Please provide us with an
3. NOx Compliance Test for 1990

WATER ELECTRIC

FORT PIERCE UTILITIES AUTHORITY

GAS SEWER

206 S. SIXTH STREET * P. O. BOX 3191 * FORT PIERCE, FLORIDA 34948 * PHONE (407) 464-5600

You have a choice
1. NG on all units 6, 7, 8, 9 or if you want to burn oil in
Gr modeling
6, 7, 8 model for all sources you want to burn oil in

RECEIVED

DEC 6 - 1990

DER - BAQM

December 5, 1990

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

Attention: Mr. C. H. Fancy

OK

Dear Mr. Fancy:

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

Enclosed is our response to your second comment letter dated November 21, 1990.

Please note that the enclosed modeling is for nitrogen oxide only and does not include sulfur dioxide or particulate modeling. While we would prefer to retain our authorization to burn No. 2 Fuel Oil in Unit 9 under emergency conditions, we are hereby withdrawing any prior request to do so if the DER believes that SO_2 and TSP modeling is necessary for this reauthorization. We must insist that the relicensing of Unit 9 proceed without the delay that this additional modeling would entail. We would also point out that the DER can request SO_2 and TSP modeling for the repermitting of Units 6, 7, and 8 if the DER believes this to be necessary to ensure compliance with ambient air quality standards. This repermitting will begin this month. Should FPUA, request authorization in the future to burn No. 2 Fuel Oil in Unit 9, then we will provide the appropriate demonstrations of compliance with that request. In the meantime, DER is to proceed with our application without consideration of the No. 2 Fuel Oil option for Unit 9. It is worth repeating and emphasizing the fact that we are willing to forego burning of fuel oil in Unit 9 in order to eliminate the need for SO_2 and TSP modeling, and thereby expedite action on the subject application.

We are most anxious for your letter of completeness on our Unit 9 permit application. With cold weather about to be upon us, it becomes critical that the Unit 9 permit be reissued immediately or some other appropriate action be suggested by the DER. We will not intentionally violate our permit conditions without your prior authorization to do so in an emergency. Consequently, our customers face potential cold weather blackouts until this issue is resolved.

Refer to 26 Dec 1990 as another reason for requiring modeling for oil. All primary & alternate fuels were also used

~~It's in regs~~

It is our understanding that the person assigned to oversee DER's review of the subject application is Mr. Mike Harley. Mr. Harley has indicated that he will be out of the office from December 7 through the end of the year. In view of that, we are requesting that review of this submittal, and hopefully, issuance of a letter of completeness, be accomplished prior to his upcoming period of absence. It is essential that the permitting process continue during December, and we are prepared to meet with you further to ensure that this occurs.

Sincerely,

Harry Schindehette by [illegible]

Harry Schindehette, P.E.
Director of Utilities

Enclosure

cc: Mr. Jack Miller
Mr. Harry Lamb
Mr. Steve Day

C. [illegible]
S. Brooks, SE Dist.
J. Harper, EPA

#8 can burn oil as alternate fuel.
Current operation permits have limits on use of oil
Permit limitations on #9 restrict oil burning on 6, 7, 8 to zero.

DER Comment 1

- Please fully explain how the stack parameters listed in Attachment 3 relate to the actual stack parameters for FPUA Unit 9 and provide numerical comparisons.

Response

- The stack parameters listed in Attachment 3 (submitted with the letter dated October 23, 1990 responding to the DER's comment letter dated September 28, 1990) are based on the worst case ambient conditions (20 F) expected for the unit. Combustion turbine outputs (megawatts, fuel burn rates, and emissions) increase for operation at lower ambient temperatures. Therefore, worst case project impacts occur at this lower temperature rather than at ISO (59 F) or more typical operating conditions. The attached table provides a numerical comparison of operating parameters for three different ambient conditions, 20 F, 59 F, and 90 F when operating in the combined cycle mode (HRSG stack).

FPUA UNIT 9 COMBUSTION TURBINE STACK PARAMETERS - NATURAL GAS

Ambient Temperature, F	20	59	90
Turbine Generator Output, kW	31,200	27,000	23,600
Stack Exit Flow, lb/h	1,090,000	999,000	928,000
Stack exit temperature, F	494	487	481
Stack exit volume, acfm	447,000	409,000	380,000
, dscfm	226,000	207,000	190,000
Stack velocity, fpm	4,530	4,150	3,850
Stack moisture, % by volume	8.10	8.67	10.26
Stack oxygen, % by volume	14.53	14.51	14.29
NO_x Emissions, ppmvd @ 15% O_2	42	42	42
, lb/h	59	53	49
CO Emissions, ppmvd @ 15% O_2	10	10	10
, lb/h	8.5	7.7	7.0
NMHC Emissions, ppmvd @ 15% O_2	5	5	5
, lb/h	2.4	2.2	2.0

DER Comment 2

- o Please explain how the emission rates for nitrogen oxides, carbon monoxide, non-methane hydrocarbons (NMHC), and particulate were determined for FPUA Unit 9 by General Electric. Provide supporting information.

Response

- o Unit 9 consists of one General Electric Frame 5 combustion turbine. Previously provided Unit 9 emission estimates were based on the following emission rates provided by General Electric for a Frame 5 combustion turbine (see attached GE performance table for MS5001PA frame size).

  Nitrogen oxides = 42 ppmvd at 15 percent oxygen.
  Carbon monoxide = 10 ppmvd at 15 percent oxygen.
  Unburned hydrocarbons = 7 ppmvd at 15 percent oxygen.
  Particulate = 2.5 lb/h

  These emission rates are consistent with those expected for all Frame 5 turbine generators installed throughout the United States. General Electric did not specifically guarantee these emission levels for Unit 9. However, the Unit 9 Frame 5 turbine generator does not have any unique differences from other Frame 5 turbine generators sold with the above emission guarantees. Non-methane hydrocarbons will occur as a portion of total unburned hydrocarbons. Based on previous performance information NMHC were conservatively estimated to be 5 ppmvd at 15 percent oxygen.

HEAVY DUTY PRODUCT LINE
PERFORMANCE AND EMISSIONS

TURBINE MODEL/ COMBUSTOR	EMISSIONS LEVEL	DILUENT	OUTPUT KW		HEAT RATE BTU/KWH		INJ RATE LB/H		NOx PPMVD @ 15% O2		CO PPMVD		UHC PPMVW		VOC'S PPMVW		PART. LB/H		INSP. INT. HRS. FH/FS > 100	
			G	D	G	D	G	D	G	D	G	D	G	D	G	D	G	D	G	D
MS5001PA																				
AO LINER	DRY		26300	25800	11820	11930	-	-	135	202	10	10	7	7	1.4	3.5	2.5	5	12000	12000
	NSPS	WATER	26670	26710	11910	12160	4020	10000	87	86	10	10	7	7	1.4	3.5	2.5	5	12000	6000
		STEAM	26820	26990	11690	11630	5940	13610	87	86	10	10	7	7	1.4	3.5	2.5	5	12000	6000
	42/65	WATER	27320	27080	12070	12260	11050	14180	42	65	10	10	7	7	1.4	3.5	2.5	5	6000	6000
		STEAM	27690	27380	11480	11540	15970	18180	42	65	10	10	7	7	1.4	3.5	2.5	5	6000	6000
	42/42	WATER	27320	27780	12070	12430	11050	21970	42	42	10	10	7	7	1.4	3.5	2.5	5	6000	4000
		STEAM	27690	28000	11480	11390	15970	25460	42	42	10	10	7	7	1.4	3.5	2.5	5	6000	4000
MS6001B																				
AO LINER	DRY		38340	37520	10860	10970	-	-	148	267	10	10	7	7	1.4	3.5	2.5	17	12000	12000
	NSPS	WATER	38830	38690	10940	11180	4700	11510	95	94	10	10	7	7	1.4	3.5	2.5	10	8000	6000
		STEAM	39010	39390	10770	10710	6780	18980	95	94	10	10	7	7	1.4	3.5	2.5	17	8000	6000
	42/65	WATER	40010	39290	11140	11280	16020	17410	42	65	10	10	7	7	1.4	3.5	2.5	10	6000	4000
		STEAM	40630	40230	10560	10600	23150	27620	42	65	10	10	7	7	1.4	3.5	2.5	17	8000	6000
	42/42	WATER	40010	40360	11140	11460	16020	28070	42	42	10	10	7	7	1.4	3.5	2.5	10	6000	1500
		STEAM	40630	41480	10560	10440	23150	40600	42	42	10	10	7	7	1.4	3.5	2.5	17	8000	3000
MDI*	25/42	WATER	-	40360	-	11460	-	28070	-	42	-	10	-	7	-	3.5	-	10	-	1500
		STEAM	42740	41480	10300	10440	44970	40600	25	42	40	10	7	7	1.4	3.5	2.5	17	3000	3000
DLN	25/165	DRY	38180	37360	10890	11000	-	-	25	165	15	20	7	7	1.4	2.5	2.5	17	8000	8000
	25/65	WATER	38180	38370	10890	11180	-	10010	25	65	15	20	7	7	1.4	3.5	2.5	17	8000	8000
	25/65	STEAM	38180	38990	10890	10770	-	16680	25	65	15	20	7	7	1.4	3.5	2.5	17	8000	8000

NOTE: NSPS NOx IS 75 PPMVD AT 15% O2 WITH THE HEAT RATE CORRECTION.
ALL PERFORMANCE IS RUN WITH PFI INLET AND EXHAUST LOSSES, ISO CONDITIONS.

• MDI - MASSIVE DILUENT INJECTION

DER Comment 3

- Explain and show how the actual emissions of each pollutant listed in Table 500-2 of F.A.C. Rule 17-2.500 were calculated in units of the applicable emission limiting standard, lb/hr, and tons/year for each source at the H. D. King facility.

Response

- Actual emissions and estimates of actual emissions (see attached table) were provided to the DER for each source at the H. D. King facility in a letter dated October 23, 1990 responding to the DER's comment letter dated September 28, 1990. As discussed in the response, in the absence of actual performance tests, emission rates were calculated based on appropriate emission factors from AP-42. Attached please find sample calculations illustrating how these emissions were calculated.

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*
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	0.81

*Emission rates based on the attached emission test results.

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Owner	FPUA	Computed By	[signature]
Plant	King Unit 6-9	Date	12/4 1990
Project No.	16589 File No.	Checked By	[initials]
Title	Actual Emission Estimates	Date	[illegible] 19 [illegible]
		Page	1 of 3

Unit 8 NOx Emissions from 9/11/89 compliance test = 0.181 lb/MBtu

Unit 8 fuel burn rate = 611 MBtu/h

Unit 8 Actual NOx Emission = (0.181 lb/MBtu)(611 MBtu/h) = 111 lb/hr

Based on Unit 9 permit restrictions Unit 8 is allowed to operate 6384 hr/yr

Unit 8 Actual Annual NOx Emission = (111 lb/h)(6384 hr/yr)(ton/2000 lb)
= 353 tons/yr

Unit 9 NOx Emissions from 9/12/89 compliance test = $\frac{59+43}{2}$ = 51 ppmvd @ 15% O_2

CO Emissions = 1 ppmvd @ 15% O_2

Ambient Temperature = 90 F   Flue Gas Flow = 926,000 lb/h

	Volume %	Moles	Moles @ 15% O_2 dry
Oxygen	14.92	4950	3663
Nitrogen	73.63	24097	19630
Carbon Dioxide	2.54	831	831
Argon	0.90	295	294
Moisture	8.11	2654	
	100.00	32,727	24,418

NO_x Emission Rate = $\left(51 \frac{\text{moles } NO_2}{10^6 \text{ moles flue gas}}\right)\left(24{,}418 \frac{\text{moles}}{h}\right)\left(46.0055 \frac{\text{lb } NO_x}{\text{mol } NO_2}\right)$
= 57.3 lb/h

Unit 9 permit restrictions limit annual hours of operation to 3736 hr/yr.

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BLACK & VEATCH ENGINEERS-ARCHITECTS		
Owner FPUA		Computed By [illegible]
Plant Kin	Unit 6-9	Date 12/4 19 92
Project No. 16592	File No.	Checked By
Title Actual Emission Estimates		Date 19
		Page 2 of 3

Unit 9 Actual Annual NO_x Emission = $(57.3\ \text{lb/h})(8736\ \text{hr/yr})\left(\frac{\text{ton}}{2000\ \text{lb}}\right)$

$= \underline{250\ \text{tons/yr}}$

Unit 9 CO Emissions = $\left(\frac{1\ \text{mol CO}}{10^6\ \text{mol flue gas}}\right)\left(24419\ \frac{\text{mol flue gas}}{\text{hr}}\right)\left(28.01055\ \frac{\text{lb CO}}{\text{mol CO}}\right)$

$= \underline{0.684\ \text{lb/h}}$

Unit 9 Actual Annual CO Emission = $(0.684\ \text{lb/h})(8736\ \text{hr/yr})\left(\frac{\text{ton}}{2000\ \text{lb}}\right)$

$= \underline{2.99\ \text{ton/yr}}$

Remaining actual emission estimates will be calculated based on emission factors from AP-42

AP-42 Emission Factors for Natural Gas Combustion

Particulate	=	1 to 5 $\text{lb}/10^6\ \text{ft}^3$ (use 3 $\text{lb}/10^6\ \text{ft}^3$)
SO_2	=	0.6 $\text{lb}/10^6\ \text{ft}^3$
NO_x	=	550 $\text{lb}/10^6\ \text{ft}^3$
CO	=	40 $\text{lb}/10^6\ \text{ft}^3$
NMHC	=	1.4 $\text{lb}/10^6\ \text{ft}^3$

Fuel Burn Rates:

Unit 6 = 213,000 ft^3/h

Unit 7 = 456,300 ft^3/h

Unit 8 = 596,000 ft^3/h

Unit 9 = 310,600 ft^3/h

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Owner FPUA
Plant King Unit 6-9
Project No. 16599 File No.
Title Actual Emission Estimates

Computed By [illegible]
Date 12/4 1990
Checked By [illegible]
Date [illegible] 19[illegible]
Page 3 of 3

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Actual Emission Estimates (lb/h)

	Unit 6	Unit 7	Unit 8	Unit 9
Particulate	0.639	1.37	1.79	0.932
SO_2	0.128	0.274	0.358	0.186
NO_x	117	251		
CO	8.52	18.3	23.8	
NMHC	0.298	0.639	0.834	0.435

Actual Emission Estimates (tons/year)

	Unit 6	Unit 7	Unit 8	Unit 9
Particulate	0.0038	0.92	5.7	4.1
SO_2	0.00077	0.18	1.1	0.81
NO_x	0.70	169		
CO	0.051	12.3	76	
NMHC	0.0018	0.43	2.7	1.9
Annual Operation, hr/yr	12	1344	6394	8736

P-GN-172A

REVISED, SUPERSEDED, AND VOID CALCULATIONS MUST BE CLEARLY IDENTIFIED, INITIALED, AND DATED BY THE RESPONSIBLE INDIVIDUAL.

DER Comment 4

o Describe the situations that make it necessary to burn oil in each of the units located at the H. D. King facility. List the actual number of hours per year (during each of the last two years) that oil was burned in each air pollution source at the H. D. King facility including each diesel.

Response

o Natural gas is the primary fuel for the H. D. King Electric Generating Plant. The facility has retained the flexibility in Units 6, 7, 8, and 9 to burn fuel oil in the event of natural gas curtailments (emergency situations). Units 6, 7, and 8 steam generators are capable of burning either natural gas or fuel oil No. 6 (residual oil). The Unit 9 combustion turbine is capable of burning either natural gas or fuel oil No. 2 (distillate oil). At the current time, due to emission restrictions contained in Unit 9's operating permit, Units 6, 7, and 8 cannot burn fuel oil. No oil will be burned in these units until the Unit 9 permit is reissued.

FPUA is hereby withdrawing it's application to burn fuel oil in Unit 9 during emergencies. Natural gas will be the primary fuel for Unit 9.

In addition to Units 6 through 9, the H. D. King Electric Generating Plant periodically operates two diesel electric generators. These generators burn fuel oil No. 2 (distillate oil). These diesel generators are operated strictly during peak demand periods.

The attached table lists the actual hours of operation that these sources have burned oil during the last two years (1989 and 1990).

H. D. KING ELECTRIC GENERATING PLANT FUEL OIL FIRED OPERATION

		Fuel Oil Fired	1989 hours	1990 hours	hours of opn's allowed
	Unit 6 16.5MW	Residual	0	0	12
	Unit 7 33MW	Residual	0	0	1344
	Unit 8 53MW 1976	Residual	108*	0	6384
CC	Unit 9 32 MW	Distillate	0	0	8736-Intent
	Diesel No. 1	Distillate	61	51	
	Diesel No. 2	Distillate	74	85	

*Fuel oil burned during a natural gas curtailment.

DER Comment 5

- o Provide the maximum 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 source at the H. D. King facility when oil is burned.

Response

- o The attached table provides estimates of maximum hourly emission rates for Units 6, 7, and 8 when burning residual fuel oil, and diesel generators 1 and 2 when burning distillate fuel oil.

  Since it would be impossible to meet the emission limits listed in the Unit 9 permit for Units 6, 7, and 8 (when Units 6, 7, and 8 are burning oil) no oil will be burned in these units until the Unit 9 permit is reissued. Accordingly, no annual emissions can be estimated at this time. Except for Unit 8 NO_x and SO_2, emission estimates provided in the attached table are based on AP-42 emission factors. Nitrogen oxide emissions for Unit 8 are based on an emission limit of 0.20 lb/MBtu. Sulfur dioxide emission estimates for Unit 8 are based on a maximum fuel sulfur content of 0.75 percent. Attached please find the detailed calculations illustrating determination of these values.

  As previously discussed, FPUA is withdrawing it's application to burn fuel oil in the Unit 9 combustion turbine during natural gas curtailments (emergencies). Natural gas will be the primary fuel for Unit 9. Accordingly, no emission estimates are provided in this response for Unit 9 when burning fuel oil.

H. D. KING ELECTRIC GENERATING PLANT FUEL OIL FIRED EMISSION RATES

	Unit 6 lb/h	Unit 7 lb/h	Unit 8 lb/h	Diesel Generators* lb/h
Nitrogen Oxides	98	210	122	4.2
Carbon Monoxide	7.3	16	20	1.1
Particulate	34	72	43	0.42
Non-Methane Hydrocarbons	1.1	2.4	3.1	0.042
Sulfur Dioxide	458	984	504	12
	2.5%S	2.5%S	.87%S	

*Diesel generators 1 and 2 are identically sized. Values listed are for one diesel generator only.

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Owner FPUA
Plant Vine Unit 6-8
Project No. 16589 File No.
Title Maximum Emission Rates When Burning Residual Oil

Computed By [signature]
Date 12/3 1990
Checked By [signature]
Date 19
Page 1 of 2

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AP-42 Emission Factors for Residual Oil Fired Boilers

Particulate = $[10(S) + 3]$ lb/10^3 gal (S is weight % S in fuel)
SO_2 = $157(S)$ lb/10^3 gal
NO_x = 67 lb/10^3 gal
CO = 5 lb/10^3 gal
NMHC = 0.76 lb/10^3 gal

Fuel Burn Rates

Unit 6 = $(219 \frac{MBtu}{h})(10^6 \frac{Btu}{MBtu})(\frac{gal}{150{,}000\ Btu})$ = 1460 gal/h
Unit 7 = $470 \frac{MBtu}{h} (10^6)(\frac{1}{150{,}000})$ = 3133 gal/h
Unit 8 = $611 \frac{MBtu}{h} (10^6)(\frac{1}{150{,}000})$ = 4073 gal/h

Unit 6-7 fuel oil sulfur = 2.0% Unit 8 fuel oil sulfur = 0.75%

Hourly Emission Rates

	Unit 6 lb/h	Unit 7 lb/h	Unit 8 lb/h
Particulate	33.6	72.1	42.8
SO_2	459 ok	984	
NO_x	97.8	210	
CO	7.3	15.7	20.4
NMHC	1.11	2.38	3.10

PGN-172A

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BLACK & VEATCH ENGINEERS-ARCHITECTS	Owner FPUA	Computed By [signature]
	Plant Vero Unit 6-8	Date 12/3 1990
	Project No. 16589 File No.	Checked By
	Title Maximum Emission Rates When Burning Residual Oil	Date 19
		Page 2 of 2

Unit 8 NO_x Emission Limit = 0.20 lb/MBtu

Maximum Unit 8 NO_x Emission = (0.20 lb/MBtu)(611 MBtu/h) = <u>122 lb/h</u>

Unit 8 Fuel Oil Sulfur Content Limited to 0.75%

Maximum Unit 8 SO_2 Emission = $\left(\frac{0.75 \text{ lbS}}{100 \text{ lb fuel}}\right)\left(\frac{\text{lb fuel}}{18200 \text{ Btu}}\right)\left(611 \frac{\text{MBtu}}{\text{h}}\right)\left(\frac{10^6 \text{ Btu}}{\text{MBtu}}\right) \times \left(\frac{64 \text{ lb } SO_2}{32 \text{ lbS}}\right)$ = <u>504 lb/h</u>

<u>AP-42 Emission Factors for Diesel Fired Electric Generators</u>

Assume Industrial Boiler - Distillate Oil

Particulate	=	2 lb/10^3gal
SO_2	=	142(S) lb/10^3gal
NO_x	=	20 lb/10^3gal
CO	=	5 lb/10^3gal
NMHC	=	0.2 lb/10^3gal

Distillate Oil Sulfur Content = 0.4%

Fuel Burn Rate = 210 gal/h

Particulate	= (2 lb/10^3gal)(210 gal/h)	=	0.42 lb/h
SO_2	= (142)(0.4 lb/10^3gal)(210 gal/h)	=	11.9 lb/h
NO_x	= (20 lb/10^3gal)(210 gal/h)	=	4.2 lb/h
CO	= (5 lb/10^3gal)(210 gal/h)	=	1.05 lb/h
NMHC	= (0.2 lb/10^3gal)(210 gal/h)	=	0.042 lb/h

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DER Comment 6

- Provide the stack parameters for each source at the H. D. King facility when oil is burned. 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).

Response

- The attached table lists stack parameters for Units 6, 7, and 8 when burning residual fuel oil, and diesel generators 1 and 2 when burning distillate oil. As discussed previously, FPUA will not burn fuel oil in Unit 9, therefore, no stack parameters are provided for Unit 9.

H. D. KING ELECTRIC GENERATING PLANT FUEL OIL FIRED STACK PARAMETERS

	Unit 6	Unit 7	Unit 8	Diesel Generators*
Stack height, ft	148	148	150	23
Exit diameter, ft	5	7.1	8	3
Volumetric flow, acfm	64,400	138,000	190,000	16,600
, dscfm	39,900	85,500	119,000	5,400
Gas temperature, F	300	300	295	950
Exit velocity, fpm	3,280	3,490	3,780	2,350
Stack moisture, percent	10.97	10.98	10.82	12.74
Stack oxygen, percent	2.68	2.69	3.50	1.72

*Diesel generators 1 and 2 are identically sized. Values listed are for one diesel generator only.

DER Comment 7

- o Please model the ambient concentrations and increment consumption for the criteria pollutants sulfur dioxide, particulate, and nitrogen oxides from all sources (including the bypass stack) and for all averaging times when oil is burned. Incidentally, based on the available information, it appears that FPUA Unit 8 is an increment consuming source. Also, please update the soils and vegetation analysis to account for the effects of oil burning.

Response

- o As stated previously, Unit 9 will now only be permitted to operate while firing natural gas. The Unit 9 Prevention of Significant Deterioration (PSD) Application - August 1990 showed that, when firing natural gas, Unit 9 has predicted significant impacts for NO_x only. Consequently, NO_x is the only criteria pollutant for which impacts are considered.

  The only FPUA source which consumes Class II PSD NO_x increment is Unit 9. (Note that Unit 8 began operating in 1976 and, thus, does not consume NO_x increment.) The August 1990 PSD application showed that Unit 9 (alone) consumes only 38 percent of the available Class II increment. This result is not affected by the burning of oil in the other FPUA sources. OK

  OK

  Revised NAAQS modeling (accounting for oil use in other FPUA sources) was performed following the modeling methodology described in Section 5.0 of the August 1990 PSD application. It was shown in this application that the FPUA sources were the only sources that had the potential to interact with the Unit 9 NO_x significant impact area. Thus, FPUA Units 6 - 8 (firing No. 6 Fuel Oil) and Diesel Units 1 and 2 (firing No. 2 fuel oil) were considered along with Unit 9 (firing natural gas in the HRSG mode). Unit 9 source parameters and emission rates are given in the response to DER Comment 1. Source parameters and emission rates for the other FPUA sources are given in the responses to DER Comments 5 and 6. All sources were conservatively assumed to operate 8,760 hours per year for the modeling analysis.

The attached table shows the results of the NAAQS modeling. The maximum combined source impact was 59.2 ug/m3, which occurred 100 meters west of the Unit 9 stack. This value was added to the 24 ug/m3 background value (West Palm Beach monitor - 1989) to get a total concentration of 83.2 ug/m3. This concentration is well below the annual NO_x standard of 100 ug/m3. Therefore, the FPUA facility annual NO_x impacts, including Unit 9, do not exceed the NAAQS. Copies of the NAAQS modeling runs are attached.

Note that NAAQS impacts with Unit 9 operating in the bypass mode would be even lower since the stack gas exit temperature and acfm flow values are higher for the bypass case. Higher temperatures and flows increase the thermal and momentum buoyancy and thus, increase the plume height. It is commonly accepted that, in the absence of elevated terrain, higher plume heights lead to lower ground-level pollutant impacts.

Since Unit 9 will only fire natural gas, the soils and vegetation analysis originally presented in the August 1990 PSD application is still applicable.

NAAQS MODELING SUMMARY FOR FPUA SOURCES

	NAAQS Modeling Summary
Maximum Impact Location	
Distance:	100 meters
Direction:	280 degrees
Meteorological Year:	1982
Combined Source Maximum Impact*:	59.2 ug/m3
Background Concentration**:	24 ug/m3
Total NAAQS Concentration: (Combined Maximum Impact plus Background)	83.2 ug/m3
NAAQS Primary NO_x Standard:	100 ug/m3

*Maximum Combined Impact From: Unit 9 (HRSG firing natural gas)
Units 6 - 8 (firing No. 6 fuel oil)
Diesel Units 1 and 2 (firing No. 2 fuel oil)

**Background concentration measured in 1989 at West Palm Beach monitor.

DER Comment 8

- o Please explain what the situation in the Middle East has to do with the escalation rates. Explain the basis for the capital cost escalation rate of 6%, the operating cost escalation rate of 7%, the indirect cost factor of 16%, and the present worth discount rate of 8%. Provide data to support the selection of these rates as representative of the real world.

Response

- o Iraq's invasion of Kuwait substantially disrupted the world's oil supply. Accordingly, markets reacted increasing the price of crude oil from between $15 and $20 per barrel to as high as $40 per barrel. Further price increases are likely should the Middle East situation result in a direct armed conflict.

  Secondary effects of this large price increase (and potential future increases) will be felt throughout the economy, affecting alternate energy source and consumer product prices, and ultimately payroll costs. The most pronounced effect will be on natural gas prices. Natural gas competes directly with fuel oil for use in a number of applications. Natural gas price deregulation and fuel oil price increases will allow natural gas suppliers to increase prices substantially without risking competitive damage. Fort Pierce Utilities Authority has already experienced a substantial increase in the price of natural gas. Since Iraq's invasion, FPUA natural gas prices have increased 42 percent. Accordingly, the capital and operating cost escalation rates used in the revised BACT analysis reflect current and future economic uncertainty. Operating costs are escalated at a higher rate (7 percent) than capital costs (6 percent) since there is more uncertainty inherent in projecting operating costs over the remaining Unit 9 life of 25 years. These escalation rates are representative of rates used in a number of recent project financial viability evaluations.

Indirect costs listed in the calculation of total capital cost reflect owner and architect/engineer costs to design, procure, construct, and start-up the SCR system. The indirect cost factor of 16 percent is applied to the escalated direct capital cost of equipment. The rate of 16 percent is based on historical information regarding projects of this nature.

The present worth concept is a method of taking into account the time value of money. Therefore, the present worth discount rate of 8 percent used in the BACT analysis is based on the cost to FPUA for financing projects through the issuance of municipal bonds. This present worth discount rate was used in conjunction with the operating cost escalation rate (7 percent) and the remaining plant life assumption (25 years) to determine a levelization factor of 1.94. Levelized costs were determined by multiplying first year costs by the levelization factor. Levelized costs reflect the effects of escalation and present worth of future annual expenditures.

DER Comment 9

o Explain why the installation of SCR on the combined cycle unit will require additional personnel equivalent to one operator for one-half shift per day. Please explain the term loaded payroll cost as it is used in conjunction with the additional personnel cost.

Response

o The plant has been staffed to man existing operations in an efficient manner. Addition of an SCR system on Unit 9 will add complexity to operation of the existing facility. Mechanical and control equipment associated with operation of the SCR system will require periodic inspections to ensure operability, reliability, and safety. Periodic shipments of ammonia will be received by truck. Plant personnel will be required to monitor and assist in the receipt of these ammonia supplies. In addition, SCR system operation will require periodic surveillance of performance to ensure reliable compliance. All of these services associated with retrofit of an SCR system will require plant staffing. However, due to the relative simplicity of SCR system operation only four operating personnel hours per day were included in the evaluation.

Operating personnel costs were based on a loaded payroll cost of $45,000 per year (1990 dollars). Loaded payroll costs include basic wages, social security, insurance, and other benefit costs.

DER Comment 10

- Explain the difference between a catalyst that is suitable only for units that burn gas and a catalyst for units that burn both gas and oil. Please explain the difference both in technical and economic terms.

Response

- FPUA is withdrawing it's application to burn fuel oil in Unit 9 during emergencies (see response to DER comments 4 and 5). Natural gas will be the primary fuel for Unit 9. As stated previously, the costs presented in the BACT analysis are based on a catalyst designed to treat flue gas from the combustion of natural gas only. If the facility were requesting dual fuel capabilities (natural gas or fuel oil) the catalyst would be larger, and therefore, more expensive. Larger catalysts are required for oil fired applications due to the fouling characteristics of the fuel oil's flue gas (predominately due to the sulfur content of the fuel) in the presence of ammonia. More reactive catalysts (used in natural gas applications) would tend to convert SO_2 in the flue gas to SO_3. Subsequently, this SO_3 could react with ammonia to form ammonia sulfate and bisulfate salts. Ammonia salts would tend to blind catalyst surface areas and foul downstream equipment. Accordingly, to effectively treat flue gas from fuel oil combustion, the catalyst would consist of a less reactive catalyst material and have a lower space velocity (a parameter inversely related to the residence time of the flue gas in the catalyst bed).

DER Comment 11

- Please explain why the emission reductions for using SCR to control NO_x are not consistent in Table 4-1 for the original application and the additional information response (218 vs. 202 tons per year).

Response

- The original application's calculation of the annual emission difference between a 42 and a 9 ppmvd NO_x emission limit of 218 tons per year was in error. The correct difference is 202 tons per year. The example calculation provided in Attachment 4 (submitted with the letter dated October 23, 1990 responding to the DER's comment letter dated September 28, 1990) correctly illustrates the calculation of emission rate based on an outlet NO_x concentration of 42 ppmvd. The following response to DER comment 12 will provide an example calculation of the difference used in the BACT analysis.

DER Comment 12

- Please show the calculations to document the NO_x emission reduction achieved by SCR shown in Table 4-1.

Response

- As documented in the BACT analysis, a new SCR system catalyst can achieve up to 90 percent reduction of NO_x emissions. However, as the catalyst ages the maximum NO_x emission reduction efficiency will decrease to between 80 and 85 percent. To ensure reliable compliance with emission limits it is recommended that an SCR system is capable of maintaining an emission limit of 9 ppmvd (at 15 percent oxygen) continuously. The attached calculation (included as a supplement to the example calculation provided in Attachment 4 of the previous response) documents the calculation of emissions and emission differences based on a maximum NO_x emission of 9 ppmvd.

Best Available Copy

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Owner FPUA
Plant H.D. King Unit 9
Project No. 16599 File No.
Title Unit 9 NO_x Emission When Using an SCR System

Computed By [signature]
Date 12/5 1990
Checked By [initials]
Date 12/5 1990
Page 1 of 1

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Reference Sample Calculation provided to DER in Attachment 4 in response to previous DER comments (submitted dated 10/23/90).

Unit 9

Flue Gas Mole @ 15% Oxygen = 30489 mols/h (See previous Attachment 4)

SCR NO_x Emission Rate = 9 ppmvd @ 15% O_2

NO_x Emission Rate = $\left(9 \frac{\text{mols } NO_2}{10^6 \text{ mols flue gas}}\right)\left(30{,}489 \frac{\text{mols}}{h}\right)\left(46.0055 \frac{\text{lb } NO_2}{\text{mol } NO_2}\right)$

NO_x Emission Rate = 12.6 lb/h

NO_x Emission Rate @ 42 ppmvd (15% O_2) = 58.9 lb/h (see previous Attachment 4)

Annual Plant Operation = 8760 hr/yr

Annual NO_x Reduction From Use of SCR = $\left(58.9 - 12.6 \frac{lb}{h}\right)\left(8760 \frac{hr}{yr}\right)\left(\frac{ton}{2000\ lb}\right)$

= 202 tpy

P-GN-172A

REVISED, SUPERSEDED, AND VOID CALCULATIONS MUST BE CLEARLY IDENTIFIED, INITIALED.