JACKSONVILLE ELECTRIC AUTHORITY

21 WEST CHURCH STREET • JACKSONVILLE, FL 32202-3139

JEA "POWER TO SERVE"

March 12, 1998

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BUREAU OF
AIR REGULATION

Mr. Martin Costello, P.E.
Florida Department of Environmental Protection
Twin Towers Office Bldg.
2600 Blair Stone Rd., Mail Station 5500
Tallahassee, FL 32399-2400

RE: Kennedy Generating Station Proposed Single-Cycle Combustion Turbine

Dear Mr. Costello:

Per previous conversations with DEP staff, it is JEA's intent to permit the above referenced unit at the levels proposed in my letter dated February 12, 1998 while "netting-out" of the Prevention of Significant Deterioration (PSD) process.

Attached please find NOAA statistical information which shows that 1997 was an unusually moderate year resulting in below normal power demand. Since 1997 was not representative of normal operation, we are proposing to exclude 1997 from baseline calculations and use 1995 and 1996 as the baseline years for determining baseline emission levels. It is noted that the total permitted emissions of SO_2, NO_x, and PM combined will be just over 200 tons per year, with actual emissions expected to be considerably less.

The unit will utilize dry low NO_x burner technology with expected guaranteed full-load emission rates of 15 ppm NO_x on gas fuel and 42 ppm NO_x on #2 oil utilizing water injection.

If you have any questions with regard to this matter, please advise.

Sincerely,

N. Bert Gianazza, P.E.
Environmental, Health & Safety

cc: Mr. Steve Pace, P.E., RESD
Ms. Christi Veleta, RESD

Jacksonville Electric Authority
Statistical Information
for the Twelve Months Ending September 30, 1997
Total Degree Day Comparison

Month	NOAA 30 Year Average	Fiscal Year 1995/96	Fiscal Year 1996/97	Percentage Change 97 vs 96	Percentage Change 97 vs NOAA
October	210	296	198	-33%	-6%
November	205	288	218	-24%	6%
December	356	377	313	-17%	-12%
January	452	405	348	-14%	-23%
February	318	303	221	-27%	-31%
March	217	302	174	-42%	-20%
April	134	180	159	-12%	19%
May	260	350	243	-31%	-7%
June	423	416	365	-12%	-14%
July	515	549	531	-3%	3%
August	502	445	485	9%	-3%
September	393	381	415	9%	6%
Total	3,985	4,292	3,670	-14%	-8%
JAN-SEPT	3214		2941		-8.5%

Firm KWH Sales

	Fiscal Year 1995/96	Fiscal Year 1996/97	Percentage Change 97 vs 96
Total	10,110,464,307	10,023,800,060	-1.0%

Average Number of Territorial Customers

	Fiscal Year to Date 1995/96	Fiscal Year to Date 1996/97	Percentage Change 97 vs 96
Total	328,371	335,463	2.3%

Jacksonville Electric Authority

Statistical Information

for the Five Months Ending February 28, 1998

Total Degree Day Comparison

Month	NOAA 30 Year Average	Fiscal Year 1996/97	Fiscal Year 1997/98	Percentage Change 98 vs 97	Percentage Change 98 vs NOAA
October	210	198	197	-1%	-6%
November	203	218	219	0%	8%
December	356	313	336	7%	-6%
January	452	348	300	-14%	-34%
February	318	221	232	5%	-27%
Total	1,539	1,298	1,284	-1%	-17%
Oct - Dec	769		752		-1.33%
Jan - Dec	3983		3693		-6.17%

Firm KWH Sales

	Fiscal Year 1996/97	Fiscal Year 1997/98	Percentage Change 98 vs 97
Total	3,757,605,362	3,963,232,061	5.5%

Average Number of Territorial Customers

	Fiscal Year to Date 1996/97	Fiscal Year to Date 1997/98	Percentage Change 98 vs 97
Total	331,383	338,509	2.2%

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JEA "POWER TO SERVE"

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AIR REGULATION

February 12, 1998

Mr. Clair H. Fancy, P.E.
Chief, Bureau of Air Regulation
Florida Department of Environmental Protection
2600 Blair Stone Road
Tallahassee, FL 32399-2400

Subject: Request for PSD Determination

Dear Mr. Fancy:

On December 17, 1997, the Jacksonville Electric Authority (JEA) and Black & Veatch (JEA's air permitting consultant) met with the Florida Department of Environmental Protection (FDEP) to discuss air permitting issues associated with a potential new emission source. At the December 17 meeting, FDEP staff suggested that JEA submit information which would allow FDEP to make an official determination of Prevention of Significant Deterioration (PSD) applicability to this project. Therefore, this letter is submitted to FDEP to formally request such a determination.

JEA is proposing to install one simple cycle, 160 MW Frame F combustion turbine (CT) at the Kennedy Generating Station. This unit will be used primarily as a peaking unit, firing natural gas as its primary fuel and low sulfur distillate fuel oil as a backup fuel. Following the installation of the CT, the existing natural gas and residual oil-fired boiler KE10 will be taken out of service. Commensurate with PSD regulations and guidance, the determination of whether the proposed CT is a major modification to a major stationary source is based upon the potential emission increases from the new unit, combined with any contemporaneous increases or decreases in source emissions exceeding significant levels. Such a determination is often referred to as a "netting analysis". JEA has prepared a netting analysis in which past actual emissions from KE10 have been subtracted from the potential emission increases of the CT to determine the net emissions change. The assumptions and information used in this analysis are discussed in the following paragraphs.

Estimated CT Emission Increases

At this time, selection of a specific CT has yet to be completed. The range of choices has been narrowed to either a GE PG7241 FA or a Westinghouse 501F. Therefore, emissions from both of these CTs have been examined. In both cases, potential emissions of all PSD-regulated pollutants except lead have been calculated based on expected base load emissions data provided by the vendor. These data were developed based on ISO conditions (i.e., 59 F ambient temperature and 60% relative humidity). Lead emissions were based on AP-42 emission factors and the base load heat input rate.

The CT, once installed, will be used to supply peaking power. Therefore, JEA is proposing a reduced capacity factor for the CT. The proposed capacity factors, which are outlined in Table 1, would allow the project to "net out" of PSD review. As shown in the table, the specific limitations which would be imposed are dependent on the final turbine selection.

Table 1
Proposed Operational Limitations for Combustion Turbine

	Maximum Natural Gas Firing (hours/year)	Maximum #2 Fuel Oil Firing (hours/year)	Fuel Oil Sulfur Content
GE PG7241 (FA)	3120 - 3.25X *	960	0.05 wt%
Westinghouse 501F	1841 - 2.63X *	700	0.05 wt%

* X = hours of #2 fuel oil firing during the year

Contemporaneous Emission Decreases

Past actual KE10 emission estimates are presented in Table 2. These have been calculated based upon 1995 and 1996 operations. This satisfies PSD guidance, as these represent the two most recent available years of operational data which are representative of normal operation.

Table 2
Estimated Average KE10 Emissions During 1995-96

Pollutant	KE10 1995-96 Average Emissions (ton/year)
NO_x	115.9
CO	14.8
VOC	1.0
SO_2	128.2
PM_{10} (front half)	11.5
Lead	0.001
H_2SO_4	5.7

Emissions of the PSD-regulated pollutants (excluding NO_x) from residual oil and natural gas combustion were calculated using emission factors from Sections 1.3 and 1.4, respectively, of AP-42 (fifth edition, including supplements). Relevant operational data were taken from Steam-Electric Plant Operation and Design Reports for 1995 and 1996 operations, submitted to the U.S. Department of Energy. Emission calculations for a given year were based on actual fuel usage, weighted average heating values, and weighted average residual oil sulfur content for that year, as reported on the Operation and Design Reports. SO_2 emissions from natural gas combustion were based on an average sulfur content of 2000 grains/10^6 SCF, as suggested by AP-42, Section 1.4. H_2SO_4 emissions from residual oil combustion have been estimated using the emission factor for SO_3 emissions (taken from AP-42 Section 1.3), and assuming that all SO_3 is eventually converted to H_2SO_4.

The NO_x emission factors for fuel oil firing and natural gas firing were obtained from stack testing data. Several stack tests were reviewed to determine which provided the most realistic and time-representative information. Isolated tests were performed on the unit in the early nineties at part-load operations. Testing was again performed at numerous loads for both oil and gas firing in December 1994. This testing was part of the Acid Rain Part 75 certification tests. Because the 1994 testing represents the most recent and comprehensive testing at all loads, the emission factors derived from the testing were utilized to calculate NO_x emissions for KE10.

The December 1994 stack test data are believed to provide a good representation of KE10 NO_x emissions during steady state operation. However, these data do not account for unsteady state operations such as startup, shutdown, load changes and malfunctions. Due largely to the age of the unit, KE10 air emissions are thought to be much higher during these conditions than during steady-state operation. Furthermore, the time required to bring the unit and its associated emissions to steady state conditions following an unsteady state event is greater than would be expected with a newer unit. Since KE10 has been operated primarily as a peaking unit over the past several years, unsteady state operations occurred more often than would be expected with a baseload unit. As the December 1994 stack test results do not take into account unsteady state operation, annual emission estimates based on the stack testing are believed to be conservatively low.

In addition, while the December 1994 stack test data do suggest slightly higher NO_x emissions from residual oil combustion than AP-42 (0.472 lb/10^6 Btu from the testing versus ~0.441 lb/10^6 Btu from AP-42 Section 1.3 for normal firing), the NO_x emission rate derived from the stack tests during natural gas firing is less than the appropriate AP-42 emission factor by 0.31 lb/10^6 Btu. Consequently, the stack test results lead to annual emission estimates which are notably lower than if AP-42 factors were used.

Since the NO_x emission estimates are believed to be of a conservative nature, and the magnitude of annual NO_x emissions is relatively low, the JEA proposes that the NO_x emissions calculation approach described above be used to determine baseline NOx emissions.

Attachment 1 outlines the net emission calculations for this project, considering both the GE and Westinghouse CTs. Based upon the assumptions and operational limits proposed above, the data presented in Attachment 1 demonstrate that the proposed project will not trigger PSD review. Attachment 2 contains detailed spreadsheet calculations which support the values reported in Attachment 1.

If you have any questions on this issue, please contact me at (904) 632-6247.

Sincerely,

N. Bert Gianazza, P.E.
Environmental Health & Safety Group

Enclosures

cc: Amy Carlson, Black & Veatch
Marty Costello, FDEP

Attachment 1

PSD Netting Analysis Summaries

GE PG7241(FA)

	Combustion Turbine Potential Emissions (ton/year)	KE10 Average Emissions 1995-96 (ton/year)	Net Emission Increase (ton/year)	PSD Signifcant Emission Rate (ton/year)	PSD Significant?
NOx	154.560	115.940	38.620	40	No
CO	74.880	14.777	60.103	100	No
VOC	4.368	1.008	3.360	40	No
SO2	45.648	128.229	-82.581	40	No
PM10 Front Half	14.040	11.507	2.533	15	No
Lead	0.051	0.001	0.050	0.6	No
H2SO4	4.800	5.696	-0.896	7	No

Westinghouse 501F

	Combustion Turbine Potential Emissions (ton/year)	KE10 Average Emissions 1995-96 (ton/year)	Net Emission Increase (ton/year)	PSD Signifcant Emission Rate (ton/year)	PSD Significant?
NOx	154.000	115.940	38.060	40	No
CO	75.481	14.777	60.704	100	No
VOC	6.650	1.008	5.642	40	No
SO2	31.150	128.229	-97.079	40	No
PM10 Front Half	24.624	11.507	13.117	15	No
Lead	0.033	0.001	0.031	0.6	No
H2SO4	3.271	5.696	-2.425	7	No

NOTE: Combustion turbine emissions have been calculated based on the proposed operational limitations.

GE PG7241(FA) Potential Emissions

Potential emissions have been calculated based on the proposed operational limitations. For each pollutant, the range of operational scenarios was examined, and the scenario producing the highest annual emission rate is presented below for each pollutant.

Hourly emission rates reflect base load operation.

	Combustion Turbine Emissions [GE PG7241(FA)]									Allowable Emissions		
	Natural Gas Firing				Fuel Oil Firing				Total Emissions (ton/yr)	KE10 Average 95-96 Emissions (ton/yr)	PSD Significant Emission Rate (ton/yr)	Allowable CT Emission Rate (ton/yr)
	Expected Emissions (lb/hr)	Reference	Operating Hours	Annual Emissions (ton/yr)	Expected Emissions (lb/hr)	Reference	Operating Hours	Annual Emissions (ton/yr)				
NOx	99.00	GE Data	0	0	322	GE Data	960	154.56	154.56	115.9396	40	155.9396
CO	48	GE Data	3120	74.88	97	GE Data	0	0	74.88	14.7773	100	114.7773
VOC	2.8	GE Data	3120	4.368	7.5	GE Data	0	0	4.368	1.0078	40	41.0078
SO2	22.8603	Note 1	0	0.0000	95.1	GE Data	960	45.648	45.6480	128.2288	40	168.2288
PM10	9	GE Data	3120	14.04	17	GE Data	0	0	14.04	11.5072	15	26.5072
Lead	4.18E-04	Note 2	0	0.0000	0.10629	AP-42 Table 3.1-4	960	0.0510	0.0510	0.0013	0.6	0.6013
H2SO4 Mist					10	GE Data	960	4.8	4.8	5.6962	7	12.6962

NOTES:
1) Based upon AP-42 Table 3.1-1 emission factor, 0.015 wt% sulfur in fuel, and maximum heat input as reported by G.E.
2) Based upon AP-42 Table 1.4-5 emission factor, 1050 Btu/SCF fuel heating value, and base load heat input as reported by G.E.

Westinghouse 501F Potential Emissions

Potential emissions have been calculated based on the proposed operational limitations. For each pollutant, the range of operational scenarios was examined, and the scenario producing the highest annual emission rate is presented below for each pollutant.

Hourly emission rates reflect base load operation.

	Combustion Turbine Emissions									Allowable Emissions		
	Natural Gas Firing				Fuel Oil Firing				Total Emissions (ton/yr)	KE10 Average 95-96 Emissions (ton/yr)	PSD Significant Emission Rate (ton/yr)	Allowable CT Emission Rate (ton/yr)
	Expected Emissions (lb/hr)	Reference	Operating Hours	Annual Emissions (ton/yr)	Expected Emissions (lb/hr)	Reference	Operating Hours	Annual Emissions (ton/yr)				
NOx	167.00	Westinghouse data	0	0.0000	440	Westinghouse data	700	154	154.0000	115.9396	40	155.9396
CO	82	Westinghouse data	1841	75.4810	166	Westinghouse data	0	0	75.4810	14.7773	100	114.7773
VOC	7	Westinghouse data	0	0.0000	19	Westinghouse data	700	6.65	6.6500	1.0078	40	41.0078
SO2	20	Note 1	0	0.0000	89	Westinghouse data	700	31.15	31.1500	128.2288	40	168.2288
PM10	19	Westinghouse data	0	0.0000	70.355	Note 3	700	24.62425	24.6243	11.5072	15	26.5072
Lead	4.19E-04	Note 2	0	0	0.093032	AP-42 Table 3.1-4	700	0.0325612	0.0326	0.0013	0.6	0.6013
H2SO4 Mist					9.345	Note 4	700	3.27075	3.2708	5.6962	7	12.6962

NOTES:
1) Emission rate reflects 10 times the rate predicted by vendor data.
2) Based upon AP-42 Table 1.4-5 emission factor,1050 Btu/SCF fuel heating value, and base load heat input (LHV).
3) Reflects Westinghouse data for front + back half PM, less estimated H2SO4 emission rate.
4) Estimated from available vendor data as follows: ratio of H2SO4/SO2 mass emission rates for GE turbine used to estimate H2SO4 emissions from Westinghouse turbine by muliplying SO2 mass emission rate for Westinghouse turbine by the GE turbine ratio.

Jacksonville Electric Authority – Kennedy Generating Station
KE10 Emissions Calculations

Natural Gas Firing

	Emission Factor				1995			1996		
	Value		Reference	Justification	Fuel Use (M ft3)	Fuel Heating Value (Btu/SCF)	Emissions (ton/year)	Fuel Use (M ft3)	Fuel Heating Value (Btu/SCF)	Emissions (ton/year)
NOx	0.2119	lb / MBtu	Note 1	Note 2	666.9	1048	74.0496	344.4	1051	38.3501
CO	40	lb / M ft3	Note 3, 4	Standard reference	666.9	1048	13.9782	344.4	1051	7.2393
VOC	1.411	lb / M ft3	Note 4, 5	Standard reference	666.9	1048	0.4931	344.4	1051	0.2554
SO2	0.6	lb / M ft3	Note 3, 4	Standard reference	666.9	1048	0.2097	344.4	1051	0.1086
PM10 Front Half	5	lb / M ft3	Note 4, 6	Standard reference	666.9	1048	1.7473	344.4	1051	0.9049
Lead	2.71E-04	lb / M ft3	Note 4, 7	Standard reference	666.9	1048	9.47E-05	344.4	1051	4.905E-05
H2SO4										

Fuel Oil Firing

	Emission Factor				1995				1996			
			Reference	Justification	Fuel Use (kgal)	Fuel Sulfur Content, S (%)	Fuel Heating Value (Btu/gal)	Emissions (ton/year)	Fuel Use (kgal)	Fuel Sulfur Content, S (%)	Fuel Heating Value (Btu/gal)	Emissions (ton/year)
NOx	0.47155	lb/MBtu	Note 1	Note 9	184.8		151869	8.6171	3150		151964	112.8624
CO	5	lb/kgal	AP-42, Table 1.3-1	Standard reference	184.8			0.4620	3150			7.8750
VOC	0.76	lb/kgal	AP-42, Table 1.3-2	Standard reference	184.8			0.0702	3150			1.1970
SO2	157*S	lb/kgal	AP-42, Table 1.3-1	Standard reference	184.8	0.969		14.0571	3150	0.979		242.0822
PM10 Front Half	9.19*S+3.22	lb/kgal	AP-42, Table 1.3-1	Standard reference	184.8	0.969		1.1204	3150	0.979		19.2418
Lead	1.51E-03	lb/kgal	AP-42, Table 1.3-10	Standard reference	184.8			0.0001	3150			0.0024
H2SO4	6.983*S	lb/kgal	Note 8	Standard reference	184.8	0.969		0.6252	3150	0.979		10.7673

Total Emissions

	1995	1996	95-96 Average
	Emissions (ton/year)	Emissions (ton/year)	Emissions (ton/year)
NOx	80.6668	151.2125	115.9396
CO	14.4402	15.1143	14.7773
VOC	0.5633	1.4524	1.0078
SO2	14.2668	242.1908	128.2288
PM10 Front Half	2.8676	20.1467	11.5072
Lead	0.0002	0.0024	0.0013
H2SO4	0.6252	10.7673	5.6962

NOTES
1) Stack test data for KE10 dated 12/94
2) Of available data, the stack test results shown are believed to provide the most accurate estimate of unit emissions; note that this emission factor is lower than the AP-42 factor of ~0.55 lb/MBtu
3) AP-42, Table 1.4-1
4) Factor shown is based on natural gas heating value of 1000 Btu/SCF; for emission calculations, factor is ratioed to reflect actual heating value shown.
5) AP-42, Table 1.4-3
6) AP-42, Table 1.4-2
7) AP-42, Table 1.4-5
8) H2SO4 emissions from fuel oil combustion calculated as follows: AP-42, Table 1.3-1 Factor used to estimate SO3 emissions. All SO3 assumed to convert to H2SO4
9) Of available data, the stack test results shown are believed to provide the most accurate estimate of unit emissions; note that this emission factor is almost equal to the AP-42 factor of ~0.47 lb/MBtu