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

August 1992

Revision 1

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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.

NESCAUM / STAPPA-ALAPCO → 0.25 & 0.43

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

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

OIL /GAS

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 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)		Data Source
		Oil	Gas	
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 <u>existing</u> 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. <u>Equity</u>--considering the relative contribution of various types of sources to the problem,
2. <u>Efficiency</u>--considering how to get the maximum benefit for the investment made, and
3. <u>Effectiveness</u>--phasing in reductions in a programmed approach that allows effectiveness of reductions to be evaluated prior to additional requirements.

1.3 <u>FPL SOURCES</u>

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) (EACH)	NO_x Emission Rate ($lb/10^6$ Btu)		Data Source
		Oil	Gas	
Turkey Point (PTF) 1 & 2	2@402	0.78	0.56	FPL test data, April 1992
Lauderdale (PFL) 4 & 5[b]	2@156	0.45	0.55	AP-42
Port Everglades (PPE) 1 & 2	2@225	0.40	0.22	FPL test data, April 1992
Port Everglades (PPE) 3 & 4	2@402	0.77	0.55	FPL test data, March 1991
Riviera Beach (PRV) 3 & 4	2@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	24@ 34.2	0.82	0.43	FPL test data, May 1992
Port Everglades Gas Turbines (PPEGT) 1-12	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.

$\frac{702}{40.5} = 17.3$

$\boxed{\frac{351}{40.5} = 8.67}$

486 -

$40.5 - 12{,}400 \frac{\text{BTU}}{\text{KWH}}$

$= \frac{\overset{2}{500}\ \text{MMBTU/HR}}{40\ \text{MW}}$

VS. 702 MMBTU

Doug Scott - Eng.

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.

GG4A7

17-20 MW

2.2 1990 NO_x EMISSIONS

1971- 463.2 M.W.

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)].

SYSTEM-WIDE
BASELINE lb/10^6 BTU

OIL

4892.8 X .78 = 3816.4
7597.3 X .78 = 5925.9
2477.6 X .40 = 991.0
5452.8 X .40 = 2,181.1
12,815.2 X 0.74 = 9,483.2
7,321.2 X 0.74 = 5,417.7
3540.6 X 0.92 = 3,257.4
3012 X 0.92 = 2,771
193.3 X 0.82 = 158.5
99.8 X 0.82 = 81.8

$$\frac{34,083,900 \text{ lbs}}{47,402,600\ (10)^6 \text{ BTU}} = 0.719$$

GAS

5,973.4 X .56 = 3,345.1
11,596.0 X .56 = 6,493.8
7,815.8 X .22 = 1,719.5
5,557.1 X .22 = 1,222.6
9,746.1 X .52 = 5,068.
3,957.2 X .52 = 2,057.7
9,006.2 X .72 = 6,484.5
5,798.9 X .72 = 4,175.2
1,131.8 X .14 = 158.5
673.7 X .16 = 107.8
3132.6 X .43 = 1,347.0
985.5 X .43 = 423.8

$$\frac{32,603,500 \text{ lbs}}{65,374,300\ (10)^6 \text{ BTU}} = 0.49$$

N.D. = NO TEST DATA

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

Unit Name	%LOAD	Heat Input (10^9 Btu) Oil	Heat Input (10^9 Btu) Gas	%LOAD	NO_x Emission Rate (lb/10^6 Btu) Oil	NO_x Emission Rate (lb/10^6 Btu) Gas		NO_x Emissions (tons)	RACT
PTF-1	90	4,892.8	5,973.4	90	0.78 x 4892.8 = 3816 + 3345 = 7161 x 10³ / 2000 = 3580.7	0.56 x 5973.4 = 3345	9790.5 / 2 = 4895	3,580.7	
PTF-2	N.D.	7,597.3	11,596.0	N.D.	0.78	0.56		6,209.8	
PFL-4	N.D.	207.0	722.5	N.D.	0.45	0.55	1375.1	245.3	
PFL-5	N.D.	124.5	4,006.6	N.D.	0.45	0.55		1,129.8	
PPE-1	N.D.	2,477.6	7,815.8	N.D.	0.40	0.22	3057.1 / 2 = 1,529	1,355.3	LEA
PPE-2	80	5,452.8	5,557.1	85	0.40	0.22		1,701.8	LEA
PPE-3	75	12,815.2	9,746.1	80	0.7~~7~~4	0.5~~6~~3	11,520.9 / 2 = 5,760	7,614.0	
PPE-4	78	7,321.2	3,957.2	80	0.7~~7~~4	0.5~~8~~2		3,906.9	
PRV-3	90	3,540.6	9,006.2	100	0.92	0.72	8344 / 2 = 4,172	4,870.9	
PRV-4	N.D.	3,012.0	5,798.9	N.D.	0.92	0.72		3,473.1	
PCU-5		NA	1,131.8	80	NA	0.14		79.2	LEA
PCU-6		NA	673.7	85	NA	0.16		53.9	LEA
PFLGT (1-24)		193.3	3,132.6		0.82	0.43	752.8 / 2 = 376.4	752.8	
PPEGT (1-12)		99.8	985.5		0.82	0.43		252.8	
TOTAL		47,402.6 + 331.5 47,734.1	65,374.3 4,729.1 70,103.4					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.

47,402.6
65,374.3
112,776.9 $(10)^9$ BTU

33,851 X 2000 = 67,702,000 lb / 112,776,900 $(10)^6$ BTU = 0.60 SYSTEM WIDE BASELINE

1990 BTU

25,494 X 2000 = 50,988,000 / (43,415,000 + 64,623,800) = 0.47 SYSTEM WIDE PROPOSED

43,415,000
108,038,800

1995-2000 BTU

(.60 - .47) / .60 = 22%

112,776,900
50,114,800
162,891,700

38% = (162,891,700 - 117,837,500) / 117,837,500

Lauderdale BTU

	OIL	GAS
4 -	163.2	26,135.5
5 -	711.9	23,104.2
	875.1	49,239.7
		+ 875.1
		50,114,800

(112,776,900 - 108,038,800) / 112,776,900 = 4.2% drop in BTU for RACT ONLY 1990 vs. 1995-2000

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
PTF-1	3,580.7	10.2
PTF-2	6,209.8	17.6
PFL-4	245.3	0.7
PFL-5	1,129.8	3.2
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
PRV-3	4,870.9	13.8
PRV-4	3,473.1	9.9
PCU-5	79.2	0.2
PCU-6	53.9	0.2
PFLGT (1-24)	752.8	2.1
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.

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.

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.

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
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

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[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.

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

	Total		Incremental From LNBT	
Control Technology	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:

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, 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/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 REDUCTION (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.

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.

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.

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.

733
727
1460

DEP PROPOSED

	OIL		GAS	
PTF-1	7,253.4 × .53 = 3844.3	4698.5	600.2 × .40 = 240.1	276.3+4698.5 = 4974,800/2000 = 2487.4 →
PTF-2	10,476.8 × .53 = 5,552.7		781.2 × .40 = 312.5	
PPE-1	4,578.7 × .36 = 1,648.3	1713	3,261.5 × .20 = 652.3	647.8 +1713 = 2,410,758/2000 = 1205.4
PPE-2	4,938.3 × .36 = 1,777.8		3,715.8 × .20 = 743.2	
PPE-3	5,409.4 × .53 = 2,866.9	2808.3	15,277.4 × .40 = 6,110.9	5991+2808.3 = 8,799,3~~00~~/2000 → = 4400
PPE-4	5,188.1 × .53 = 2,749.7		14,677.8 × .40 = 5,871.1	
PRV-3	2,661.6 × ~~.55~~ .62 = ~~1,463.9~~ 1,650.19	1649.5 ~~1507.6~~	10,471.2 × ~~.43~~ .50 = ~~4,502.6~~ 5,235.6	5216.7+1699.5 ~~4486.3+1507.6~~ 6,916,150 ~~=5993,900~~/2000 = ~~2997~~ 3458 →
PRV-4	2,820.5 × ~~.55~~ .62 = ~~1,551.3~~ 1,748.7		10,395.4 × ~~.43~~ .50 = ~~4,470.~~ 5,197.7	
PCU-5	0		421.3 × .14 = 58.9	58,900/2000 = 29.45 →
PCU-6	0		2,188.8 × .16 = 350.2	350,200/2000 = 175 →
PFLGT	88.6 × .82 = 72.7		2,226.5 × .43 = 957.4	+ 72.7 = 1030,000/2000 = 515/2 = 257 each side
PPEGT	0		606.3 × .43 = 260.7	
	43,415.4	~~21,912~~ 21,527.6 25,258 ~~24,530~~ ~~47,169.7~~ ~~46,057.6~~	64,623.4	~~25,258~~ ~~24,530~~

43,415.4
64,623.4
108,038.8

$$\frac{47169.7 \;\; \cancel{46057.6}}{108{,}038.8} = \cancel{.426}\ .44$$

$$\frac{253-130}{253} = 49.$$

$$\frac{376-258}{376} = 31.4$$

$$\frac{.60-.42}{.60} = 30\%$$

$$\frac{35226-27978}{35226} = 21$$

$$\frac{33851-23022}{33851} = .32$$

$$\frac{35226-26998}{35226} = 23$$

$$\frac{33851-24001}{33851} = 0.29$$

6916
-5994
922
23079
24001

BTU/HR × 2.93 (10)^-4 = KW(H) 597.7 MW

(0.85) 2400 (10)^6 BTU/HR 2.93 (10)^-4 = KW = 597700 KW 1.19 (10)^9 BTU/HR

3414 BTU/KWH × 220,000 KW = 751. MM BTU/H ÷ .31 eff = 2400 BTU/HR

4578.7
3,261.5
7,840.2 (10)^9 BTU/YR × YR/4584 HR = 1.19 (10)^9

7253.4
600.2
7,853.6 (10)^9 BTU/YR × YR/3378 HR = 2.33 (10)^9 BTU/HR = 2,330 (10)^6 BTU/HR

12150C1
07/14/92

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	1990	Prop.	Projected 1995-2000 Average Heat Input (10^9 Btu)			Projected 1995-2000 NO_x Emissions (TPY)	
			Oil	Gas			
PTF-1	4895	2738	7,253.4×.59=4,279.5	252.1 600.2×.42	5747/2 = 2738	2,247.7	(4895-2738)/4895 = .44
PTF-2	4895	2738	10,476.8×.59=6,181.3	328.1 781.2×.42		3,228.5	
PFL-4	1375	X	3977.3 163.2	26,135.5	3977.3	2,072.5	
PFL-5		X	711.9	23,104.2		1,904.8	
PPE-1	1529	1202	4,578.7×.36=1,648.3	652.3 3,261.5×.20		1,147.1 ✓	(1,529-1202)/1,529 = .214
PPE-2	1529	1202	4,938.3×.36=1,777.8	743.2 3,715.8×.20	2,404/2 = 1202 avg for [illegible] 1,2	1,256.8 ✓	
PPE-3	5760	4619	5,409.4×.58=3,137.5	6,263.7 15,277.4×.41		4,712.9	(5760-4619)/5760 = 19.8
PPE-4	5760	4619	5,188.1×.58=3,009	6,017.9 14,677.8×.41	9238/2 = 4619	4,525.4	
PRV-3	4172	3763	2,661.6×.69=1836.5	5,654.4 10,471.2×.54	7525.3/2 = 3763	3,745.5	(4,172-3763)/4172 = 9.8
PRV-4	4172	3763	2,820.5×.69=1946.1	5613.5 10,395.4×.54		3,779.8	
PCU-5	79	102	0.0	84.3 421.3×.20 = 84,300/2000 = 42.1	102	29.5	? 42.1 (79-42)/.79 = 46.8
PCU-6	54	102	0.0	437.8 2,188.8×.20 = 437800/2000 = 218.9		175.1	? 218.9
PFLGT	752	516	88.6×.82= 72.7	957.4 2,226.5×.43	515/2 = 258	515.0	29.5 175.1 204.6 vs 261.0
PPEGT	253	130	0.0	260.7 606.3×.43	27265400/64,623,400 = .42	130.4	42.1 218.9 261.0 -204.6 56.4
TOTAL	33851 +1375 35,226	25,494 +3977 29,471	43,415.4/0.55 ⇒ 23,888,700 lbs/43,415,400 (10)^6 BTU			29,470.8	25494 25,550
Percent Reduction From Baseline (1990):			(33,851-25494)/33,851 = 25			16.3 [a]	

→ (4895-2487.4)/4895 = 49.2

→ (5760-4400)/5760 = 23.6

4172 3458 17
→ (3763-2997)/3763 4172 = 20.4

(79-29)/79 = 63.3

(72-.55)/.72 = 24%

[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.

43,415.4
64,623.4
108,038.8
vs. 112,776.9

4.2% drop

Difference is due to PFL 4 & 5

(35,226 - 29471)/35,226 = 16.3

23,888,700
+27,265,400
51,154,100/108,038,800 = .47 lb/mmBtu

(Same as p 2-5)

(112,776.9 - 108,038.8)/112,776.9 = 4.2%

CORRECTION FOR 4.2% DROP:

25494 × 112,776.9/108,038.8 = 26,612

(33851 - 26,612)/33851 = 21.4%

(.72-.50)/.72 = 30.6%

(.92-.62)/.92 = 32.6%

(x - .43)/x = .40

.4x = x - .43

.43 = .6x

x = .72

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

04/22/92

FLORIDA POWER AND LIGHT CO.
PLANT SERVICES OPERATIONS SUPPORT
NOx EMISSION RATE PTF UNIT 1

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

04/22/92

FLORIDA POWER AND LIGHT CO.
PLANT SERVICES OPERATIONS SUPPORT
NOx EMISSION RATE PTF UNIT 1

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 / C02/ 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

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 02

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 02	3.4
RUN 8 LB/MMBTU	0.560

02 / C02/ CO
3.4/10.1/138

PPE 2 NOx TEST DATA

UNIT #: 2 TEST #: 11 DATE: 4/7/92

TEST CONDITIONS: OIL 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 Δ P 6.6 " H_2O

S.H. TEMP E 980 /L 1003 °F STEAM FLOW 1500 lbs/Hr x 1000

REHEAT TEMP E 1000 /L 1000 °F F.W. FLOW 1500 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.
PORT EVERGLADES PLANT UNIT NO. 2

04/07/92

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 Δ P 8.35 " H_2O ↓

S.H. TEMP E 980 /L 1000 °F STEAM FLOW 1450 lbs/Hr x 1000

REHEAT TEMP E 1020 /L 990 °F F.W. FLOW 1480 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

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

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 ΔP 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

OP3/KTW6/PPE3NXBO.DRW
UPDATED: 4/1/91

OIL

EMISSION RATE SUMMARY
PORT EVERGLADES UNIT NO. 3

31 - .81 = 2.29

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

0.81

0.71

2.8 - .71 = 2.09

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

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 %

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.

GAS

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	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

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

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
					Excess O_2		
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 0.77	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 0.69	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

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 Δ P 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:

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 100 ~~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)

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: GAS 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 TO APH EAST 527 °F　　WEST 527 °F

GAS	OUTLET
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

05/05/92

FLORIDA POWER AND LIGHT CO.
PLANT SERVICES OPERATIONS SUPPORT
NOx EMISSION RATE PCU UNIT 5

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

05/05/92

FLORIDA POWER AND LIGHT CO.
PLANT SERVICES OPERATIONS SUPPORT
NOx EMISSION RATE PCU UNIT 5

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

02 / 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 Δ P 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

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

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

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

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

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

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

[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			EXXON'S QUOTE
Thermal $DeNO_x$ Component	Estimated[a]	2,312,536	1,760,000*
(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	592,000
(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.

* INCLUDES 280,000 for ENG,
500,000 OTHER INDIRECT
250,000 FIELD LABOR
730,000 EQUIP.
$ 1,760,000

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

[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

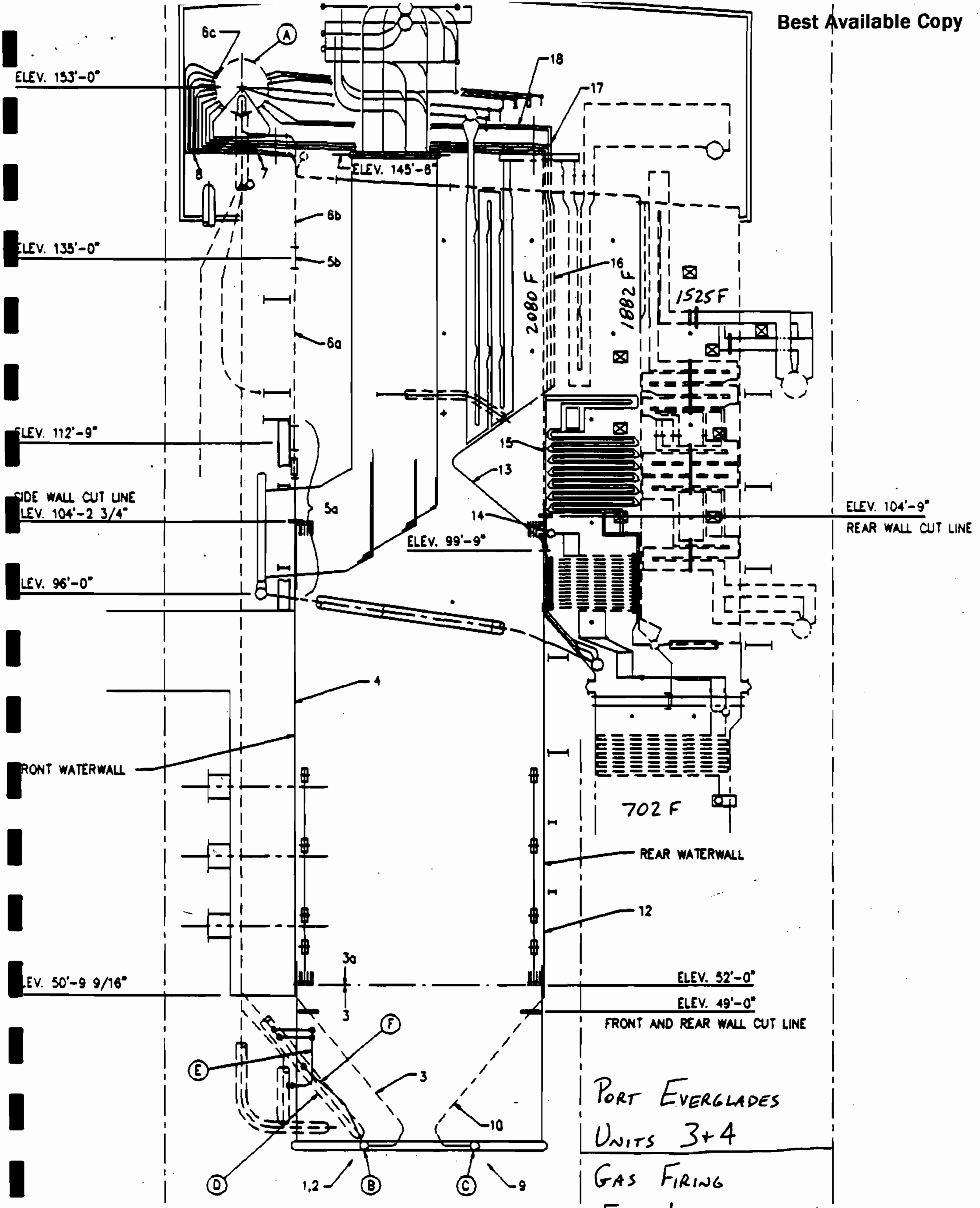
PORT EVERGLADES UNITS 3 & 4

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
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
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. DATE 7/13/92



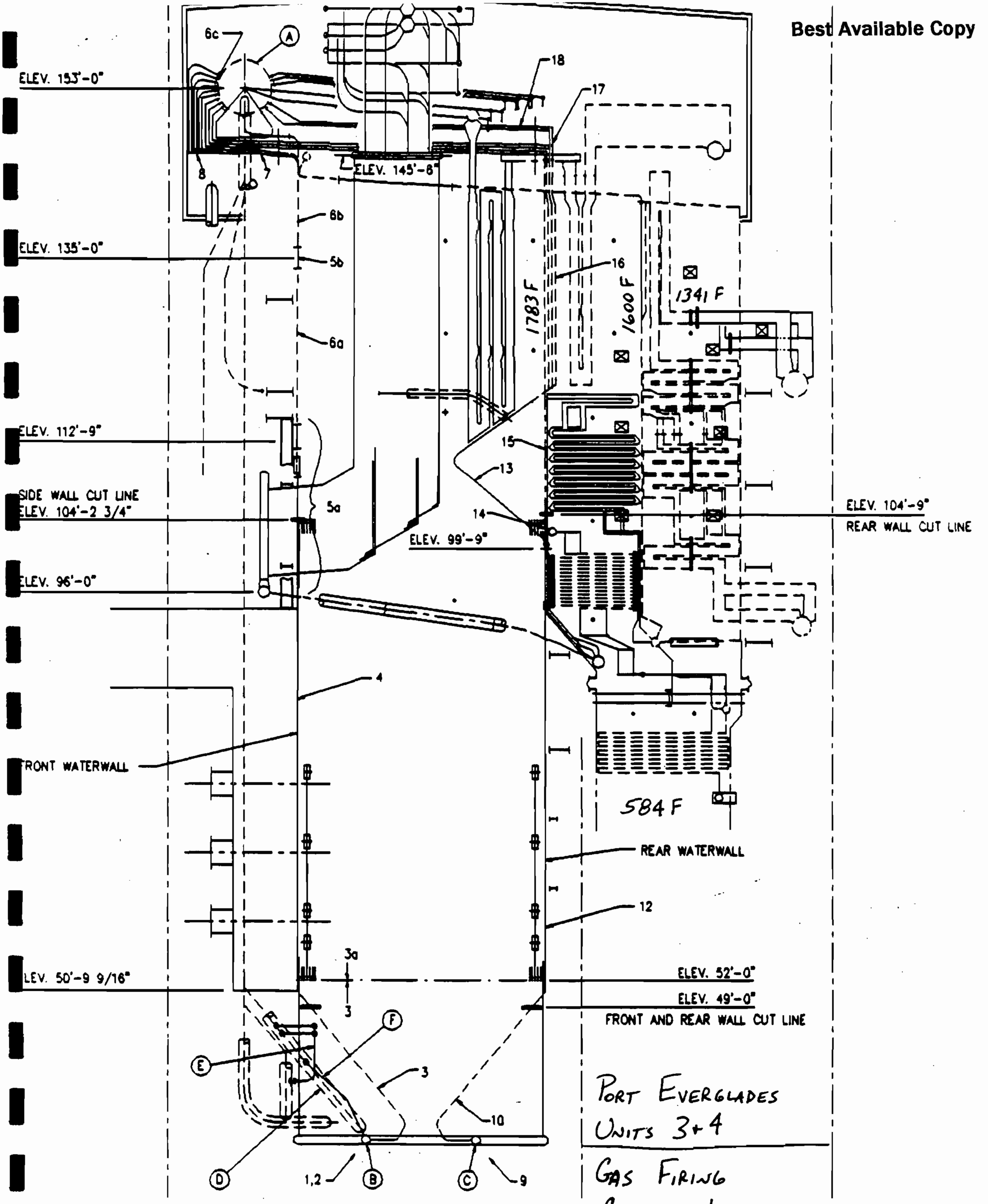
Port Everglades

Units 3+4

Gas Firing

Full Load

FIGURE 2

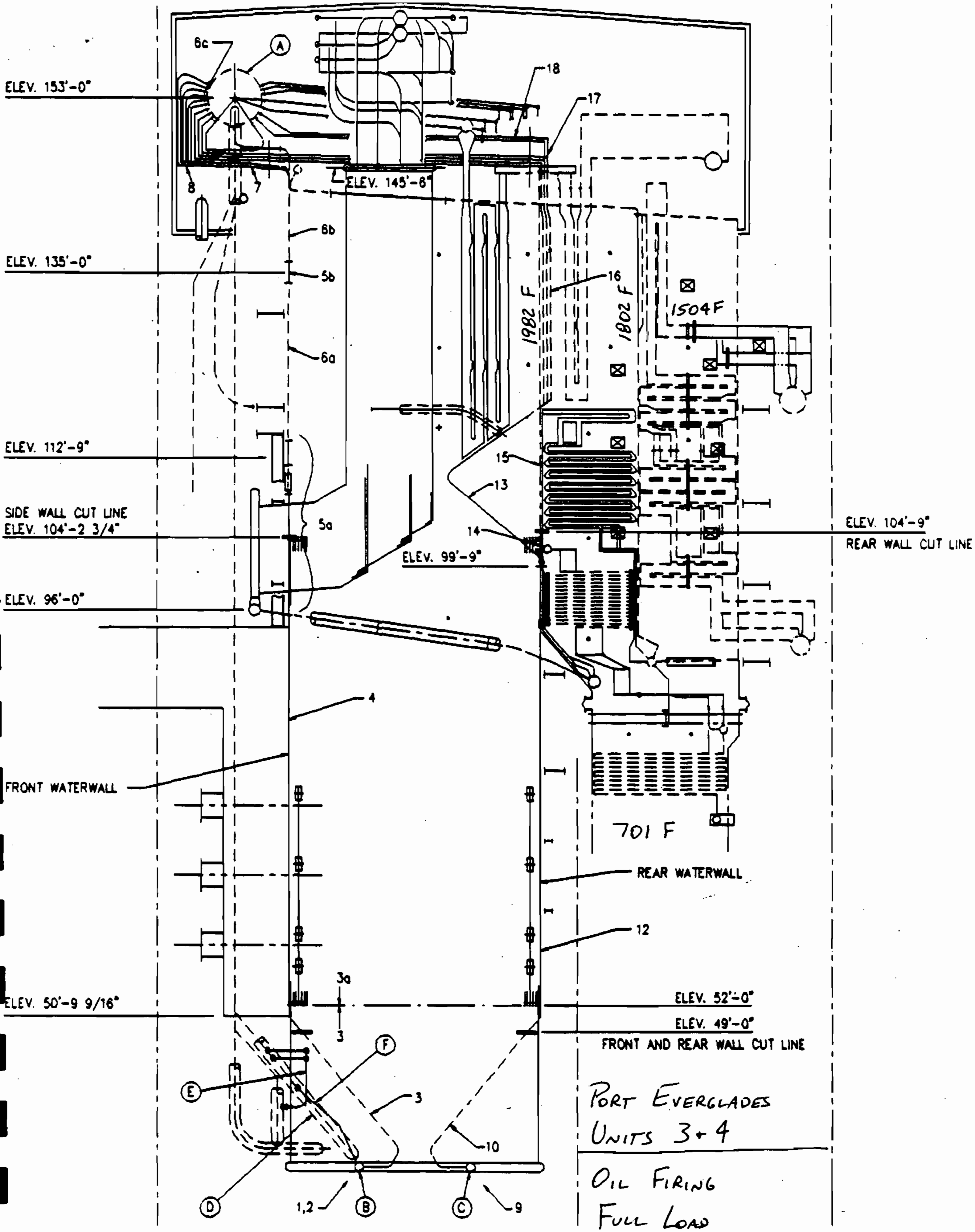


Port Everglades
Units 3+4

Gas Firing

FIGURE 2 Control Load

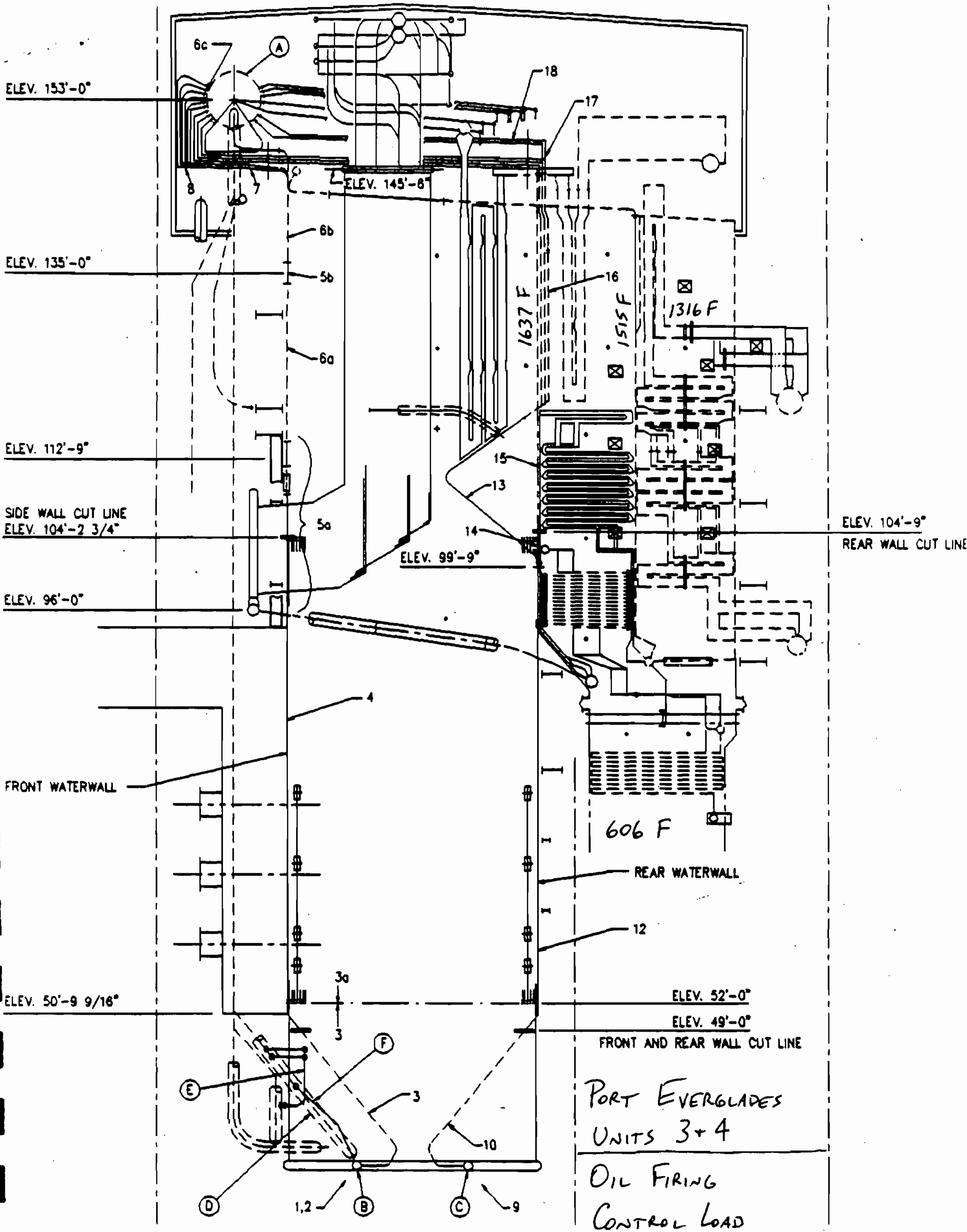
(SHEET 1 OF 1)



Port Everglades
Units 3+4

Oil Firing
Full Load

FIGURE 2



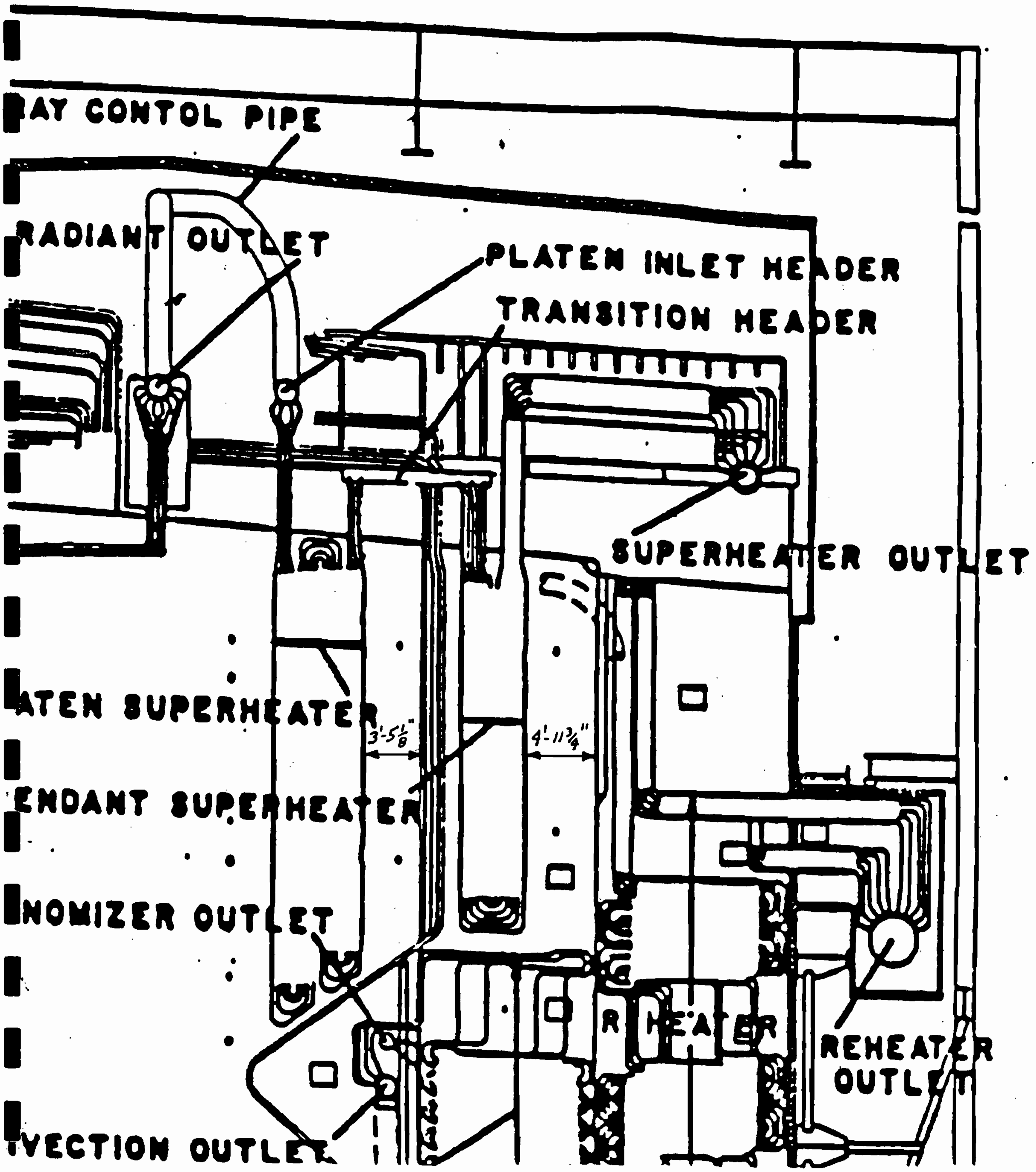
Port Everglades
Units 3+4

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	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	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	

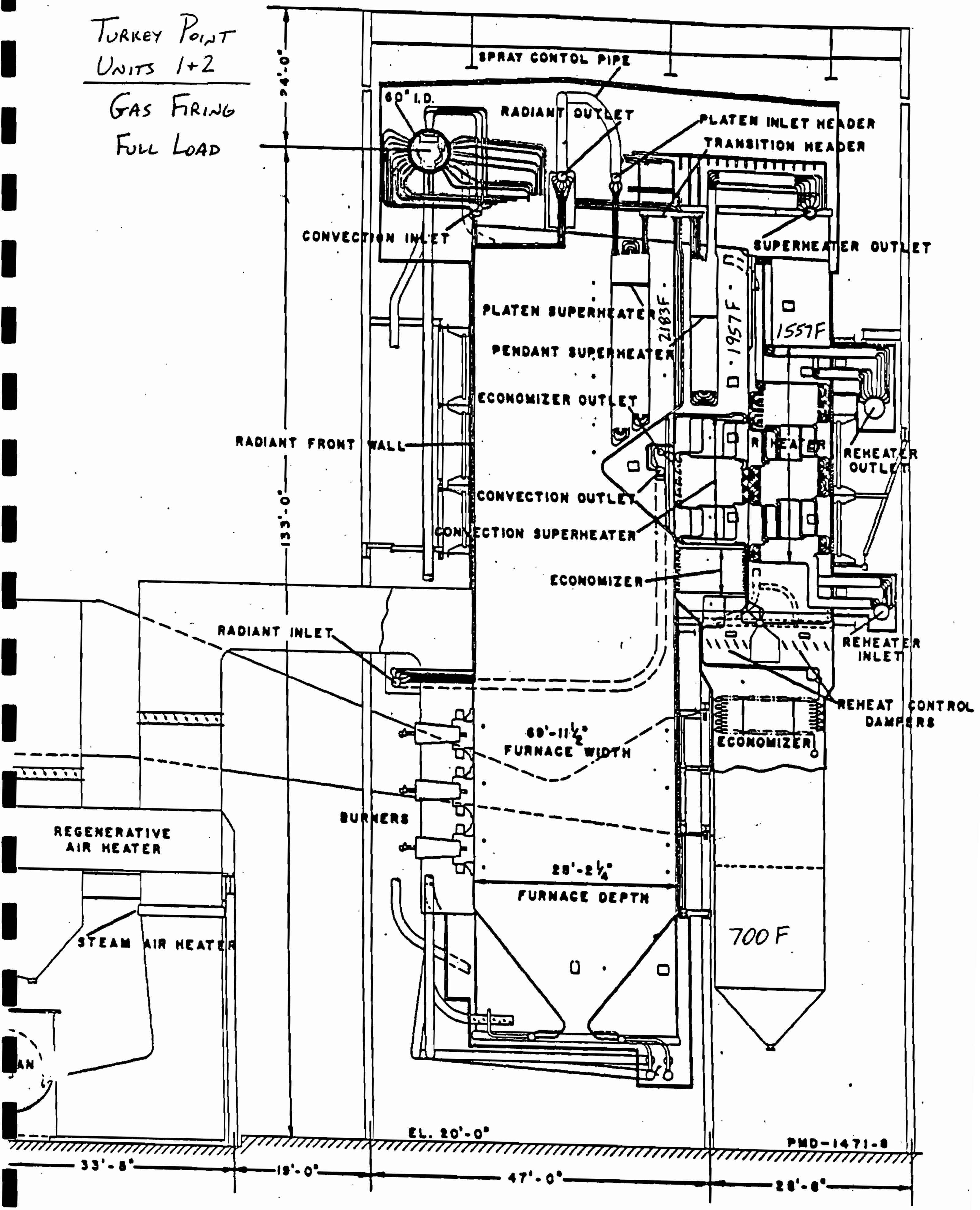
0.250 Req'd

0.250 req'd

PRELIMINARY

ENG. Al E [illegible] DATE 7/13/92

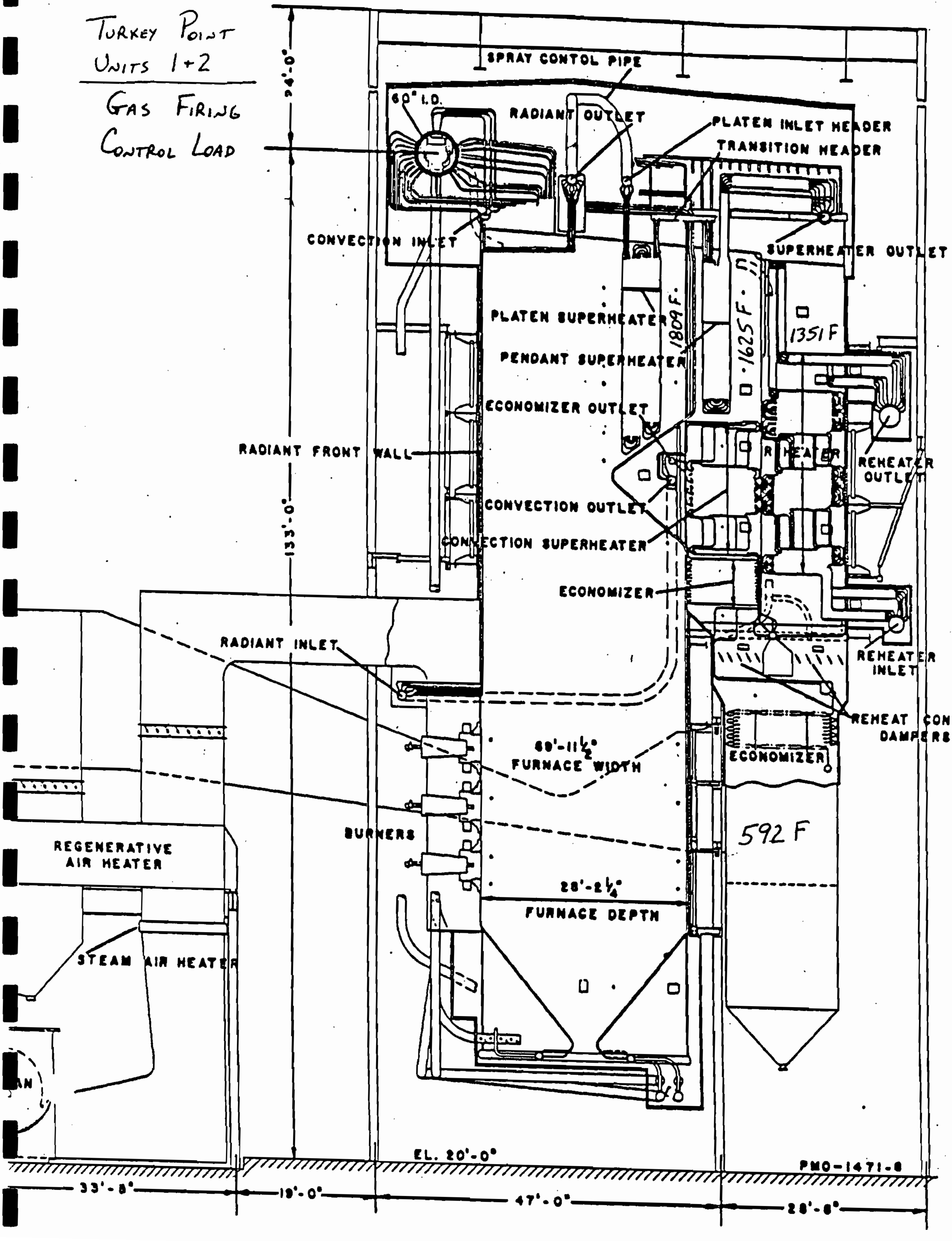
General Arrangement of Steam Generator



Turkey Point
Units 1+2

Gas Firing
Full Load

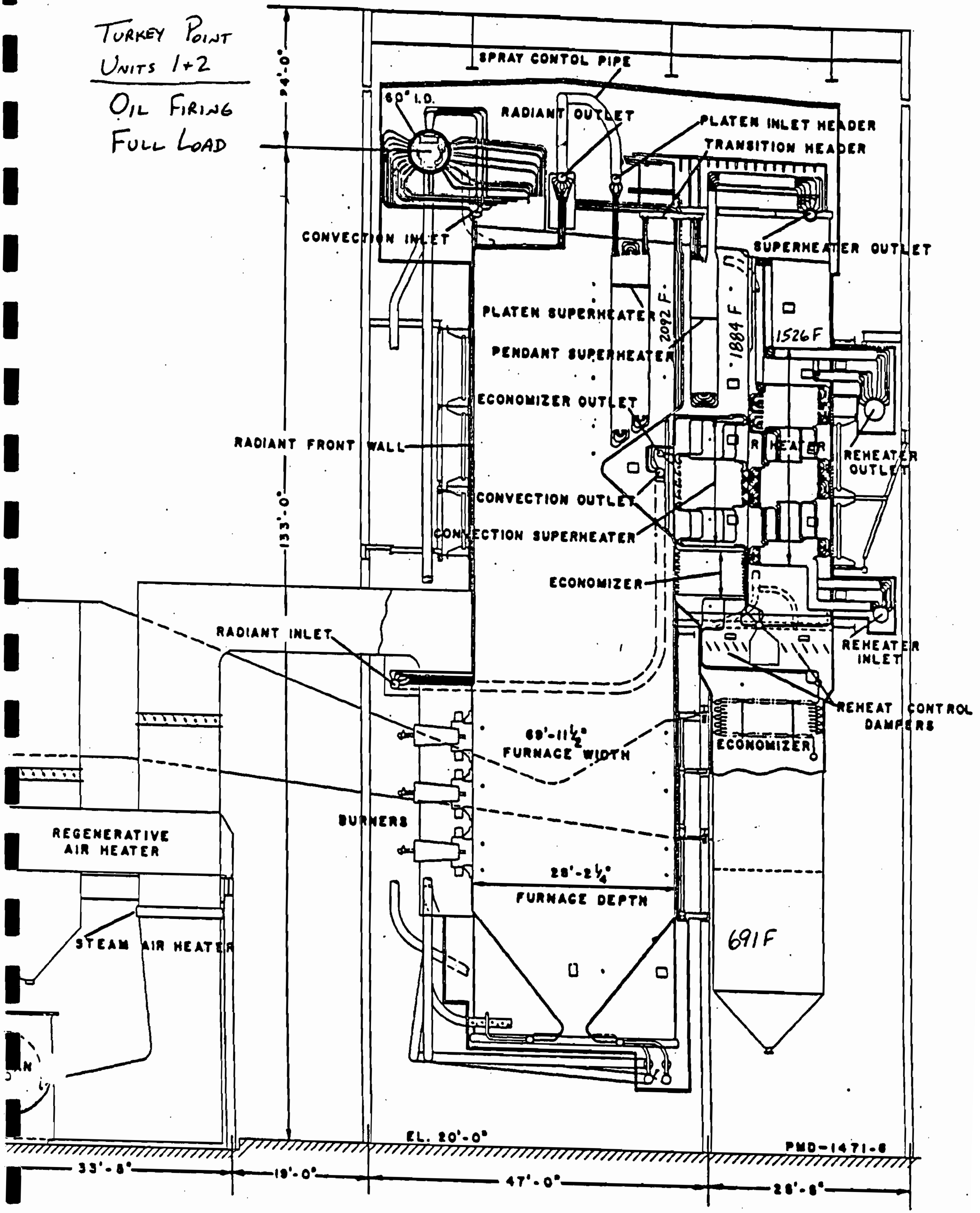
General Arrangement of Steam Generator



Turkey Point
Units 1+2

Gas Firing
Control Load

General Arrangement of Steam Generator



Turkey Point
Units 1+2

Oil Firing
Full Load

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.

APPENDIX E
PROPOSED RULE

DRAFT
6/29/92

Chapter 17-296
Stationary Sources - Emission Standards

17-296.200 Definitions.

The following words and phrases when used in this chapter shall, unless content clearly indicates otherwise, have the following meanings:

(1) through (48) No change.

(49) "Control Techniques Guidelines Document" or "CTG" - A guidance document issued by the U.S. Environmental Protection Agency under Section 183 of the Clean Air Act to define reasonably available control technology.

( ) "Fossil Fuel Steam Electric Generating Units"--Fossil fuel steam generators that supply steam primarily for the purpose of electrical generation.

( ) "Reasonable Further Progress (RFP)" - A level of annual incremental reductions in emissions of relevant air pollutants such as may be required for ensuring attainment of the applicable national ambient air quality standard by the applicable date.

(49) through (198) Renumber as (50) through (199).

Specific Authority: 403.061, F.S.

Law Implemented: 403.021, 403.031, 403.061, 403.087, F.S.

History: Formerly 17-2.100; Amended ________________.

17-296.500 Reasonably Available Control Technology (RACT) - Volatile Organic Compounds (VOC) and Nitrogen Oxides (NOx).

(1) Applicability.

(a) The specific emission limiting standards and other requirements of Rules 17-296.500 through 17-296.516, F.A.C., shall apply to existing VOC sources ~~of volatile organic compounds~~ in all designated ozone nonattainment and air quality maintenance areas. In addition, the emission limiting standards of these rules shall apply to new and modified VOC sources ~~of volatile organic compounds~~ in all designated ozone nonattainment and air quality maintenance areas except those new and modified VOC sources ~~of volatile organic compounds~~ subject to review pursuant to Rule 17-212.400 or 17-212.500, F.A.C.

(b) The general requirements of Rule 17-296.570, F.A.C., shall apply in moderate or higher designated ozone nonattainment areas to major VOC emitting facilities not regulated in whole under Rules 17-296.500 through 17-296.516, F.A.C., and major NOx emitting facilities, except those new and modified major VOC and NOx emitting facilities subject to review pursuant to Rule 17-296.400 or 17-296.500, F.A.C.

(2) through (6) No change.

Specific Authority: 403.061, F.S.

Law Implemented: 403.021, 403.031, 403.061, 403.087, F.S.

History: Formerly 17-2.650; Amended ____________________;

17-296.570 Reasonably Available Control Technology (RACT) - Requirements for Major VOC and NOx Emitting Facilities.

(1) Applicability.

(a) The requirements of this section shall apply only in moderate or higher designated ozone nonattainment areas.

(b) The requirements of this section shall apply to those existing VOC sources within major VOC emitting facilities which are not regulated under Rules 17-296.500 through 17-296.516, F.A.C., and to existing NOx sources within major NOx emitting facilities.

(c) The requirements of this section shall not remain in effect in any area that, subsequent to the effective date of this rule, is redesignated as attainment for ozone unless the Department, by rule, determines that such requirements are necessary to maintain attainment status.

(d) The requirements of this section shall not apply to sources subject to BACT emission limits for NOx or VOC established in construction permits issued subsequent to the date of enactment of the 1990 Clean Air Act Amendments.

(e) The requirements of the section shall not apply to sources that are exempt from the permitting requirements of this chapter and Chapter 17-4,F.A.C., pursuant to Rule 17-2.210(3).

(2) Compliance Requirements.

Sources subject to the requirements of this section shall comply with the operation permit requirements of Rule 17-296.570(3), F.A.C., and the RACT emission limiting standards determined pursuant to ~~the procedures of~~ Rule 17-296.570(4) or (5), F.A.C.

(3) Operation Permit Requirements.

(a) The owner or operator of any source subject to the requirements of this section shall apply for a new or revised permit to operate in accordance with the provisions of this section by March 1, 1993, unless a later filing date is specified by the Department in writing.

(b) If the existing operation permit for any source subject to the requirements of this section would expire between the effective date of this section and March 1, 1993, the expiration date of such permit is hereby extended until March 1, 1993. This provision shall not apply in the case of a revocation or suspension of such permit pursuant to Chapter 17-4, F.A.C.

(3) If, pursuant to Rule 17-296.570(1)(c), F.A.C., the requirements of this section do not remain in effect following redesignation of an area as attainment for ozone, operation permits issued under this section prior to such redesignation shall be revised accordingly.

(4) RACT Determination Procedure.

The procedure set forth in this section shall apply to all sources except those for which source-specific RACT standards are established under Rule 17-296.570(5), F.A.C.

(a) Sources Not Covered by a Control Techniques Guidelines (CTG) Document.

1. Each applicant for a new or revised operation permit under Rule 17-296.570(3), F.A.C., for a source for which the U. S. Environmental Protection Agency has not published a CTG document as of the effective date of this section shall have the option of proposing RACT emission limiting standards and/or RACT emission control technology to be imposed by the new or revised operation permit. In exercising this option, the applicant shall recommend a determination of RACT setting forth the basis for such determination and proposing a schedule for implementation of the recommended RACT measures as expeditiously as practicable but no later than May 31, 1995. The Department shall make a case-by-case determination of RACT based on the applicant's proposal, consistent with the definition of "Reasonably Available Control Technology" in Rule 17-2.100, F.A.C. In making its RACT determination, the Department ~~and~~ shall also give consideration to the following:

a. Emission limiting standards and/or emission control technology ~~required~~ established as RACT in the implementation plan of any state for such class or category of source in a nonattainment area with the same classification under Section 181(a)(1) of the Clean Air Act.

b. All scientific, engineering, economic, and technical material or other relevant information, including compliance test results from the affected source or substantially similar sources, that may be available to the Department.

c. The information contained in any applicable alternative control techniques document or other guidance published by the U. S. Environmental Protection Agency.

d. The technological feasibility of emission controls, recognizing design features of the existing source and engineering considerations relevant to retrofitting emission controls to the source.

e. The economic feasibility of emission control technology, including the cost-effectiveness of available technologies in reducing emissions of VOC or NOx (as applicable) from the source.

f. The net effect on overall air quality associated with available control technologies.

g. The extent to which any reduction in emissions resulting from implementation of the RACT proposal (in combination with implementation of RACT for any other sources owned or operated by the same entity in the same ozone nonattainment area) is consistent with reasonable further progress toward attainment of the AAQS for ozone.

h. Measured ozone concentrations in the nonattainment area in which the source is located and the classification of the area under Section 181(a)(1) of the Clean Air Act.

2. Any applicant for a revised operation permit for a non-CTG source who elects not to propose RACT emission limiting standards and/or RACT emission control technology to be imposed by the revised operation permit shall be subject to a RACT determination by the Department. Such determination of RACT shall

be made based on consideration of the criteria listed in Rule 17-296.570(4)(a)1.a. through ~~e~~ h., F.A.C., above.

(b) Sources covered by a Control Techniques Guidelines (CTG) Document.

~~a.~~1. Each applicant for a new or revised operation permit for a source for which the U. S. Environmental Protection Agency has published a CTG document as of the effective date of this section shall be required to propose RACT emission limiting standards and/or RACT emission control technology to be imposed by the new or revised operation permit that will be consistent with the recommendations set forth in the applicable CTG for the source. The Department shall make a determination of RACT based on the applicant's proposal and shall also give consideration to the following:

a. The information contained in any applicable CTG document published by the U. S. Environmental Protection Agency.

b. Emission limiting standards and/or emission control technology required in the implementation plan of any state for such class or category of source.

c. All scientific, engineering, economic, and technical material or other relevant information, including compliance test results from the affected source or substantially similar sources, that may be available to the Department.

d. The information contained in any applicable alternative control techniques document or other guidance published by the U. S. Environmental Protection Agency.

e. The technological feasibility of emission controls, recognizing design features of the existing source and engineering considerations relevant to retrofitting emission controls to the source.

f. The economic feasibility of emission control technology, including the cost-effectiveness of available technologies in reducing emissions of VOC or NOx (as applicable) from the source.

g. The net effect on overall air quality associated with available control technologies.

h. The extent to which any reduction in emissions resulting from implementation of the RACT proposal (in combination with implementation of RACT for any other sources owned or operated by the same entity in the same ozone nonattainment area) is consistent with reasonable further progress toward attainment of the AAQS for ozone.

i. Measured ozone concentrations in the nonattainment area in which the source is located and the classification of the area under Section 181(a) (1) of the Clean Air Act.

2. Any applicant for a revised operation permit for a CTG source who elects not to propose RACT emission limiting standards and/or RACT emission control technology to be imposed by the revised operation permit shall be subject to a RACT determination by the Department. Such determination of RACT shall be made based on consideration of the criteria listed in Rule 17-296.570(4)(b)1.a. through ~~d~~ i., F.A.C. above.

(c) Compliance Provisions.

1. NOx emission limits established under this section may include averaging times of up to 30 days for sources with continuous NOx emission monitoring systems.

2. In demonstrating compliance with NOx emission limits established under Rules 17-296.570(4) or (5), F.A.C., emissions from all sources subject to such limits that are owned or operated by the same entity may be averaged on a BTU-weighted basis.

(5) Source Specific RACT Standards

(a) Fossil Fuel Steam Electric Generating Units

1. Applicability

The requirements of this section apply to all fossil fuel fired steam electric generating units with a heat input greater than 250 million Btu per hour and located in a moderate or higher designated ozone nonattainment area.

2. Emission Limiting Standards for NOx

a. Natural gas and/or oil fired units with maximum NOx emission rates greater than 0.5 lb/million Btu heat input as of the date of enactment of the 1990 Amendments to the Clean Air Act shall not exceed a fuel specific emission limit reflecting a 25 percent reduction from the maximum emissions rates as of the enactment date.

b. Natural gas and/or oil fired units with maximum NOx emission rates greater than 0.2 lb/million Btu heat input but no greater than 0.5 lb/million Btu heat input as of the date of enactment of the 1990 Amendments to the Clean Air Act shall not exceed a fuel specific emission limit reflecting a 10 percent reduction from the maximum emissions rates as of the enactment date.

c. Natural gas and/or oil fired units with maximum NOx emission rates less than 0.2 lb/million Btu heat input as of the date of enactment of the 1990 Amendments to the Clean Air Act shall not exceed an emission rate of 0.2 lb/million Btu heat input.

3. Compliance Dates and Monitoring

a. Fuel specific NOx emission limits established under this section shall be incorporated into the operation permit for each unit after submittal of information (including representative test data) that provides reasonable assurance of the unit's maximum emission rate as of the enactment date.

b. Compliance with the emission limits established in this section must be demonstrated as expeditiously as practicable but no later than May 31, 1995, in accordance with a schedule specified in the unit's air operation permit issued pursuant to Rule 17-296.570(3).

c. For units that are not equipped with a continuous emission monitoring system (CEMS) for NOx, compliance with the emission limits established in this section shall be demonstrated by annual emission testing in accordance with EPA Reference Methods 7 or 7E.

d. For units that are equipped with a CEMS, compliance shall be demonstrated based on a 30 day rolling average. The CEMS must meet the performance specifications contained in 40 Code of Federal Regulations Part 60, Appendix B.

(b) Simple Cycle Combustion Turbine Electric Generating Units

1. Applicability

The requirements of this section apply to all simple cycle combustion turbine units greater than 25 MW and located in a moderate or higher designated ozone nonattainment area.

2. Emission Limiting Standards for NOx

a. Units with an annual capacity factor of greater than 10 percent shall not exceed a fuel specific emission limit reflecting a 25 percent reduction from the maximum emissions rates as of the enactment of the 1990 amendments of the Clean Air Act.

b. Units with an annual capacity factor of less than or equal to 10 percent shall not exceed a fuel specific emission limit reflecting the maximum emissions rates as of the enactment date of the 1990 amendments of the Clean Air Act.

3. Compliance Dates and Monitoring

a. Fuel specific NOx emission limits established under this section shall be incorporated into the operation permit for each unit after submittal of information (including representative test data) that provides reasonable assurance of the unit's maximum emission rate as of the enactment date.

b. Compliance with the emission limits established in this section must be demonstrated as expeditiously as practicable but no later than May 31, 1995, in accordance with a schedule specified in the unit's air operation permit issued pursuant to Rule 17-296.570(3).

c. Compliance with the emission limits established in this section shall be demonstrated by annual emission testing in accordance with EPA Reference Methods 7E or 20. For facilities with multiple similar units, compliance can be determined on a representative number of units.

(c) In demonstrating compliance with NOx emission limits established under Rules 17-296.570(4) or (5), F.A.C., emissions from all sources subject to such limits that are owned or operated by the same entity may be averaged on a BTU-weighted basis.

Specific Authority: 403.061, F.S.

Law Implemented: 403.021, 403.031, 403.061, 403.087, F.S.

History: New ____________________.