33	0	151.549
92	4	8	13	34	0	150.913
92	4	8	13	35	0	151.381
92	4	8	13	36	0	150.906
92	4	8	13	37	0	152.018
92	4	8	13	38	0	152.501
92	4	8	13	39	0	154.649
92	4	8	13	40	0	154.172
92	4	8	13	41	0	153.636
92	4	8	13	42	0	153.002
92	4	8	13	43	0	152.633
92	4	8	13	44	0	151.490
92	4	8	13	45	0	150.665

SYSTEM BIAS AND SYSTEM DRIFT DATA

ANALYZER VALUE	PRETEST CHECK	% SPAN	POSTTEST CHECK	% SPAN	% DRIFT
0.0	0.0	0.0	0.0	0.0	0.0
138.5	137.5	-0.4	138.0	-0.2	0.2

	RUN 4 PPM	152.53
	CORRECTED PPM	151.81
W.O.V.	RUN 4 % O2	5.6
	RUN 4 LB/MMBTU	0.215

OIL

PPE 3 & 4 NO_X TEST DATA

UNIT #: 3 TEST #: BASELINE DATE: 3/20/91

TEST CONDITIONS: 100% OIL CONTINUOUS CAPABILITY
AVERAGE OF 3 TEST RUNS

OPERATING PARAMETERS

FUEL OIL MW GROSS 376 NET 368

NUMBER OF BURNERS IN SERVICE 18 THROTTLE PRESSURE 2401 PSIG

F.O. (GAS) SUPPLY PRESSURE 736 PSIG F.O. RETURN PRESSURE 469 PSIG

F.O. ΔP 267 PSIG GAS BURNER PRESSURE N/A PSIG

F.O. TEMP 191 °F FUEL FLOW 74.9 % AIR FLOW 76.3 %

EXCESS O_2 EAST 0.81 % WEST 0.71 % (SET POINTS?)

WINDBOX PRESSURE EAST 19.0 " H_2O WEST 19.4 " H_2O

FURNACE PRESSURE 12.4 " H_2O

FURNACE/WINDBOX PRESSURE Δ P 6.8 " H_2O

S.H. TEMP 1000 °F STEAM FLOW 2504 lbs/Hr x 1000

REHEAT TEMP 1000 °F F.W. FLOW 2510 lbs/Hr x 1000

F.D. FAN SPEED EAST 1012 RPM WEST 1069 RPM

F.D. FAN AMPS EAST 254 WEST 266

AIR FROM APH EAST 534 °F WEST 543 °F

GAS TO APH EAST 668 °F WEST 681 °F

OPACITY 4.8 %

NO_X EAST OR WEST 578 PPM 0.74 #/BTU 6

LOWER SPRAY FLOW 0 lbs/HR x 1000 UPPER SPRAY FLOW 40.1 lbs/HR x 1000

R.H. SPRAY FLOW 0 lbs/HR x 1000

TEST VAN DATA: CO 144 PPM; CO_2 14.1 % O_2 2.8 %

COMMENTS: 74.9% FUEL FLOW = APPROX. 9986 #/HR. FLOW PER BURNER X18 = 179,748 lb/hr

OP3/KTW6/PPE3NXBO.DRW
UPDATED: 4/1/91

OIL

HIGHER O_2
LOWER NO_x
THAN WEST BANK

EMISSION RATE SUMMARY
PORT EVERGLADES UNIT NO. 3

RUN NUMBER	CONCENTRATION PPM	AVG ZERO BIAS CHECK	AVG BIAS CHECK	CORRECTED PPM	OXY %	EMISSION lb/MM BTU	FUEL
1 EAST	512.8	0.0	835.5	519.2	3.1	0.668	OIL
2 EAST	529.7	0.0	827.0	541.8	3.1	0.697	OIL
3 EAST	530.3	0.0	827.0	542.5	3.0	0.694	OIL
1 WEST	611.6	0.0	832.0	621.8	2.8	0.786	OIL
2 WEST	611.0	0.0	829.0	623.5	2.8	0.788	OIL
3 WEST	605.1	0.0	825.0	620.5	2.7	0.780	OIL

EMISSION RATE RUN 1 = 0.727

EMISSION RATE RUN 2 = 0.743

EMISSION RATE RUN 3 = 0.737

AVERAGE EMISSION RATE 100% OIL = 0.736

GAS

PPE 3 & 4 NO_X TEST DATA

UNIT #: 3 TEST #: Baseline DATE: 3/19/91

TEST CONDITIONS: 100% Gas Continuous Capability

Average of 3 Test Runs

OPERATING PARAMETERS

FUEL Gas MW GROSS 376 NET 368

NUMBER OF BURNERS IN SERVICE 18 THROTTLE PRESSURE 2401 PSIG

F.O. (GAS) SUPPLY PRESSURE 57.3 PSIG F.O. RETURN PRESSURE N/A PSIG

F.O. ΔP N/A PSIG GAS BURNER PRESSURE 20.1 PSIG

F.O. TEMP N/A °F FUEL FLOW 81.1 % AIR FLOW 80.4 %

EXCESS O_2 EAST 0.87 % WEST 0.68 % CONTROL ROOM SET PTS.

WINDBOX PRESSURE EAST 20.9 "H_2O WEST 21.1 "H_2O

FURNACE PRESSURE 13.1 "H_2O

FURNACE/WINDBOX PRESSURE Δ P 7.9 "H_2O

S.H. TEMP 1000 °F STEAM FLOW 2493 lbs/Hr x 1000

REHEAT TEMP 1000 °F F.W. FLOW 2517 lbs/Hr x 1000

F.D. FAN SPEED EAST 1050 RPM WEST 1115 RPM

F.D. FAN AMPS EAST 270 WEST 290

AIR FROM APH EAST 546 °F WEST 548 °F

GAS TO APH EAST 674 °F WEST 684 °F

OPACITY 0.1 %

NO_X EAST OR WEST 426 PPM 0.52 #/BTU 6

LOWER SPRAY FLOW 106.4 lbs/HR x 1000 UPPER SPRAY FLOW 107.7 lbs/HR x 1000

R.H. SPRAY FLOW 0 lbs/HR x 1000

TEST VAN DATA: CO 161 PPM; CO_2 10.2 % O_2 3.2 %

COMMENTS: Total Gas Flow = 3.510 Million Ft^3 /Hr.

OP2/KTW6/PPE3NXBG.DRW
UPDATED: 4/1/91

GAS

EMISSION RATE SUMMARY
PORT EVERGLADES UNIT NO. 3

EAST HAS Higher O_2, LOWER NO_x THAN WEST BANK

RUN NUMBER	CONCENTRATION PPM	AVG ZERO BIAS CHECK	AVG BIAS CHECK	CORRECTED PPM	OXY %	EMISSION lb/MM BTU	FUEL
1 EAST	376.6	0.0	820.5	388.3	3.6	0.487	GAS
2 EAST	391.7	0.0	841.0	394.0	3.9	0.503	GAS
3 EAST	406.4	0.0	827.0	415.8	3.2	0.510	GAS
1 WEST	427.8	0.0	833.0	434.4	2.8	0.521	GAS
2 WEST	453.8	0.0	836.0	459.2	3.0	0.557	GAS
3 WEST	463.9	0.0	838.0	468.3	3.0	0.568	GAS

WHERE IS THIS MEASURED?

EMISSION RATE RUN 1 = 0.504

EMISSION RATE RUN 2 = 0.530

EMISSION RATE RUN 3 = 0.539

AVERAGE EMISSION RATE 100% GAS = 0.524

PPE 3 & 4 NO_X TEST DATA

UNIT #: 4 TEST #: BASELINE DATE: 3/22/91

TEST CONDITIONS: 100% OIL CONTINUOUS CAPABILITY
AVERAGE OF 3 TEST RUNS

OPERATING PARAMETERS

FUEL OIL MW GROSS 378 NET 370

NUMBER OF BURNERS IN SERVICE 18 THROTTLE PRESSURE 2402 PSIG

F.O. (GAS) SUPPLY PRESSURE 784 PSIG F.O. RETURN PRESSURE 500 PSIG

F.O. ΔP 284 PSIG GAS BURNER PRESSURE N/A PSIG

F.O. TEMP 212 °F FUEL FLOW 77.0 % AIR FLOW 78.8 %

EXCESS O_2 EAST 0.77 % WEST 0.69 %

WINDBOX PRESSURE EAST 19.8 " H_2O WEST 19.8 " H_2O

FURNACE PRESSURE 11.5 " H_2O

FURNACE/WINDBOX PRESSURE Δ P 7.9 " H_2O

S.H. TEMP 1002 °F STEAM FLOW 2457 lbs/Hr x 1000

REHEAT TEMP 1000 °F F.W. FLOW 2511 lbs/Hr x 1000

F.D. FAN SPEED EAST 993 RPM WEST 931 RPM

F.D. FAN AMPS EAST 277 WEST 263

AIR FROM APH EAST 529 °F WEST 562 °F

GAS TO APH EAST 681 °F WEST 672 °F

OPACITY 3.2 %

NO_X EAST OR WEST 635 PPM 0.79 #/BTU 6

LOWER SPRAY FLOW 2.7 lbs/HR x 1000 UPPER SPRAY FLOW 83.8 lbs/HR x 1000

R.H. SPRAY FLOW 0 lbs/HR x 1000

TEST VAN DATA: CO 127 PPM; CO_2 14.3 % O_2 2.6 %

COMMENTS: 77% FUEL FLOW = APPROX. 10266 #/HR PER BURNER

OP3/KTW6/PPE4NXBO.DRW
UPDATED: 3/26/91

EMISSION RATE SUMMARY
PORT EVERGLADES UNIT NO. 4

RUN NUMBER	CONCENTRATION PPM	AVG ZERO BIAS CHECK	AVG BIAS CHECK	CORRECTED PPM	OXY %	EMISSION lb/MM BTU	FUEL
1 EAST	595.5	0.0	533.0	604.4	2.8	0.764	OIL
2 EAST	600.3	0.0	538.0	603.6	2.6	0.755	OIL
3 EAST	581.0	0.0	538.0	584.2	2.6	0.731	OIL
1 WEST	647.7	0.0	530.0	661.1	2.7	0.831	OIL
2 WEST	673.5	0.0	538.0	677.2	2.3	0.833	OIL
3 WEST	674.6	0.0	538.0	678.4	2.4	0.839	OIL

EMISSION RATE RUN 1 = 0.798

EMISSION RATE RUN 2 = 0.794

EMISSION RATE RUN 3 = 0.785

AVERAGE EMISSION RATE 100% OIL = 0.792

PPE 3 & 4 NO_X TEST DATA

UNIT #: 4 TEST #: Baseline DATE: 3/21/91

TEST CONDITIONS: 100% Gas Continuous Capability

Average of 3 Test Runs

OPERATING PARAMETERS

FUEL Gas MW GROSS 376 NET 368

NUMBER OF BURNERS IN SERVICE 18 THROTTLE PRESSURE 2402 PSIG

F.O. (GAS) SUPPLY PRESSURE 56.7 PSIG F.O. RETURN PRESSURE N/A PSIG

F.O. ΔP N/A PSIG GAS BURNER PRESSURE 20.3 PSIG

F.O. TEMP N/A °F FUEL FLOW 80.2 % AIR FLOW 80.2 %

EXCESS O_2 * EAST 0.3 % WEST 0.7 %

WINDBOX PRESSURE EAST 20.1 " H_2O WEST 20.2 " H_2O

FURNACE PRESSURE 11.5 " H_2O

FURNACE/WINDBOX PRESSURE Δ P 8.4 " H_2O

S.H. TEMP 1000 °F STEAM FLOW 2428 lbs/Hr x 1000

REHEAT TEMP 1000 °F F.W. FLOW 2495 lbs/Hr x 1000

F.D. FAN SPEED EAST 963 RPM WEST 943 RPM

F.D. FAN AMPS EAST 269 WEST 237

AIR FROM APH EAST 544 °F WEST 562 °F

GAS TO APH EAST 681 °F WEST 675 °F

OPACITY 0.2 %

NO_X EAST OR WEST 489 PPM 0.57 #/BTU 6

LOWER SPRAY FLOW 139.9 lbs/HR x 1000 UPPER SPRAY FLOW 131.0 lbs/HR x 1000

R.H. SPRAY FLOW 0 lbs/HR x 1000

TEST VAN DATA: CO 270 PPM; CO_2 10.8 % O_2 2.3 %

COMMENTS: Total Gas Flow = 3.459 Million Ft^3 /Hr.

* Installed meter O/S using portable analyzer

OP2/KTW6/PPE3NXBG.DRW
UPDATED: 4/02/91

EMISSION RATE SUMMARY
PORT EVERGLADES UNIT NO. 4

RUN NUMBER	CONCENTRATION PPM	AVG ZERO BIAS CHECK	AVG BIAS CHECK	CORRECTED PPM	OXY %	EMISSION lb/MM BTU	FUEL
1 EAST	442.2	0.0	529.5	451.8	2.6	0.536	GAS
2 EAST	403.9	0.0	537.5	406.5	1.9	0.464	GAS
3 EAST	404.5	0.0	538.0	406.8	2.2	0.472	GAS
1 WEST	569.9	0.0	527.0	585.0	2.6	0.693	GAS
2 WEST	539.9	0.0	537.0	543.9	2.3	0.634	GAS
3 WEST	537.7	0.0	535.0	543.8	2.2	0.631	GAS

EMISSION RATE RUN 1 = 0.614

EMISSION RATE RUN 2 = 0.549

EMISSION RATE RUN 3 = 0.551

AVERAGE EMISSION RATE 100% GAS = 0.572

PRV 3 NO_X TEST DATA

UNIT #: 3 TEST #: 7 DATE: 3/03/92

TEST CONDITIONS: 100% OIL 90% LOAD CONTINOUS CAPABILITY "NORMAL" O_2

OPERATING PARAMETERS

FUEL OIL MW GROSS 288 NET 273

NUMBER OF BURNERS IN SERVICE 24 THROTTLE PRESSURE 2000 PSIG

F.O. (GAS) SUPPLY PRESSURE 900 PSIG F.O. RETURN PRESSURE 610 PSIG

F.O. ΔP 290 PSIG GAS BURNER PRESSURE — PSIG

F.O. TEMP 192 °F FUEL FLOW 84 % AIR FLOW 88 %

EXCESS O_2 EAST 1.4 % WEST 0.6 %

WINDBOX PRESSURE EAST 10.6

FURNACE PRESSURE -0.5 " H_2O

FURNACE/WINDBOX PRESSURE ΔP 11.1 " H_2O

S.H. TEMP 997 °F STEAM FLOW 2050 lbs/Hr x 1000

REHEAT TEMP 997 °F F.W. FLOW 2000 lbs/Hr x 1000

F.D. FAN SPEED A 115 RPM B 125 RPM

F.D. FAN AMPS A 220 B 210

AIR FROM APH A 580 °F B 570 °F

GAS TO APH A 705 °F B 675 °F

OPACITY 12 %

NO_X EAST OR WEST 634 PPM .919 #/BTU 6

S. H. CONDENSER FLOW 55.7 lbs/HR x 1000 ECONOMIZER 44.4 % VALVE POSITION

R.H. SPRAY FLOW 16.3 lbs/HR x 1000

TEST VAN DATA: CO 475 PPM; CO_2 12.6 % O_2 5.1 %

COMMENTS:

JPS\OS3\KTW\PRVOIL07.DRW
UPDATED: 7/15/92

FLORIDA POWER & LIGHT CO.
RIVIERA PLANT UNIT NO. 3

03/03/92

CALIBRATION RESPONSE

TANK VALUE	ANALYZER VALUE	DIFF	% SPAN
0	0.0	0.0	0.0
212	210.0	-2.0	-0.2
554	547.0	-7.0	-0.7

O2 NORMAL
90% LOAD - 100% OIL

Year	Month	Day	Hour	Minute	Second	Average:
92	3	3	12	7	37	618.306
92	3	3	12	8	19	612.125
92	3	3	12	9	19	608.297
92	3	3	12	10	19	602.050
92	3	3	12	11	19	604.305
92	3	3	12	12	19	594.654
92	3	3	12	13	19	591.078
92	3	3	12	14	19	594.287
92	3	3	12	15	19	597.895
92	3	3	12	16	19	598.989
92	3	3	12	17	19	596.704
92	3	3	12	18	19	594.328
92	3	3	12	19	19	591.998
92	3	3	12	20	19	591.307
92	3	3	12	21	19	596.908
92	3	3	12	22	19	606.868

SYSTEM BIAS AND SYSTEM DRIFT DATA

ANALYZER VALUE	PRETEST CHECK	% SPAN	POSTTEST CHECK	% SPAN	% DRIFT
0.0	0.0	0.0	0.0	0.0	0.0
547.0	528.0	-1.9	520.0	-2.7	-0.8

RUN 3 PPM	600.01
CORRECTED PPM	634.36
RUN 3 % O2 NORMAL	5.1
RUN 3 LB/MMBTU	0.919

PRV 3 NO_X TEST DATA

UNIT #: 3 TEST #: 7 DATE: 3/04/92

TEST CONDITIONS: 100% GAS 90% LOAD CONTINOUS CAPABILITY

NOTE: CANNOT VARY AIR ... FANS ARE AT MAXIMUM "NORMAL" O_2

OPERATING PARAMETERS

FUEL GAS MW GROSS 276 NET 262

NUMBER OF BURNERS IN SERVICE 24 THROTTLE PRESSURE 2000 PSIG

F.O. (GAS) SUPPLY PRESSURE 62 PSIG F.O. RETURN PRESSURE — PSIG

F.O. ΔP — PSIG GAS BURNER PRESSURE 28 PSIG

F.O. TEMP — °F FUEL FLOW 89 % AIR FLOW 89 %

EXCESS O_2 EAST 0.7 % WEST 1.1 %

WINDBOX PRESSURE 11.8 " H_2O

FURNACE PRESSURE 0 " H_2O

FURNACE/WINDBOX PRESSURE Δ P 11.8 " H_2O

S.H. TEMP 993 °F STEAM FLOW 1950 lbs/Hr x 1000

REHEAT TEMP 1000 °F F.W. FLOW 1900 lbs/Hr x 1000

F.D. FAN SPEED A 120 RPM B 125 RPM

F.D. FAN AMPS A 220 B 210

AIR FROM APH A 550 °F B 570 °F

GAS TO APH A 670 °F B 690 °F

OPACITY 4 %

NO_X EAST OR WEST 501 PPM .722 #/BTU 6

S. H. CONDENSER FLOW 98 lbs/HR x 1000 ECONOMIZER 2.0 % VALVE POSITION

R.H. SPRAY FLOW 18 lbs/HR x 1000

TEST VAN DATA: CO 436 PPM; CO_2 9.5 % O_2 5.0 %

COMMENTS: NOTE: I.D. FANS MAXED OUT

GAS HEADER PRESSURE @ 28 PSIG

FUEL FLOW = 2.66 MILL FT 3 (113,720)

JPS\OS3\KTW\PRVOIL07.DRW
UPDATED: 7/15/92

FLORIDA POWER & LIGHT CO.
RIVIERA PLANT UNIT NO. 3

03/04/92

CALIBRATION RESPONSE

TANK VALUE	ANALYZER VALUE	DIFF	% SPAN
0	0.0	0.0	0.0
212	213.0	1.0	0.1
554	557.0	3.0	0.3

O2 NORMAL
90% LOAD - 100% GAS
MAX ID FANS

Year	Month	Day	Hour	Minute	Second	Average:
92	3	4	11	2	30	502.143
92	3	4	11	3	0	498.687
92	3	4	11	4	0	496.465
92	3	4	11	5	0	494.790
92	3	4	11	6	0	490.240
92	3	4	11	7	0	487.498
92	3	4	11	8	0	491.181
92	3	4	11	9	0	490.478
92	3	4	11	10	0	487.432
92	3	4	11	11	0	487.501
92	3	4	11	12	0	484.532
92	3	4	11	13	0	482.511
92	3	4	11	14	0	482.395
92	3	4	11	15	0	480.345
92	3	4	11	16	0	482.611
92	3	4	11	17	0	484.808

SYSTEM BIAS AND SYSTEM DRIFT DATA

ANALYZER VALUE	PRETEST CHECK	% SPAN	POSTTEST CHECK	% SPAN	% DRIFT
0.0	0.0	0.0	0.0	0.0	0.0
557.0	550.0	-0.7	530.0	-2.7	-2.0

RUN 3 PPM	488.98
CORRECTED PPM	501.65
RUN 3 O2 NORMAL	5.0
RUN 3 LB/MMBTU	0.722

PCU 5 NO_X TEST DATA

UNIT #: 5 TEST #: 8 DATE: 5/05/92

TEST CONDITIONS: ALL PILOTS ABIS 90% LOAD

NORMAL O_2

EAST DUCT

OPERATING PARAMETERS

FUEL GAS MW GROSS 76 NET 72

NUMBER OF BURNERS IN SERVICE 12 THROTTLE PRESSURE 1300 PSIG

F.O. (GAS) SUPPLY PRESSURE 53 PSIG F.O. RETURN PRESSURE ____ PSIG

F.O. ΔP ____ PSIG GAS BURNER PRESSURE 11.5 PSIG

F.O. TEMP ____ °F FUEL FLOW 75 % AIR FLOW 78 %

675

EXCESS O_2 0.85 %

WINDBOX PRESSURE 4.4 " H_2O

FURNACE PRESSURE -0.60 " H_2O

FURNACE/WINDBOX PRESSURE Δ P 5.0 " H_2O

S.H. TEMP 947 °F STEAM FLOW 520 lbs/Hr x 1000

REHEAT TEMP F.W. FLOW 565 lbs/Hr x 1000

F.D. FAN SPEED EAST 40 RPM WEST 60 RPM

I.D. FAN AMPS EAST 110 WEST 120

AIR FROM APH EAST 492 °F WEST 444 °F GAS OUTLET

GAS TO APH EAST 527 °F WEST 527 °F 301 281

OPACITY ____ %

NO_X EAST OR WEST 92.9 PPM 0.135 #/BTU 6

S.H. SPRAY FLOW E 0 % VALVE POSITION W 0

R.H. SPRAY FLOW

TEST VAN DATA: CO 143 PPM; CO_2 8.4 % O_2 6.0 %

COMMENTS: FD FAN DISCHARGE A 5.0 B 5.0

GAS BURN 829.6

JPS\OS3\KTW\PCU5G08.DRW
UPDATED: 6/23/92

FLORIDA POWER AND LIGHT CO.
PLANT SERVICES OPERATIONS SUPPORT
NOx EMISSION RATE PCU UNIT 5

05/05/92

ANALYZER CALIBRATION RESPONSE

	TANK VALUE ppm	ANALYZER RESPONSE ppm	ABSOLUTE DIFF. ppm	% OF SPAN
ZERO	0	0	0	0
MID	54.2	54.2	0	0
HIGH	82.9	83.3	0.4	0.4

NORMAL 02 (90% LOAD)
EAST DUCT

Year	Month	Day	Hour	Minute	Second	Average:
92	5	5	12	10	7	88.971
92	5	5	12	11	0	89.762
92	5	5	12	12	0	91.259
92	5	5	12	13	0	92.907
92	5	5	12	14	0	92.747
92	5	5	12	15	0	93.151
92	5	5	12	16	0	92.022
92	5	5	12	17	0	92.665
92	5	5	12	18	0	92.165
92	5	5	12	19	0	94.241
92	5	5	12	20	0	95.484
92	5	5	12	21	0	94.389
92	5	5	12	22	0	95.083
92	5	5	12	23	0	94.361
92	5	5	12	24	0	94.367

	ANALYZER RESPONSE ppm	SYSTEM RESPONSE ppm	% OF SPAN	SYSTEM RESPONSE ppm	% OF SPAN	DRIFT % SPAN
ZERO	0	0	0	0	0	0
UPSCALE	54.2	53.3	-0.9	55.1	0.9	1.8

02 / CO2/ CO
6.0 / 8.4/143

RUN 8 PPM	92.905
RUN 8 CORRECTED	92.905
RUN 8 02	6.0
RUN 8 LB/MMBTU	0.135

PCU 5 NO_X TEST DATA

UNIT #: 5 TEST #: 9 DATE: 5/05/92

TEST CONDITIONS: 90% LOAD ALL PILOTS ABIS

NORMAL O_2

WEST DUCT

OPERATING PARAMETERS

FUEL GAS MW GROSS 76 NET 72

NUMBER OF BURNERS IN SERVICE 12 THROTTLE PRESSURE 1300 PSIG

F.O. (GAS) SUPPLY PRESSURE 53 PSIG F.O. RETURN PRESSURE ______ PSIG

F.O. ΔP ______ PSIG GAS BURNER PRESSURE 11.5 PSIG

F.O. TEMP ______ °F FUEL FLOW 75 % AIR FLOW 78 %

675

EXCESS O_2 0.85 %

WINDBOX PRESSURE 4.4 " H_2O

FURNACE PRESSURE -0.6 " H_2O

FURNACE/WINDBOX PRESSURE Δ P 5.0 " H_2O

S.H. TEMP 951 °F STEAM FLOW 520 lbs/Hr x 1000

REHEAT TEMP F.W. FLOW 565 lbs/Hr x 1000

F.D. FAN SPEED EAST 40 RPM WEST 60 RPM

I.D. FAN AMPS EAST 115 WEST 120

AIR FROM APH EAST 493 °F WEST 446 °F

GAS TO APH EAST 529 °F WEST 529 °F

GAS	OUTLET
302	282

OPACITY ______ %

NO_X EAST OR WEST 88.4 PPM 0.138 #/BTU 6

S.H. SPRAY FLOW E 0 % VALVE POSITION W 0

R.H. SPRAY FLOW

TEST VAN DATA: CO 23 PPM; CO_2 7.5 % O_2 7.0 %

COMMENTS: FD FAN DISCHARGE A 5.0 B 5.0

GAS BURN 830.3

JPS\OS3\KTW\PCU5G09.DRW
UPDATED: 7/16/92

FLORIDA POWER AND LIGHT CO.
PLANT SERVICES OPERATIONS SUPPORT
NOx EMISSION RATE PCU UNIT 5

05/05/92

ANALYZER CALIBRATION RESPONSE

	TANK VALUE ppm	ANALYZER RESPONSE ppm	ABSOLUTE DIFF. ppm	% OF SPAN
ZERO	0	0	0	0
MID	54.2	54.2	0	0
HIGH	82.9	83.3	0.4	0.4

NORMAL 02 (90% LOAD)
WEST DUCT

Year	Month	Day	Hour	Minute	Second	Average:
92	5	5	12	43	49	88.891
92	5	5	12	44	0	88.427
92	5	5	12	45	0	89.708
92	5	5	12	46	0	87.608
92	5	5	12	47	0	88.219
92	5	5	12	48	0	88.676
92	5	5	12	49	0	88.485
92	5	5	12	50	0	91.974
92	5	5	12	51	0	93.247
92	5	5	12	52	0	91.427
92	5	5	12	53	0	92.253
92	5	5	12	54	0	91.013
92	5	5	12	55	0	89.065
92	5	5	12	56	0	90.041
92	5	5	12	57	0	90.196

	ANALYZER RESPONSE ppm	SYSTEM RESPONSE ppm	% OF SPAN	SYSTEM RESPONSE ppm	% OF SPAN	DRIFT % SPAN
ZERO	0	0	0	0	0	0
UPSCALE	54.2	55.1	0.9	55.1	0.9	0

O2 / CO2/ CO
7.0 / 7.5/ 23

RUN 9 PPM	89.949
RUN 9 CORRECTED	88.479
RUN 9 02	7.0
RUN 9 LB/MMBTU	0.138

PCU 6 NO_X TEST DATA

UNIT #: 6 TEST #: 6 DATE: 5/08/92

TEST CONDITIONS: ALL PILOTS ABIS 90% LOAD
NORMAL O_2

OPERATING PARAMETERS

FUEL GAS MW GROSS 148 NET 141

NUMBER OF BURNERS IN SERVICE 12 THROTTLE PRESSURE 1450 PSIG

F.O. (GAS) SUPPLY PRESSURE 54 PSIG F.O. RETURN PRESSURE ——— PSIG

F.O. ΔP ——— PSIG GAS BURNER PRESSURE 23.5 PSIG

F.O. TEMP ——— °F FUEL FLOW 80 % AIR FLOW 83 %

EXCESS O_2 1.20 %

WINDBOX PRESSURE 4.8 " H_2O

FURNACE PRESSURE -0.55 " H_2O

FURNACE/WINDBOX PRESSURE ΔP 5.35 " H_2O

S.H. TEMP 1000 °F STEAM FLOW 980 lbs/Hr x 1000

REHEAT TEMP 1001 °F F.W. FLOW 925 lbs/Hr x 1000

F.D. FAN SPEED EAST 95 RPM WEST 90 RPM

I.D. FAN AMPS EAST 135 WEST 135

AIR FROM APH EAST 342 °F WEST 337 °F

GAS TO APH EAST 518 °F WEST 511 °F

GAS OUTLET
285 275

OPACITY ——— %

NO_X EAST OR WEST 103.8 PPM 0.157 #/BTU 6

S.H. SPRAY FLOW 55 lbs. / HR. X 1000

R.H. SPRAY FLOW 3200 lbs / HR. X 1000

TEST VAN DATA: CO 31 PPM; CO_2 8.5 % O_2 6.6 %

COMMENTS: FD FAN DISCHARGE A 7.0 B 6.5
GAS BURN 1475.2

JPS\OS3\KTW\PCU6G06.DRW
UPDATED: 7/16/92

FLORIDA POWER AND LIGHT CO.
PLANT SERVICES OPERATIONS SUPPORT
NOx EMISSION RATE PCU UNIT 6

05/08/92

ANALYZER CALIBRATION RESPONSE

	TANK VALUE ppm	ANALYZER RESPONSE ppm	ABSOLUTE DIFF. ppm	% OF SPAN
ZERO	0.0	0.0	0.0	0.0
MID	54.2	54.2	0.0	0.0
HIGH	82.9	82.9	0.0	0.0

NORMAL 02 - 90% LOAD

Year	Month	Day	Hour	Minute	Second	Average:
92	5	8	10	51	2	106.240
92	5	8	10	52	0	106.244
92	5	8	10	53	0	107.678
92	5	8	10	54	0	106.644
92	5	8	10	55	0	106.712
92	5	8	10	56	0	106.191
92	5	8	10	57	0	105.273
92	5	8	10	58	0	105.485
92	5	8	10	59	0	105.001
92	5	8	11	0	0	105.289
92	5	8	11	1	0	103.303
92	5	8	11	2	0	103.332
92	5	8	11	3	0	105.501
92	5	8	11	4	0	105.964
92	5	8	11	5	0	106.723
92	5	8	11	6	0	106.032

	ANALYZER RESPONSE ppm	SYSTEM RESPONSE ppm	% OF SPAN	SYSTEM RESPONSE ppm	% OF SPAN	DRIFT % SPAN
ZERO	0.0	0.0	0.0	0.0	0.0	0.0
UPSCALE	54.2	55.2	1.0	55.2	1.0	0.0

O2 / CO2/ CO
6.6/ 8.5/ 31

RUN 6 PPM	105.726
RUN 6 CORRECTED	103.810
RUN 6 02	6.6
RUN 6 LB/MMBTU	0.157

APPENDIX B

CONTROL TECHNOLOGY COST ESTIMATES

Table B-1. Summary of Capital and Annualized Costs for OFA

Plant	Unit	Capital Cost	Annualized Cost
Port Everglades	1	$4,405,000	$855,000
Port Everglades	2	$4,405,000	$855,000
Port Everglades	3	$4,459,000	$1,038,000
Port Everglades	4	$4,459,000	$1,038,000
Turkey Point	1	$4,956,000	$1,126,000
Turkey Point	2	$4,956,000	$1,126,000
Riviera	3	$7,447,000	$1,433,000
Riviera	4	$7,447,000	$1,433,000
	Total:	$42,534,000	$8,904,000

LNB + OFA
COST EFF:

$\frac{(855,000 + 592,000)}{(1529 - 1262)} = \frac{1447,000}{327} = 4425$ $\frac{4,405,000}{200,000} = 22.02$ + 16.83 = 38.85

$\frac{855,000}{200,000 \times 0.7 \times 8760} = \cancel{4.28}$ .0007 + $\cancel{2.96}$ = $\cancel{7.24}$

$\frac{1,038,000 + 682,000}{(5760 - 4619)} = \frac{1,720,000}{1141} = 1507$ $\frac{4,459,000}{400,000} = 11.15$ + 9.15 = 20.30

1141

$\frac{1,038,000}{400,000} = 2.60$ .0007 + 1.71 = $\cancel{4.31}$

Table B-2. Summary of Capital and Annualized Costs for FGR

Plant	Unit	Capital Cost	Annualized Cost
Port Everglades	1	$18,875,000	$3,517,000
Port Everglades	2	$18,875,000	$3,517,000
Port Everglades	3	$20,981,000	$4,153,000
Port Everglades	4	$20,981,000	$4,153,000
Turkey Point	1	$20,981,000	$4,153,000
Turkey Point	2	$20,981,000	$4,153,000
Riviera	3	$23,743,000	$4,451,000
Riviera	4	$23,743,000	$4,451,000
	Total:	$169,160,000	$32,548,000

COST EFF

$\frac{3517000}{(1529-1202)} = 10,755$
(Baseline - RACT)

$\frac{4153000}{(5760-4619)} = 3,640$
1141

$\frac{18,875,000}{200,000} = 94.38$

$\frac{20,981,000}{400000} : 52.45$

$\frac{3,517,000}{200,000 \times 0.7 \times 8760} = \cancel{17.59}$ .0029

$\frac{4,153,000}{400,000} - \cancel{10.38}$ .0017

Table B-3. Summary of Capital and Annualized Costs for LNBT

Plant	Unit	Capital Cost	Annualized Cost
Port Everglades	1	$3,366,000	$592,000
Port Everglades	2	$3,366,000	$592,000
Port Everglades	3	$3,658,000	$682,000
Port Everglades	4	$3,658,000	$682,000
Turkey Point	1	$3,798,000	$691,000
Turkey Point	2	$3,798,000	$691,000
Riviera	3	$4,733,000	$830,000
Riviera	4	$4,733,000	$830,000
	Total:	$31,110,000	$5,590,000

COST EFF.

$\frac{592,000}{(1529-1202)} = \$1,810$

327

$\frac{3,366,000}{200,000} = 16.83$ ~~15.30~~

$\frac{592,000}{200,000 \times 0.7 \times 8760} = .0005$ ~~2.96~~

$\frac{682,000}{(5760-4619)} = 598$

1141

$\frac{3,658,000}{400,000} = 9.15$

$\frac{682,000}{400000 \times 0.7 \times 8760} = .0003$ ~~1.71~~

$\frac{691,000}{(4895-2738)}$

2157

Table B-4. Summary of Capital and Annualized Costs for SNCR

Plant	Unit	Capital Cost	Annualized Cost
Port Everglades	1	$6,549,327	$2,118,224
Port Everglades	2	$6,549,327	$2,118,224
Port Everglades	3	$13,206,961	$4,479,712
Port Everglades	4	$13,206,961	$4,479,712
Turkey Point	1	$13,206,961	$4,479,712
Turkey Point	2	$13,206,961	$4,479,712
Riviera	3	$9,932,721	$3,419,052
Riviera	4	$9,932,721	$3,419,052
	Total:	$85,791,940	$28,993,400

COST EFF:

$\frac{2,118,224}{(1529-1202)} = 6,478$

327

$\frac{6,549,327}{200,000} = 32.75$

$\frac{2,118,224}{200,000 \times 0.7 \times 8760} = \cancel{10.59}$ .0017

$\frac{4,479,712}{(5760-4619)} = 3,926$

1141

$\frac{13,206,961}{400,000} = 33.02$

$\frac{4,479,712}{400,000} = \cancel{11.20}$ .0018

Table B-5. Summary of Capital and Annualized Costs for SCR

Plant	Unit	Capital Cost	Annualized Cost
Port Everglades	1	$18,460,094	$6,987,320
Port Everglades	2	$18,460,094	$6,987,320
Port Everglades	3	$29,049,296	$11,220,972
Port Everglades	4	$29,049,296	$11,220,972
Turkey Point	1	$29,049,296	$11,220,972
Turkey Point	2	$29,049,296	$11,220,972
Riviera	3	$23,417,192	$8,870,936
Riviera	4	$23,417,192	$8,870,936
	Total:	$199,951,756	$76,600,400

COST EFF:

$\frac{6,987,320}{1529-1202} = 21,368$

$\frac{18,460,094}{200,000} = 92.30$

$\frac{6,987,320}{200000 \times 0.7 \times 8760} = \cancel{34.94}\ .0057$

$\frac{11,220,972}{(5760-4619)} = 9834$

1141

$\frac{29,049,296}{400,000} = 72.62$

$\frac{11,220,972}{400,000} = \cancel{28.05}\ .0046$

Table B-6. Cost Summary For Low NO_x Burners at Port Everglades Units 3&4

Cost Component	Costs ($)	Basis for Cost Estimate
DIRECT CAPITAL COSTS:		
Burner Costs	5,168,550	Estimate based on vendor contract
Spare Parts	131,090	Estimate based on actuals
Misc. Materials & Stores (Aux Bldg)	50,000	Estimate based on actuals
Asbestos Abatement	14,350	Estimate based on actuals
Sales Tax	321,839	6% of all Material Purchases
Engineering	180,517	Estimate based on actuals
Erection Supervision & Start-Up	425,000	Estimate based on actuals
Project Support	286,000	Estimate based on actuals
INDIRECT CAPITAL COSTS:		
Corp Overheads	341,150	6% of Direct Capital Costs
Liability Insurance	113,006	2% of Direct Capital Costs
Potential Scope Changes	70,315	1% of Capital Costs
Interest During Construction	213,894	.7% per month of all Capital Costs
TOTAL CAPITAL INVESTMENT	7,315,711	
DIRECT OPERATING COSTS (DOC):		
Operations & Maintenance	65,773	1% of total DCC
Heat Rate Degradation	107,000	Loss of 10 BTU/KWH @ 10,700/(BTU/KWH)
TOTAL DOC:	172,773	
CAPITAL RECOVERY COST (CRC):	1,190,266	CRF of 0.1627 * TCI
ANNUALIZED COST:	1,363,040	DOC+CRC

Table B-7. Cost Summary For Low NO_x Burners at Port Everglades Units 1&2

Cost Component	Costs ($)	Basis for Cost Estimate
DIRECT CAPITAL COSTS:		
Burner Costs (prorated -10	4,622,384	Estimate based on PPE 3&4
Spare Parts	131,090	Estimate based on PPE 3&4
Misc. Materials & Stores (Aux Bldg)	50,000	Estimate based on PPE 3&4
Asbestos Abatement	14,350	Estimate based on PPE 3&4
Sales Tax	289,069	6% of all Material Purchases
Engineering	180,517	Estimate based on PPE 3&4
Erection Supervision & Start-Up	425,000	Estimate based on PPE 3&4
Project Support	286,000	Estimate based on PPE 3&4
INDIRECT CAPITAL COSTS:		
Corp Overheads	306,414	6% of Direct Capital Costs
Liability Insurance	101,500	2% of Direct Capital Costs
Contingency	128,126	2% of Capital Costs
Interest During Construction	196,806	.7% per month of all Capital Costs
TOTAL CAPITAL INVESTMENT	6,731,256	
DIRECT OPERATING COSTS (DOC):		
Operations & Maintenance	59,984	1% of total DCC
Heat Rate Degradation	31,000	Loss of 10 BTU/KWH @ 3,100/(BTU/KWH)
TOTAL DOC:	90,984	
CAPITAL RECOVERY COST (CRC):	1,095,175	CRF of 0.1627 * TCI
ANNUALIZED COST:	1,186,159	DOC+CRC

Table B-8. Cost Summary For Low NO_x Burners at Turkey Point Units 1&2

Cost Component	Costs ($)	Basis for Cost Estimate
DIRECT CAPITAL COSTS:		
Burner Costs (prorated 4%)	5,341,421	Estimate based on PPE 3&4
Spare Parts	131,090	Estimate based on PPE 3&4
Misc. Materials & Stores (Aux Bldg)	50,000	Estimate based on PPE 3&4
Asbestos Abatement	14,350	Estimate based on PPE 3&4
Sales Tax	332,212	6% of all Material Purchases
Engineering	180,517	Estimate based on PPE 3&4
Erection Supervision & Start-Up	425,000	Estimate based on PPE 3&4
Project Support	286,000	Estimate based on PPE 3&4
INDIRECT CAPITAL COSTS:		
Corp Overheads	352,144	6% of Direct Capital Costs
Liability Insurance	116,648	2% of Direct Capital Costs
Contingency	144,588	2% of Capital Costs
Interest During Construction	222,090	.7% per month of all Capital Costs
TOTAL CAPITAL INVESTMENT	7,596,059	
DIRECT OPERATING COSTS (DOC):		
Operations & Maintenance	67,606	1% of total DCC
Heat Rate Degradation	78,000	Loss of 10 BTU/KWH @ 7,800/(BTU/KWH)
TOTAL DOC:	145,606	
CAPITAL RECOVERY COST (CRC):	1,235,879	CRF of 0.1627 * TCI
ANNUALIZED COST:	1,381,485	DOC+CRC

Table B-9. Cost Summary For Low NO_x Burners at Riviera Units 3&4

Cost Component	Costs ($)	Basis for Cost Estimate
DIRECT CAPITAL COSTS:		
Burner Costs (prorated 33%	6,830,856	Estimate based on PPE 3&4
Spare Parts (prorated 33%	174,350	Estimate based on PPE 3&4
Misc. Materials & Stores (Aux Bldg) (prorated 33%	66,500	Estimate based on PPE 3&4
Asbestos Abatement (prorated 33%	19,086	Estimate based on PPE 3&4
Sales Tax	425,448	6% of all Material Purchases
Engineering	180,517	Estimate based on PPE 3&4
Erection Supervision & Start-Up	425,000	Estimate based on PPE 3&4
Project Support	286,000	Estimate based on PPE 3&4
INDIRECT CAPITAL COSTS:		
Corp Overheads	450,974	6% of Direct Capital Costs
Liability Insurance	149,385	2% of Direct Capital Costs
Contingency	180,162	2% of Capital Costs
Interest During Construction	276,734	.7% per month of all Capital Costs
TOTAL CAPITAL INVESTMENT	9,465,012	
DIRECT OPERATING COSTS (DOC):		
Operations & Maintenance	84,078	1% of total DCC
Heat Rate Degradation	35,000	Loss of 10 BTU/KWH @ 3,500/(BTU/KWH)
TOTAL DOC:	119,078	
CAPITAL RECOVERY COST (CRC):	1,539,958	CRF of 0.1627 * TCI
ANNUALIZED COST:	1,659,035	DOC+CRC

Table B-10. Cost Summary Over-Fire Air Retrofit at PPE 3&4

Cost Component	Costs/Unit ($)	Basis for Cost Estimate
DIRECT CAPITAL COSTS (DCC)		
OFA duct, etc. (1.)	850,000	based on recent projects
Windbox modeling (2.)	150,000	based on recent projects
Windbox baffles (3.)	500,000	based on recent projects
OFA ports, etc. (4.)	1,500,000	based on recent projects
Pressure part mods (5.)	100,000	based on recent projects
Engineering	200,000	
Erection supervision & startup	200,000	
Project Support	200,000	
Asbestos abatement	TBD	
Total	3,700,000	
INDIRECT CAPITAL COSTS (ICC)		
Corporate overhead	186,000	6% of DCC
Liability insurance	62,000	2% of DCC
Contingency	465,000	15% of DCC
Interest during construction	46,337	.7% per month
Total	759,337	
TOTAL CAPITAL INVEST. (TCI)	4,459,337	DCC+ICC
DIRECT OPERATING COSTS (DOC)		
Operating & maintenance	62,000	2% of DCC
Auxiliary power	100,000	engrg. calc/plant predictions
Heat rate degradation	150,000	engrg. calc/plant predictions
Total	312,000	
CAPITAL RECOVERY COST (CRC)	725,534	CRF of .1627*TCI
ANNUALIZED COST/unit	1,037,534	DOC+CRC

Table B-11. Cost Summary Over-Fire Air Retrofit at PTF 1&2

Cost Component	Costs/Unit ($)	Basis for Cost Estimate
DIRECT CAPITAL COSTS (DCC)		
OFA duct, etc. (1.)	850,000	based on recent projects
Windbox modeling (2.)	150,000	based on recent projects
Windbox baffles (3.)	500,000	based on recent projects
OFA ports, etc. (4.)	1,500,000	based on recent projects
Pressure part mods (5.)	500,000	based on recent projects
Engineering	200,000	
Erection supervision & startup	200,000	
Project Support	200,000	
Asbestos abatement	TBD	
Total	4,100,000	
INDIRECT CAPITAL COSTS (ICC)		
Corporate overhead	210,000	6% of DCC
Liability insurance	70,000	2% of DCC
Contingency	525,000	15% of DCC
Interest during construction	51,503	.7% per month
Total	856,503	
TOTAL CAPITAL INVEST. (TCI)	4,956,503	DCC+ICC
DIRECT OPERATING COSTS (DOC)		
Operating & maintenance	70,000	2% of DCC
Auxiliary power	100,000	engrg. calc/plant predictions
Heat rate degradation	150,000	engrg. calc/plant predictions
Total	320,000	
CAPITAL RECOVERY COST (CRC)	806,423	CRF of .1627*TCI
ANNUALIZED COST/UNIT	1,126,423	DOC+CRC

Table B-12. Cost Summary Over-Fire Air Retrofit at PRV 3&4

Cost Component	Costs/Unit ($)	Basis for Cost Estimate
DIRECT CAPITAL COSTS (DCC)		
OFA duct, etc. (1.)	1,062,500	based on recent projects
Windbox modeling (2.)	0	
Windbox baffles (3.)	0	
OFA ports, etc. (4.)	2,000,000	based on recent projects
Pressure part mods (5.)	1,750,000	based on recent projects
Engineering	300,000	
Erection supervision & startup	200,000	
Project Support	200,000	
Asbestos abatement	750,000	
Total	6,262,500	
INDIRECT CAPITAL COSTS (ICC)		
Corporate overhead	288,750	6% of DCC
Liability insurance	96,250	2% of DCC
Contingency	721,875	15% of DCC
Interest during construction	77,378	.7% per month
Total	1,184,253	
TOTAL CAPITAL INVEST. (TCI)	7,446,753	DCC+ICC
DIRECT OPERATING COSTS (DOC)		
Operating & maintenance	96,250	2% of DCC
Auxiliary power	50,000	engrg. calc/plant predictions
Heat rate reduction	75,000	engrg. calc/plant predictions
Total	221,250	
CAPITAL RECOVERY COST (CRC)	1,211,587	CRF of .1627*TCI
ANNUALIZED COST/UNIT	1,432,837	DOC+CRC

Table B-13. Cost Summary Over-Fire Air Retrofit at PPE 1&2

Cost Component	Costs/Unit ($)	Basis for Cost Estimate
DIRECT CAPITAL COSTS (DCC)		
OFA duct, etc. (1.)	1,275,000	based on recent projects
Windbox modeling (2.)	0	
Windbox baffles (3.)	0	
OFA ports, etc. (4.)	1,000,000	based on recent projects
Pressure part mods (5.)	375,000	based on recent projects
Engineering	200,000	
Erection supervision & startup	200,000	
Project Support	200,000	
Asbestos abatement	500,000	
Total	3,750,000	
INDIRECT CAPITAL COSTS (ICC)		
Corporate overhead	159,000	6% of DCC
Liability insurance	53,000	2% of DCC
Contingency	397,500	15% of DCC
Interest during construction	45,775	.7% per month
Total	655,275	
TOTAL CAPITAL INVEST. (TCI)	4,405,275	DCC+ICC
DIRECT OPERATING COSTS (DOC)		
Operating & maintenance	53,000	2% of DCC
Auxiliary power	35,000	engrg. calc/plant predictions
Heat rate reduction	50,000	engrg. calc/plant predictions
Total	138,000	
CAPITAL RECOVERY COST (CRC)	716,738	CRF of .1627*TCI
ANNUALIZED COST/UNIT	854,738	DOC+CRC

Table B-14. Cost Summary Flue Gas Recirculation Retrofit at PTF 1&2 and PPE 3&4

Cost Component	Costs/Unit ($)	Basis for Cost Estimate
DIRECT CAPITAL COSTS (DCC):		
FD fans, etc. (1.)	660,000	from fan vendor
FD fan motor, etc. (2.)	3,220,000	from motor vendor
Air duct structural (3.)	400,000	based recent projects
Windbox mods (4. & 5.)	300,000	based recent projects
Burner mods (6.)	500,000	from burner vendor
Pressure part structural (7.)	1,400,000	based on orimulsion study
SH/RH/Econ. upgrades (8. & 9.)	4,000,000	based on orimulsion study
Flue reinforcements (10.)	400,000	based recent projects
FGR ducts, etc. (11a,c & d.)	850,000	based recent projects
FGR fans, etc. (11b.)	420,000	from fan vendor
FGR fan motor, etc. (11e.)	990,000	from motor vendor
FD and FGR aux. equip. (12.)	2,510,000	from vendor/recent projects
Engineering	500,000	
Erection supervision & startup	500,000	
Project Support	300,000	
Asbestos abatement	TBD	
Total	16,950,000	
INDIRECT CAPITAL COSTS (ICC):		
Corporate overhead	939,000	6% of DCC
Liability insurance	313,000	2% of DCC
Contingency	2,347,500	15% of DCC
Interest during construction	431,540	.7% per month of TCI
Total	4,031,040	
TOTAL CAPITAL INVEST. (TCI)	20,981,040	DCC+ICC
DIRECT OPERATING COSTS (DOC)		
Operating & maintenance	339,000	2% of DCC
Auxiliary power	300,000	fan vendor/plant predictions
Heat rate degradation	100,000	engr. calc/plant predictions
Total	739,000	
CAPITAL RECOVERY COST (CRC)	3,413,615	CRF of 0.1627*TCI
ANNUALIZED COST/UNIT	4,152,615	DOC+CRC

Table B-15. Cost Summary Flue Gas Recirculation Retrofit at PRV 3&4

Cost Component	Costs/Unit ($)	Basis for Cost Estimate
DIRECT CAPITAL COSTS (DCC):		
FD/ID fans, etc. (1.)	924,000	from fan vendor
FD/ID fan motor, etc. (2.)	4,508,000	from motor vendor
Air duct structural (3.)	400,000	based recent projects
Windbox mods (4. & 5.)	300,000	based recent projects
Burner mods (6.)	666,666	from burner vendor
Pressure part structural (7.)	1,400,000	based on orimulsion study
SH/RH/Econ. upgrades (8. & 9.)	3,000,000	based on orimulsion study
Flue reinforcements (10.)	400,000	based recent projects
FGR ducts, etc. (11a,c & d.)	1,275,000	based recent projects
FGR fans, etc. (11b.)	315,000	from fan vendor
FGR fan motor, etc. (11e.)	742,500	from motor vendor
FD/ID and FGR aux. equip. (12.	2,698,250	from vendor/recent projects
Engineering	500,000	
Erection supervision & startup	500,000	
Project Support	300,000	
Asbestos abatement	1,500,000	
Total	19,429,416	
INDIRECT CAPITAL COSTS (ICC):		
Corporate overhead	997,765	6% of DCC
Liability insurance	332,588	2% of DCC
Contingency	2,494,412	15% of DCC
Interest during construction	488,338	.7% per month of TCI
Total	4,313,103	
TOTAL CAPITAL INVEST. (TCI)	23,742,519	DCC+ICC
DIRECT OPERATING COSTS (DOC)		
Operating & maintenance	388,588	2% of DCC
Auxiliary power	150,000	fan vendor/plant predictions
Heat rate degradation	50,000	engr. calc/plant predictions
Total	588,588	
CAPITAL RECOVERY COST (CRC)	3,862,908	CRF of 0.1627*TCI
ANNUALIZED COST/UNIT	4,451,496	DOC+CRC

Table B-16. Cost Summary Flue Gas Recirculation Retrofit at PPE 1&2

Cost Component	Costs/Unit ($)	Basis for Cost Estimate
DIRECT CAPITAL COSTS (DCC):		
FD/ID fans, etc. (1.)	825,000	from fan vendor
FD/ID fan motor, etc. (2.)	4,025,000	from motor vendor
Air duct structural (3.)	400,000	based recent projects
Windbox mods (4. & 5.)	300,000	based recent projects
Burner mods (6.)	444,444	from burner vendor
Pressure part structural (7.)	700,000	based on orimulsion study
SH/RH/Econ. upgrades (8. & 9.)	2,200,000	based on orimulsion study
Flue reinforcements (10.)	400,000	based recent projects
FGR ducts, etc. (11a,c & d.)	425,000	based recent projects
FGR fans, etc. (11b.)	231,000	from fan vendor
FGR fan motor, etc. (11e.)	544,500	from motor vendor
FD/ID and FGR aux. equip. (12.	2,259,000	from vendor/recent projects
Engineering	500,000	
Erection supervision & startup	500,000	
Project Support	300,000	
Asbestos abatement	1,500,000	
Total	15,553,944	
INDIRECT CAPITAL COSTS (ICC):		
Corporate overhead	765,237	6% of DCC
Liability insurance	255,079	2% of DCC
Contingency	1,913,092	15% of DCC
Interest during construction	388,234	.7% per month of TCI
Total	3,321,641	
TOTAL CAPITAL INVEST. (TCI)	18,875,585	DCC+ICC
DIRECT OPERATING COSTS (DOC)		
Operating & maintenance	311,079	2% of DCC
Auxiliary power	100,000	fan vendor/plant predictions
Heat rate degradation	35,000	engr. calc/plant predictions
Total	446,079	
CAPITAL RECOVERY COST (CRC)	3,071,058	CRF of 0.1627*TCI
ANNUALIZED COST/UNIT	3,517,137	DOC+CRC

Table B-17. Capital Cost Estimates for Using SNCR to Control NO_x Emissions on 400 MW Class Units - PPE 3 & 4

Cost Components	Cost Factors	Cost ($)
DIRECT CAPITAL COSTS (DCC):		
(1) Purchased Equipment Cost		
(a) Basic Equipment/Services Thermal $DeNO_x$ Component	Estimated[a]	3,083,381
(b) Other Boiler Modifications	0.25 x (1a)	770,845
(c) Instrumentation & Controls	0.10 x (1a-1b)	385,423
(d) Structural Support	0.10 x (1a-1b)	385,423
(e) Freight[b]	0.05 x (1a-1d)	231,254
(f) Sales Tax (Florida)	0.06 x (1a-1d)	277,504
(g) Subtotal	(1a-1f)	5,133,829
(2) Direct Installation[b]	0.30 x (1g)	1,540,149
Total DCC:	(1) + (2)	6,673,978
INDIRECT CAPITAL COSTS (ICC):		
(3) Indirect Installation Costs		
(a) Technology License Fee	Estimated[a]	1,417,500
(b) Engineering & Supervision[b]	0.10 x (DCC)	667,398
(c) Construction & Field Expenses[b]	0.05 x (DCC)	333,699
(d) Construction Contractor Fee[b]	0.10 x (DCC)	667,398
(e) Contingencies[c]	0.20 x (DCC)	1,334,796
(4) Other Indirect Costs		
(a) Startup & Testing[c]	0.15 x (DCC)	1,001,097
(b) Model Study	Vendor Quote	110,000
(c) Interest During Construction	0.15 x (DCC)	1,001,097
Total ICC:	(3) + (4)	6,532,983
TOTAL CAPITAL INVESTMENT (TCI):	DCC + ICC	13,206,961

$\frac{13,206,961}{400,000} = \frac{\$ 33.00}{KW}$

[a] Estimates developed from vendor quotes.
[b] From OAQPS Control Cost Manual, Fourth Edition.
[c] Based on consideration that SNCR is an unproven technology for oil-fired boilers.

Table B-18. Capital Cost Estimates for Using SNCR to Control NO_x Emissions on 300 MW Class Units - PRV 3 & 4

Cost Components	Cost Factors	Cost ($)
DIRECT CAPITAL COSTS (DCC):		
(1) Purchased Equipment Cost		
(a) Basic Equipment/Services		
Thermal $DeNO_x$ Component	Estimated[a]	2,312,536
(b) Other Boiler Modifications	0.25 x (1a)	578,134
(c) Instrumentation & Controls	0.10 x (1a-1b)	289,067
(d) Structural Support	0.10 x (1a-1b)	289,067
(e) Freight[b]	0.05 x (1a-1d)	173,440
(f) Sales Tax (Florida)	0.06 x (1a-1d)	208,128
(g) Subtotal	(1a-1f)	3,850,372
(2) Direct Installation[b]	0.30 x (1g)	1,155,112
Total DCC:	(1) + (2)	5,005,483
INDIRECT CAPITAL COSTS (ICC):		
(3) Indirect Installation Costs		
(a) Technology License Fee	Estimated[a]	1,063,125
(b) Engineering & Supervision[b]	0.10 x (DCC)	500,548
(c) Construction & Field Expenses[b]	0.05 x (DCC)	250,274
(d) Construction Contractor Fee[b]	0.10 x (DCC)	500,548
(e) Contingencies[c]	0.20 x (DCC)	1,001,097
(4) Other Indirect Costs		
(a) Startup & Testing[c]	0.15 x (DCC)	750,823
(b) Model Study	Vendor Quote	110,000
(c) Interest During Construction	0.15 x (DCC)	750,823
Total ICC:	(3) + (4)	4,927,238
TOTAL CAPITAL INVESTMENT (TCI):	DCC + ICC	9,932,721

[a] Estimates developed from vendor quotes.
[b] From OAQPS Control Cost Manual, Fourth Edition.
[c] Based on consideration that SNCR is an unproven technology for oil-fired boilers.

Table B-19. Capital Cost Estimates for Using SNCR to Control NO_x Emissions on 200 MW Class Units - PPE 1 & 2

Cost Components	Cost Factors	Cost ($)
DIRECT CAPITAL COSTS (DCC):		
(1) Purchased Equipment Cost		
(a) Basic Equipment/Services Thermal $DeNO_x$ Component	Estimated[a]	1,512,874
(b) Other Boiler Modifications	0.25 x (1a)	378,218
(c) Instrumentation & Controls	0.10 x (1a-1b)	189,109
(d) Structural Support	0.10 x (1a-1b)	189,109
(e) Freight[b]	0.05 x (1a-1d)	113,466
(f) Sales Tax (Florida)	0.06 x (1a-1d)	136,159
(g) Subtotal	(1a-1f)	2,518,935
(2) Direct Installation[b]	0.30 x (1g)	755,680
Total DCC:	(1) + (2)	3,274,615
INDIRECT CAPITAL COSTS (ICC):		
(3) Indirect Installation Costs		
(a) Technology License Fee	Estimated[a]	708,750
(b) Engineering & Supervision[b]	0.10 x (DCC)	327,462
(c) Construction & Field Expenses[b]	0.05 x (DCC)	163,731
(d) Construction Contractor Fee[b]	0.10 x (DCC)	327,462
(e) Contingencies[c]	0.20 x (DCC)	654,923
(4) Other Indirect Costs		
(a) Startup & Testing[c]	0.15 x (DCC)	491,192
(b) Model Study	Vendor Quote	110,000
(c) Interest During Construction	0.15 x (DCC)	491,192
Total ICC:	(3) + (4)	3,274,711
TOTAL CAPITAL INVESTMENT (TCI):	DCC + ICC	6,549,327 = 32.74 / 200,000

[a] Estimates developed from vendor quotes.
[b] From OAQPS Control Cost Manual, Fourth Edition.
[c] Based on consideration that SNCR is an unproven technology for oil-fired boilers.

Table B-20. Annualized Cost Estimates for Using SNCR to Control NO_x Emissions on 400 MW Class Units

Cost Components	Basis	Cost ($)
DIRECT OPERATING COSTS (DOC):		
(1) Operating Labor		
Operator[a]	2,080 hr/yr per unit @ $25/hr	52,000
Supervisor[b]	15% of operator cost	7,800
(2) Maintenance[b]	8% of total DCC	533,918
(3) Utilities	50/MW-hr; see Note 1	245,140
(4) Ammonia	250/ton; see Note 2	366,500
(5) Contingency	20% (1) through (4)	241,072
Total DOC		1,446,430
INDIRECT OPERATING COSTS (IOC):		
(7) Overhead[b]	60% of oper. labor & maint.	356,231
(8) Property Taxes[b]	1% of total capital investment	132,070
(9) Insurance[b]	1% of total capital investment	132,070
(10) Administration[b]	2% of total capital investment	264,139
Total IOC		884,509
CAPITAL RECOVERY COST (CRC)	CRF of 0.1627 times TCI	2,148,773
ANNUALIZED COST (AC):	DOC + IOC + CRC	4,479,712
	DCC	6,673,978
	TCI	13,206,961

Note: Thermal $DeNO_x$: Based on vendor's estimate of approximately 1.66 kW-hr required per pound of NH_3 or an equivalent of 4,868 MW-hr per year.
Total NH_3 cost is: $250/ton NH_3 x 1,466 TPY = $366,500

[a] Based on 1 operator working 8 hours/day, 5 days/week, 52 weeks/year for each boiler or 2,080 hr/yr.
[b] Based on catalytic incinerators, from OAQPS Control Cost Manual, Fourth Edition.

Table B-21. Annualized Cost Estimates for Using SNCR to Control NO_x Emissions on 300 MW Class Units

Cost Components	Basis	Cost ($)
DIRECT OPERATING COSTS (DOC):		
(1) Operating Labor		
Operator[a]	2,080 hr/yr per unit @ $25/hr	52,000
Supervisor[b]	15% of operator cost	7,800
(2) Maintenance[b]	8% of total DCC	400,439
(3) Utilities	50/MW-hr; see Note 1	191,957
(4) Ammonia	250/ton; see Note 2	289,092
(5) Contingency	20% (1) through (4)	188,258
Total DOC		1,129,546
INDIRECT OPERATING COSTS (IOC):		
(7) Overhead[b]	60% of oper. labor & maint.	276,143
(8) Property Taxes[b]	1% of total capital investment	99,327
(9) Insurance[b]	1% of total capital investment	99,327
(10) Administration[b]	2% of total capital investment	198,654
Total IOC		673,452
CAPITAL RECOVERY COST (CRC)	CRF of 0.1627 times TCI	1,616,054
ANNUALIZED COST (AC):	DOC + IOC + CRC	3,419,052
	DCC	5,005,483
	TCI	9,932,721

Note: Thermal $DeNO_x$: Based on vendor's estimate of approximately 1.66 kW-hr required per pound of NH_3 or an equivalent of 3,748 MW-hr per year.
Total NH_3 cost is: $250/ton NH_3 x 1,129 TPY = $282,232

[a] Based on 1 operator working 8 hours/day, 5 days/week, 52 weeks/year for each boiler or 2,080 hr/yr.
[b] Based on catalytic incinerators, from OAQPS Control Cost Manual, Fourth Edition.

Table B-22. Annualized Cost Estimates for Using SNCR to Control NO_x Emissions on 200 MW Class Units

Cost Components	Basis	Cost ($)
DIRECT OPERATING COSTS (DOC):		
(1) Operating Labor		
Operator[a]	2,080 hr/yr per unit @ $25/hr	52,000
Supervisor[b]	15% of operator cost	7,800
(2) Maintenance[b]	8% of total DCC	261,969
(3) Utilities	50/MW-hr; see Note 1	70,328
(4) Ammonia	250/ton; see Note 2	105,915
(5) Contingency	20% (1) through (4)	99,602
Total DOC		597,614
INDIRECT OPERATING COSTS (IOC):		
(7) Overhead[b]	60% of oper. labor & maint.	193,062
(8) Property Taxes[b]	1% of total capital investment	65,493
(9) Insurance[b]	1% of total capital investment	65,493
(10) Administration[b]	2% of total capital investment	130,987
Total IOC		455,035
CAPITAL RECOVERY COST (CRC)	CRF of 0.1627 times TCI	1,065,575
ANNUALIZED COST (AC):	DOC + IOC + CRC	2,118,224
	DCC	3,274,615
	TCI	6,549,327

Note: Thermal $DeNO_x$: Based on vendor's estimate of approximately 1.66 kW-hr required per pound of NH_3 or an equivalent of 2,458 MW-hr per year.
Total NH_3 cost is: $250/ton NH_3 x 740 TPY = $185,118

[a] Based on 1 operator working 8 hours/day, 5 days/week, 52 weeks/year for each boiler or 2,080 hr/yr.
[b] Based on catalytic incinerators, from OAQPS Control Cost Manual, Fourth Edition.

Table B-23. Direct and Indirect Capital Cost for Selective Catalytic Reduction (SCR), FPL 400 MW Class Units

Cost Component	Costs ($)	Basis for Cost Estimate
Direct Capital Costs		
SCR Associated Equipment	2,358,400	Developed from manufacturer budget quotations.
Ammonia Storage Tank	438,100	Developed from manufacturer budget quotations.
HRSG Modification	3,100,400	Developed from manufacturer budget quotations.
Indirect Capital Costs		
Installation	4,042,500	45% of SCR associated equipment and ammonia storage tank.
Engineering, Erection Supervision, Start-up, and O&M Training	1,822,000	10% SCR equipment and catalyst, ammonia storage tank and HRSG costs.
FPL Project Support	1,002,100	10% SCR equipment and catalyst, ammonia storage tank, HRSG and engineering costs.
Ammonia Emergency Preparedness Program	23,100	Engineering estimate.
Liability Insurance	100,200	0.5% SCR equipment and catalyst, ammonia storage tank, HRSG and engineering costs.
Interest During Construction	3,175,200	15% of all direct and indirect capital costs including catalyst cost.
Contingency	3,954,900	25% of all capital costs.
Total Capital Costs	20,768,300	Sum of all capital costs.
Annualized Capital Costs	3,379,000	Capital recovery of 10% over 15 years, 16.46% per year.
Recurring Capital Costs		
SCR Catalyst (Materials & Labor)	6,624,800	Developed from manufacturer budget quotations.
Contingency	1,656,200	25% of recurring capital costs.
Total Recurring Capital Costs	8,281,000	Sum of recurring capital costs.
Annualized Recurring Capital Costs	3,329,900	Capital recovery of 10% over 3 years, 40.21% per year.

Table B-24. Annualized Cost for Selective Catalytic Reduction (SCR), FPL 400 MW Class Units

Cost Component	Costs ($)	Basis for Cost Estimate
Direct Annual Costs		
Operating Personnel	52,000	Full time position @ $25/hour.
Ammonia	342,100	$250/ton; NH_3:NO_x = 1:1.1 volume.
Accident/Emergency Response Plan	8,600	Consultant estimate, 80 hours/year @ $80/hour plus expenses @ 35% labor.
Inventory Cost	363,700	Capital recovery (16.47%/year) for 1/3 of catalyst cost.
Catalyst Disposal Cost	87,600	Engineering estimate.
Contingency	275,800	25% of indirect costs.
ENERGY COSTS		
Electrical	92,300	344 kwh/hr; $0.05/KWH.
Heat Rate Penalty	616,300	Heat rate reduction of 0.5%, energy loss at $0.05/KWH.
MW Loss Penalty	805,900	Replacement power cost differential; $50/MWh, 3 days, fuel cost subtracted.
Fuel Escalation Costs	688,400	Real cost increase of fuel.
Contingency	349,300	25% of energy costs; excludes fuel escalation.
Total Direct Annual Costs	3,682,000	Sum of all direct annual costs.
Indirect Annual Costs		
Overhead	249,000	60% of ammonia plus 115% of O&M labor; plus 15% of O&M labor (OAQPS Cost Control Manual.
Property Taxes and Insurance	581,000	2% of total capital costs.
Annualized Capital Costs	3,379,000	Capital recovery of 10% over 15 years, 16.46% per year.
Recurring Capital Costs	3,329,900	Capital recovery of 10% over 3 years, 40.21% per year.
Total Indirect Annual Costs	7,538,900	Sum of all indirect annual costs.
Total Annual Costs	11,220,900	Total annualized cost.

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

Table B-25. Annualized Cost for Selective Catalytic Reduction (SCR), FPL 300 MW Class Units

Cost Component	Costs ($)	Basis for Cost Estimate
Direct Annual Costs		
Operating Personnel	52,000	Full time position at all shifts @ $30/hour.
Ammonia	263,400	$250/ton; NH_3:NO_x = 1:1.1 volume.
Accident/Emergency Response Plan	8,600	Consultant estimate, 80 hours/year @ $80/hour plus expenses @ 35% labor.
Inventory Cost	279,700	Capital recovery (16.47%/year) for 1/3 of catalyst cost.
Catalyst Disposal Cost	67,400	Engineering estimate.
Contingency	218,200	25% of indirect costs.
ENERGY COSTS		
Electrical	71,100	344 kwh/hr; $0.05/KWH.
Heat Rate Penalty	475,900	Heat rate reduction of 0.5%, energy loss at $0.05/KWH.
MW Loss Penalty	626,500	Replacement power cost differential; $50/MWh, 3 days, fuel cost subtracted.
Fuel Escalation Costs	533,400	Real cost increase of fuel.
Contingency	270,100	25% of energy costs; excludes fuel escalation.
Total Direct Annual Costs	2,866,300	Sum of all direct annual costs.
Indirect Annual Costs		
Overhead	201,700	60% of ammonia plus 115% of O&M labor; plus 15% of O&M labor (OAQPS Cost Control Manual.
Property Taxes and Insurance	468,300	2% of total capital costs.
Annualized Capital Costs	2,773,900	Capital recovery of 10% over 15 years, 16.46% per year.
Recurring Capital Costs	2,560,700	Capital recovery of 10% over 3 years, 40.21% per year.
Total Indirect Annual Costs	6,004,600	Sum of all indirect annual costs.
Total Annual Costs	8,870,900	Total annualized cost.

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

Table B-26. Direct and Indirect Capital Cost for Selective Catalytic Reduction (SCR), FPL 300 MW Class Units

Cost Component	Costs ($)	Basis for Cost Estimate
Direct Capital Costs		
SCR Associated Equipment	2,106,700	Developed from manufacturer budget quotations.
Ammonia Storage Tank	336,900	Developed from manufacturer budget quotations.
HRSG Modification	2,393,800	Developed from manufacturer budget quotations.
Indirect Capital Costs		
Installation	3,240,600	45% of SCR associated equipment and ammonia storage tank.
Engineering, Erection Supervision, Start-up, and O&M Training	1,444,600	10% SCR equipment and catalyst, ammonia storage tank and HRSG costs.
FPL Project Support	1,002,100	10% SCR equipment and catalyst, ammonia storage tank, HRSG and engineering costs.
Ammonia Emergency Preparedness Program	19,200	Engineering estimate.
Liability Insurance	100,200	0.5% SCR equipment and catalyst, ammonia storage tank, HRSG and engineering costs.
Interest During Construction	2,551,900	15% of all direct and indirect capital costs including catalyst cost.
Contingency	3,257,000	25% of all capital costs.
Total Capital Costs	17,049,000	Sum of all capital costs.
Annualized Capital Costs	2,773,900	Capital recovery of 10% over 15 years, 16.46% per year.
Recurring Capital Costs		
SCR Catalyst (Materials & Labor)	5,094,500	Developed from manufacturer budget quotations.
Contingency	1,273,600	25% of recurring capital costs.
Total Recurring Capital Costs	6,368,200	Sum of recurring capital costs.
Annualized Recurring Capital Costs	2,560,700	Capital recovery of 10% over 3 years, 40.21% per year.

Table B-27. Direct and Indirect Capital Cost for Selective Catalytic Reduction (SCR), FPL 300 MW Class Units

Cost Component	Costs ($)	Basis for Cost Estimate
Direct Capital Costs		
SCR Associated Equipment	1,888,200	Developed from manufacturer budget quotations.
Ammonia Storage Tank	249,100	Developed from manufacturer budget quotations.
HRSG Modification	1,737,000	Developed from manufacturer budget quotations.
Indirect Capital Costs		
Installation	2,544,300	45% of SCR associated equipment and ammonia storage tank.
Engineering, Erection Supervision, Start-up, and O&M Training	1,112,600	10% SCR equipment and catalyst, ammonia storage tank and HRSG costs.
FPL Project Support	1,002,100	10% SCR equipment and catalyst, ammonia storage tank, HRSG and engineering costs.
Ammonia Emergency Preparedness Program	19,200	Engineering estimate.
Liability Insurance	100,200	0.5% SCR equipment and catalyst, ammonia storage tank, HRSG and engineering costs.
Interest During Construction	2,004,000	15% of all direct and indirect capital costs including catalyst cost.
Contingency	2,637,600	25% of all capital costs.
Total Capital Costs	13,752,800	Sum of all capital costs.
Annualized Capital Costs	2,237,600	Capital recovery of 10% over 15 years, 16.46% per year.
Recurring Capital Costs		
SCR Catalyst (Materials & Labor)	3,765,900	Developed from manufacturer budget quotations.
Contingency	941,500	25% of recurring capital costs.
Total Recurring Capital Costs	4,707,300	Sum of recurring capital costs.
Annualized Recurring Capital Costs	1,892,900	Capital recovery of 10% over 3 years, 40.21% per year.

Table B-28. Annualized Cost for Selective Catalytic Reduction (SCR), FPL 200 MW Class Units

Cost Component	Costs ($)	Basis for Cost Estimate
Direct Annual Costs		
Operating Personnel	52,000	Full time position at all shifts @ $30/hour.
Ammonia	172,800	$250/ton; NH_3:NO_x = 1:1.1 volume.
Accident/Emergency Response Plan	8,600	Consultant estimate, 80 hours/year @ $80/hour plus expenses @ 35% labor.
Inventory Cost	206,700	Capital recovery (16.47%/year) for 1/3 of catalyst cost.
Catalyst Disposal Cost	49,800	Engineering estimate.
Contingency	159,300	25% of indirect costs.
ENERGY COSTS		
Electrical	46,600	344 kwh/hr; $0.05/KWH.
Heat Rate Penalty	493,300	Heat rate reduction of 0.5%, energy loss at $0.05/KWH.
MW Loss Penalty	446,600	Replacement Energy Costs at $50/MWh for 3 days; Fuel cost subtracted.
Fuel Escalation Costs	448,400	Real cost increase of fuel.
Contingency	247,100	25% of energy costs; excludes fuel escalation.
Total Direct Annual Costs	2,331,200	Sum of all direct annual costs.
Indirect Annual Costs		
Overhead	147,300	60% of ammonia plus 115% of O&M labor; plus 15% of O&M labor (OAQPS Cost Control Manual.
Property Taxes and Insurance	369,200	2% of total capital costs.
Annualized Capital Costs	2,237,600	Capital recovery of 10% over 15 years, 16.46% per year.
Recurring Capital Costs	1,892,900	Capital recovery of 10% over 3 years, 40.21% per year.
Total Indirect Annual Costs	4,647,000	Sum of all indirect annual costs.
Total Annual Costs	6,978,200	Total annualized cost.

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

APPENDIX C

BOILER CONFIGURATIONS AND RESIDENCE TIMES

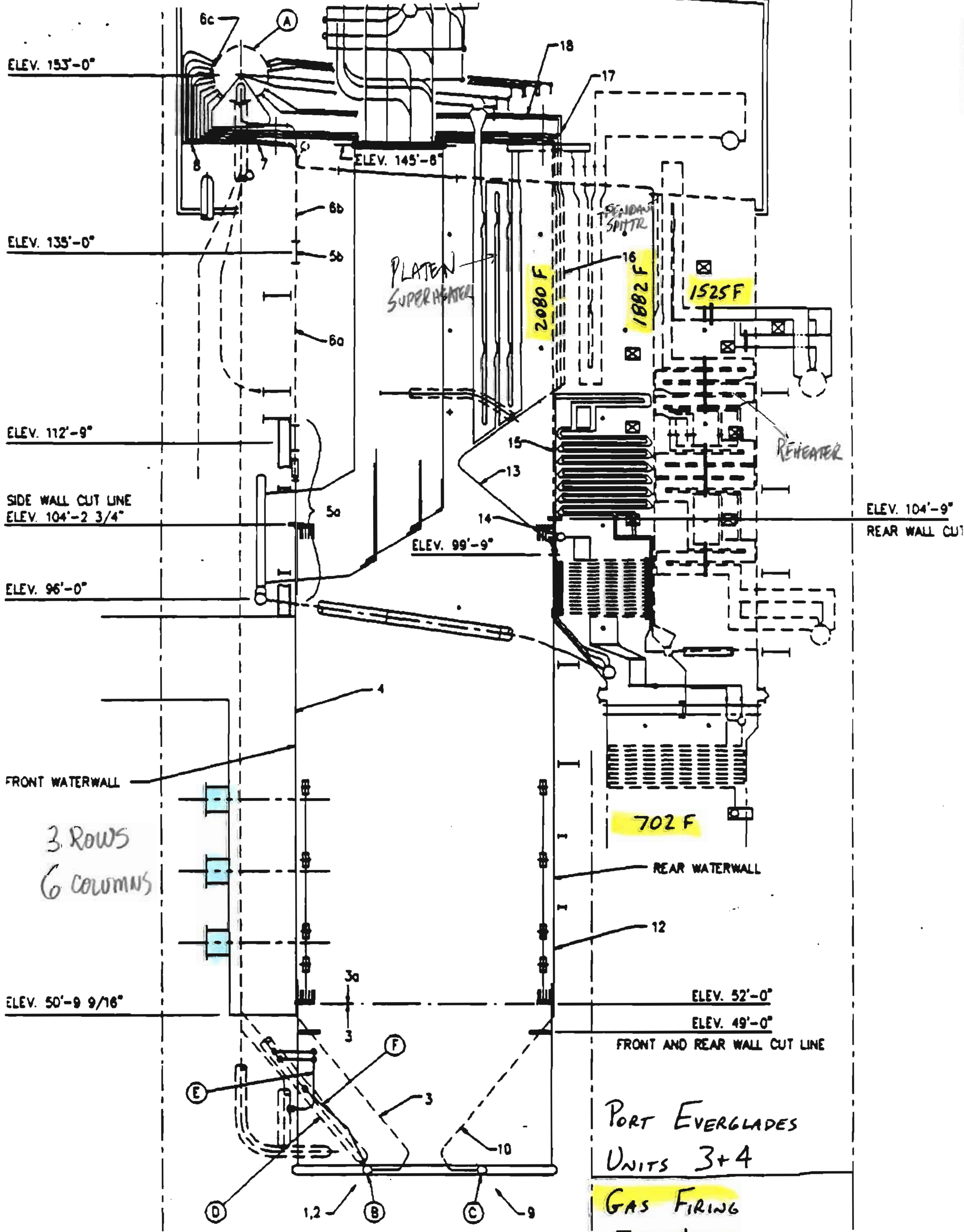
PORT EVERGLADES UNITS 3 & 4

TEMPERATURES AND RESIDENCE TIMES

FUEL	LOAD	CAVITY	FLUE GAS FLOW (LB/HR)	TEMPERATURE (F)	RESIDENCE TIME (SEC)	
Gas	Control	Screen	1,720,900	1783	0.186	
Gas	Control	Pendant	1,548,800	1600	0.326	
Gas	Control	Reheat	538,900	1341		
Gas	MCR	Screen	2,916,400	2080	0.097	
Gas	MCR	Pendant	2,624,800	1882	0.169	.26
Gas	MCR	Reheat	1,883,400	1525		
Gas	Overpressure	Screen	3,328,700	2129	0.083	
Gas	Overpressure	Pendant	2,995,800	1935	0.145	
Gas	Overpressure	Reheat	2,110,000	1584		
Oil	Control	Screen	1,685,100	1637	0.203	
Oil	Control	Pendant	1,516,600	1515	0.348	
Oil	Control	Reheat	168,500	1316		
Oil	MCR	Screen	2,812,900	1982	0.104	
Oil	MCR	Pendant	2,531,600	1802	0.182	.28
Oil	MCR	Reheat	1,922,000	1504		
Oil	Overpressure	Screen	3,294,000	2032	0.087	
Oil	Overpressure	Pendant	2,964,600	1851	0.152	
Oil	Overpressure	Reheat	2,289,000	1561		

PRELIMINARY

ENG. [signature] DATE 7/13/92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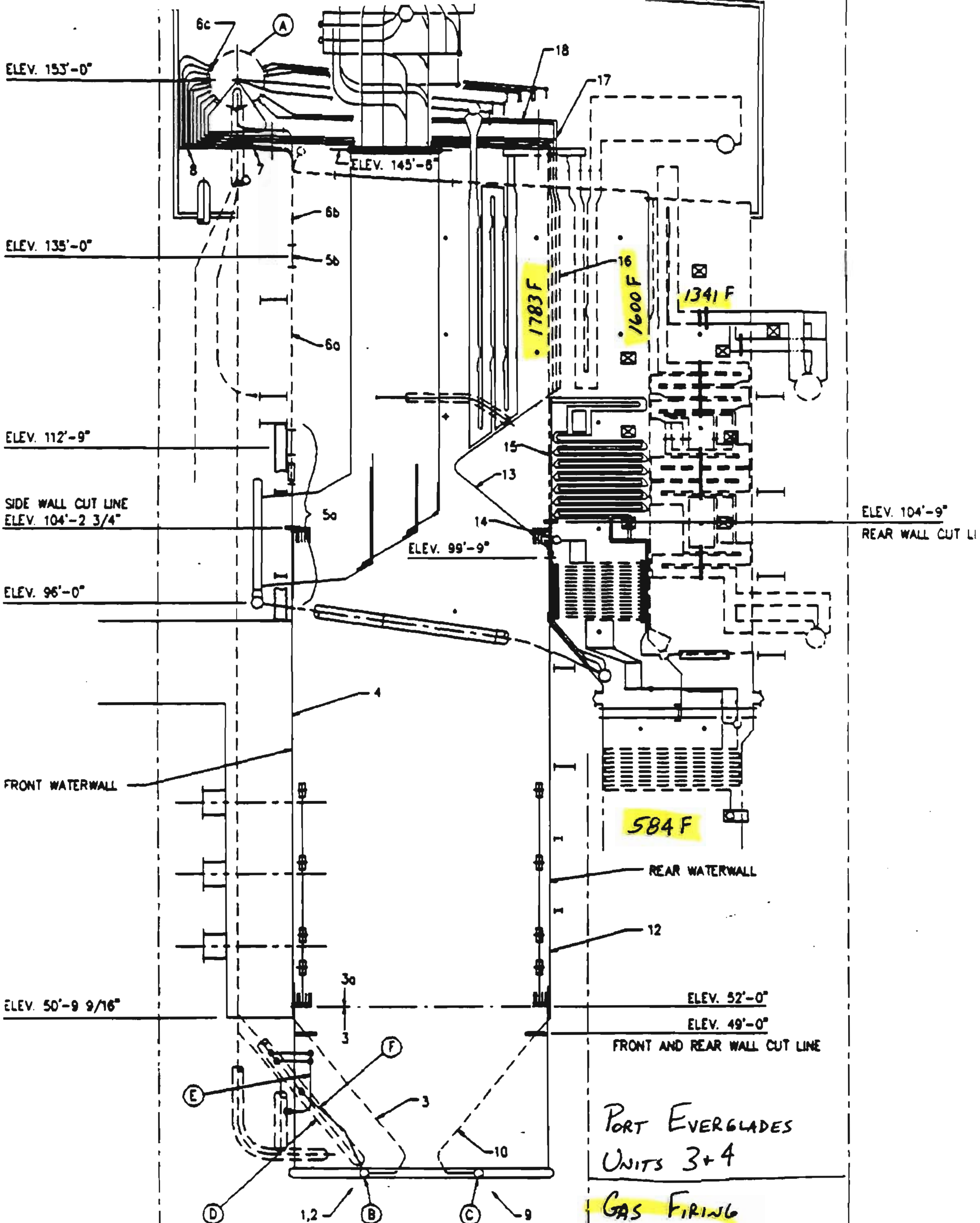
ELEV. 145'-8"
ELEV. 135'-0"
ELEV. 112'-9"
SIDE WALL CUT LINE
ELEV. 104'-2 3/4"
ELEV. 99'-9"
ELEV. 96'-0"
ELEV. 104'-9"
REAR WALL CUT
FRONT WATERWALL
REAR WATERWALL
ELEV. 50'-9 9/16"
ELEV. 52'-0"
ELEV. 49'-0"
FRONT AND REAR WALL CUT LINE
PLATEN SUPERHEATER
PENDANT SPHTR
REHEATER
2080 F
1882 F
1525 F
702 F
3 ROWS
6 COLUMNS
PORT EVERGLADES
UNITS 3+4
GAS FIRING
FULL LOAD

FIGURE 2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ELEV. 145'-6"
ELEV. 135'-0"
ELEV. 112'-9"
SIDE WALL CUT LINE
ELEV. 104'-2 3/4"
ELEV. 99'-9"
ELEV. 96'-0"
ELEV. 104'-9"
REAR WALL CUT LI
FRONT WATERWALL
REAR WATERWALL
ELEV. 50'-9 9/16"
ELEV. 52'-0"
ELEV. 49'-0"
FRONT AND REAR WALL CUT LINE
1783 F
1600 F
1341 F
584 F
Port Everglades
Units 3+4
Gas Firing
Control Load

FIGURE 2

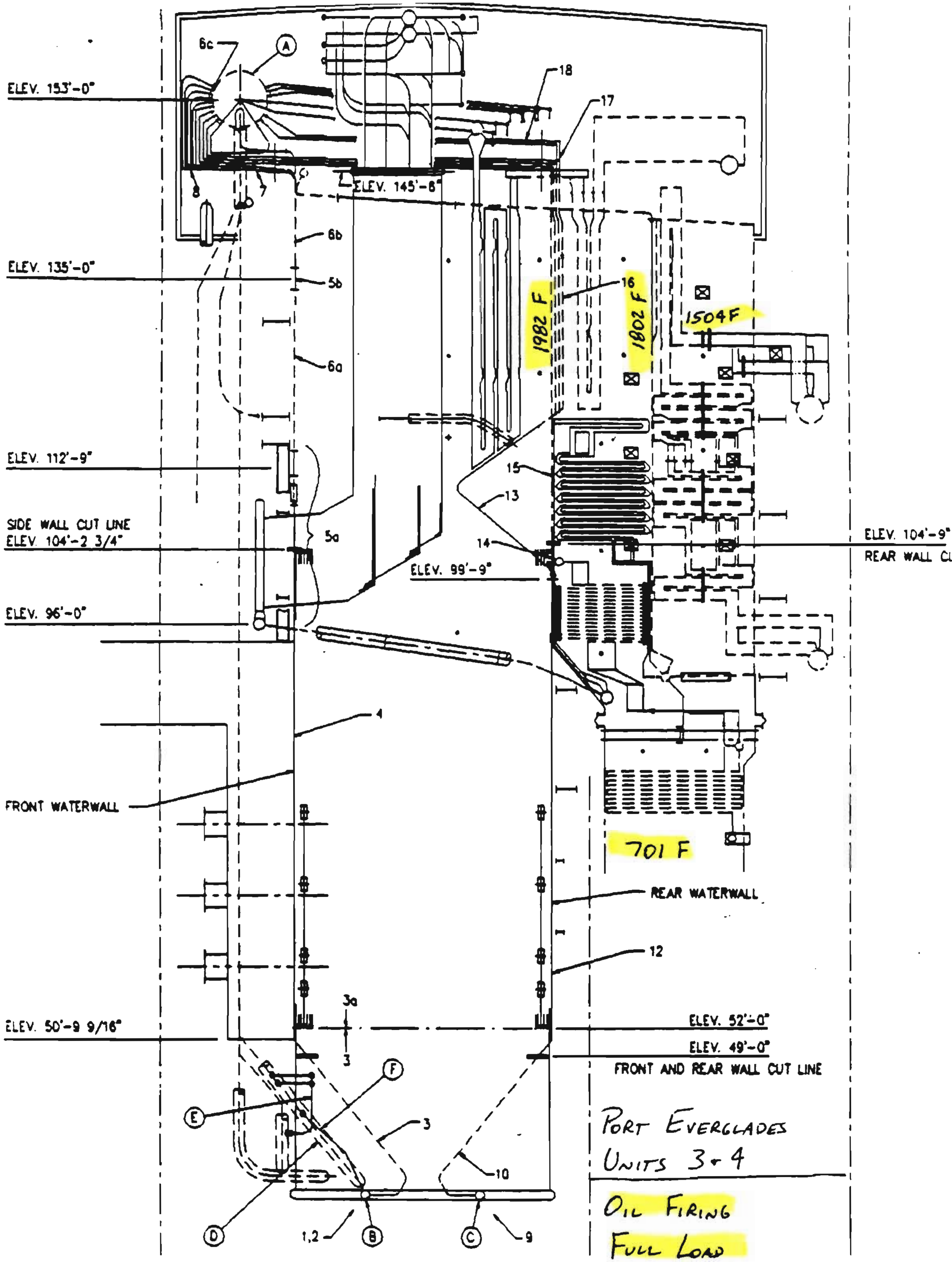

ELEV. 153'-0"
6c
A
18
17
ELEV. 145'-8"
6b
ELEV. 135'-0"
5b
16
1982 F
1802 F
1504F
6a
ELEV. 112'-9"
15
13
SIDE WALL CUT LINE
ELEV. 104'-2 3/4"
5a
14
ELEV. 104'-9"
REAR WALL CU
ELEV. 99'-9"
ELEV. 96'-0"
4
FRONT WATERWALL
701 F
REAR WATERWALL
12
3a
ELEV. 50'-9 9/16"
ELEV. 52'-0"
ELEV. 49'-0"
3
FRONT AND REAR WALL CUT LINE
F
E
3
10
D
1,2
B
C
9
Port Everglades
Units 3 + 4
Oil Firing
Full Load

FIGURE 2

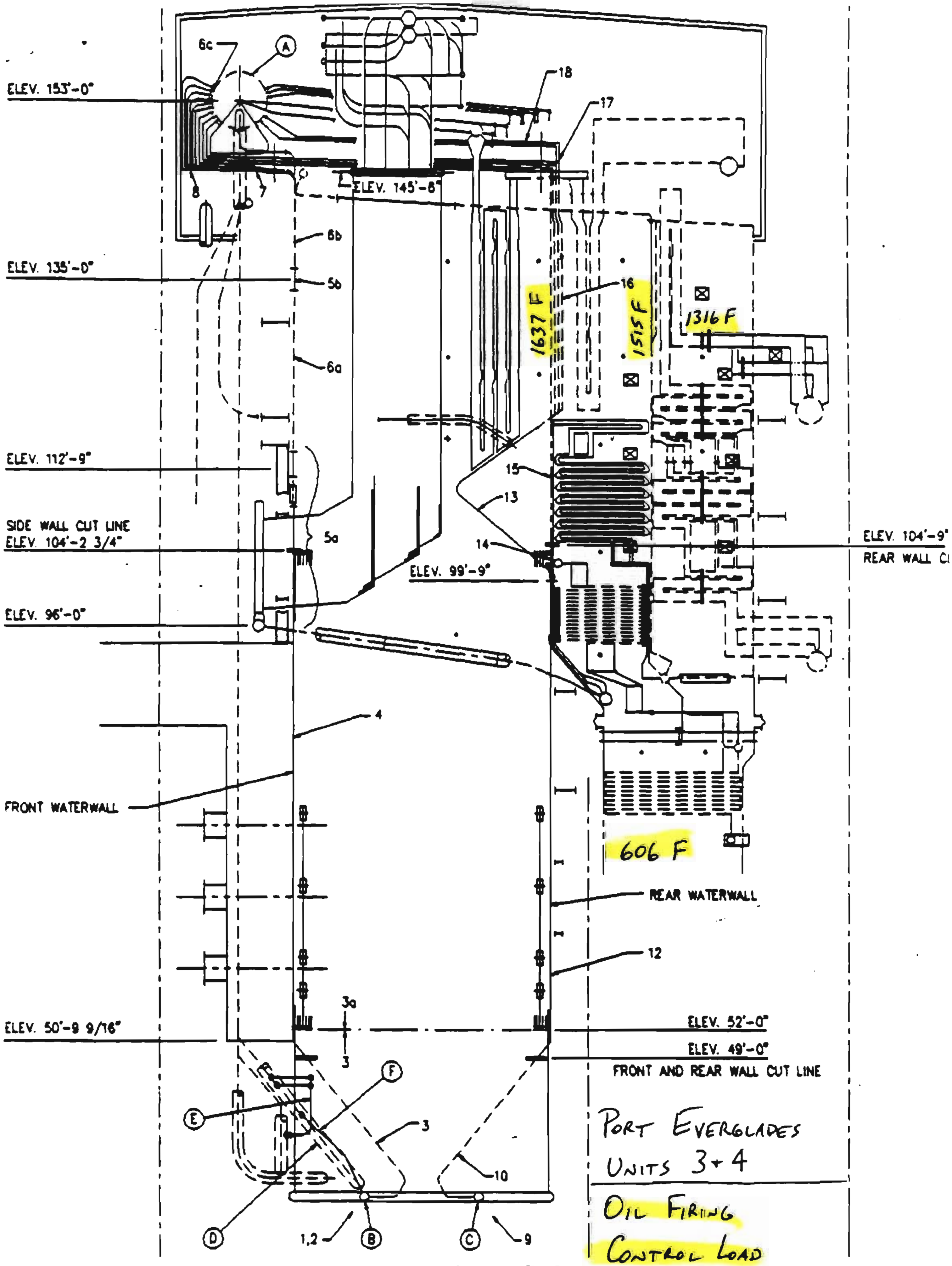
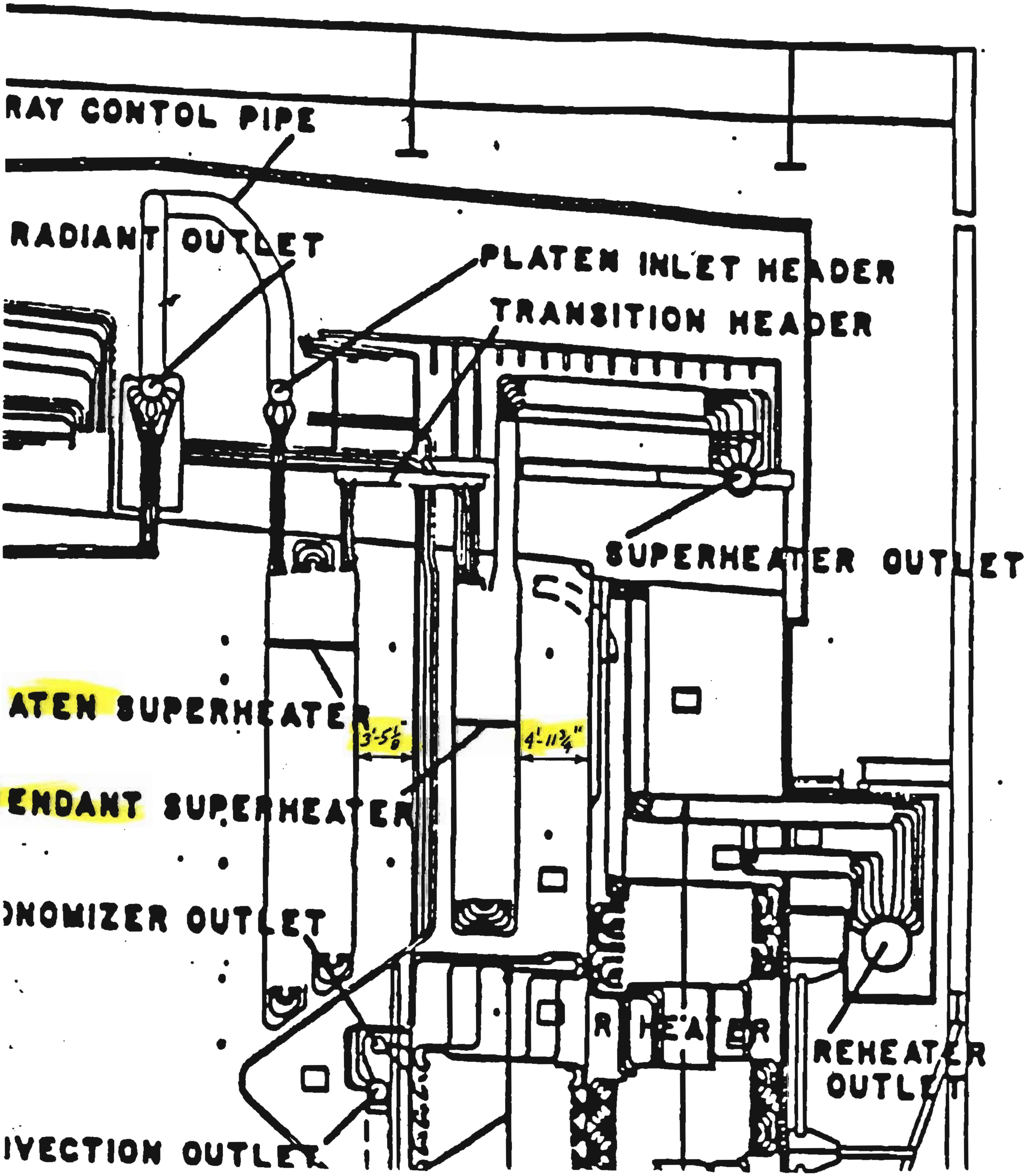

ELEV. 153'-0"
ELEV. 145'-6"
ELEV. 135'-0"
ELEV. 112'-9"
SIDE WALL CUT LINE
ELEV. 104'-2 3/4"
ELEV. 99'-9"
ELEV. 96'-0"
ELEV. 104'-9"
REAR WALL C
FRONT WATERWALL
REAR WATERWALL
ELEV. 50'-9 9/16"
ELEV. 52'-0"
ELEV. 49'-0"
FRONT AND REAR WALL CUT LINE
1637 F
1515 F
1316 F
606 F
Port Everglades
Units 3+4
Oil Firing
Control Load

FIGURE 2

am Generator

Turkey Point Units 1+2
Port Everglades Units 3+4



TURKEY POINT UNITS 1 & 2

TEMPERATURES AND RESIDENCE TIMES

FUEL	LOAD	CAVITY	FLUE GAS FLOW (LB/HR)	TEMPERATURE (F)	RESIDENCE TIME (SEC)
Gas	Control	Screen	1,770,000	1809	0.179
Gas	Control	Pendant	1,593,000	1625	0.314
Gas	Control	Reheat	1,470,000	1351	
Gas	Full MCR	Screen	2,975,000	2183	0.091
Gas	MCR	Pendant	2,677,500	1957	0.161
Gas	MCR	Reheat	2,050,000	1557	
Gas	Overpressure	Screen	3,239,400	2267	0.081
Gas	Overpressure	Pendant	2,915,500	1954	0.148
Gas	Overpressure	Reheat	2,331,100	1622	
Oil	Control	Screen	2,152,400	1727	0.152
Oil	Control	Pendant	1,937,200	1567	0.265
Oil	Control	Reheat	1,721,900	1293	
Oil	Full MCR	Screen	2,973,700	2092	0.094
Oil	MCR	Pendant	2,676,300	1884	0.166
Oil	MCR	Reheat	2,282,400	1526	
Oil	Overpressure	Screen	3,252,200	2190	0.083
Oil	Overpressure	Pendant	2,927,000	1982	0.146
Oil	Overpressure	Reheat	2,592,400	1623	

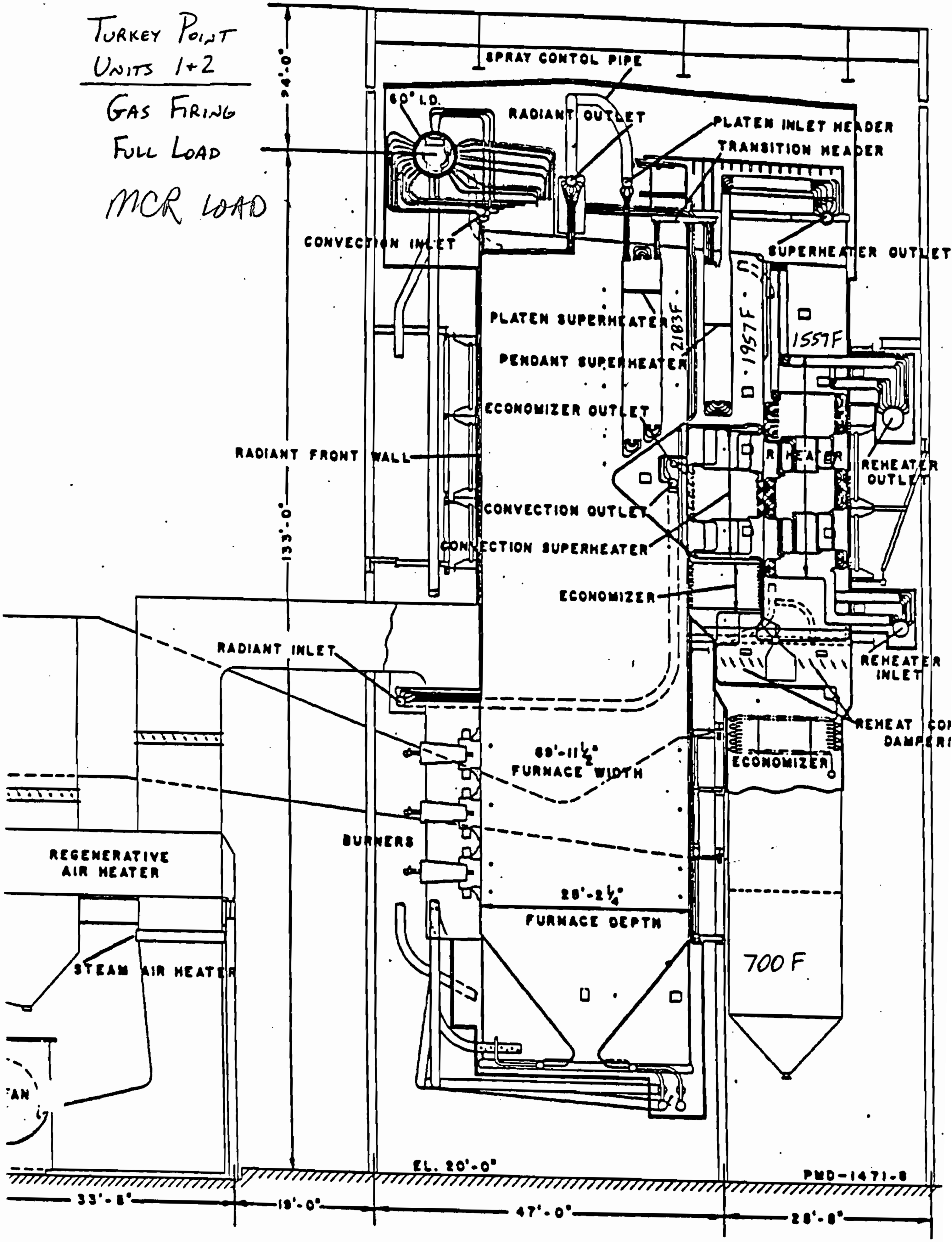
PRELIMINARY

ENG. Alan E Pasold DATE 7/13/92

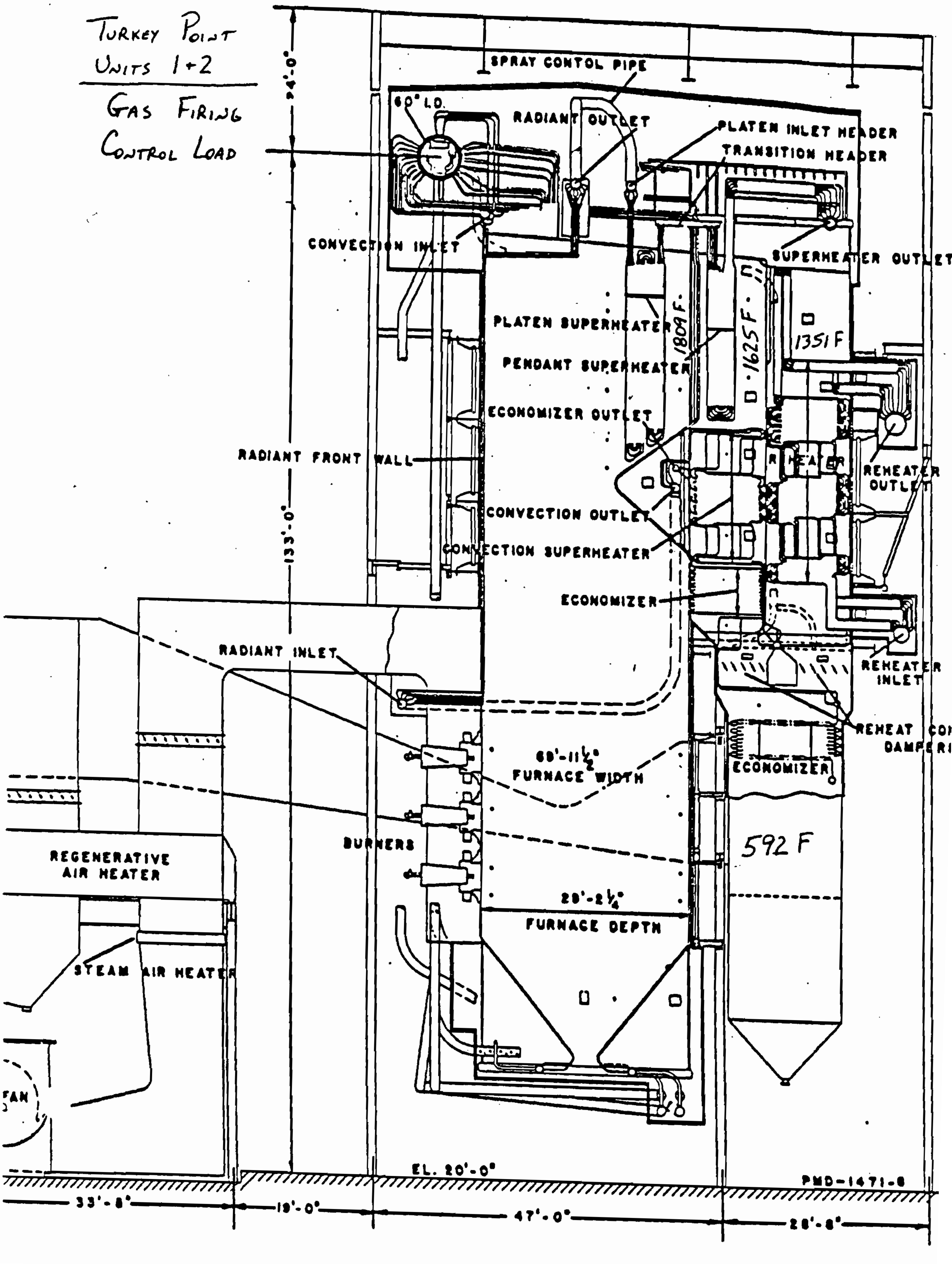
General Arrangement of Steam Generator

Turkey Point
Units 1+2

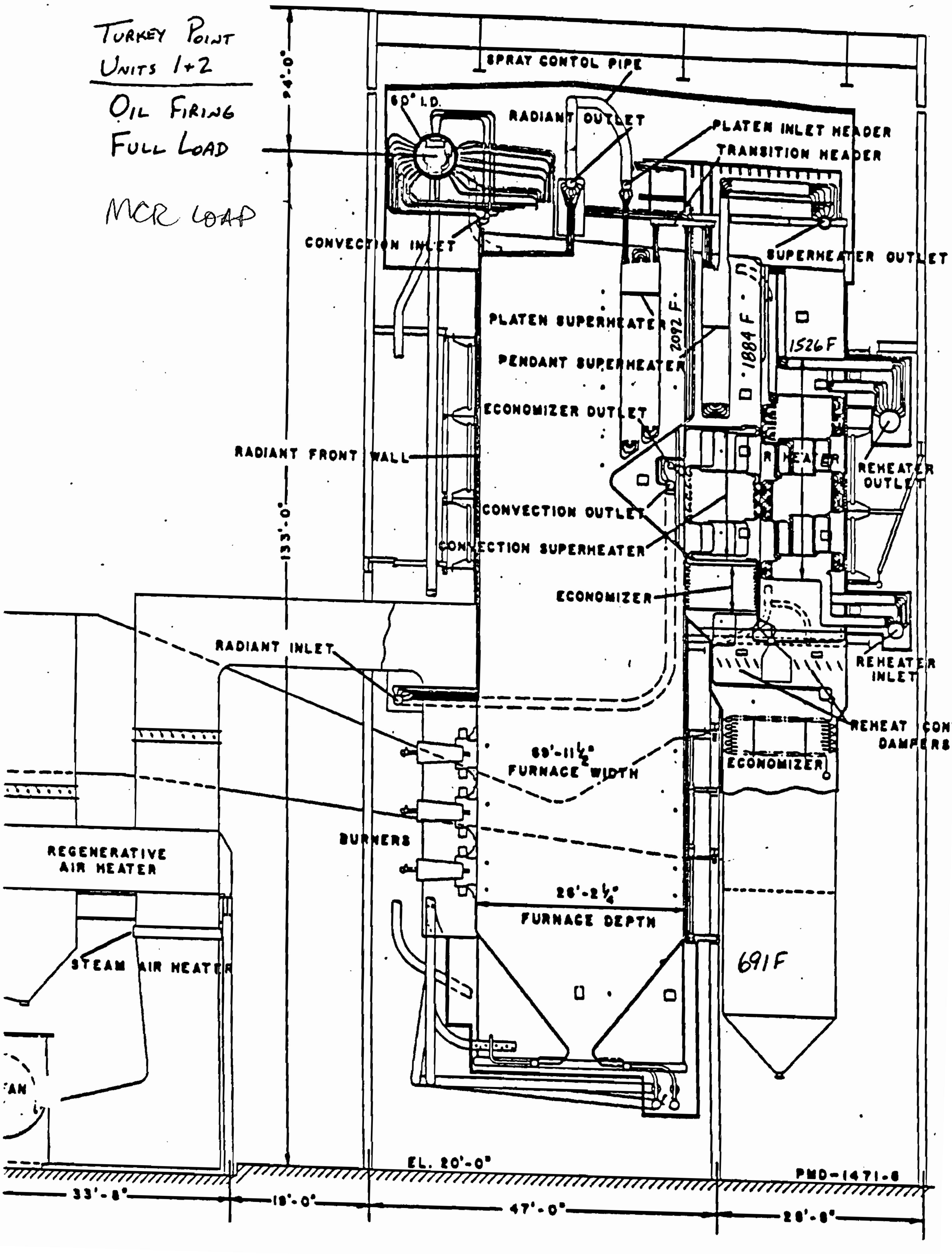
Gas Firing
Full Load
MCR Load



General Arrangement of Steam Generator



General Arrangement of Steam Generator



APPENDIX D

ENVIRONMENTAL CONSEQUENCES OF AMMONIA

APPENDIX D - ENVIRONMENTAL CONSEQUENCES OF AMMONIA

The use of ammonia is necessary for the reduction of NO_x emissions by means of a catalytic reaction. This process will require the construction and maintenance of storage vessels of anhydrous or aqueous ammonia for use in the reaction. Ammonia has a number of potential health effects, and the construction of ammonia storage facilities triggers the application of at least three major standards: Clean Air Act (section 112), OSHA 29 CFR 1910.1000, and OSHA 29 CFR 1910.119.

Ammonia is a colorless gas with a sharp, pungent odor which can be identified at about 5 ppm. It is lighter than air and very soluble in water. Other chemical and physical properties include:

Molecular weight - 17.03
Density (gas) - 0.5967, (liquid) 0.67
Boiling point - (-33.35°C)
Freezing point - (-77.7°C)
Vapor pressure(liquid) - 8.5 atmospheres at 20°C
Solubility - very soluble in water, alcohol, and ether
Flammable limits in air - LEL 15 percent, UEL 28 percent

Elevated temperatures may contribute to instability and cause containers to burst. Ammonia is incompatible with strong oxidizers, calcium, hypochlorite bleaches, gold, mercury, halogens, and silver. Liquid ammonia will corrode some forms of plastic, rubber, and coatings.

The toxicology of ammonia is well understood from a variety of animal and human studies. Ammonia is a severe irritant of the eyes, especially the cornea, the respiratory tract, and the skin. It is detectable at about 5 ppm and causes respiratory irritation in humans above 25 ppm. The irritating effects of ammonia are less noticeable with chronic exposure. There is at least one reference in the literature that indicates exposure to ammonia and amines increases the incidence of cancer.

The eyes are generally the organ of most concern in an acute exposure. As a strong alkali, ammonia can cause severe burns of the cornea and the effects are often delayed. Even burns that at the time of injury appear to be mild can go on to opacification, vascularization, and ulceration or perforation. Of all the alkali compounds that cause eye damage, ammonia penetrates the cornea the most rapidly, resulting in potentially severe damage to the cornea.

Because ammonia is very soluble in water, it is irritating to the upper respiratory tract. Inhalation of the gas will cause throat and nose irritation and dyspnea as aqueous ammonia is formed. Liquid anhydrous ammonia will cause first and second degree burns on contact with the skin. Standards applicable to ammonia are listed below:

OSHA--35 ppm as a 15-minute short-term exposure limit (STEL), 29 CFR 1910.1000.
ACGIH/NIOSH--25 ppm as an 8-hour TWA, 35 ppm as a 15-minute STEL.

NIOSH has also established an immediately dangerous to life or health (IDLH) recommendation of 500 ppm. The U.S. Navy has established a limit of 25 ppm for continuous exposure to personnel in submarines.

Employee exposure to ammonia should be measured on a regular basis to assure compliance with the applicable standards and verify that the protective equipment chosen is effective. Monitoring should follow the procedures outlined in the NIOSH Manual of Analytical Methods, Number 6701. Air-purifying respirators may be used if concentrations do not exceed 250 ppm. If concentrations exceed 250 ppm, a supplied air system must be used to provide maximum protection. The use of any respirator requires the implementation of a respiratory protection program in compliance with 29 CFR 1910.134.

Protective clothing should be provided to employees if there is any chance of skin or eye contact with solutions of more than 10 percent ammonia. Protective clothing includes goggles or face shields for face and eye protection and impervious clothing. Facilities should be provided for quick drenching of the skin and eyes of employees exposed to ammonia.

The utilization of ammonia will require the installation of one or more pressure vessels (anhydrous ammonia) or atmospheric tanks (aqueous ammonia). OSHA, in 29 CFR 1910.119, requires a stringent process safety review if 10,000 pounds of anhydrous ammonia or 15,000 pounds of aqueous ammonia (> 44 percent ammonia by weight) is stored in one location at the site. Compliance with the standard requires the preparation of a process safety analysis that is updated every 5 years. Other major requirements include: written operating procedures, employee training, pre-startup review, mechanical integrity checks, hot work permit system, incident investigation (releases), emergency action plan, and a compliance audit every 3 years.

Section 112 of the 1990 Clean Air Act Amendments proposes to regulate a number of highly toxic substances. Anhydrous and aqueous ammonia are both listed as compounds that may cause a threat to the public if released to the atmosphere. Regulated facilities must prepare a risk management plan which shall include a hazard assessment to predict the effect of any release. Other requirements include the development of worst-case release scenarios, training, monitoring, and actions to be taken in the event of a spill.