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H.D. KING ELECTRIC GENERATING PLANT

311 North Indian River Drive (34950)
Post Office Box 1298 (34954)
Fort Pierce, Florida
(407) 464-5792

October 23, 1990

FEDERAL EXPRESS

Florida Department of Environmental Regulation
Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Attn: Mr. C. H. Fancy

Dear Mr. Fancy:

Re: AC 56-185836 - Fort Pierce Utilities Authority - H. D. King, Unit 9

Enclosed is our response to your comment letter of September 28, 1990 and subsequent telephone clarifications regarding our permit to relicense Unit 9.

Your comment #12, Requested Construction Permits for Units 6, 7 & 8, we have reviewed our files and records, contacted former employees, and have not been able to locate a copy of any construction permits for these units. We have also contacted former employees of Reynolds, Smith & Hills which was our engineer of record in the past; however, their files have been purged and we are unable to obtain any information regarding construction permits from them. We have contacted the Florida Dept. of Environmental Regulation, Southeast District office regarding the possibility of construction permits in their files. We will research their archives within the next few days and will forward copies to your office of any construction permits we are able to locate.

We have attempted to formulate our responses based on the methodology approved most recently by the DER in the BACT determination for TECO's Hardee County permit. We believe that this consistency of analysis is important to both the DER and to applicants trying to comply with BACT analysis requirements.

We are most interested in discussing this with the DER further, to ensure that we are correctly applying the DER's policy decisions made during the Hardee County permit process.

Sincerely,

Harry Schindehette, P.E.
Director of Utilities

RECEIVED
OCT 24 1990
DER - BAQM

HL/HS:m

Enclosure
cc: Jack Miller
Harry Lamb

DER Comment 1

- o Please provide a completed State of Florida permit application form [DER Form 17-1.202(1)] that is signed by the owner or the owner's authorized agent. The permit application form is also to be signed and sealed with a metallic impression-type seal by a professional engineer registered in Florida.

Response

- o Attached please find a completed permit application form.

STATE OF FLORIDA

DEPARTMENT OF ENVIRONMENTAL REGULATION

RTHEAST DISTRICT

3426 BILLS ROAD
JACKSONVILLE, FLORIDA 32207

BOB GRAHAM
GOVERNOR

VICTORIA J. TSCHINKEL
SECRETARY

G. DOUG DUTTON
DISTRICT MANAGER

APPLICATION TO OPERATE/CONSTRUCT AIR POLLUTION SOURCES

SOURCE TYPE: Combustion Turbine [X] New[1] [ ] Existing[1]

APPLICATION TYPE: [X] Construction [ ] Operation [ ] Modification

COMPANY NAME: Fort Pierce Utilities Authority COUNTY: St. Lucie

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

SOURCE LOCATION: ~~Street~~ 311 North Indian River Drive City Fort Pierce

UTM: East 566.692 North 3036.292

Latitude 27 ° 27 ' 01 "N Longitude 80 ° 19 ' 29 "W

APPLICANT NAME AND TITLE: Harry Schindehette, Director

APPLICANT ADDRESS: FPUA, P.O. Box 3191, Fort Pierce, Florida 33448

SECTION I: STATEMENTS BY APPLICANT AND ENGINEER

A. APPLICANT

I am the undersigned owner or authorized representative* of Fort Pierce Utilities Authorities

I certify that the statements made in this application for a Construction permit are true, correct and complete to the best of my knowledge and belief. Further I agree to maintain and operate the pollution control source and pollution control facilities in such a manner as to comply with the provision of Chapter 403, Florida Statutes, and all the rules and regulations of the department and revisions thereof. I also understand that a permit, if granted by the department, will be non-transferable and I will promptly notify the department upon sale or legal transfer of the permitted establishment.

*Attach letter of authorization

Signed: [signature]

Harry Schindehette, Director
Name and Title (Please Type)

Date: 0-23-90 Telephone No. (305)464-5600

B. PROFESSIONAL ENGINEER REGISTERED IN FLORIDA (where required by Chapter 471, F.S.)

This is to certify that the engineering features of this pollution control project have been designed/examined by me and found to be in conformity with modern engineering principles applicable to the treatment and disposal of pollutants characterized in the permit application. There is reasonable assurance, in my professional judgment, th

[1] See Florida Administrative Code Rule 17-2.100(57) and (104)

the pollution control facilities, when properly maintained and operated, will discharge an effluent that complies with all applicable statutes of the State of Florida and the rules and regulations of the department. It is also agreed that the undersigned will furnish, if authorized by the owner, the applicant a set of instructions for the proper maintenance and operation of the pollution control facilities and, if applicable, pollution sources.

Signed [signature]

Steven M. Day
Name (Please Type)

Black & Veatch
Company Name (Please Type)

P. O. Box 8405, Kansas City, MO 64114
Mailing Address (Please Type)

Florida Registration No. 43028 Date: 10/19/90 Telephone No. (913)339-2880

SECTION II: GENERAL PROJECT INFORMATION

A. Describe the nature and extent of the project. Refer to pollution control equipment, and expected improvements in source performance as a result of installation. State whether the project will result in full compliance. Attach additional sheet if necessary.

See Section 2.0 of the AAQIA (Attachment 1) & the revised BACT Analysis (Attachment 2). The project will result in full compliance with all applicable regulations.

B. Schedule of project covered in this application (Construction Permit Application Only)

Start of Construction April 1988 Completion of Construction January 1990

C. Costs of pollution control system(s): (Note: Show breakdown of estimated costs only for individual components/units of the project serving pollution control purposes. Information on actual costs shall be furnished with the application for operation permit.)

See Attachment 2. Note that steam injection for reduction of NO_x emissions is an integral part of the gas turbine.

D. Indicate any previous DER permits, orders and notices associated with the emission point, including permit issuance and expiration dates.

Permit to Construct: AC 56-141460 Issued March 28, 1990

Permit to Operate: AO 56-175955 Issued May 1, 1990

Expires March 30, 1995

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E. Requested permitted equipment operating time: hrs/day 24 ; days/wk 7 ; wks/yr 52

if power plant, hrs/yr 8760 ; if seasonal, describe: N/A

F. If this is a new source or major modification, answer the following questions. (Yes or No)

1. Is this source in a non-attainment area for a particular pollutant? No

a. If yes, has "offset" been applied?

b. If yes, has "Lowest Achievable Emission Rate" been applied?

c. If yes, list non-attainment pollutants.

2. Does best available control technology (BACT) apply to this source? If yes, see Section VI. Yes

3. Does the State "Prevention of Significant Deterioriation" (PSD) requirement apply to this source? If yes, see Sections VI and VII. Yes

4. Do "Standards of Performance for New Stationary Sources" (NSPS) apply to this source? Yes

5. Do "National Emission Standards for Hazardous Air Pollutants" (NESHAP) apply to this source? No

H. Do "Reasonably Available Control Technology" (RACT) requirements apply to this source? No

a. If yes, for what pollutants? N/A

b. If yes, in addition to the information required in this form, any information requested in Rule 17-2.650 must be submitted.

Attach all supportive information related to any answer of "Yes". Attach any justification for any answer of "No" that might be considered questionable.

SECTION III: AIR POLLUTION SOURCES & CONTROL DEVICES (Other than Incinerators)

A. Raw Materials and Chemicals Used in your Process, if applicable:

Description	Contaminants Type	Contaminants % Wt	Utilization Rate - lbs/hr	Relate to Flow Diagram
Water	(NA - No	Emissions	from Water)	

B. Process Rate, if applicable: (See Section V, Item 1)

1. Total Process Input Rate (lbs/hr): NA

2. Product Weight (lbs/hr): NA

C. Airborne Contaminants Emitted: (Information in this table must be submitted for each emission point, use additional sheets as necessary)

Name of Contaminant	Emission[1] Maximum lbs/hr	Emission[1] Actual T/yr	Allowed[2] Emission Rate per Rule 17-2	Allowable[3] Emission lbs/hr	Potential[4] Emission lbs/yr	Potential[4] Emission T/yr	Relate to Flow Diagram
Particulates	2.5	11.0	NA				
SO_x	0.2	0.9	150 ppmdv				
NO_x	58.9	258.0	268.4 *				
VOC	2.4	10.5	NA				
CO	8.5	37.2	41.6 NA				

[1] See Section V, Item 2.

[2] Reference applicable emission standards and units (e.g. Rule 17-2.600(5)(b)2. Table II, E. (1) - 0.1 pounds per million BTU heat input)

[3] Calculated from operating rate and applicable standard.

[4] Emission, if source operated without control (See Section V, Item 3).

*New Source Performance Standards for combustion turbines (40 CFR 60 Subpart GG) limits NO_x to 75 ppmdv at 15% O_2, corrected for fuel nitrogen content and turbine heat rate, or 84 ppmdv at 15% O_2, whichever is more stringent.

D. Control Devices: (See Section V, Item 4)

Name and Type (Model & Serial No.)	Contaminant	Efficiency	Range of Particles Size Collected (in microns) (If applicable)	Basis for Efficiency (Section V Item 5)
	See Attachment 2. NO_x emissions control by steam injection			
is an integral part of the gas turbine				

E. Fuels

Type (Be Specific)	Consumption*		Maximum Heat Input (MMBTU/hr)
	avg/hr	max./hr	
Natural Gas		0.380	353
		(@20 F	Ambient Conditions)
No. 2 Fuel Oil		2672	350
(Emergency Backup)		(@20 F	Ambient Conditions)

*Units: Natural Gas--MMCF/hr; Fuel Oils--gallons/hr; Coal, wood, refuse, other--lbs/hr.

Fuel Analysis: Natural Gas

Percent Sulfur: 2000 gr/MMCF Percent Ash: Nil

Density: 0.0446 lb/SCF XXXXXXX Typical Percent Nitrogen: 0.71%

Heat Capacity: 20,860 BTU/lb 930 Btu/SCF XXXXXXX

Other Fuel Contaminants (which may cause air pollution): See Section 3.3 of the AAQIA (Attachment 1) and Attachment 2.

F. If applicable, indicate the percent of fuel used for space heating.

Annual Average NA Maximum NA

G. Indicate liquid or solid wastes generated and method of disposal.

NA

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H. Emission Stack Geometry and Flow Characteristics (Provide data for each stack): *

Stack Height: ______ ft. Stack Diameter: ______ ft

Gas Flow Rate: ______ ACFM ______ DSCFM Gas Exit Temperature: ______ °F

Water Vapor Content: ______ % Velocity: ______ FP

*See Attachment 3 for HRSG and Bypass Stack Characteristics.

SECTION IV: INCINERATOR INFORMATION

NA

Type of Waste	Type 0 (Plastics)	Type I (Rubbish)	Type II (Refuse)	Type III (Garbage)	Type IV (Pathological)	Type V (Liq.& Gas By-prod.)	Type VI (Solid By-prod.)
Actual lb/hr Incinerated							
Uncontrolled (lbs/hr)							

Description of Waste ______

Total Weight Incinerated (lbs/hr) ______ Design Capacity (lbs/hr) ______

Approximate Number of Hours of Operation per day ______ day/wk ______ wks/yr. ______

Manufacturer ______

Date Constructed ______ Model No. ______

	Volume (ft)^3	Heat Release (BTU/hr)	Fuel		Temperature (°F)
			Type	BTU/hr	
Primary Chamber					
Secondary Chamber					

Stack Height: ______ ft. Stack Diameter: ______ Stack Temp. ______

Gas Flow Rate: ______ ACFM ______ DSCFM* Velocity: ______ FPS

*If 50 or more tons per day design capacity, submit the emissions rate in grains per standard cubic foot dry gas corrected to 50% excess air.

Type of pollution control device: [ ] Cyclone [ ] Wet Scrubber [ ] Afterburner

[ ] Other (specify) ______

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Brief description of operating characteristics of control devices: ________________

____

____

____

____

Ultimate disposal of any effluent other than that emitted from the stack (scrubber water, ash, etc.):

____

____

____

____

NOTE: Items 2, 3, 4, 6, 7, 8, and 10 in Section V must be included where applicable.

SECTION V: SUPPLEMENTAL REQUIREMENTS

Please provide the following supplements where required for this application.

1. Total process input rate and product weight -- show derivation [Rule 17-2.100(127)]

2. To a construction application, attach basis of emission estimate (e.g., design calculations, design drawings, pertinent manufacturer's test data, etc.) and attach proposed methods (e.g., FR Part 60 Methods 1, 2, 3, 4, 5) to show proof of compliance with applicable standards. To an operation application, attach test results or methods used to show proof of compliance. Information provided when applying for an operation permit from a construction permit shall be indicative of the time at which the test was made. See AAQIA (Attachment 1) and calculations included in Attachment 4.

3. Attach basis of potential discharge (e.g., emission factor, that is, AP42 test). See Attachment 4

4. With construction permit application, include design details for all air pollution control systems (e.g., for baghouse include cloth to air ratio; for scrubber include cross-section sketch, design pressure drop, etc.) See Attachment 2

5. With construction permit application, attach derivation of control device(s) efficiency. Include test or design data. Items 2, 3 and 5 should be consistent: actual emissions = potential (1-efficiency). See Attachment 2

6. An 8 1/2" x 11" flow diagram which will, without revealing trade secrets, identify the individual operations and/or processes. Indicate where raw materials enter, where solid and liquid waste exit, where gaseous emissions and/or airborne particles are evolved and where finished products are obtained. See Attachment 5.

7. An 8 1/2" x 11" plot plan showing the location of the establishment, and points of airborne emissions, in relation to the surrounding area, residences and other permanent structures and roadways (Example: Copy of relevant portion of USGS topographic map). See Figure 2-1 in the AAQIA (Attachment 1)

8. An 8 1/2" x 11" plot plan of facility showing the location of manufacturing processes and outlets for airborne emissions. Relate all flows to the flow diagram. See Figure 2-2 in the AAQIA (Attachment 1)

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9. The appropriate application fee in accordance with Rule 17-4.05. The check should [be] made payable to the Department of Environmental Regulation.
Fee has already been submitted.

10. With an application for operation permit, attach a Certificate of Completion of Construction indicating that the source was constructed as shown in the construction permit.

SECTION VI: BEST AVAILABLE CONTROL TECHNOLOGY

A. Are standards of performance for new stationary sources pursuant to 40 C.F.R. Part [ ] applicable to the source?

[X] Yes [ ] No

Contaminant	Rate or Concentration
SO_2	150 ppmvd at 15% O_2
NO_x	*

*75 ppmvd at 15% O_2 corrected for nitrogen content and heat rate, or 84 ppmdv at 15% O_2.

B. Has EPA declared the best available control technology for this class of sources (If yes, attach copy)

[ ] Yes [X] No Case-by-case determination

Contaminant	Rate or Concentration

C. What emission levels do you propose as best available control technology?

Contaminant	Rate or Concentration
See Attachment 2.	
NOx	42 ppmvd at 15% O_2 (Natural Gas)

D. Describe the existing control and treatment technology (if any).

See Attachment 2

1. Control Device/System:
2. Operating Principles:
3. Efficiency:*
4. Capital Costs:

*Explain method of determining

5. Useful Life:

6. Operating Costs:

7. Energy:

8. Maintenance Cost:

9. Emissions:

Contaminant	Rate or Concentration

10. Stack Parameters

a. Height: ft.

b. Diameter: ft.

c. Flow Rate: ACFM

d. Temperature: °F.

e. Velocity: FPS

E. Describe the control and treatment technology available (As many types as applicable, use additional pages if necessary).

1. See Attachment 2

a. Control Device:

b. Operating Principles:

c. Efficiency:[1]

d. Capital Cost:

e. Useful Life:

f. Operating Cost:

g. Energy:[2]

h. Maintenance Cost:

i. Availability of construction materials and process chemicals:

j. Applicability to manufacturing processes:

k. Ability to construct with control device, install in available space, and operate within proposed levels:

2.

a. Control Device:

b. Operating Principles:

c. Efficiency:[1]

d. Capital Cost:

e. Useful Life:

f. Operating Cost:

g. Energy:[2]

h. Maintenance Cost:

i. Availability of construction materials and process chemicals:

[1]Explain method of determining efficiency.
[2]Energy to be reported in units of electrical power - KWH design rate.

j. Applicability to manufacturing processes:

k. Ability to construct with control device, install in available space, and operat within proposed levels:

3.

a. Control Device:

b. Operating Principles:

c. Efficiency:[1]

d. Capital Cost:

e. Useful Life:

f. Operating Cost:

g. Energy:[2]

h. Maintenance Cost:

i. Availability of construction materials and process chemicals:

j. Applicability to manufacturing processes:

k. Ability to construct with control device, install in available space, and operat within proposed levels:

4.

a. Control Device:

b. Operating Principles:

c. Efficiency:[1]

d. Capital Costs:

e. Useful Life:

f. Operating Cost:

g. Energy:[2]

h. Maintenance Cost:

i. Availability of construction materials and process chemicals:

j. Applicability to manufacturing processes:

k. Ability to construct with control device, install in available space, and operat within proposed levels:

F. Describe the control technology selected: See Attachment 2

1. Control Device:

2. Efficiency:[1]

3. Capital Cost:

4. Useful Life:

5. Operating Cost:

6. Energy:[2]

7. Maintenance Cost:

8. Manufacturer:

9. Other locations where employed on similar processes:

a. (1) Company:

(2) Mailing Address:

(3) City:

(4) State:

Explain method of determining efficiency.
Energy to be reported in units of electrical power - KWH design rate.

(5) Environmental Manager:

(6) Telephone No.:

(7) Emissions:[1]

Contaminant	Rate or Concentration

(8) Process Rate:[1]

b. (1) Company:

(2) Mailing Address:

(3) City: (4) State:

(5) Environmental Manager:

(6) Telephone No.:

(7) Emissions:[1]

Contaminant	Rate or Concentration

(8) Process Rate:[1]

10. Reason for selection and description of systems:

[1] Applicant must provide this information when available. Should this information not [illegible] available, applicant must state the reason(s) why.

SECTION VII - PREVENTION OF SIGNIFICANT DETERIORATION

See Section 6.5 of the AAQIA (Attachment 1)

A. Company Monitored Data

1. ________ no. sites ________ TSP ________ ( ) SO^2* ________ Wind spd/dir

Period of Monitoring ____/____/____ to ____/____/____
month day year month day year

Other data recorded ________________

Attach all data or statistical summaries to this application.

*Specify bubbler (B) or continuous (C).

2. Instrumentation, Field and Laboratory

a. Was instrumentation EPA referenced or its equivalent? [ ] Yes [ ] No

b. Was instrumentation calibrated in accordance with Department procedures?

[ ] Yes [ ] No [ ] Unknown

8. Meteorological Data Used for Air Quality Modeling See Section 5.5 of the AAQIA (Attachment 1)

1. ______ Year(s) of data from ______________ to ______________
month day year month day year

2. Surface data obtained from (location) ______________

3. Upper air (mixing height) data obtained from (location) ______________

4. Stability wind rose (STAR) data obtained from (location) ______________

. Computer Models Used See Section 5.3 of the AAQIA

1. ______________ Modified? If yes, attach description.

2. ______________ Modified? If yes, attach description.

3. ______________ Modified? If yes, attach description.

4. ______________ Modified? If yes, attach description.

Attach copies of all final model runs showing input data, receptor locations, and principle output tables.

Applicants Maximum Allowable Emission Data See Section 5.2 of the AAQIA (Attachment 1)

Pollutant	Emission Rate	
TSP	______________	grams/sec
SO^2	______________	grams/sec

Emission Data Used in Modeling *

Attach list of emission sources. Emission data required is source name, description o point source (on NEDS point number), UTM coordinates, stack data, allowable emissions and normal operating time.

Attach all other information supportive to the PSD review. *

Discuss the social and economic impact of the selected technology versus other applicable technologies (i.e., jobs, payroll, production, taxes, energy, etc.). Include assessment of the environmental impact of the sources.*

Attach scientific, engineering, and technical material, reports, publications, journals, and other competent relevant information describing the theory and application o the requested best available control technology.

* E-H: See AAQIA (Attachment 1) for detail.

ATTACHMENT 1

AMBIENT AIR QUALITY IMPACT ANALYSIS (AAQIA)
AUGUST 1990

FORT PIERCE UTILITIES AUTHORITY
H. D. KING UNIT 9

PREVENTION OF SIGNIFICANT DETERIORATION
(PSD)
APPLICATION

B&V PROJECT 16589.070
AUGUST 1990

Black & Veatch
Engineers-Architects

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APPENDIX A DIRECTION-SPECIFIC BUILDING ANALYSIS

1.0 INTRODUCTION

On May 1, 1990, the Fort Pierce Utilities Authority (FPUA) was issued a permit (AO 56-175955) by the Florida Department of Environmental Regulation (FDER) for the operation of a 31.6 MW combined cycle gas turbine at the H. D. King power plant in Fort Pierce, Florida. This combined cycle system (Unit 9 and 5) consists of a 23.4 MW natural gas fired combustion turbine generator, steam generator, and an 8.2 MW condensing steam turbine. Unit 9 commenced operation in early 1989; the final operating permit was issued in early 1990.

In the Unit 9 construction permit, the operating hours for the existing H. D. King Units 6, 7, and 8 were restricted such that the net increase of all regulated pollutants were below Prevention of Significant Deterioration (PSD) significant emission increases. Therefore, Unit 9 was previously not subject to PSD regulations. Due to increased electricity demands, it is now necessary to remove the operational limitation for Units 6, 7, and 8 that were imposed in the original Unit 9 permit. If the Unit 9 permit operational restrictions on Unit 6, 7, and 8 are removed, then Unit 9 requires repermitting subject to PSD regulations.

This report describes the PSD applicability and modeling methodology for air quality permitting of the Unit 9 combined cycle system. The permit methodology assumes that Units 6, 7, and 8 can operate at the levels described in their respective permits (AO-56-113534, AO-56-112679, and AO-56-112678). The purpose of this analysis is to demonstrate that the combustion turbine will not cause or contribute to an exceedance of any national or state ambient air quality standards and will not consume more than the applicable amount of Prevention of Significant Deterioration (PSD) air quality increment. A Workplan which described the proposed methodology to be followed in this analysis was discussed with the appropriate FDER staff on July 24, 1990.

2.0 PROJECT DESCRIPTION

The FPUA Project is located in St. Lucie County, Florida, on land currently owned by the FPUA. The land is zoned M-1 and is adjacent to the Indian River. A project site location map is shown in Figure 2-1. The approximate Universal Transverse Mercator (UTM) coordinates of the facility are: 566.8 kilometers (East) and 3,036.3 kilometers (North). The project site arrangement is shown in Figure 2-2.

The combined cycle system includes a 23.4 MW combustion turbine (CT), a steam generator, and an 8.2 MW condensing steam turbine. The CT will burn natural gas as the primary fuel. No. 2 fuel oil (distillate) will only be used as emergency backup fuel. Emergency fuel is defined in Subpart GG, Standard of Performance for Stationary Gas Turbines, 40 CFR 60.331.

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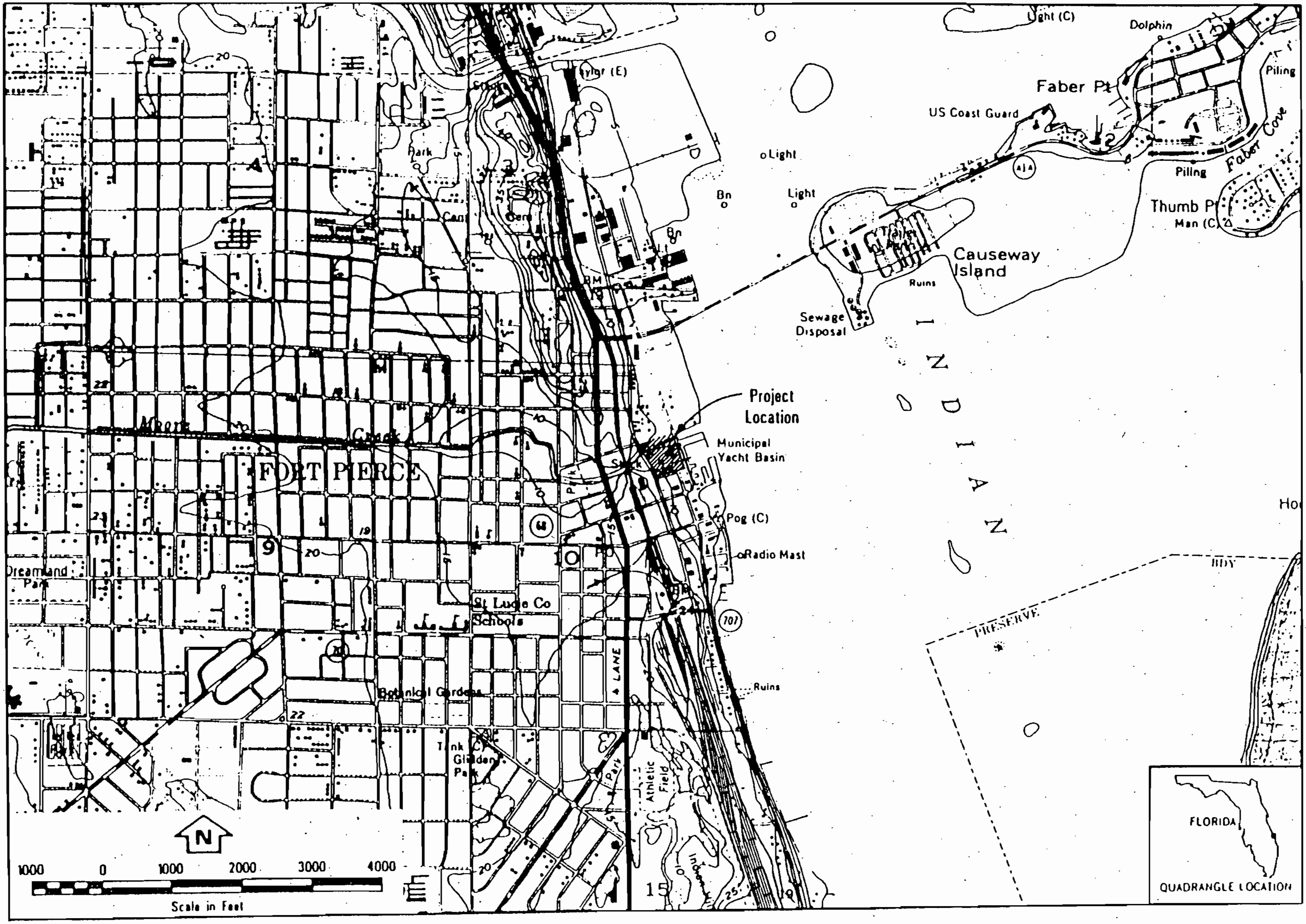


Base Map Source: USGS,
Fort Pierce, FL Quadrangle, 1983

PROJECT SITE LOCATION

Figure 2-1

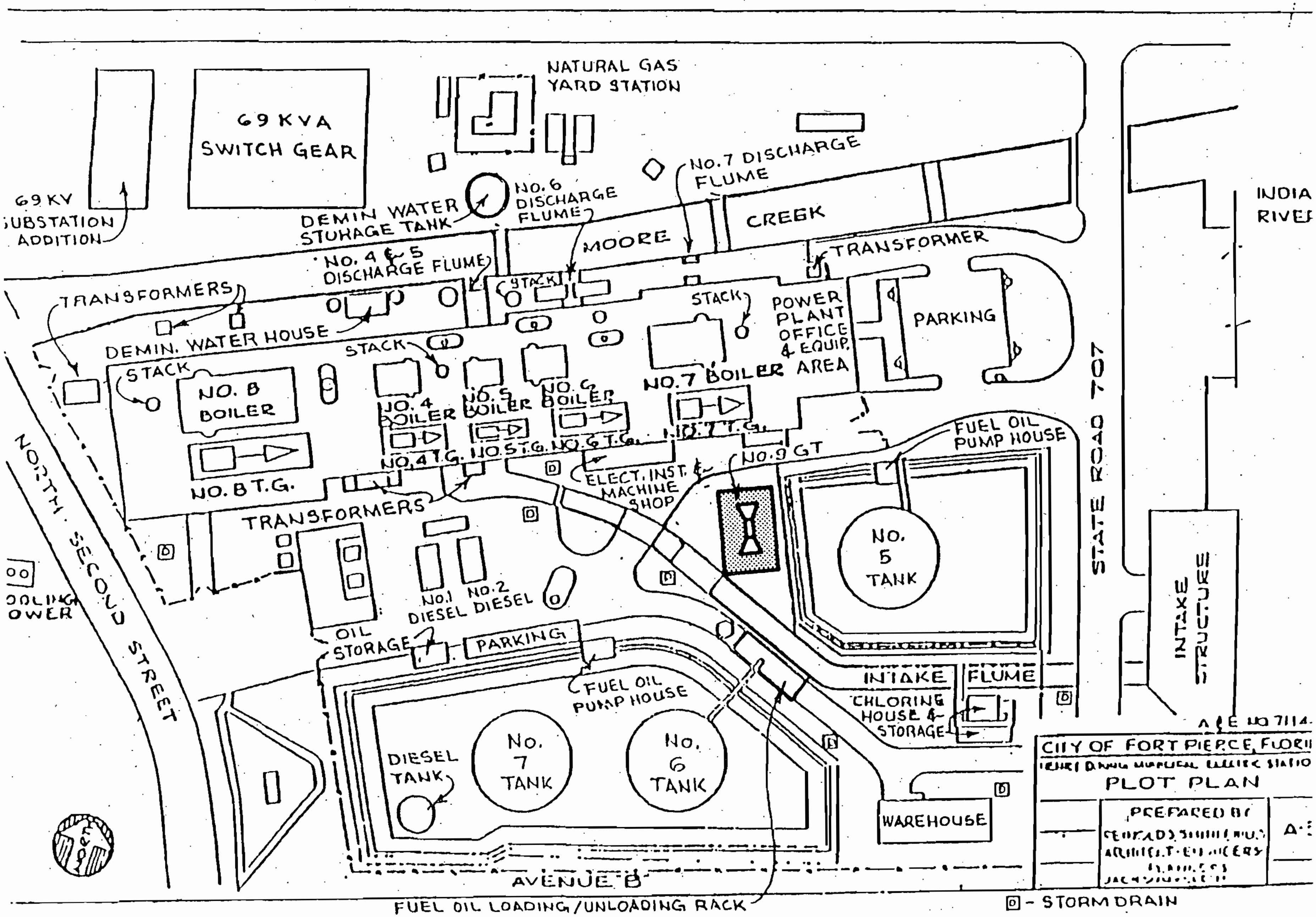


FIGURE 2-2. SITE ARRANGEMENT

3.0 APPLICABILITY ANALYSIS

For PSD regulations to be applicable, a source must be considered a new major stationary source or a major modification to an existing facility. In addition, the source must be located in an area which is designated as "attainment" or "unclassifiable" for at least one pollutant emitted by the source and regulated under the Clean Air Act. If a source is determined to be subject to PSD regulations, then each regulated pollutant that is emitted in excess of designated "significant emission rates" is subject to additional PSD review. Additional review includes a Best Available Control Technology (BACT) analysis, an Ambient Air Quality Impact Analysis (AAQIA), and additional impacts analysis, as appropriate.

3.1 CURRENT AIR QUALITY STATUS

The project site is located in St. Lucie County. This area is currently designated as attainment or unclassifiable with regard to carbon monoxide (CO), particulate matter (PM_{10}), nitrogen oxides (NO_x), ozone (VOCs) and sulfur dioxide (SO_2).

An area is designated as "attainment" for a pollutant if ambient air quality standards for that pollutant are being met and "nonattainment" if they are not. An area is designated as "unclassifiable" for a pollutant if the attainment status cannot be determined. Unclassifiable areas will be considered in attainment for this PSD analysis.

The nearest nonattainment area is Palm Beach County, which is designated nonattainment for ozone. This area, located over 50 km from the H. D. King site, is not anticipated to be significantly impacted by the proposed project.

3.2 SOURCE APPLICABILITY

A major stationary source is defined as any one of 28 source categories listed in 40 CFR 52.21 which emits, or has the potential to emit, 100 tons per year or more of any regulated pollutant. In addition, any stationary source not listed in 40 CFR 52.21 which emits 250 tons per year (tpy) or more of any regulated pollutant is also considered a major stationary source. The existing Unit 6, 7, and 8 boilers can be categorized in one of the 28 listed source categories. These boilers emit at least 100 tpy of a criteria pollutant and are thus considered to be a major existing source.

A major modification is defined as any physical or operational change in a major stationary source that would result in a significant net emissions increase of any regulated pollutant. The previous permit for Unit 9 restricted the operational hours of Units 6, 7, and 8 such that the net emission increases were below PSD significant levels. The emission calculations were based on net emission increases from Unit 9 minus the net emission decreases resulting from the operational limitations of Units 6, 7, and 8.

Due to increased energy demands, it is necessary to remove operational restrictions on Units 6, 7, and 8. Therefore, the emission credit can no longer be taken for the contemporaneous decreases in emissions for these units. Thus, the net increases from Unit 9 alone must be compared to the PSD significant emission rates.

The significant emission rates and Unit 9 emissions are given in Table 3-1. The annual emissions are based on Unit 9 operating at maximum load for 8,760 hours per year. The NO_x emissions are based on 42 parts per million on a dry volume basis (ppmvd), referenced to 15 percent oxygen. As shown in the table, Unit 9 emissions of NO_x exceed the PSD significant emission rate. Therefore, the project is considered to be a major modification to an existing major source and is subject to PSD regulations.

3.3 POLLUTANT APPLICABILITY

Once a source is determined to be subject to PSD regulations, each regulated pollutant must be assessed for PSD program applicability. The significant emission rate criteria used to determine source applicability are also used to establish pollutant applicability. Table 3-1 shows that only NO_x has the potential to be emitted at levels above the PSD significant emission rates. Thus, NO_x is subject to further PSD review, including a BACT assessment and an AAQIA.

TABLE 3-1. SIGNIFICANT AND UNIT 9 ANNUAL EMISSION RATES

Pollutant	Significant Emission Rates tpy	Unit 9 Estimated Annual Emissions[a] tpy	Applicable Pollutant Yes/No
Carbon Monoxide (CO)	100	41.6	No
Nitrogen Oxide (NO_x)	40	288.4	Yes
Sulfur Dioxide (SO_2)	40	0.9	No
Particulate (TSP)	25	11.0	No
Particulate (PM_{10})	15	11.0[b]	No
Ozone (VOC)	40	17.5	No
Lead	0.6	<<0.6	No
Asbestos	0.007	<<0.007	No
Beryllium	0.0004	<<0.0004	No
Mercury	0.1	<<0.1	No
Fluorides	3	<<3	No
Sulfuric Acid Mist	7	0.027	No
Vinyl Chloride	1.0	<<1.0	No
Total Reduced Sulfur (TRS)	10	<< 10	No
Reduced Sulfur	10	<< 10	No
Hydrogen Sulfide	10	<< 10	No

[a]Emissions are based on 8,760 hours per year of natural gas firing at full load.

[b]Assumes all particulate less than 10 microns.

4.0 BEST AVAILABLE CONTROL TECHNOLOGY ANALYSIS

(See Attachment 2 for Revised BACT Analysis)

5.0 MODELING METHODOLOGY

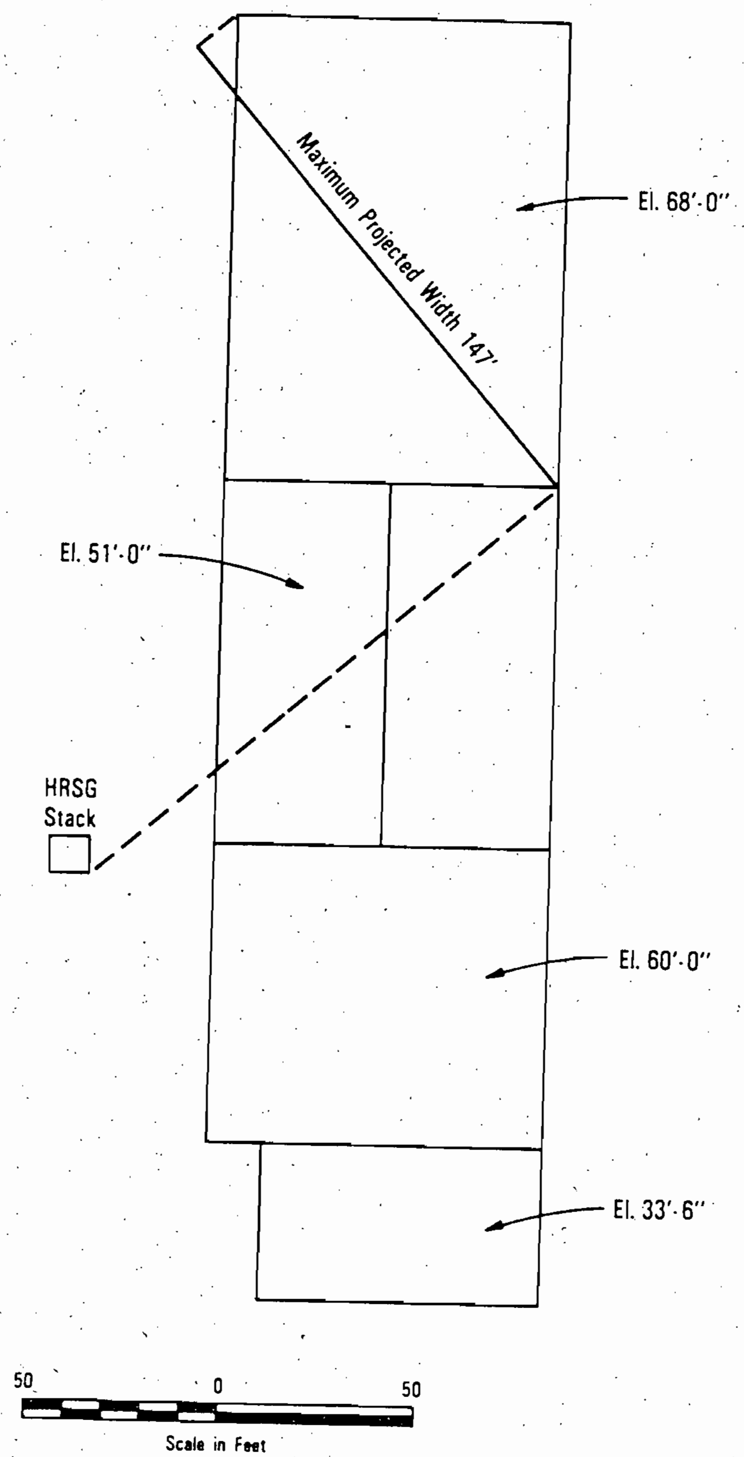
This section describes the modeling methodology for determining the ambient air quality impacts for Unit 9. The methodology is based on FDER and EPA guidelines and used EPA approved dispersion models. The dispersion models have been revised to include the most recent changes associated with EPA dispersion modeling guidelines. The modeling methodology includes a discussion of the GEP stack height, source data, appropriate dispersion models, receptor locations, meteorological data, and the definition of modeling assumptions used in the preliminary modeling analysis.

The air quality modeling output files supporting the PSD Permit Application will be submitted to the FDER on diskette and as hardcopy.

5.1 GEP STACK HEIGHT DETERMINATION

A Good Engineering Practice (GEP) stack height is defined as the height at which emissions are not significantly influenced by building downwash. The GEP stack height is calculated as the height of a nearby building plus 1.5 times the lesser of the building height or maximum projected width. A nearby building is defined as one which is located within five times the lesser of its height or maximum projected width from the stack. The resultant GEP stack height is the highest calculated stack height based on all influencing building dimensions.

Emissions from the Unit 9 stack will be influenced by the structures associated with the existing H. D. King facility. The building dimensions and GEP determination are shown in Figure 5-1. The GEP stack height of 170 feet is based on the steam turbine building height of 68 feet, and a maximum projected width that exceeds the height. The bypass and HRSG stacks for Unit 9 are constructed at 60 feet. Because the stack height is less than the calculated GEP height, the effect of building downwash on pollutant dispersion will be incorporated in the modeling analysis. In fact, since the stack height is less than the dominant building height, direction-specific building heights and widths must be used in the refined modeling analysis. Appendix A shows the output of Trinity Consultant's "BRZWAKE" program, which was used to determine direction-specific building dimensions.



GEP STACK HEIGHT
DETERMINATION

Figure 5-1

5.2 PROPOSED SOURCE DATA

Unit 9 will fire natural gas as the primary fuel with distillate used as emergency backup fuel. Modeling was based on natural gas firing assuming 8,760 hours of operation per year at maximum design capacity. Unlike steam generating plants, gas turbines typically operate at maximum (100 percent) load and generally do not operate at reduced load conditions.

The bypass stack will operate only when the HRSG is being serviced. The flue gas exiting the bypass stack is hotter than the HRSG flue gas. Increased thermal buoyancy associated with the bypass stack will enhance plume rise and subsequent dispersion. Thus, impacts from the bypass stack are expected to be less than those from HRSG operation. Therefore, only impacts from HRSG operation were modeled in this analysis.

Modeling parameters for Unit 9 operating in combined cycle and firing natural gas are given in Table 5-1.

5.3 MODEL SELECTION AND DESCRIPTION

For most air quality modeling assessments, it is desirable to use both screening-level and refined dispersion modeling techniques. In this analysis, screening-level modeling was used to determine impacts in the building cavity region. Refined dispersion modeling was used to identify the maximum ambient pollutant impacts, the location of those impacts, and the area which will be significantly impacted by the source.

5.3.1 Screening Modeling

The EPA approved "Screen" model was used to determine the impacts in the building cavity region. This model assumes worst case meteorological conditions to predict maximum 1-hour pollutant impacts. If the cavity region is on FPUA property, then the cavity impacts need not be considered. However, if the cavity region extends beyond the property boundary, then the impacts must be considered in the AAQIA.

5.3.2 Refined Modeling

In order to assess the Unit 9 impacts, the modeling analyses incorporated simple terrain, rural land use, calculation of short-term and annual impacts, and building downwash effects. EPA guideline documents

TABLE 5-1. SOURCE DATA FOR THE UNIT 9 COMBUSTION TURBINE FIRING NATURAL GAS

Model Parameters	Unit 9	
Stack Height, feet	60	
Stack Exit Diameter, feet	11.2	
Stack Flow Volume, acfm	418,540	
Stack Exit Velocity, fpm	4,271	
Stack Exit Temperature, F	491	
Ambient Temperature, F	20	
Emissions*		
SO_2 emissions, lb/h	0.2**	
NO_x emissions, lb/h	65.9***	$-8.3\ g s^{-1}$
CO emissions, lb/h	9.5	
TSP/PM_{10} emissions, lb/h	2.5	
VOC emissions, lb/h	4	
Model Coordinates, km		
(East - x)	0	
(North - y)	0	
Source Coordinates, km		
(East - x)	566.8	
(North - y)	3036.3	

*Emissions based on manufacturer's performance estimates with natural gas firing.

**The SO_2 emission rate is based on a sulfur content of 2,000 grains of sulfur per million cubic feet of natural gas (AP-42), a heat content of 929.6 Btu/ft^3, and a heat input of 340 MBtu/h.

***The NO_x emission rate is based on 42 ppmvd referenced to 15 percent oxygen.

recommend that the Industrial Source Complex Short-Term (ISCST) dispersion model be used for these modeling situations. EPA has issued guidelines to assist in determining what model options should be used. The following assumptions were made for the modeling analyses:

- o The site was considered rural based on actual land use within 3 km.
- o Standard EPA default modeling options were applied.
- o Terrain elevations were not used.
- o Schulman-Scire building downwash with direction-specific building heights and widths were considered.
- o The highest modeled concentrations were used to represent the annual impacts.

Preliminary modeling (see Section 6.0) for determining the Unit 9 significant impact areas and maximum impacts was based on a nominal emissions rate (1 g/s) and a ratio of actual pollutant emissions. That is, individual pollutant impacts were determined by multiplying the nominal impacts by the actual pollutant emission rates (g/s).

5.4 RECEPTOR LOCATIONS

Initial modeling for the Unit 9 stack was performed with receptors placed along the 36 standard radial directions surrounding the Unit 9 stack at the following downwind distances: 100 meter intervals from 100 to 1,000 meters, 250 meter intervals from 1,250 to 3,000 meters, and 1,000 meter intervals from 4,000 to 10,000 meters. Furthermore, discrete receptors were placed at the boundaries that restrict public access along the 36 radial directions.

5.5 METEOROLOGICAL DATA

Five consecutive years of meteorological data from a nearby National Weather Service station can be considered to be representative of the dispersion patterns at the site. Specifically, West Palm Beach surface and upper air data for the period 1982 through 1986 were obtained from the FDER and were used for the analysis.

6.0 AIR QUALITY IMPACT ANALYSES

6.1 CAVITY ANALYSIS

The "Screen" model cavity analysis showed that the cavity region extends 33 meters downwind from the source. Since this distance is well within the facility property boundary, cavity impacts were not considered in the ambient impact analysis.

6.2 PRELIMINARY MODELING

Unit 9 was modeled with ISCST and the five years of meteorological data. The modeling was based on the stack parameters and modeling assumptions given in Section 5.0. The results of the modeling were used to determine if a pollutant's impact exceeds PSD significant impact levels, determine whether preconstruction monitoring is required, and establish pollutant significant impact areas.

The results of the preliminary modeling are given in Table 6-1. As demonstrated in Section 3-2, it was only necessary to model NO_x. As shown, the annual NO_x impact (9.6 ug/m3) is predicted to exceed the PSD significant impact level (1 ug/m3) but not the monitoring threshold (14 ug/m3). The maximum impact for each year occurred along the plant boundary. Since the annual NO_x impact exceeds the significance level, interacting source modeling must be performed.

For each applicable pollutant, the extent of the significant impact area must be defined. The radii of significant impact is determined by extending the receptor array outward until the predicted pollutant concentration at a receptor distance is less than the appropriate significance level. The highest modeled annual concentrations were used to determine the significant impact area.

The significant impact area for NO_x was found to extend only 300 meters from the HRSG stack. This radius is small because of the extreme downwash associated with the nearby H. D. King structures.

TABLE 6-1. RESULTS OF THE PRELIMINARY MODELING ANALYSIS

	Unit 9 NO_x Annual Impact
Significant Impact Criteria	1 ug/m3
Monitoring Criteria	14 ug/m3
Maximum Impact*	9.6 ug/m3
Location	
Distance	0.88 km
Direction	260 deg
Year	1984

* Maximum nominal impacts for 1 g/s are 1.15697 ug/m^3 (annual).

6.3 POTENTIAL INTERACTING SOURCES

Since the annual NO_x impact is greater than the PSD significant impact criteria, potential interacting sources must be assessed. The FDER provided copies of the Air Pollution Information System Master Detail Report ("the inventory") for St. Lucie, Indian River, and Martin counties. All sources in these counties that satisfied one of the following conditions were considered potential interacting sources.

- o All sources within the Unit 9 NO_x significant impact area (300 meters).
- o All sources within 50 kilometers of Unit 9 which have annual NO_x emissions greater than 100 tons per year and show a significant impact in the Unit 9 significant impact area.
- o All sources within 10 kilometers of Unit 9 which have annual NO_x emissions greater than 1 ton per year and show a significant impact in the Unit 9 significant impact area.

From the inventory, it is apparent that the only NO_x sources within the 300 meter significant impact area are associated with the FPUA H.D. King power plant. Consequently, the H.D. King Unit 6, 7, and 8 boilers were used in the National Ambient Air Quality Standards (NAAQS) interacting source modeling. However, since the inventory does not indicate that these sources are subject to PSD regulations, they were not used in the PSD increment modeling. The source parameters for these boilers were extracted from the inventory and are listed in Table 6-2.

Check Unit 8

All 100 ton per year sources within 50 kilometers and 1 ton per year sources within 10 kilometers were extracted from the inventory and are listed below by facility.

- o City of Vero Beach Steam Power Plant
- o Tropicana Products
- o Fort Pierce Lawnwood Regional Medical Center
- o Minton Sun Citrus Processing Plant
- o Fort Pierce Contracting Corporation Asphalt Plant

These facilities were modeled using ISCST and the source parameters listed in the inventory to determine if the significant impact level was exceeded at the FPUA facility. Where possible, the maximum allowable

TABLE 6-2. NAAQS INTERACTING SOURCES

Parameter[a]	FPUA Unit 6	FPUA Unit 7	FPUA Unit 8
East Coordinate[b] (m):	-18.6	6.7	-68.0
North Coordinate[b] (m):	36.3	33.8	18.3
Volumetric Flow (acfm)	42,735	83,333	125,847
Stack Exit Diameter (ft)	5	7.1	8.0
Stack Exit Velocity (fps)	36.3	35.1	41.7
Stack Height (ft)	148	128	150
Exit Temperature (F)	325	253	275
NO_x Emission Rate[c] (lb/h)	1.3	104.4	173.2

[a] Source parameters extracted from FDER source inventory.

[b] Stack coordinates relative to FPUA Unit 9 stack.

[c] Hourly emission rates as stated in FPUA Unit 9 permit.

pounds per hour NO_x emission rate was used in the modeling. However, since the allowable emission rate was not listed in the inventory, the actual NO_x emission rate was used for the Tropicana and Fort Pierce Contracting Corporation sources. The modeling showed that the highest annual NO_x impact from these facilities was 0.08 ug/m3. Since this impact is well below the PSD significance level of 1.0 ug/m3, these sources were not included in the NAAQS or PSD increment modeling.

6.4 PSD INCREMENT ANALYSIS

PSD regulations were promulgated as a result of the 1977 Clean Air Act Amendments to ensure that air quality in defined areas does not significantly deteriorate or exceed NAAQS while providing a margin for future growth. Currently SO_2, NO_x, and TSP are regulated by the PSD program. The EPA is currently proposing PSD regulations for PM_{10}.

The proposed site is located in a PSD Class II area. Since Unit 9 has significant ambient impacts for NO_x, compliance with the NO_x Class II PSD increment (25 ug/m3) must be demonstrated. As stated in Section 6.3, only the FPUA sources have the potential to significantly interact with Unit 9 impacts. These sources are not considered PSD increment consuming sources. Thus, only the Unit 9 impact was compared to the PSD Class II NO_x increment. As shown in Table 6-1, the Unit 9 annual NO_x impact is 9.6 ug/m3, which is 38.4 percent of the available PSD Class II increment. Consequently, the addition of Unit 9 does not cause an exceedance of PSD Class II increments.

The nearest mandatory PSD Class I area is the Everglades National Park, located approximately 150 kilometers south-southwest of the site. A Class I analysis was not necessary because this area is more than 100 km from the site.

6.5 NAAQS ANALYSIS

To predict the total impact on ambient air quality, a refined air quality assessment must be performed for applicable pollutants. This analysis must show compliance with the applicable NAAQS.

The NAAQS concentration was determined by adding the Unit 9 and additional source impacts to a representative background level. To show compliance with NAAQS, the combined NO_x annual impacts must be less than 100 ug/m3. Identification of interacting NO_x sources for use in demonstrating NAAQS compliance was performed as described in Section 6.3. A representative NO_x background concentration of 24 ug/m3 was obtained from the FDER. This value represents the annual arithmetic mean measured at the West Palm Beach monitor in 1989. Data from the West Palm Beach monitor are considered conservatively high since West Palm Beach is significantly more urbanized than Fort Pierce.

NAAQS modeling was performed following the modeling methodology described in Section 5.0. FPUA Units 6, 7, and 8 were included as the only significant interacting sources. Table 6-3 shows the results of the NAAQS modeling. The maximum combined source impact was 11.3 ug/m3, which occurred along the property boundary. This value was added to the 24 ug/m3 background value to get a total concentration of 35.3 ug/m3. This value is only 35.3 percent of the annual NO_x standard. Consequently, the Unit 9 annual NO_x impacts do not exceed the NAAQS.

TABLE 6-3. NAAQS MODELING RESULTS

	NAAQS Modeling Summary
Maximum Impact Location	
Distance	0.88 km
Direction	260 deg
Meteorological Year	1984
Combined Source Maximum Impact	11.3 ug/m3
Background Concentration	24 ug/m3
Total Concentration (Combined Maximum Impact plus Background)	35.3 ug/m3
NAAQS Primary NO_x Standard	100 ug/m3
Percent of Standard	35.3 percent

7.0 ADDITIONAL IMPACT ANALYSIS

7.1 VISIBILITY

The nearest PSD Class I area is the Everglades National Park. The Everglades National Park is located approximately 150 kilometers south-southwest of the project site. Since this area is not within 100 kilometers of the plant site, no visibility assessment is considered necessary.

7.2 SOILS AND VEGETATION

Ambient air quality standards have been established to protect public health and welfare from any adverse effect of air pollutants. It is not expected that the estimated effects of the proposed project will significantly add to the background pollutant concentrations. Therefore, no adverse effects on soils and terrestrial vegetation is expected.

7.3 GROWTH

The operation of the Unit 9 combustion turbine at the H. D. King Power Plant is not expected to induce any secondary growth in the surrounding area.

APPENDIX A

DIRECTION-SPECIFIC BUILDING ANALYSIS

RBRZWAKE
IBM-PC VERSION (2.0)
(C) COPYRIGHT 1989, TRINITY CONSULTANTS, INC.
SERIAL NUMBER 6440 SOLD TO BLACK & VEATCH CONSULTING ENG
RUN NAME: FPHD
RUN BEGAN ON 08-09-90 AT 16:53:32

NUMBER OF SOURCES = 4

THE FOLLOWING OPTIONS HAVE BEEN CHOSEN:

CALCULATIONS ARE MADE FOR THE ISCST MODEL.

ALL STACKS MUST BE WITHIN 5L TO BE CONSIDERED FOR DIRECTION SPECIFIC DOWNWASH.

DOWNWASH IS CALCULATED IN 36 RADIAL DIRECTIONS.

BUILDINGS ARE COMBINED REPEATEDLY.

ALGORITHMS:

----
0 = NO DOWNWASH
1 = HUBER-SNYDER DOWNWASH
2 = SCHULMAN-SCIRE DOWNWASH

INPUT BUILDINGS

DESCRIPTION	BLDG #	BLDG HT(M)	# OF CORNERS	X(M)	Y(M)
F.O. TANK 5	1	13.23	10		
				39.12	1.51
				42.72	-3.44
				42.72	-9.56
				39.12	-14.51
				33.30	-16.40
				27.48	-14.51
				23.88	-9.56
				23.88	-3.44
				27.48	1.51
				33.30	3.40
F.O. TANK 6	2	12.93	10		
				9.72	-47.69
				13.32	-52.64
				13.32	-58.76
				9.72	-63.71
				3.90	-65.60
				-1.92	-63.71
				-5.52	-58.76
				-5.52	-52.64
				-1.92	-47.69
				3.90	-45.80
F.O. TANK 7	3	13.92	10		
				-18.91	-46.94
				-15.02	-52.29
				-15.02	-58.91
				-18.91	-64.26
				-25.20	-66.30
				-31.49	-64.26
				-35.38	-58.91
				-35.38	-52.29
				-31.49	-46.94
				-25.20	-44.90
GEN BUILD 68 FT	4	20.73	4		
				-33.53	4.88
				-38.71	30.48
				-74.68	22.86
				-69.49	-2.74
GEN BUILD 60 FT	5	18.29	4		
				17.37	15.54
				12.19	41.15
				-10.67	36.58
				-5.79	10.67
GEN BUILD 51 FT	6	15.54	4		
				-5.79	10.67
				-10.67	36.58
				-38.71	30.48
				-33.53	4.88
GEN BUILD 33.5 FT	7	10.21	4		
				28.65	22.86
				24.38	43.89
				12.19	41.15
				16.76	19.81

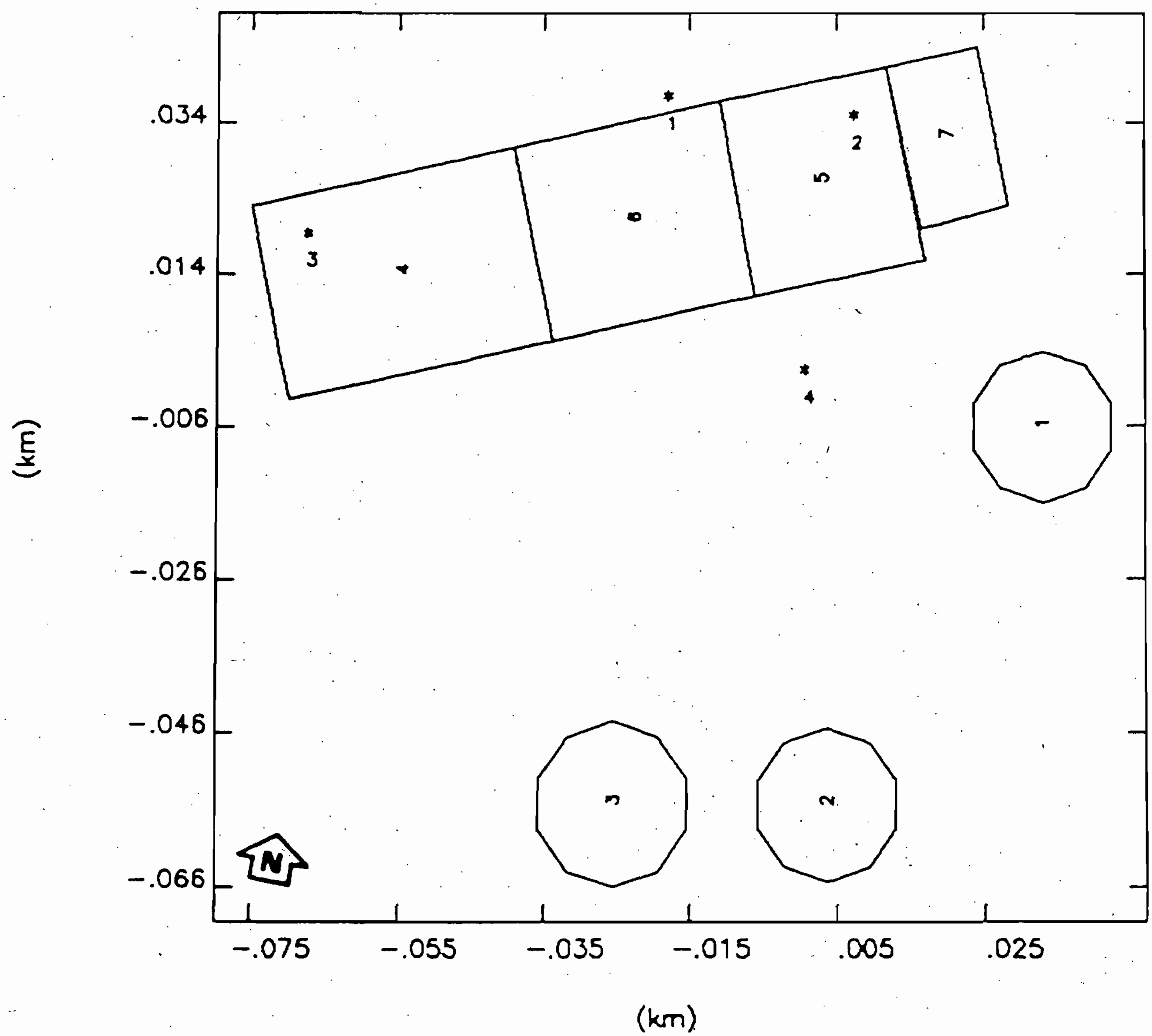
COMBINED BUILDINGS

```
STRUCTURE  1 HAS A HEIGHT 20.73 METERS AND CONTAINS THE FOLLOWING BUILDINGS:
             BUILDING # 4:  GEN BUILD 68 FT
STRUCTURE  2 HAS A HEIGHT 18.29 METERS AND CONTAINS THE FOLLOWING BUILDINGS:
             BUILDING # 5:  GEN BUILD 60 FT
STRUCTURE  3 HAS A HEIGHT 15.54 METERS AND CONTAINS THE FOLLOWING BUILDINGS:
             BUILDING # 4:  GEN BUILD 68 FT
             BUILDING # 5:  GEN BUILD 60 FT
             BUILDING # 6:  GEN BUILD 51 FT
STRUCTURE  4 HAS A HEIGHT 13.92 METERS AND CONTAINS THE FOLLOWING BUILDINGS:
             BUILDING # 3:  F.O. TANK 7
STRUCTURE  5 HAS A HEIGHT 13.23 METERS AND CONTAINS THE FOLLOWING BUILDINGS:
             BUILDING # 1:  F.O. TANK 5
             BUILDING # 4:  GEN BUILD 68 FT
             BUILDING # 5:  GEN BUILD 60 FT
             BUILDING # 6:  GEN BUILD 51 FT
STRUCTURE  6 HAS A HEIGHT 12.93 METERS AND CONTAINS THE FOLLOWING BUILDINGS:
             BUILDING # 2:  F.O. TANK 6
             BUILDING # 3:  F.O. TANK 7
STRUCTURE  7 HAS A HEIGHT 10.21 METERS AND CONTAINS THE FOLLOWING BUILDINGS:
             BUILDING # 1:  F.O. TANK 5
             BUILDING # 4:  GEN BUILD 68 FT
             BUILDING # 5:  GEN BUILD 60 FT
             BUILDING # 6:  GEN BUILD 51 FT
             BUILDING # 7:  GEN BUILD 33.5 FT
```

INPUT STACKS

STACK ID #	STACK #	STACK HT(M)	X(M)	Y(M)
1	1	45.11	-18.60	36.30
2	2	39.01	6.70	33.80
3	3	45.72	-68.00	18.30
4	4	18.29	.00	.00

FORT PIERCE PLANT SITE



STACK ID # 1, STACK # 1

THE DOMINANT STRUCTURE WITHIN 5L IS
STRUC= 1 H= 20.73 W= 45.29 GEP= 51.81

DIRECTION SPECIFIC BUILDING DOWNWASH

DEGREE	STRUCTURE #	HEIGHT	WIDTH	GEP	ALGORITHM
10	1	20.73	43.65	51.81	1
20	1	20.73	44.82	51.81	1
30	1	20.73	44.63	51.81	1
40	1	20.73	43.08	51.81	1
50	1	20.73	40.22	51.81	1
60	1	20.73	36.15	51.81	1
70	1	20.73	30.97	51.81	1
80	1	20.73	27.37	51.81	1
90	1	20.73	33.22	51.81	1
100	1	20.73	38.06	51.81	1
110	2	18.29	34.79	45.72	1
120	2	18.29	35.39	45.72	1
130	2	18.29	34.91	45.72	1
140	2	18.29	33.37	45.72	1
150	2	18.29	30.81	45.72	1
160	2	18.29	27.32	45.72	1
170	2	18.29	23.96	45.72	1
180	2	18.29	28.04	45.72	1
190	1	20.73	43.65	51.81	1
200	1	20.73	44.82	51.81	1
210	1	20.73	44.63	51.81	1
220	1	20.73	43.08	51.81	1
230	1	20.73	40.22	51.81	1
240	1	20.73	36.15	51.81	1
250	1	20.73	30.97	51.81	1
260	1	20.73	27.37	51.81	1
270	1	20.73	33.22	51.81	1
280	1	20.73	38.06	51.81	1
290	2	18.29	34.79	45.72	1
300	2	18.29	35.39	45.72	1
310	2	18.29	34.91	45.72	1
320	2	18.29	33.37	45.72	1
330	2	18.29	30.81	45.72	1
340	2	18.29	27.32	45.72	1
350	2	18.29	23.96	45.72	1
360	2	18.29	28.04	45.72	1

STACK ID # 2, STACK # 2

THE DOMINANT STRUCTURE WITHIN 5L IS
STRUC= 1 H= 20.73 W= 45.29 GEP= 51.81

DIRECTION SPECIFIC BUILDING DOWNWASH

DEGREE	STRUCTURE #	HEIGHT	WIDTH	GEP	ALGORITHM
10	2	18.29	31.27	45.72	1
20	2	18.29	33.55	45.72	1
30	2	18.29	34.80	45.72	1
40	2	18.29	35.00	45.72	1
50	1	20.73	40.22	51.81	1
60	1	20.73	36.15	51.81	1
70	1	20.73	30.97	51.81	1
80	1	20.73	27.37	51.81	1
90	1	20.73	33.22	51.81	1
100	2	18.29	33.14	45.72	1
110	2	18.29	34.79	45.72	1
120	2	18.29	35.39	45.72	1
130	2	18.29	34.91	45.72	1
140	2	18.29	33.37	45.72	1
150	2	18.29	30.81	45.72	1
160	2	18.29	27.32	45.72	1
170	2	18.29	23.96	45.72	1
180	2	18.29	28.04	45.72	1
190	2	18.29	31.27	45.72	1
200	2	18.29	33.55	45.72	1
210	2	18.29	34.80	45.72	1
220	2	18.29	35.00	45.72	1
230	1	20.73	40.22	51.81	1
240	1	20.73	36.15	51.81	1
250	2	18.29	29.36	45.72	1
260	2	18.29	26.89	45.72	1
270	1	20.73	33.22	51.81	1
280	2	18.29	33.14	45.72	1
290	2	18.29	34.79	45.72	1
300	2	18.29	35.39	45.72	1
310	2	18.29	34.91	45.72	1
320	2	18.29	33.37	45.72	1
330	2	18.29	30.81	45.72	1
340	2	18.29	27.32	45.72	1
350	2	18.29	23.96	45.72	1
360	2	18.29	28.04	45.72	1

STACK ID # 3, STACK # 3

THE DOMINANT STRUCTURE WITHIN 5L IS
STRUC= 1 H= 20.73 W= 45.29 GEP= 51.81

DIRECTION SPECIFIC BUILDING DOWNWASH

DEGREE	STRUCTURE #	HEIGHT	WIDTH	GEP	ALGORITHM
10	1	20.73	43.65	51.81	1
20	1	20.73	44.82	51.81	1
30	1	20.73	44.63	51.81	1
40	1	20.73	43.08	51.81	1
50	1	20.73	40.22	51.81	1
60	1	20.73	36.15	51.81	1
70	1	20.73	30.97	51.81	1
80	1	20.73	27.37	51.81	1
90	1	20.73	33.22	51.81	1
100	1	20.73	38.06	51.81	1
110	1	20.73	41.74	51.81	1
120	1	20.73	44.16	51.81	1
130	1	20.73	45.23	51.81	1
140	1	20.73	44.93	51.81	1
150	1	20.73	43.27	51.81	1
160	1	20.73	40.29	51.81	1
170	1	20.73	37.40	51.81	1
180	1	20.73	41.15	51.81	1
190	1	20.73	43.65	51.81	1
200	1	20.73	44.82	51.81	1
210	1	20.73	44.63	51.81	1
220	1	20.73	43.08	51.81	1
230	1	20.73	40.22	51.81	1
240	1	20.73	36.15	51.81	1
250	1	20.73	30.97	51.81	1
260	1	20.73	27.37	51.81	1
270	1	20.73	33.22	51.81	1
280	1	20.73	38.06	51.81	1
290	1	20.73	41.74	51.81	1
300	1	20.73	44.16	51.81	1
310	1	20.73	45.23	51.81	1
320	1	20.73	44.93	51.81	1
330	1	20.73	43.27	51.81	1
340	1	20.73	40.29	51.81	1
350	1	20.73	37.40	51.81	1
360	1	20.73	41.15	51.81	1

STACK ID # 4, STACK # 4

THE DOMINANT STRUCTURE WITHIN 5L IS
STRUC= 1 H= 20.73 W= 45.29 GEP= 51.81

DIRECTION SPECIFIC BUILDING DOWNWASH

DEGREE	STRUCTURE #	HEIGHT	WIDTH	GEP	ALGORITHM
10	2	18.29	31.27	45.72	2
20	2	18.29	33.55	45.72	2
30	2	18.29	34.80	45.72	2
40	2	18.29	35.00	45.72	2
50	2	18.29	34.14	45.72	2
60	2	18.29	32.24	45.72	2
70	2	18.29	29.36	45.72	2
80	1	20.73	27.37	51.81	2
90	1	20.73	33.22	51.81	2
100	1	20.73	38.06	51.81	2
110	1	20.73	41.74	51.81	2
120	1	20.73	44.16	51.81	2
130	1	20.73	45.23	51.81	2
140	1	20.73	44.93	51.81	2
150	2	18.29	30.81	45.72	2
160	2	18.29	27.32	45.72	2
170	2	18.29	23.96	45.72	2
180	2	18.29	28.04	45.72	2
190	2	18.29	31.27	45.72	2
200	2	18.29	33.55	45.72	2
210	2	18.29	34.80	45.72	2
220	2	18.29	35.00	45.72	2
230	2	18.29	34.14	45.72	2
240	2	18.29	32.24	45.72	2
250	2	18.29	29.36	45.72	2
260	1	20.73	27.37	51.81	2
270	1	20.73	33.22	51.81	2
280	1	20.73	38.06	51.81	2
290	1	20.73	41.74	51.81	2
300	1	20.73	44.16	51.81	2
310	1	20.73	45.23	51.81	2
320	1	20.73	44.93	51.81	2
330	2	18.29	30.81	45.72	2
340	2	18.29	27.32	45.72	2
350	2	18.29	23.96	45.72	2
360	2	18.29	28.04	45.72	2

STACK # 1

STACK ID: 1, BUILDING HEIGHT: 20.73, BUILDING WIDTH: 45.29

20.73	20.73	20.73	20.73	20.73	20.73	20.73	20.73	20.73	20.73	18.29	18.29
18.29	18.29	18.29	18.29	18.29	18.29	20.73	20.73	20.73	20.73	20.73	20.73
20.73	20.73	20.73	20.73	18.29	18.29	18.29	18.29	18.29	18.29	18.29	18.29
43.65	44.82	44.63	43.08	40.22	36.15	30.97	27.37	33.22	38.06	34.79	35.39
34.91	33.37	30.81	27.32	23.96	28.04	43.65	44.82	44.63	43.08	40.22	36.15
30.97	27.37	33.22	38.06	34.79	35.39	34.91	33.37	30.81	27.32	23.96	28.04

STACK # 2

STACK ID: 2, BUILDING HEIGHT: 20.73, BUILDING WIDTH: 45.29

18.29	18.29	18.29	18.29	20.73	20.73	20.73	20.73	20.73	18.29	18.29	18.29
18.29	18.29	18.29	18.29	18.29	18.29	18.29	18.29	18.29	18.29	20.73	20.73
18.29	18.29	20.73	18.29	18.29	18.29	18.29	18.29	18.29	18.29	18.29	18.29
31.27	33.55	34.80	35.00	40.22	36.15	30.97	27.37	33.22	33.14	34.79	35.39
34.91	33.37	30.81	27.32	23.96	28.04	31.27	33.55	34.80	35.00	40.22	36.15
29.36	26.89	33.22	33.14	34.79	35.39	34.91	33.37	30.81	27.32	23.96	28.04

STACK # 3

STACK ID: 3, BUILDING HEIGHT: 20.73, BUILDING WIDTH: 45.29

20.73	20.73	20.73	20.73	20.73	20.73	20.73	20.73	20.73	20.73	20.73	20.73
20.73	20.73	20.73	20.73	20.73	20.73	20.73	20.73	20.73	20.73	20.73	20.73
20.73	20.73	20.73	20.73	20.73	20.73	20.73	20.73	20.73	20.73	20.73	20.73
43.65	44.82	44.63	43.08	40.22	36.15	30.97	27.37	33.22	38.06	41.74	44.16
45.23	44.93	43.27	40.29	37.40	41.15	43.65	44.82	44.63	43.08	40.22	36.15
30.97	27.37	33.22	38.06	41.74	44.16	45.23	44.93	43.27	40.29	37.40	41.15

STACK # 4

STACK ID: 4, BUILDING HEIGHT: 20.73, BUILDING WIDTH: 45.29

18.29	18.29	18.29	18.29	18.29	18.29	18.29	20.73	20.73	20.73	20.73	20.73
20.73	20.73	18.29	18.29	18.29	18.29	18.29	18.29	18.29	18.29	18.29	18.29
18.29	20.73	20.73	20.73	20.73	20.73	20.73	20.73	18.29	18.29	18.29	18.29
31.27	33.55	34.80	35.00	34.14	32.24	29.36	27.37	33.22	38.06	41.74	44.16
45.23	44.93	30.81	27.32	23.96	28.04	31.27	33.55	34.80	35.00	34.14	32.24
29.36	27.37	33.22	38.06	41.74	44.16	45.23	44.93	30.81	27.32	23.96	28.04

ATTACHMENT 2

REVISED BACT ANALYSIS

4.0 BEST AVAILABLE CONTROL TECHNOLOGY ANALYSIS

4.1 INTRODUCTION

The existing Fort Pierce Utilities Authority H. D. King Electric Generating Plant Unit 9 consists of one 23.4 MW General Electric Frame 5 combustion turbine. The combustion turbine is followed by a heat recovery steam generator (HRSG) manufactured by the Henry Vogt Machine Company. Steam from the HRSG is directed to the 8.2 MW Unit 5 steam turbine for repowering.

The primary fuel for the Unit 9 combustion turbine is natural gas. However, distillate fuel oil may be burned as an emergency back-up fuel. Since distillate fuel oil will only be burned during emergencies this Best Available Control Technology analysis will only consider the combustion of natural gas. Section 3.0 concluded that when natural gas is burned for the maximum project operation (8,760 hours per year), the project's nitrogen oxide emissions are subject to the provisions of the PSD program.

The existing operating permit for Unit 9 limits NO_x emissions to New Source Performance Standards for combustion turbines (40 CFR 60 Subpart GG) of 75 parts per million dry volume (ppmdv) at 15 percent oxygen, corrected for fuel nitrogen content and turbine heat rate, or 84 ppmdv at 15 percent oxygen, whichever is more stringent. Nitrogen oxide emissions from the existing combustion turbine are controlled by steam injection.

Under the federal Clean Air Act, BACT represents the maximum degree of pollutant reduction determined on a case-by-case basis considering technical, economic, energy, and environmental considerations. However, BACT cannot be less stringent than the emission limits established by any applicable New Source Performance Standards (NSPS).

This BACT analysis follows the general requirements of EPA's draft "top down" BACT guidance document. This approach requires that the BACT analysis start by assuming the use of the Lowest Achievable Emission Rate (LAER) control alternative. Other, less efficient emission control technologies are similarly evaluated when LAER is determined to be unreasonable considering the above factors.

4.2 NITROGEN OXIDES EMISSIONS CONTROL

During combustion, two types of NO_x are formed; fuel NO_x and thermal NO_x. Fuel NO_x emissions are formed through the oxidation of a portion of the nitrogen contained in the fuel. Thermal NO_x emissions are generated through the oxidation of a portion of the nitrogen contained in the combustion air. Nitrogen oxides formation can be limited by lowering combustion temperatures, and staging combustion (a reducing atmosphere followed by an oxidizing atmosphere).

4.2.1 Alternative NOx Emission Reduction Systems

A review of the Environmental Protection Agency's BACT/LAER Clearinghouse - A Compilation of Control Technology Determinations (1985 edition and subsequent supplements) indicates that the lowest NO_x emission limit established to date for a combustion turbine is 4.5 ppmdv (at 15 percent oxygen) for a combustion turbine with a heat recovery steam generator located in California. That permit value was based on the use of water injection into the combustion turbine and a selective catalytic reduction (SCR) system contained within the heat recovery steam generator (combined cycle operation). Therefore, the LAER NO_x emission control alternative for use with combustion turbines is established as water or steam injection followed by an SCR system.

Injection of steam into the Unit 9 turbine combustion chamber is capable of limiting NO_x emissions to 42 ppmdv (at 15 percent oxygen) when burning natural gas. Addition of an SCR system downstream of the Unit 9 combustion turbine has the potential to limit NO_x emissions to 9 ppmdv (at 15 percent oxygen).

In addition to combustion controls and addition of an SCR system, NO_x emissions from other types of combustion sources have also been controlled through installation of selective non-catalytic reduction (SNCR) systems such as Thermal $DeNO_x$. However, a SNCR system requires gas temperatures of at least 1,500 F for NO_x reduction. The temperature at the outlet of a combustion turbine is too low (950 F to 1,100 F) for such systems. Since raising the flue gas exit temperature to 1,500 F would require supplemental heating of the flue gas, thereby increasing total emissions from increased fuel usage, this alternative is judged technically unacceptable for application on a combustion turbine.

4.2.1.1 Selective Catalytic Reduction. SCR is a post-combustion method for control of NO_x emissions. The SCR process combines vaporized ammonia with NO_x in the presence of a catalyst to form nitrogen and water. The vaporized ammonia is injected into the exhaust gases prior to passage through the catalyst bed. The SCR process can achieve up to 90 percent reduction of NO_x with a new catalyst. However, an aged catalyst will provide a maximum of between 80 and 85 percent percent NO_x reduction.

The optimum flue gas temperature range for SCR operation is approximately 650 to 750 F. Flue gas from the combustion turbines will typically be 950 F to 1100 F. Therefore, an SCR would be installed in an intermediate point of the existing heat recovery steam generator boiler where a temperature of approximately 700 F occurs. The existing Unit 9 HRSG does not include adequate space to incorporate an SCR system. For an SCR system to be installed downstream of the Unit 9 combustion turbine it will be necessary to split and expand the existing HRSG.

4.2.1.2 Steam Injection. Use of steam injection in the combustion zones of a combustion turbine can limit the amount of NO_x formed. Existing operation of the Unit 9 combustion turbines uses steam injection. Thermal NO_x formation is avoided due to lower combustion temperatures resulting from the steam injection. The degree of reduction in NO_x formation is somewhat proportional to the amount of steam injected into the turbine.

Since the combustion turbine NSPS was last revised in 1982, combustion turbines have improved their tolerance to the water or steam necessary to control NO_x emissions below the current NSPS level. However, there is still a point at which the amount of water or steam injected into the turbine seriously degrades the turbine's reliability and operational life. With the existing turbine design for Unit 9 this generally occurs below a NO_x emission level of about 42 ppmdv (at 15 percent oxygen) when firing natural gas and 65 ppmdv when firing distillate oil. These NO_x emission levels can be achieved with little additional cost and without significant impact on reliability or power output over those costs required to comply with the current NSPS.

4.2.2 Capital and Operating Costs of Alternatives

Table 4-1* presents the capital and levelized annual cost of installing an SCR system within the existing HRSG. Annual operating costs and NO_x emissions are based on natural gas firing for a maximum of 8,760 hours per year in the turbines.

The differential capital costs for the SCR system include the costs of the ammonia storage/injection system, the catalytic reactors, HRSG modifications and balance of plant equipment. In addition to the 1991 equipment costs of the two alternatives, the total capital costs include a contingency charge, escalation, indirect costs, and interest during construction.

Levelized annual costs include operating personnel, maintenance costs (primarily catalyst replacement), ammonia additive, energy, lost generating capacity and fixed charges on capital investment. The differential energy cost and lost generating capacity for the SCR alternative is the result of the reduced net output of the turbine and the energy requirements of associated equipment. Levelized annual costs are based on the following parameters.

- Remaining plant life of 25 years.
- Operator cost of $45,000 per man-year.
- Catalyst life of three years.
- Ammonia cost of $250 per ton.
- Energy cost of 70 mills/kwh.
- Demand cost of $800 per kw.
- Escalation rate of ~~6~~* percent.
- Present worth discount rate of 8.0 percent.
- Levelization factor of ~~1.75~~.*

The 1993 total capital cost for addition of an SCR system to Unit 9 is ~~$3.2 million~~.* The levelized annual cost for addition of SCR is ~~$0.98 million~~* per year. This levelized annual cost results in a removal cost of approximately $~~4,500~~* per ton of NO_x reduction (~~218~~* tons per year).

*REVISED. SEE RESPONSE TO DER COMMENT 10.

REVISED. SEE RESPONSE TO DER COMMENT 10.

TABLE 4-1. NITROGEN OXIDE EMISSIONS REDUCTION SYSTEM CAPITAL AND LEVELIZED ANNUAL COSTS

	SCR SYSTEM $1,000
Capital Costs:	
SCR System	930
HRSG Modifications	590
System Erection	520
Differential Balance of Plant	70
1991 Capital Cost	2,110
Contingency (15 percent)	320
Direct Capital Cost	2,430
Escalation (6 percent)	150
Indirects (16 percent)	410
Interest During Construction (8 percent)	240
1993 Total Capital Cost	3,230
Levelized Annual Costs*:	
Operating Personnel	60
Maintenance	420
Ammonia	70
Energy	40
Lost Generation	40
1993 Annual Operating Cost	630
Fixed Charges on Capital (13.6 percent)	350
1993 Total Annual Cost	980
Nitrogen Oxides Emission Rate, ppmdv	9
Annual NO_x Emission Reduction, tpy	218
NO_x Emission Reduction Cost, $/ton	4,500

*Annual costs are based on a 100 percent capacity factor.

4.2.3 Other Considerations

Compared to the existing combustion turbine with steam injection, the energy requirements of the SCR system would reduce the output of the combustion turbines by approximately one percent.

The use of an SCR system could result in a negative environmental impact due to the release of quantities of unreacted ammonia to the atmosphere. Ammonia and a number of amine compounds are recognized hazardous air pollutants. This represents a potential adverse human health effect, since prolonged exposure to these compounds can increase chances of contracting a number of debilitating diseases. Although ammonia emissions are not regulated nationally, a number of sources are limited to ammonia emissions as low as 10 ppm. Unreacted ammonia emissions from an SCR system could average 7 to 10 ppm, and could create objectionable odor and health hazards.

Ammonia is also a hazardous material. Accordingly, this material must be handled and stored with extreme care. Additionally, some catalytic elements are toxic, and because they have to be replaced periodically, hazardous waste disposal procedures may be necessary.

4.2.4 Conclusions

Installation of an SCR system on Unit 9 designed to meet a NO_x emission limitation of 9 ppmdv would cost Fort Pierce Utilities Authority approximately ~~$3.3 million~~.* Addition of an SCR system increases total levelized annual costs for the project by ~~$1.01 million~~* resulting in a removal cost of ~~$4,640~~* per ton of NO_x removed while burning natural gas (8760 hrs/yr). The use of SCR would reduce the effective output of the turbine generator by approximately ~~one percent~~.* In addition, the use of an SCR system could result in adverse environmental effects due to unreacted ammonia being released to the atmosphere causing a potential human health hazard. Project emissions of 42 ppmdv do not result in any violation of ambient air quality standards. Therefore, based on economic, energy, and environmental considerations, NO_x BACT proposed for this combustion turbine facility is the use of steam injection to achieve NO_x emissions of 42 ppmdv

* REVISED. SEE RESPONSE TO DER COMMENT 10.

(at 15 percent oxygen) when burning natural gas. Additionally, it is recommended that during emergency situations where distillate oil must be used NO_x emissions be limited to 65 ppmdv (at 15 percent oxygen) through the use of steam injection.

BLACK & VEATCH
ENGINEERS-ARCHITECTS

Owner: FPUA
Plant: H.D. KING Unit: 9
Project No.: 16539 File No.:
Title: EMISSION RATE SAMPLE CALCULATIONS

Computed By: RC
Date: 10/20 1990
Checked By: SMcC
Date: 10/21 1990

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CALCULATIONS

FLUE GAS MOLECULAR WEIGHT = $(0.1453)(31.9988) + (0.7376)(28.0134) + (0.0270)(44.0103) + (0.0091)(39.948) + (0.0810)(18.01534)$ = 28.32 lb/mol ✓

O_2, O_2, N_2, CO_2, Ar, H_2O

$PV = nRT$

$$V = \frac{nRT}{P}$$

$$n = \frac{(1{,}086{,}350 \ \mathrm{lb/h})}{(28.32 \ \mathrm{lb/mol})} = 38{,}356 \ \frac{\mathrm{mols}}{\mathrm{h}}$$

$$R = 1545 \ \frac{\mathrm{ft\text{-}lb}}{\mathrm{mol\text{-}°R}}$$

$$T = 460 + 488 = 948 \ °\mathrm{R}$$

$$P = (29.92 \ \mathrm{in\ Hg})\left(0.4912 \ \frac{\mathrm{lb/in^2}}{\mathrm{in\ Hg}}\right)\left(\frac{144 \ \mathrm{in^2}}{\mathrm{ft^2}}\right) = 2116 \ \mathrm{lb/ft^2}$$

$$V = \frac{\left(38356 \ \frac{\mathrm{mols}}{\mathrm{h}}\right)\left(1545 \ \frac{\mathrm{ft\cdot lb}}{\mathrm{mol\cdot R}}\right)(948 \ \mathrm{R})}{(2116 \ \mathrm{lb/ft^2})(60 \ \mathrm{min/h})} = \underline{\underline{442{,}000 \ \mathrm{acfm}}}$$ ✓

P-GN-172A

ATTACHMENT 3

STACK CHARACTERISTICS (HRSG AND BYPASS)

FPUA UNIT 9 COMBUSTION TURBINE STACK PARAMETERS - NATURAL GAS*

	HRSG Stack	Bypass Stack
Stack Height, ft	60	60
Effective Stack Diameter, ft	11.2**	11.2**
Stack Exit Volume, acfm	440,420	621,140
, dscfm	225,350	225,350
Stack Velocity, fpm	4,470 H	6,305
Stack Exit Temperature, F	488	877
Stack Moisture, % by volume	8.10	8.10
Stack Oxygen, % by volume	14.53	14.53

*Stack parameters are given for a GE PG5371 gas turbine with steam injection at an ambient temperature of 20 F. This ambient condition gives the highest pounds per hour emission rate.

**Actual stack is rectangular with dimensions: 9' 3" x 10' 7 1/8".

NOTE

All HRSG stack modeling performed in support of the Unit 9 air permit used preliminary stack flow parameters (See Table 5-1 of the AAQIA). These modeling parameters included lower stack flows and higher pounds per hour emission rates than the final values presented in this application. The lower gas flows used in the modeling decrease the momentum plume rise and thus, give higher ground-level impacts than the revised flows presented here. Likewise, the higher pound per hour emission rates used in the modeling analyses give higher ground level impacts than the emission rates presented in this application. Consequently, the modeled Unit 9 impacts are now expected to be slightly smaller than those presented in support of the Unit 9 Ambient Air Quality Impact Analysis.

OK

ATTACHMENT 4

EMISSION ESTIMATES: SOURCES AND CALCULATIONS

ASSUMPTIONS

- GENERAL ELECTRIC FRAME 5 COMBUSTION TURBINE
- NATURAL GAS FIRED (930 BTU/SCF)
- 100% LOAD
- AMBIENT CONDITIONS:
  - TEMPERATURE = 20 F
  - PRESSURE = 29.92 in Hg
  - RELATIVE HUMIDITY = 60%
- COMBINED CYCLE OPERATION
- FLUE GAS TEMPERATURE = 488 F*
- OUTLET FLUE GAS PRESSURE = 0 in wg
- FLUE GAS FLOW RATE = 1,086,350 lb/h*
- FLUE GAS ANALYSIS (VOLUMETRIC):*

OXYGEN	=	14.53% ✓
NITROGEN	=	73.76% ✓
CARBON DIOXIDE	=	2.70% ✓
ARGON	=	0.91% ✓
MOISTURE	=	8.10% ✓
		100.00%

- MOLECULAR WEIGHTS:

OXYGEN	=	31.9988 lb/mol ✓
CARBON	=	12.01115 lb/mol ✓
HYDROGEN	=	2.01594 lb/mol ✓
SULFUR	=	32.064 lb/mol ✓
NITROGEN	=	28.0134 lb/mol ✓
ARGON	=	39.948 lb/mol ✓
CO_2	=	44.00995 lb/mol ✓
H_2O	=	18.01534 lb/mol ✓
NO_2	=	46.0055 lb/mol ✓

* VALUES FROM TABLE 1 (ATTACHED). OPERATION VALUES BASED ON MANUFACTURER PERFORMANCE CURVES.

BLACK & VEATCH ENGINEERS-ARCHITECTS

Owner FPUA
Plant H.D. King Unit 9
Project No. 16589 File No.
Title Emission Rate Sample Calculations

Computed By
Date 10/20 1990
Checked By SMD
Date 10/21 1990

NO_x Emission Rate = 42 ppmdv @ 15% Oxygen

	Volume %	Moles*	Dry Volume %
Oxygen	14.53	5573	15.81
Nitrogen	73.76	28291	80.26
Carbon Dioxide	2.70	1036	2.94
Argon	0.91	349	0.99
Moisture	8.10	3107	
		38356	100.00

* Moles = (Volume, % / 100) × 38356 mols/h

Dry Moles = 38356 − 3107 = 35249 mols/h

– Air consists of 21% Oxygen : 79% Nitrogen (By Volume)

– To correct to 15% Oxygen it is necessary to hypothetically subtract air from the flue gas

X = moles of air added

$$0.15 = \frac{5573 + 0.21X}{35249 + X}$$

$$0.15(35249 + X) = 5573 + 0.21X$$

$$5287.35 + 0.15X = 5573 + 0.21X$$

$$X(0.15 - 0.21) = 5573 - 5287.35$$

$$X = -4760.8 \ \frac{\text{mols Air}}{h}$$

DO NOT WRITE IN THIS SPACE

P-GN-172A

BLACK & VEATCH
ENGINEERS-ARCHITECTS

Owner FPUA
Plant H.D. KING Unit 9
Project No. 16589 File No.
Title EMISSION RATE SAMPLE CALCULATIONS

Computed By [signature]
Date 10/20 1990
Checked By SMO
Date 10/21 1990
Page 4 of 4

	ACTUAL MOLES mol/h		$15\% O_2$ CORRECTED MOLES mol/h	CORRECTED DRY VOLUME %
OXYGEN	5573	− 4760.8 (0.21) =	4573	15.0
NITROGEN	28291	− 4760.8 (0.79) =	24530	80.5
CARBON DIOXIDE	1036		1036	3.4
ARGON	349		349	1.1
TOTAL	35,249		30488	100.0

$$NO_x \text{ EMISSION RATE} = 42 \text{ ppmdv} = 42 \frac{\text{mols } NO_2}{10^6 \text{ mols FLUE GAS}}$$

$$NO_x \text{ EMISSION RATE} = \left(42 \frac{\text{mols } NO_2}{10^6 \text{ mols FLUE GAS}}\right)\left(30488 \frac{\text{mols}}{h}\right)\left(46.0055 \frac{\text{lb } NO_2}{\text{mol } NO_2}\right)$$

$$NO_x \text{ EMISSION RATE} = \underline{\underline{58.9 \text{ lb/h}}}$$

$$CO \text{ EMISSION RATE} = 10 \text{ ppmdv @ } 15\% O_2$$

$$CO \text{ EMISSION RATE} = \left(\frac{10}{10^6}\right)(30488)(12.01115 + 31.9988/2) = \underline{\underline{8.5 \text{ lb/h}}}$$

$$VOC = \text{NON METHANE HYDROCARBONS} = 5 \text{ ppmdv @ } 15\% O_2$$

$$\text{NON-METHANE HYDROCARBONS} = \left(\frac{5}{10^6}\right)(30488)(12.01115 + (2)(2.01594)) = \underline{\underline{2.4 \text{ lb/h}}}$$

DO NOT WRITE IN THIS SPACE

PGN-172A

FORT PIERCE, FLORIDA, COMBINED CYCLE PROJECT 10/18/90
B&V PROJECT 16589.070
ESTIMATED COMBINED CYCLE STACK PERFORMANCE VALUES

Fuel	Gas	Gas w/ SCR	Oil	Gas	Gas w/ SCR	Oil	
Ambient Temperature, F	20	20	20	59	59	59	
Exhaust Flow, lb/h	1,086,350	1,086,350	1,091,790	999,000	999,000	1,004,000	
CT Exhaust Temperature, F	877	879	877	905	907	905	
Stack Temperature, F	494	493	494	487	486	487	
Stack Exit Pressure, psia	14.7	14.7	14.7	14.7	14.7	14.7	
Exhaust Gas Constituents (mass basis)							
Percent CO2	4.20	4.20	5.50	4.12	4.12	5.39	
Percent H2O	5.15	5.15	3.96	5.53	5.53	4.37	
Percent O2	16.41	16.41	16.56	16.43	16.43	16.58	
Percent N2	72.95	72.95	72.68	72.63	72.63	72.37	
Percent Ar	1.29	1.29	1.28	1.28	1.28	1.28	
Total	100.00	100.00	99.98	99.99	99.99	99.99	
Exhaust Gas Constituent Flows, lb/h							
CO2	45,627	45,627	60,060	41,163	41,163	54,121	
H2O	55,947	55,947	43,244	55,250	55,250	43,879	
O2	178,270	178,270	180,837	164,152	164,152	166,480	
N2	792,492	792,492	793,672	725,646	725,646	726,667	
Ar	14,014	14,014	13,978	12,788	12,788	12,852	
Total, lb/h	1,086,350	1,086,350	1,091,790	999,000	999,000	1,004,000	
Exhaust Gas Constituent Flows, mole/h							MW (lb/mole)
CO2	1,036.7	1,036.7	1,364.7	935.3	935.3	1,229.7	44.010
H2O	3,105.4	3,105.4	2,400.3	3,066.7	3,066.7	2,435.6	18.016
O2	5,570.9	5,570.9	5,651.2	5,129.8	5,129.8	5,202.5	32.000
N2	28,287.1	28,287.1	28,329.2	25,901.1	25,901.1	25,937.6	28.016
Ar	350.9	350.9	350.0	320.2	320.2	321.8	39.940
Total, mole/h	38,351.0	38,351.0	38,095.4	35,353.1	35,353.1	35,127.2	
Exhaust Gas Constituents (volume basis)							
Percent CO2	2.70%	2.70%	3.58%	2.65%	2.65%	3.50%	
Percent H2O	8.10%	8.10%	6.30%	8.67%	8.67%	6.93%	
Percent O2	14.53%	14.53%	14.83%	14.51%	14.51%	14.81%	
Percent N2	73.76%	73.76%	74.36%	73.26%	73.26%	73.84%	
Percent Ar	0.91%	0.91%	0.92%	0.91%	0.91%	0.92%	
Total	100.00%	100.00%	99.99%	100.00%	100.00%	100.00%	

Wet (Total) Exhaust Gas Analysis

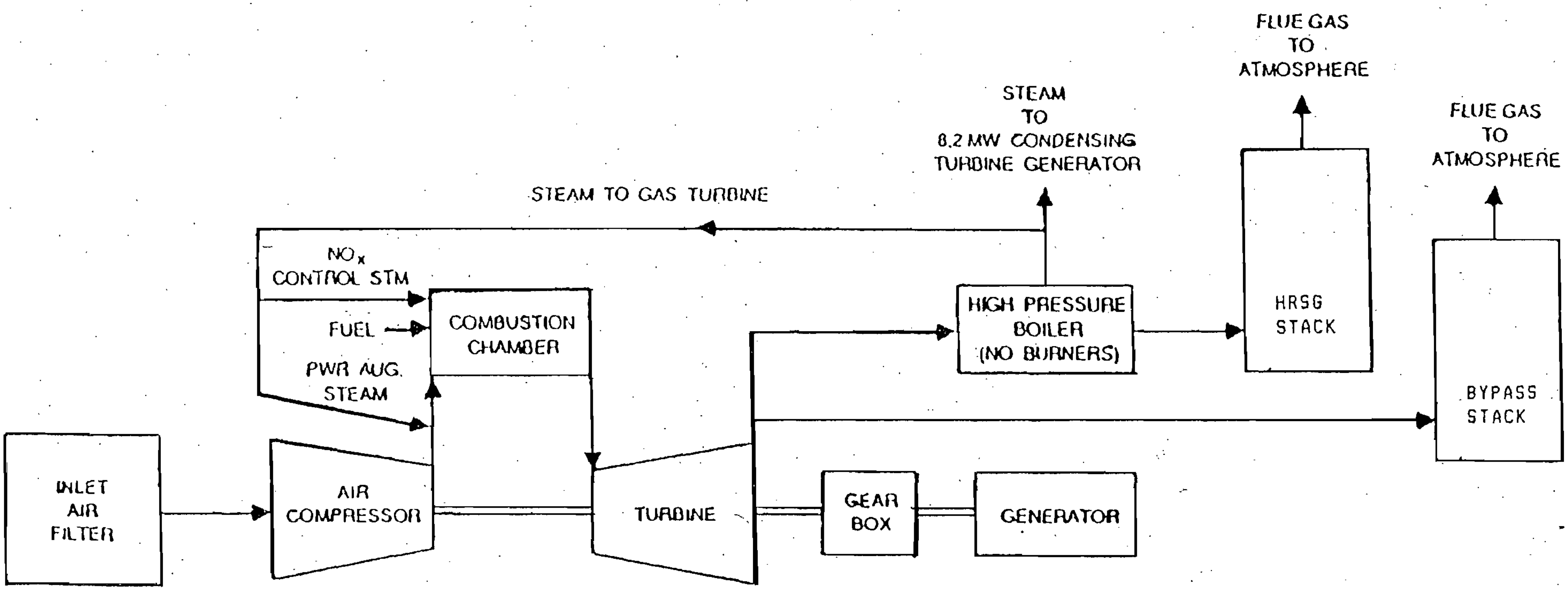
Exhaust Gas Molecular Weight, lb/mole	28.33	28.33	28.66	28.26	28.26	28.58
Gas Constant for Exhaust Gas, ft-lbf/lbm-R	54.536	54.536	53.908	54.671	54.671	54.059
Exhaust Gas Specific Volume, ft^3/lb	24.58	24.55	24.30	24.46	24.43	24.18
Exhaust Gas Flow, acfm	445,041	444,498	442,175	407,259	406,760	404,612

Dry Exhaust Gas Analysis

Exhaust Gas Molecular Weight, lb/mole	29.23	29.23	29.38	29.23	29.23	29.37
Gas Constant for Exhaust Gas, ft-lbf/lbm-R	52.857	52.857	52.587	52.857	52.857	52.605
Exhaust Gas Specific Volume, ft^3/lb	23.82	23.80	23.70	23.65	23.62	23.53
Exhaust Gas Flow, acfm	431,281	430,919	431,257	393,773	393,273	393,735

ATTACHMENT 5

COMBUSTION TURBINE FLOW DIAGRAM



Simplified process flow diagram.

DER Comment 2

- o Provide the present actual emissions of each pollutant listed in Table 500-2 of F.A.C. Rule 17-2.500 in units of the applicable emission limiting standard, lb/hr, and tons/year for each affected source [Unit 6, Unit 7, Unit 8, and Unit 9]. The present actual emissions are to be determined on the basis of the most recent source emission test wherever possible. Where emission tests are used, copies of the cover page and summary sheet are to be included.

Response

- o Unit 9 is the only affected source, however, present actual emissions are being provided for all four units. The attached table provides the actual emission rates for applicable pollutants listed in Table 500-2 of F.A.C. Rule 17-2.500. The units will only burn natural gas during 1990. Therefore, the emissions listed in the attached table are based on the combustion of natural gas only. Emission tests are not required for a number of the pollutants. In the absence of actual performance tests, emission rates are calculated based on appropriate emission factors from AP-42. When applicable, test summary sheets are attached to support emission rates listed in the tables. Annual emissions are based on the allowable hours of operation for the four sources listed in the operating permit for Unit 9.

H. D. KING UNITS 6 - 9 ACTUAL EMISSION RATES

	Unit 6	Unit 7	Unit 8	Unit 9
Allowable Annual Operation, hr	12	1344	6384	8736
Hourly Emissions, lb/h				
Nitrogen Oxides	117	251	111*	57* less than nedited
Carbon Monoxide	8.5	18	24	0.68*
Particulate	0.64	1.4	1.8	0.93
Non-Methane Hydrocarbons	0.30	0.64	0.83	0.44
Sulfur Dioxide	0.13	0.27	0.36	0.20
Annual Emissions, tons/year				
Nitrogen Oxides	0.70	169	353*	250*
Carbon Monoxide	0.051	12.3	76	3.0*
Particulate	0.0038	0.92	5.7	4.1
Non-Methane Hydrocarbons	0.0018	0.43	2.7	1.9
Sulfur Dioxide	0.00077	0.18	1.1	0.87

*Emission rates based on the attached emission test results.

SOURCE COMPLIANCE TEST REPORT
for
OXIDES OF NITROGEN AND VISIBLE EMISSIONS
UNIT 8

AND

VISIBLE EMISSIONS
EAST DIESEL UNIT

H.D. KING GENERATING STATION
FT. PIERCE MUNCIPAL UTILITIES

FDER PERMIT NUMBERS

UNIT 8	AO 56-112678
EAST DUCT UNIT	AO 56-113533

SEPTEMBER 11, 1989

Prepared for:

FT. PIERCE MUNCIPAL UTILITIES
311 NORTH INDIAN RIVER DRIVE
FT. PIERCE, FLORIDA 33454

Prepared by:

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

150-89-01

Table 1 NO_x Emission Summary
Ft. Pierce Utilities
H.D. King Generating Station
Unit 8
September 11, 1989

Run Number	Time	Oxygen (%)	NO_x Emissions Actual (ppm Dry)	NO_x Emissions Actual (lb/MMBTU)	Allowable (lb/MMBTU)
1	0820-0920	5.80	129	0.186	0.2
2	0935-1035	5.46	126	0.177	0.2
3	1105-1205	5.57	126	0.179	0.2
Average	----	5.61	127	0.181	0.2

STATIONARY GAS TURBINE EMISSION TEST

FORT PIERCE UTILITIES AUTHORITY
HENRY D. KING POWER PLANT

FORT PIERCE, FLORIDA

EEI 6103

SEPTEMBER 1989

Prepared by:

CEM/Engineering Division
Entropy Environmentalists, Inc.
Research Triangle Park, North Carolina

Prepared for:

General Electric Company
GE Turbines Division
Schenectady, New York

REPORT CERTIFICATION

The sampling and analysis performed for this report were carried out under my direction and supervision, and I hereby certify that the test report is authentic and accurate.

Date 10/24/89 Signature Kenneth R Loder

Kenneth R. Loder
Senior Projects Manager
CEM/Engineering Division

I have reviewed the testing details and results in this report, and hereby certify that the test report is authentic and accurate to the best of my knowledge.

Date 10/24/89 Signature J Ron Jernigan

J. Ron Jernigan, P.E.
Manager, Field Testing Services
CEM/Engineering Division

NORTH CAROLINA
PROFESSIONAL
SEAL
8487
ENGINEER
J. RON JERNIGAN

1. INTRODUCTION

General Electric Company's Turbine Division retained Entropy Environmentalists, Inc. to perform emissions testing on a combined cycle gas turbine installed at Ft. Pierce Utilities Authority's Henry D. King Power Plant in Ft. Pierce, Florida. EPA test methods were employed to accurately quantify the atmospheric emissions of oxygen (O_2), carbon dioxide (CO_2), nitrogen oxides (NO_x), carbon monoxide (CO), and visible emissions from the turbine at four operating load conditions.

Ken Loder, Le Tan, and Mark Winter from Entropy conducted the testing on September 13, 1989. The test program was coordinated by Betty Lou Bailey, P.E. and Chuck Prosser from General Electric, and Dave Schade from the Henry D. King Power Plant. Thomas Davis, P.E. from the environmental engineering firm of Hunter/ESE observed the testing on behalf of the plant. Tom Tittle and Joseph Kahn represented the State of Florida, Department of Environmental Regulations, during the test period.

This report presents the test data, test methods and equipment used, and data reduction and quality assurance procedures utilized during the emissions test program.

furnished by General Electric, were cleaned and purged with nitrogen prior to use. The high nitrogen content indicates inadequate sample purge of the container before sample collection. The high nitrogen sample was rejected. The analysis of the remaining sample showed the SO_2 was well within the 150 ppm (0.015%) by-volume limit.

TABLE 1.

EMISSION DATA SUMMARY
GAS TURBINE EMISSION TESTING
HENRY D. KING POWER PLANT, UNIT 9
SEPTEMBER 13, 1989

— Steam Augmentation

	Load Level			
	100%	100%	75%	30%
Operating Load (MW):	23.0	23.9	17.8	7.6
NO_x @ 15% O_2, Dry ISO Conditions (ppm_{vd}):	59	43	58	44
NO_x Emission Limit (ppm_{vd}):	84	84	84	84
SO_2 Concentration, dry (ppm_{vd}):	< 1	< 1	< 1	< 1
Average CO Concentration, dry (ppm_{vd}):	1	1	4	112
Visible Emissions (% opacity):	0	0*	---	---
Visible Emissions Limit (% opacity):	15	15	15	15
Steam Injection (lb/sec):	0.83	0.90	0.0	0.0
Steam Augmentation (lb/sec):	0.0	2.23	0.0	0.0
Fuel Flow (lb/sec)	3.72	3.80	3.09	2.02

*Daylight conditions permitted only 24 minutes of visible emissions data to be recorded.

DER Comment 3

- o Provide the maximum proposed emissions of each pollutant listed in Table 500-2 of F.A.C. Rule 17-2.500 in units of the applicable emission limiting standard, lb/h and tons/year to be emitted by each affected source [Unit 6, Unit 7, Unit 8, and Unit 9]

Response

- o The attached table provides the maximum proposed emission rates for applicable pollutants listed in Table 500-2 of F.A.C. Rule 17-2.500. The following summarizes the basis of these emission rates

Unit 8 emissions are limited by F.A.C. requirements to the following rates.

-- Nitrogen oxides = 0.20 lb/MBtu (natural gas)
= 0.30 lb/MBtu (fuel oil)

-- Particulate = 0.10 lb/MBtu

-- Opacity = 20 percent

The Unit 8 emissions listed in the attached table are based on combustion of natural gas only.

The proposed maximum emission rates for Unit 9 are as follows.

-- Nitrogen oxides = 42 ppmdv (parts per million dry volumetric) at 15 percent oxygen

-- Carbon monoxide = 10 ppmdv at 15 percent oxygen

-- Non-methane hydrocarbons = 5 ppmdv at 15 percent oxygen

-- Particulate = 2.5 lb/h

These emission rates are typical for a General Electric Frame 5 combustion turbine and were provided by the equipment manufacturer. Hourly emission rates listed in the table for Unit 9 are calculated assuming a worst case ambient temperature of 20 F (resulting in the maximum expected emissions). In addition, sulfur dioxide emissions for Unit 9 are based on a gas sulfur content of 2000 gr/10^6 scf, and a gas heating value of 930 Btu/scf.

The remaining Unit 6, Unit 7, Unit 8, and Unit 9 emission rates are calculated based on appropriate emission factors from AP-42.

H. D. KING UNITS 6 - 9 PROPOSED MAXIMUM EMISSION RATES

	Unit 6	Unit 7	Unit 8	Unit 9
Allowable Annual Operation, hr	8760	8760	8760	8760
Hourly Emissions, lb/h				
Nitrogen Oxides	117	251	122	59 ✓
Carbon Monoxide	8.5	18	24	8.5
Particulate	0.64	1.4	1.8	2.5
Non-Methane Hydrocarbons	0.30	0.64	0.83	2.4
Sulfur Dioxide	0.13	0.27	0.36	0.20
Annual Emissions, tons/year				
Nitrogen Oxides	512	1099	535	258
Carbon Monoxide	37	80	104	37
Particulate	2.8	6.0	7.8	11
Non-Methane Hydrocarbons	1.3	2.8	3.7	11
Sulfur Dioxide	0.56	1.2	1.6	0.88

DER Comment 4

- Explain why the previous application for a construction permit projected carbon monoxide emissions of 110 tons/year from Unit 9 while the present permit application indicates projected CO emissions of 41 tons/year from Unit 9. The previous application also included total contemporaneous emission reductions of about 99.3 tons/year from Units 6, 7, and 8. It appears that you may be required to determine downwind concentrations of CO using EPA approved models and perform a best available control technology (BACT) analysis for CO.

Response

- AP-42 emission factors provided the basis for the 110 tons/year CO emission rate listed in the previous application. However, actual performance of the General Electric Frame 5 combustion turbines has indicated CO emissions far below the AP-42 emission factors. Based on consultations with General Electric the maximum expected CO emission rate from the combustion turbines is 10 ppmdv (corrected to 15 percent oxygen). Based on CO emissions of 10 ppmdv the maximum emission rate for the project is expected to be 8.5 lb/h. This results in an annual emission of 37 tons/year. This annual CO emission is below the 100 ton/year PSD significance level. Therefore, no ambient air quality analyses will be required.

DER Comment 5

- ISO standard day conditions for gas turbines are defined as 288 K (59 F), 101.3 KPa (29.92 in. Hg.), and 60% relative humidity. The concentration standard for gas turbines is expressed at dry ISO conditions. Some of your gas turbine emission calculations involving standard conditions did not appear to be based on dry ISO conditions. Please make necessary corrections. For other air pollutant emission sources state and federal regulations define standard temperature and pressure to be 68 F and 29.92 in. Hg.

Response

- Emission rates listed in the application and these responses for the Unit 9 combustion turbine are based on the following constant emission rates.
  - -- Nitrogen oxides = 42 ppmdv (parts per million volumetric dry) at 15 percent oxygen
  - -- Carbon monoxide = 10 ppmdv at 15 percent oxygen
  - -- Non-methane hydrocarbons = 5 ppmdv at 15 percent oxygen
  - -- Particulate = 2.5 lb/h

  Combustion turbine outputs (megawatts, fuel burn rates, and emissions) increase for operation at lower ambient temperatures. Therefore, the maximum emission rates for a combustion turbine do not occur at 59 F ISO standard day conditions but occur during lower ambient temperatures. The lowest anticipated temperature for the Fort Pierce project is 20 F. To keep the analysis of impacts conservative, the maximum emission rates listed in the application and these responses are based on an ambient temperature of 20 F.

DER Comment 6

- Provide the present actual and proposed stack parameters for each of the affected sources [Unit 6, Unit 7, Unit 8, and Unit 9). The parameters are to include stack height, stack exit diameter, stack exit volume (ACFM and DSCFM), stack velocity, stack exit temperature, stack moisture (% by volume), and stack oxygen (% by volume). Also, provide the present actual and the proposed annual hours of operation for each of the affected sources [Unit 6, Unit7, Unit 8, and Unit 9].

Response

- The proposed stack parameters for the Unit 9 combustion turbine are given in the attached table for both HRSG and bypass operation when firing natural gas. These stack parameters are based on estimated performance of a GE PG5371 gas turbine with steam injection at an ambient temperature of 20 F. As noted in an October 4, 1990 telephone conference with the DER, the comments with respect to Units 6, 7, and 8 are no longer applicable.

FPUA UNIT 9 COMBUSTION TURBINE STACK PARAMETERS - NATURAL GAS*

	HRSG Stack	Bypass Stack
Stack Height, ft	60	60
Effective Stack Diameter, ft	11.2**	11.2**
Stack Exit Volume, acfm	440,420	621,140
, dscfm	225,350	225,350
Stack Velocity, fpm	4,470	6,305
Stack Exit Temperature, F	488	877
Stack Moisture, % by volume	8.10	8.10
Stack Oxygen, % by volume	14.53	14.53
20 F Emission Rate @ 15% O_2:		
PM, lb/h	2.5	2.5
, tpy***	11.0	11.0
SO_2, lb/h	0.2	0.2
, tpy***	0.9	0.9
NO_x, ppmdv	42	42
, lb/h	58.9	58.9
, tpy***	258.0	258.0
VOC, ppmdv	5	5
, lb/h	2.4	2.4
, tpy***	10.5	10.5
CO, ppmdv	10	10
, lb/h	8.5	8.5
, tpy***	37.2	37.2

*Stack parameters are given for a GE PG5371 gas turbine with steam injection at an ambient temperature of 20 F. This ambient condition gives the highest pounds per hour emission rate.

**Actual stack is rectangular with dimensions: 9' 3" x 10' 7 1/8".

***Annual emissions are based on 8,760 hours of operation per year.

NOTE: The bypass stack is only used during startup and for emergency peaking generation in simple cycle.

DER Comment 7

- o Considering the geography and climatology of Ft. Pierce, we question the use of an ambient temperature of 20 F [Table 5-1] in the modeling parameters. Please explain. Additional modeling may be required.

Response

- o Combustion turbine outputs (megawatts, fuel burn rates, and emissions) increase for operation at lower ambient temperatures (see response to DER Comment 5). The lowest anticipated temperature for the Fort Pierce project is 20 F. To keep the analysis of impacts conservative, the maximum emission rates used in the modeling analyses are based on an ambient temperature of 20 F. However, the dispersion analyses are based on five years (1982-1986) of hourly meteorological data from West Palm Beach, Florida as indicated in the application's ambient air quality impact analysis. Therefore, the modeling analysis is quite conservative since actual emissions will almost always be lower than the modeled emissions.

DER Comment 8

- o Provide the maximum quantities of NO_x, ammonia, and each amine compound (ppmv @ dry conditions, lbs./hr., and tons/year) that would be emitted if Unit 9 were equipped with steam injection and selective catalytic reduction. Please identify each of the amine compounds that would be expected. Please provide the stack parameters for Unit 9 based on the installation of steam injection and selective catalytic reduction.

Response

- o The maximum quantities of NO_x and ammonia that would be emitted if SCR were added to Unit 9 are given in the attached table. No detailed information is available concerning emissions of amine compounds when SCR is utilized. HRSG stack parameters considering steam injection and SCR are also given in the attached table. These stack parameters assume an ambient temperature of 20 F.

FPUA UNIT 9 COMBUSTION TURBINE STACK PARAMETERS - NATURAL GAS WITH SCR*

	HRSG Stack SCR
Stack Height, ft	60
Effective Stack Diameter, ft	11.2**
Stack Exit Volume, acfm	439,490
, dscfm	225,350
Stack Velocity, fpm	4,461
Stack Exit Temperature, F	486
Stack Moisture, % by volume	8.10
Stack Oxygen, % by volume	14.53
20 F Emission Rate @ 15% O_2:	
PM, lb/h	2.5
, tpy***	11.0
SO_2, lb/h	0.2
, tpy***	0.9
NO_x, ppmdv	9
, lb/h	12.6
, tpy***	55.2
VOC, ppmdv	5
, lb/h	2.4
, tpy***	10.5
CO, ppmdv	10
, lb/h	8.5
, tpy***	37.2
Ammonia, ppmdv	10
, lb/h	5.2
, tpy***	22.8

*Stack parameters are given for a GE PG5371 gas turbine with steam injection and SCR at an ambient temperature of 20 F. This ambient condition gives the highest pounds per hour emission rate.

**Actual stack is rectangular with dimensions: 9' 3" x 10' 7 1/8".

***Annual emissions are based on 8,760 hours of operation per year.

DER Comment 9

- o Provide the 1-hour, 8-hour, 24-hour, and annual concentrations of NO_x, ammonia, and each of the identified amine compounds that would result if Unit 9 were equipped with steam injection and catalytic reduction.

Response

- o As requested, the 1-, 8-, 24-hour, and annual concentrations of NO_x and ammonia are given in the attached table. Ground-level concentrations could not be evaluated for amine compounds since detailed emission information is not available. A diskette and paper copy of the modeling output has been included.

  It should be noted that the combustion turbine as proposed (steam injection only to achieve a NO_x emission limit of 42 ppmdv at 15 percent oxygen) showed maximum NO_x impacts to be less than ten percent of the NAAQS in the AAQIA modeling. These turbine impacts added to the NO_x background and other interacting sources were only about one third of the NAAQS. In addition, the H.D. King site is not near any ozone non-attainment areas. These facts demonstrate that there would be minimal air quality benefit from the addition of SCR for this turbine and, additionally, would create a small adverse impact from ammonia emissions.

MODELED NOx AND AMMONIA IMPACTS WITH SCR[1]

Averaging Period[3]	Maximum Ground Level Impacts[2] Ammonia with SCR (10 ppmdv) ug/m3	NO_x with SCR (9 ppmdv) ug/m3	Impact Location Dist. km	Dir. deg
Annual	0.8	1.8	0.879	260
24-Hour	19.6	47.4	0.879	260
8-Hour	36.9	89.5	0.654	90
1-Hour	71.6	173.6	0.654	90

[1]GE PG5371 combined cycle combustion turbine with steam injection and Selective Catalytic Reduction (SCR).

[2]All modeled maximum impacts occurred in 1984.

[3]Annual pollutant impacts are based on maximum modeled concentrations. The short-term impacts are based on highest, second-highest modeled concentrations.

NOTE: Modeling was performed as described in Section 5.0 of the AAQIA. Specifically, stack parameters as presented in Table 5-1 of the AAQIA were used in this analysis. SCR emission rates at 20 F ambient conditions were used to determine impacts. These rates are:

NO_x @ 15% O_2	, ppmdv	9
	, lb/h	12.6
	, tpy	55.2
Ammonia @ 15% O_2	, ppmdv	10
	, lb/h	5.2
	, tpy	22.8

DER Comment 10

- o Explain how the costs on page 4-5 were derived, what is included in each of the listed categories (contingency, escalation, indirects, maintenance, energy, lost generation, etc.), the terms "energy" and "lost generation", and how the various percentages were arrived at. Since BACT is being evaluated using "today's" cost guidelines the economic analysis for selective catalytic reduction should be based on the present cost instead of the 1993 projections.

Response

- o Based on a more current cost analysis a revised Table 4-1 from the BACT analysis is attached. Revisions were made for a number of reasons. Economic criteria used to develop the costs listed on Table 4-1 were in some cases revised to reflect current economic conditions. In light of recent developments in the Mideast it appears that the escalation rates used in original analysis may be low. Therefore, the revised Table 4-1 is based on an operating cost escalation rate of 7 percent in lieu of the original 6 percent. Other revisions and a response to the comment are fully described by the following.

  Capital costs for the SCR system and HRSG modifications were based on budgetary quotations from equipment manufacturers and in-house cost estimates. The 15 percent margin for contingency accounts for uncertainties inherent in estimating capital costs of this magnitude for a retrofit project. In addition, the contingency margin will cover costs neglected in determining the capital cost estimates.

  It would take approximately 18-months to procure, design, construct and start-up an SCR system on Unit 9. Therefore, costs presented in the revised Table 4-1 are reflective of July 1992

TABLE 4-1. NITROGEN OXIDE EMISSIONS REDUCTION SYSTEM CAPITAL AND LEVELIZED ANNUAL COSTS (REVISED)

	SCR SYSTEM $1,000
Capital Costs:	
SCR System	930
HRSG Modifications	590
System Erection	520
Differential Balance of Plant	70
1991 Capital Cost	2,110
Contingency (15 percent)	320
Escalation (6 percent)	180
Direct Capital Cost	2,610
Indirects (16 percent)	420
Interest During Construction (8 percent)	60
1993 Total Capital Cost	3,090
Levelized Annual Costs*:	
Operating Personnel	70
Maintenance	510
Ammonia	70
Energy	50
Lost Generation	210
1993 Annual Operating Cost	910
Fixed Charges on Capital (13.6 percent)	340
1993 Total Annual Cost	1,250
Nitrogen Oxides Emission Rate, ppmdv	9
Annual NO_x Emission Reduction, tpy	202
NO_x Emission Reduction Cost, $/ton	6,190

*Annual costs are based on a 100 percent capacity factor.

dollars. Previous costs listed in Table 4-1 of the application were based on a 24-month schedule.

Payment for the equipment would be expected to occur around month 15 of the project. Therefore, capital costs were escalated at an annual rate of six percent for 15 months. This results in a direct capital cost of $2,610,000. The previous Table 4-1 was based on only one year of escalation at a rate of six percent.

An indirect cost factor of 16 percent was applied to the escalated direct capital cost. Indirects cover owner and architect/engineer costs to design, procure, construct, and start-up the SCR system.

Interest during construction is applied to the escalated direct capital cost plus indirects for the construction period of three months at a rate of 8 percent. The previous Table 4-1 was based on one year of interest during construction. The July 1992 capital cost of retrofitting a SCR system to Unit 9 is $3,090,000.

The annual operating costs for use of a SCR system include operating personnel, maintenance costs (primarily catalyst replacement), ammonia additive, energy, and lost generating capacity. Current estimates of these costs were escalated to the first year of operation based on an escalation rate of 7 percent. These first year costs were also levelized to account for the effect of escalation and present worth of future annual expenditures. Assuming a constant escalation rate of 7 percent and a constant present worth discount rate of 8 percent and the 25-year life of the facility the levelization factor is 1.94. Accordingly, first year operating costs were multiplied by this levelization factor to determine the levelized annual operating costs listed in Table 4-1.

Additional detail regarding the basis of the annual operating costs follows.

Operating personnel costs are based on one operator for one-half shift per day (4 hours). Additionally, operator costs are based on a loaded payroll cost of $45,000 per year (1990 dollars).

Maintenance costs consist of a minor amount of routine SCR system maintenance and the predominant expense of catalyst replacements. It is expected that catalyst replacements will occur once every three years. Catalyst replacement costs only reflect replacement of the catalyst bed.

Ammonia costs are based on a 1990 cost of ammonia of $250 per ton. Ammonia usage rates were based on information obtained from potential SCR manufacturers.

Energy costs reflect the electrical consumption requirements of the SCR system. It is estimated that the SCR system will consume 36 kW of electricity to run pumps and vaporizers. Energy penalties are assessed based on a 1990 cost of 70 mills per kWh. This energy cost reflects fuel, O&M, and replacement plant costs.

Due to the pressure drop associated with the use of a SCR system the Unit 9 combustion turbine will be derated by approximately 0.6 percent (approximately 162 kW). This lost generation capacity must be replaced. Therefore, a penalty based on a 1990 energy cost of 70 mills per kWh is assessed against the SCR system. Previous values for lost generation listed in the original Table 4-1 only reflected the capital cost of replacement power for this lost generation. Current estimates provided in the revised Table 4-1 also include the operation and maintenance costs associated with makeup of this lost generation.

Total annual costs for an SCR system are calculated as the sum of levelized annual operating costs and fixed charges on capital. Fixed charges are those annual ownership costs that vary directly with the capital investment. A fixed charge rate of 10.9 percent was used to calculate the costs listed in Table 4-1. The fixed charge rate was calculated based on the cost of debt, depreciation, and margins for property taxes and insurance.

The total annual cost for installation of a SCR system on Unit 9 would be $1,250,000 in July 1992 dollars. The SCR system would be capable of meeting a NO_x emission limit of 9 ppmdv at 15 percent oxygen. This results in an incremental NO_x emission reduction cost of $6,190 per ton. Recent permit determinations by the DER have been based on costs representative of first operational year dollars, and not current or "today's" dollars. We would expect this project to be reviewed using those same policy guidelines. Therefore, the request by DER to convert these costs to today's dollars is not consistent with precedent and therefore, does not seem appropriate.

The estimated actual costs to Fort Pierce listed in Table 4-1 of the BACT analysis include a cost of $590,000 for HRSG modifications and an incremental cost of $312,000 for erection over and above the cost of erection of an SCR at a new site. Fort Pierce Utilities Authority did not choose its permitting history with any intent to avoid SCR. In fact, earlier BACT guideline values would not have indicated SCR had the unit originally been subject to BACT review for NO_x. Consequently, we believe that actual expected costs are the appropriate measure of this BACT analysis.

DER Comment 11

- On page 4-6, you state that the addition of a selective catalytic reduction system to meet 9 ppmv @ 15% O_2 will add $1.1 million dollars to the levelized annual cost for Unit 9? What is the present levelized annual cost for each of the other generating units at H. D. King generating station? Would the selective catalytic reduction system in your analysis achieve an NO_x concentration of 25 ppmv @ 15% O_2 when oil is burned? Fully explain your answer.

Response

- The present annual cost of operating Unit 9 is $728,830. The initial capital cost of Unit 9 was $13.4 million in 1989 dollars. To compare with the July 1992 costs listed in the revised Table 4-1 it is necessary to adjust these annual operating and capital costs by the following factors.
  - -- Capital escalation = 6 percent per year
  - -- Operating cost escalation = 7 percent per year
  - -- Levelized fixed charge rate = 10.87 percent
  - -- Operating cost levelization factor = 1.94

Escalation and levelization of the Unit 9 operating and capital cost results in a levelized annual cost of $3.46 million in July 1992 dollars. Based on a levelized annual cost of $1.25 million to own and operate a SCR system the levelized annual cost for Unit 9 would increase to $4.71 million, a 36 percent increase. Based on the October 4, 1990 telephone conference between the DER and B&V it is not necessary to present the levelized annual costs for Units 6, 7, and 8.

Unit 9's combustion turbine is capable of limiting NO_x emissions to 65 ppmdv at 15 percent oxygen when burning fuel oil. However, fuel oil will only be burned during emergency operation. Use of a SCR system when burning fuel oil could lead to a number of catalyst poisoning and downstream equipment fouling problems. Costs listed in the revised Table 4-1 reflect a catalyst designed for use with natural gas only. Therefore, the basis of the BACT's SCR scenario is that if an emergency situation arose that required the use of fuel oil the SCR system would not be operated. In emergency situations when fuel oil must be burned a NO_x emission rate of 65 ppmdv at 15 percent oxygen should be achievable.

DER Comment 12

- o Please provide a copy of each construction permit that has been issued for the construction of Unit 6, Unit 7, and Unit 8. Provide the initial date of construction and completion for each of these air pollution sources.

Response

- o If any construction permits for these units have been found in our files we have enclosed a copy of them with these responses.

DER Comment 13

- o Describe the bypass stack in terms of the circumstances and frequency of use, location within the facility, geometry [height and diameter], flue gas parameters [volume (ACFM and DSCFM), exit velocity (fpm), exit temperature (^{o}F), moisture (% by volume), and oxygen (% by volume)], and the maximum hourly and annual emissions of each pollutant listed (in) Table 500-2 of F.A.C. Chapter 17-2.

Response

- o The Unit 9 combustion turbine bypass stack is only used during startup and emergency peaking generation in simple cycle operation. Although these uses are expected to be very infrequent and/or of short duration, the stack is being permitted such that it could be operational for 8,760 hours per year. The location of the bypass stack relative to the HRSG stack is shown in the attached figure.

  The stack parameters for both HRSG and bypass operation are given in the attached table. Note that the emission rates are the same for both simple (bypass) and combined cycle operation (HRSG). However, simple cycle operation involves much higher gas exit temperatures (and thus higher ACFM exit flows). These higher temperatures and flow volumes lead to greater thermal and momentum plume rise. This increase in plume height will lead to lower ground-level impacts. Consequently, air dispersion modeling was not performed for the simple cycle case.

FPUA UNIT 9 COMBUSTION TURBINE STACK PARAMETERS - NATURAL GAS*

	HRSG Stack	Bypass Stack
Stack Height, ft	60	60
Effective Stack Diameter, ft	11.2**	11.2**
Stack Exit Volume, acfm	440,420	621,140
, dscfm	225,350	225,350
Stack Velocity, fpm	4,470	6,305
Stack Exit Temperature, F	488	877
Stack Moisture, % by volume	8.10	8.10
Stack Oxygen, % by volume	14.53	14.53
20 F Emission Rate @ 15% O_2:		
PM, lb/h	2.5	2.5
, tpy***	11.0	11.0
SO_2, lb/h	0.2	0.2
, tpy***	0.9	0.9
NO_x, ppmdv	42	42
, lb/h	58.9	58.9
, tpy***	258.0	258.0
VOC, ppmdv	5	5
, lb/h	2.4	2.4
, tpy***	10.5	10.5
CO, ppmdv	10	10
, lb/h	8.5	8.5
, tpy***	37.2	37.2

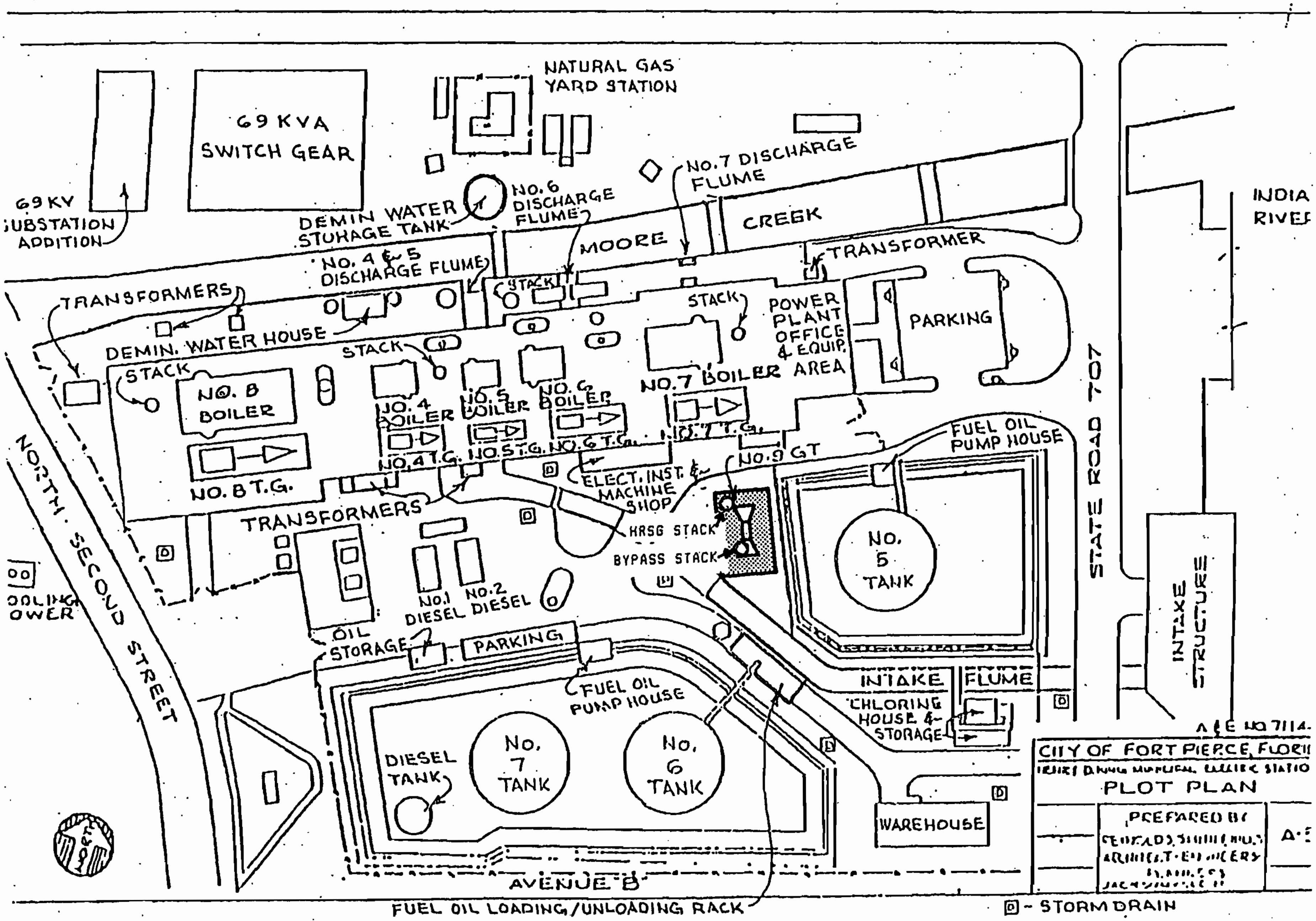
*Stack parameters are given for a GE PG5371 gas turbine with steam injection at an ambient temperature of 20 F. This ambient condition gives the highest pounds per hour emission rate.

**Actual stack is rectangular with dimensions: 9' 3" x 10' 7 1/8".

***Annual emissions are based on 8,760 hours of operation per year.

NOTE: The bypass stack is only used during startup and for emergency peaking generation in simple cycle.

FIGURE 2-2. SITE ARRANGEMENT



DER Comment 14

- Please note that we have not received a BACT application for Unit 6 as was requested by the Southeast District.

Response

- A BACT analysis for Unit 6 will not be a part of this application for Unit 9. We will be happy to provide you a copy of it when we file it with our renewal application for Unit 6 in December.