21 West Church Street
Jacksonville, Florida 32202-3139

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DIVISION OF AIR
RESOURCE MANAGEMENT

October 4, 2011

JEA

Mr. Al Linero, P.E.
Division of Air Resource Management
Department of Environmental Protection
2600 Blair Stone Road
Tallahassee, FL 32399

ELECTRIC

WATER

SEWER

RE: Biomass (Wood Chips) Exemption Request
JEA Northside Generating Station Units 1 and 2
Project No. 0310045-031-AC

Project No: 0310045-032-AC

Dear Mr. Linero:

Based on our recent discussion regarding the co-firing of biomass in NGS Units 1 and 2, JEA is requesting an exemption from the requirement to obtain an air construction permit for up to 33.3 tons per day per unit. The amount of biomass co-fired with solid fuel (pet coke and coal) represents 1 percent of the maximum heat input for Units 1 and 2 over the last 5-years (2006-2010). The analysis of co-firing biomass up to 33.3 tons/day per unit was prepared by our environmental consultant Golder Associates Inc. and is attached to this request.

If there are any further questions concerning this request please contact me at (904) 665-8729 or our environmental consultant Mr. Kennard Kosky at (352) 336-5600. The Department's expeditious review of this request is appreciated.

Sincerely,

Jay Worley
Director Environmental Programs

Enclosures

cc: Cindy Mulkey, Siting Coordination Office

Golder Associates

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OCT 07 2011

DIVISION OF AIR
RESOURCE MANAGEMENT

September 29, 2011

113-87543

Mr. Jay A. Worley
Director, Environmental Programs
Jacksonville Electric Authority (JEA)
21 West Church Street
Jacksonville, Florida 32202

RE: EXEMPTION FOR 1 PERCENT BIOMASS IN NGS BOILER NOS. 1 AND 2 (EU IDS 027 AND 026)

Dear Jay:

JEA obtained authorization from the Florida Department of Environmental Protection (FDEP) to burn up to a maximum of 12 tons per day (TPD) of biomass (i.e., wood chips from tree trimmings and similar plant materials) in Northside Generating Station (NGS) Boiler Nos. 1 and 2 (EU IDs 027 and 026) (FDEP Project No. 0310045-031-AC authorized on April 11, 2011). The FDEP exemption amounts to 0.14 percent of the heat input potential for both boilers. FDEP also determined that the biomass-burning project would have miniscule changes in emissions compared to the small and allowable day-to-day variations in the coal and petcoke and blend ratios, and therefore exempted the project from requiring an air construction permit. Based on a discussion with FDEP, an exemption to burn biomass up to a maximum of 1 percent of the heat input for both boilers per day appears appropriate. This correspondence and accompanying tables attached with this letter demonstrate that co-firing biomass up to 1 percent of heat input should be exempted from air construction permitting.

The boilers are currently permitted to fire coal, coal treated with a latex binder, petcoke, No. 2 fuel oil, natural gas, landfill gas from the adjacent North Landfill (Title V Permit No. 0310045-028-AV), and up to a maximum of 12 TPD of biomass. Nitrogen oxides (NO_x) emissions from the NGS Boiler Nos. 1 and 2 are currently controlled by a selective non-catalytic reduction (SNCR) system installed on each boiler. Particulate matter (PM) emissions from the units are controlled by fabric filters, and sulfur dioxide (SO_2) emissions are controlled by limestone injection and spray dryer absorber systems. There will be no change to the existing control equipment as a result of the proposed project and no new emission control technology will be added.

The attached Tables 1 through 8 and A-1 through A-2 calculate the change in projected emissions compared to baseline actual emissions due to the co-firing of 1 percent biomass with solid fuel.

Table 1 presents the actual annual heat inputs from different fuels reported in the Annual Operating Reports (AORs) for the period 2006 through 2010. This table also presents the total actual heat input from all fuels for Boiler Nos. 1 and 2, the actual operating hours for each unit, and percentage of total heat input from each type of fuel. The AOR data is presented in Table A-1.

Table 2 summarizes the annual emissions reported in the AORs for each calendar year in the period 2006 through 2010. The carbon dioxide (CO_2) emission rates in Table 2 were obtained from the U.S. Environmental Protection Agency's (EPA's) Acid Rain database. The Acid Rain data are presented in Table A-2. The sulfuric acid mist (SAM) emissions were not reported in the AORs and were calculated based on assuming 10 percent of SO_2 converts to SAM.

The actual emission factors in pounds per million British thermal units heat input (lb/MMBtu) were calculated in Table 3 for each calendar year in the period 2006 through 2010. The factors are calculated by dividing the total annual emissions by the total annual heat input, which includes both natural gas- and fuel oil-firing.

Golder Associates Inc.
6026 NW 1st Place
Gainesville, FL 32607 USA
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Since emissions of nitrous oxide (N_2O) and methane (CH_4) were not reported in the AORs, they were calculated based on the actual annual heat input and emission factors from Title 40, Part 98 of the Code of Federal Regulations (40 CFR 98), Subpart C. These emissions are summarized in Table 4, which also shows the CO_2 equivalent (CO_2e) rates for these pollutants.

Table 5 presents the current actual pollution control efficiency, which was calculated based on the uncontrolled emissions factors obtained from AP-42 and actual emissions factors obtained from Table 3 above. The uncontrolled emissions factors in AP-42 are based on bituminous coal-firing in a circulating fluidized bed type boiler (Tables 1.1-3, 1.1-4, and 1.1-19 of Section 1.1, AP-42). The volatile organic compound (VOC) emission factor is based on CH_4. The control efficiency of a spray dryer is typically 70 to 90 percent.

Table 6 presents the average emissions for each consecutive 2-year period based on the calendar year emissions in Tables 2 and 4. The annual average emissions for each consecutive 2-year period are consistent with the definition of baseline actual emissions for fossil fuel-fired steam electric generating units.

Table 7 presents the projected actual emissions due to the co-firing of 1 percent biomass with solid fuel. The amount of biomass co-fired with solid fuel was based on 1 percent of the maximum annual heat input for Boiler Nos. 1 and 2 over the last 5 years. This equates to 66.6 TPD of biomass-firing co-fired with solid fuel. The potential uncontrolled emissions are calculated using emission factors from Section 1.6 of AP-42 and Appendix C of Subpart C, 40 CFR 98. PM emission factors include condensable PM assuming all condensable PM is in 2.5 micron ($PM_{2.5}$) size category. There are no emission factors available in AP-42 for SAM. The SAM emission rate was calculated assuming 10 percent of the SO_2 emissions will be oxidized into sulfur trioxide (SO_3), which will then convert to SAM through chemical reaction in the atmosphere. The current actual pollution control efficiencies from Table 5 are used to calculate the projected actual emissions. No controls are used for VOC or greenhouse gas (GHG) emissions. The control efficiency for SO_2 is based on a typical conservative (low) efficiency of a spray dryer absorber system.

Table 8 presents a conservative analysis of emissions increases and decreases resulting from co-firing 1 percent biomass. The current actual emissions factors are used to calculate the emissions for solid fuel at an equivalent heat input of 1 percent; this amount would be replaced by co-firing biomass. The equivalent emissions for solid fuel are subtracted from the emissions due to co-firing biomass (see Table 7).

As shown in Table 8, increases in emissions is conservatively projected for NO_x and VOC when using biomass for an equivalent heat input of 1 percent based on the maximum heat input over the last 5 years. For carbon monoxide (CO), SO_2, PM, PM_{10}, $PM_{2.5}$, and SAM, decreases in emissions of over 40 tons per year (TPY) are projected. In addition, there is an estimated decrease in GHG emissions of about 6,600 TPY. It should be noted that the actual emissions when using biomass are not likely to increase, since the amount of biomass in the total fuel is so small that the combustion process will not likely change. Moreover, for NO_x the post-combustion control using SNCR would likely result in no change in actual emissions. The conclusion that there would be no change in the combustion process using small amounts of biomass is demonstrated by the continuous emission monitoring system (CEMS) for CO when recently burning biomass with solid fuel (petcoke and coal) under the existing exemption and CO data representing burning only solid fuel. The hourly CO emissions for Boiler No. 2 when burning biomass and solid fuel from June 15, 2011 through July 4, 2011 averaged 0.021 lb/MMBtu with a range of 0.045 to 0.008 lb/MMBtu. The average generation during this period was 223 megawatts (MW). When burning only solid fuel, the hourly CO emissions for the period July 15, 2011 through August 4, 2011 averaged 0.022 lb/MMBtu with a range of 0.058 to 0.007 lb/MMBtu. The average generation for this period was 226 MW. These data demonstrate that there is no difference in the combustion process when co-firing small amounts of biomass with solid fuel.

The conservatively estimated increases in emissions for NO_x and VOC are each less than the 5 TPY for exemption criteria in Rule 62-210.300(3)(b), Florida Administrative Code (F.A.C.), for construction permits of emission units. This very low, conservatively estimated emission increase is considered to meet the criteria cited for the original exemption of 12 TPD as specified in Rule 62-4.04(1)(b), F.A.C. This rule as stated in the April 11, 2011 exemption letter states: "Any existing or proposed installation which the Department shall determine does not or will not cause the issuance of air or water contaminants in sufficient quantity, with respect to its character, quality or content, and the circumstances surrounding its location, use and operation, as to contribute significantly to the pollution problems within the State, so that the regulation thereof is not reasonably justified." The conservative emission comparison demonstrates that the changes using 1 percent biomass are *de minimis* in comparison to the existing coal/petcoke usage and an exemption would be appropriate.

Golder appreciates this opportunity to assist JEA. If you have any questions, please do not hesitate to call me at (352) 336-5600.

Professional Engineer Certification

I understand and certify that to the best of my knowledge, any emission estimates reported or relied on in this analysis are true, accurate, and complete and are based upon reasonable techniques available for calculating emissions for the emissions units addressed in this analysis, based solely upon the materials, information and calculations submitted with this analysis.

Sincerely,

GOLDER ASSOCIATES INC.

Kennard F. Kosky

Kennard F. Kosky, P.E.
Principal Engineer
Board of Professional Engineers Certificate of Authorization #00001670

SEAL

Attachments

KFK/SKM/tz

Table 1. NGS Boiler Nos. 1 and 2 Annual Heat Inputs, 2006-2010

	Heat Input from Bituminous Coal (MMBtu/yr)			Heat Input from Distillate Oil (MMBtu/yr)			Heat Input from Natural Gas (MMBtu/yr)			Heat Input from Coke (MMBtu/yr)			Total Actual Heat Input (MMBtu/yr)			Actual Operating Hours (hr/yr)	
Year	Boiler 1	Boiler 2	Total	Boiler 1	Boiler 2	Total	Boiler 1	Boiler 2	Total	Boiler 1	Boiler 2	Total	Boiler 1	Boiler 2	Total	Boiler 1	Boiler 2
2010	1,644,874	1,722,358	3,367,232	0	0	0	34,304	24,720	59,024	15,357,748	16,661,805	32,019,553	17,036,926	18,408,883	35,445,809	6,816	7,177
2009	1,349,691	1,498,508	2,848,199	0	0	0	14,602	35,666	50,268	14,351,596	14,564,536	28,916,132	15,715,889	16,098,710	31,814,599	6,227	6,332
2008	1,698,226	1,488,040	3,186,266	0	0	0	70,283	46,200	116,483	17,798,191	15,357,664	33,155,855	19,566,700	16,891,904	36,458,604	7,940	6,885
2007	2,981,916	2,729,706	5,711,622	0	0	0	49,162	99,274	148,436	16,854,068	16,156,248	33,010,316	19,885,146	18,985,228	38,870,374	7,765	7,374
2006	2,781,275	3,284,308	6,065,583	0	0	0	51,156	52,479	103,635	14,596,540	14,969,108	29,565,648	17,428,971	18,305,895	35,734,866	7,105	7,411

Individual Fuel Heat Input as a Percent of Total Heat Input

	Heat Input from Bituminous Coal (MMBtu/yr)			Heat Input from Distillate Oil (MMBtu/yr)			Heat Input from Natural Gas (MMBtu/yr)			Heat Input from Coke (MMBtu/yr)		
Year	Boiler 1	Boiler 2	Total	Boiler 1	Boiler 2	Total	Boiler 1	Boiler 2	Total	Boiler 1	Boiler 2	Total
2010	4.6%	4.9%	9.5%	0	0	0	0.1%	0.1%	0.2%	43.3%	47.0%	90.3%
2009	4.2%	4.7%	9.0%	0	0	0	0.0%	0.1%	0.2%	45.1%	45.8%	90.9%
2008	4.7%	4.1%	8.7%	0	0	0	0.2%	0.1%	0.3%	48.8%	42.1%	90.9%
2007	7.7%	7.0%	14.7%	0	0	0	0.1%	0.3%	0.4%	43.4%	41.6%	84.9%
2006	7.8%	9.2%	17.0%	0	0	0	0.1%	0.1%	0.3%	40.8%	41.9%	82.7%

Note: All values are based on annual operating reports for the period 2006 - 2010.

Table 2. Annual Emissions Reported In 2006-2010 Annual Operating Reports

Year	Pollutant	Boiler No. 1 (tons)	Boiler No. 2 (tons)	Total (tons)
2010	NO_x	704.0	902.7	1,606.7
	CO	302.2	200.3	502.5
	SO_2	1,584.2	1,607.5	3,191.7
	VOC	21.2	22.1	43.3
	PM	21.7	16.2	38.0
	PM_{10}	27.4	20.4	47.8
	SAM [a]	--	--	488.7
	CO_2	2,090,362.3	2,125,872.5	4,216,234.8
2009	NO_x	810.0	804.1	1,614.1
	CO	119.9	150.5	270.4
	SO_2	1,397.1	1,387.9	2,785.0
	VOC	19.6	20.0	39.6
	PM	18.7	29.0	47.7
	PM_{10}	17.5	27.0	44.5
	SAM [a]	--	--	426.5
	CO_2	1,922,135.5	1,948,776.2	3,870,911.7
2008	NO_x	818.7	701.2	1,519.9
	CO	203.4	125.0	328.4
	SO_2	1,565.0	1,565.0	3,130.0
	VOC	24.6	21.2	45.9
	PM	26.4	33.5	59.8
	PM_{10}	18.9	22.9	41.8
	SAM [a]	--	--	479.3
	CO_2	2,278,188.9	1,828,111.5	4,106,300.4
2007	NO_x	724.6	719.3	1,443.9
	CO	256.8	329.5	586.3
	SO_2	1,510.5	1,411.7	2,922.2
	VOC	24.7	23.0	47.8
	PM	10.3	37.6	47.9
	PM_{10}	10.1	28.0	38.1
	SAM [a]	--	--	447.5
	CO_2	2,295,968.3	2,100,239.5	4,396,207.8
2006	NO_x	710.0	782.0	1,492.0
	CO	312.8	319.3	632.1
	SO_2	1,435.5	1,598.0	3,033.5
	VOC	21.4	22.4	43.8
	PM	8.8	36.3	45.1
	PM_{10}	8.6	27.0	35.7
	SAM [a]	--	--	464.5
	CO_2	2,042,470.2	2,253,247.0	4,295,717.2

[a] SAM was not reported in AORs; based on assuming 10% of SO_2 converts to SO_3, all of which converts to SAM.

Source: Annual Operating Reports (AORs) for JEA NGS, 2006 - 2010.

Table 3. Actual Emissions as a Function of Heat Input, 2006 - 2010

BOILER 1

Year	Actual Annual Heat Input (MMBtu/yr) [a]	Boiler 1 Actual Emissions (TPY) [b]								Emissions per Unit Heat Input [c] (lb/MMBtu)							
		NO_X	CO	VOC	SO_2	PM	PM_{10}	SAM	CO_2	NO_X	CO	VOC	SO_2	PM	PM_{10}	SAM	CO_2
2010	17,036,926	704.0	502.5	21.2	1,584.2	21.7	27.4	242.6	2,090,362.3	0.0826	0.0590	0.0025	0.1860	0.0025	0.0032	0.0285	245.4
2009	15,715,889	810.0	119.9	19.6	1,397.1	18.7	17.5	213.9	1,922,135.5	0.1031	0.0153	0.0025	0.1778	0.0024	0.0022	0.0272	244.6
2008	19,566,700	818.7	203.4	24.6	1,565.0	26.4	18.9	239.6	2,278,188.9	0.0837	0.0208	0.0025	0.1600	0.0027	0.0019	0.0245	232.9
2007	19,885,146	724.6	256.8	24.7	1,510.5	10.3	10.1	231.3	2,295,968.3	0.0729	0.0258	0.0025	0.1519	0.0010	0.0010	0.0233	230.9
2006	17,428,971	710.0	312.8	21.4	1,435.5	8.8	8.6	219.8	2,042,470.2	0.0815	0.0359	0.0025	0.1647	0.0010	0.0010	0.0252	234.4
									Maximum =	0.1031	0.0590	0.0025	0.1860	0.0027	0.0032	0.0285	245.4

BOILER 2

Year	Actual Annual Heat Input (MMBtu/yr) [a]	Boiler 2 Actual Emissions (TPY) [b]								Emissions per Unit Heat Input [c] (lb/MMBtu)							
		NO_X	CO	VOC	SO_2	PM	PM_{10}	SAM	CO_2	NO_X	CO	VOC	SO_2	PM	PM_{10}	SAM	CO_2
2010	18,408,883	902.7	200.3	22.1	1,607.5	16.2	20.4	246.1	2,125,872.5	0.0981	0.0218	0.0024	0.1746	0.0018	0.0022	0.0267	231.0
2009	16,098,710	804.1	150.5	20.0	1,387.9	29.0	27.0	212.5	1,948,776.2	0.0999	0.0187	0.0025	0.1724	0.0036	0.0034	0.0264	242.1
2008	16,891,904	701.2	125.0	21.2	1,565.0	33.5	22.9	239.6	1,828,111.5	0.0830	0.0148	0.0025	0.1853	0.0040	0.0027	0.0284	216.4
2007	18,985,228	719.3	329.5	23.0	1,411.7	37.6	28.0	216.2	2,100,239.5	0.0758	0.0347	0.0024	0.1487	0.0040	0.0029	0.0228	221.2
2006	18,305,895	782.0	319.3	22.4	1,598.0	36.3	27.0	244.7	2,253,247.0	0.0854	0.0349	0.0024	0.1746	0.0040	0.0030	0.0267	246.2
									Maximum =	0.0999	0.0349	0.0025	0.1853	0.0040	0.0034	0.0284	246.2

BOILERS 1 & 2

Year	Actual Annual Heat Input (MMBtu/yr) [a]	Boilers 1 & 2 Total Actual Emissions (TPY) [b]								Emissions per Unit Heat Input [c] (lb/MMBtu)							
		NO_X	CO	VOC	SO_2	PM	PM_{10}	SAM	CO_2	NO_X	CO	VOC	SO_2	PM	PM_{10}	SAM	CO_2
2010	35,445,809	1,606.7	702.8	43.3	3,191.7	38.0	47.8	488.7	4,216,234.8	0.0907	0.0397	0.0024	0.1801	0.0021	0.0027	0.0276	237.9
2009	31,814,599	1,614.1	270.4	39.6	2,785.0	47.7	44.5	426.5	3,870,911.7	0.1015	0.0170	0.0025	0.1751	0.0030	0.0028	0.0268	243.3
2008	36,458,604	1,519.9	328.4	45.9	3,130.0	59.8	41.8	479.3	4,106,300.4	0.0834	0.0180	0.0025	0.1717	0.0033	0.0023	0.0263	225.3
2007	38,870,374	1,443.9	586.3	47.8	2,922.2	47.9	38.1	447.5	4,396,207.8	0.0743	0.0302	0.0025	0.1504	0.0025	0.0020	0.0230	226.2
2006	35,734,866	1,492.0	632.1	43.8	3,033.5	45.1	35.7	464.5	4,295,717.2	0.0835	0.0354	0.0025	0.1698	0.0025	0.0020	0.0260	240.4
									Maximum =	0.1015	0.0397	0.0025	0.1801	0.0033	0.0028	0.0276	243.3

[a] Based on AOR data, see Table 1.

[b] Based on AOR data, see Table 2.

[c] Total actual emissions divided by total heat input.

Table 4. Estimated Actual Annual Emissions of N_2O and CH_4 for the Period 2006 - 2010
NGS Boiler Nos. 1 and 2

Unit	Actual Annual Heat Input [a] (MMBtu/yr)	N_2O Emissions: Emission Factor [b] (lb/MMBtu)	N_2O Emissions: Annual Emissions (lb/yr)	N_2O Emissions: Annual Emissions (TPY)	N_2O Emissions: CO_2e [c] Rate (TPY)	CH_4 Emissions: Emission Factor [b] (lb/MMBtu)	CH_4 Emissions: Annual Emissions (lb/yr)	CH_4 Emissions: Annual Emissions (TPY)	CH_4 Emissions: CO_2e [c] Rate (TPY)
Bituminous Coal									
2010	3,367,232	3.53E-03	11,874.2	5.9	1,840.5	2.4E-02	81,635.2	40.8	857.2
2009	2,848,199	3.53E-03	10,043.9	5.0	1,556.8	2.4E-02	69,051.7	34.5	725.0
2008	3,186,266	3.53E-03	11,236.0	5.6	1,741.6	2.4E-02	77,247.8	38.6	811.1
2007	5,711,622	3.53E-03	20,141.5	10.1	3,121.9	2.4E-02	138,472.6	69.2	1,454.0
2006	6,065,583	3.53E-03	21,389.7	10.7	3,315.4	2.4E-02	147,054.0	73.5	1,544.1
Natural Gas-Firing									
2010	59,024	2.20E-04	13.0	0.007	2.0	2.2E-03	130.1	0.065	1.4
2009	50,268	2.20E-04	11.1	0.006	1.7	2.2E-03	110.8	0.055	1.2
2008	116,483	2.20E-04	25.7	0.013	4.0	2.2E-03	256.7	0.128	2.7
2007	148,436	2.20E-04	32.7	0.016	5.1	2.2E-03	327.2	0.164	3.4
2006	103,635	2.20E-04	22.8	0.011	3.5	2.2E-03	228.4	0.114	2.4
Coke									
2010	32,019,553	3.53E-03	112,913.8	56.5	17,501.6	2.4E-02	776,282.0	388.1	8,151.0
2009	28,916,132	3.53E-03	101,969.8	51.0	15,805.3	2.4E-02	701,042.7	350.5	7,360.9
2008	33,155,855	3.53E-03	116,920.8	58.5	18,122.7	2.4E-02	803,830.6	401.9	8,440.2
2007	33,010,316	3.53E-03	116,407.6	58.2	18,043.2	2.4E-02	800,302.1	400.2	8,403.2
2006	29,565,648	3.53E-03	104,260.3	52.1	16,160.3	2.4E-02	716,789.6	358.4	7,526.3
Total									
2010	--	--	--	62.4	19,344.1	--	--	429.0	9,009.5
2009	--	--	--	56.0	17,363.8	--	--	385.1	8,087.2
2008	--	--	--	64.1	19,868.3	--	--	440.7	9,254.0
2007	--	--	--	68.3	21,170.2	--	--	469.6	9,860.6
2006	--	--	--	62.8	19,479.3	--	--	432.0	9,072.8

[a] Based on AOR data - see Table 1.

[b] Table C-2, Subpart C, 40 CFR 98. Emission factors in kg/MMBtu were converted to lb/MMBtu by multiplying by 2.204.

[c] N_2O and CH_4 are multiplied by a factor of 310 and 21, respectively, to determine CO_2 equivalence.

Table 5. Current Actual Pollution Control Efficiency

Pollutant	Uncontrolled Emission Factor [a] (lb/ton)	Fuel Heat Content [b] (MMBtu/ton)	Uncontrolled Emission Factor (lb/MMBtu)	Current Actual Emission Factors [c] (lb/MMBtu)	Actual Control Efficiency (%)
NO_x	5	26	0.192	0.1015	47.2
CO	18	26	0.692	0.04	94.3
SO_2	--	26	--	0.18	70.0 [d]
VOC	0.06	26	0.0023	0.0025	-9.0
PM	13.2	26	0.508	0.0033	99.4
PM_{10}	13.2	26	0.508	0.0028	99.4
$PM_{2.5}$	13.2	26	0.508	0.0028	99.4

[a] Based on Tables 1.1-3, 1.1-4, 1.1-19 of Section 1.1, AP-42.

[b] Based on heat content of bituminous coal, 25 MMBtu/ton.

[c] Based on maximum current actual emission rates in lb/MMBtu for Boilers 1 & 2.

[d] Based on Table 1.1-1 of AP-42, typical control efficiency for spray drying 70 - 90%.

Table 6. Annual Average Emissions for Boilers 1 & 2 for Each Consecutive Two-Year Period, 2006-2010

	Annual Emissions for Boiler Nos. 1 & 2					Two-Year Average Emissions			
Pollutant	2010	2009	2008	2007	2006	2010-2009 (tons)	2009-2008 (tons)	2008-2007 (tons)	2007-2006 (tons)
NO_x	1,606.7	1,614.1	1,519.9	1,443.9	1,492.0	1,610.4	1,567.0	1,481.9	1,468.0
CO	502.5	270.4	328.4	586.3	632.1	386.5	299.4	457.3	609.2
SO_2	3,191.7	2,785.0	3,130.0	2,922.2	3,033.5	2,988.4	2,957.5	3,026.1	2,977.8
VOC	43.3	39.6	45.9	47.8	43.8	41.4	42.7	46.8	45.8
PM	38.0	47.7	59.8	47.9	45.1	42.8	53.8	53.8	46.5
PM_{10}	47.8	44.5	41.8	38.1	35.7	46.2	43.2	40.0	36.9
$PM_{2.5}$ [a]	47.8	44.5	41.8	38.1	35.7	46.2	43.2	40.0	36.9
SAM [b]	488.7	426.5	479.3	447.5	464.5	457.6	452.9	463.4	456.0
CO_2	4,216,234.8	3,870,911.7	4,106,300.4	4,396,207.8	4,295,717.2	4,043,573.3	3,988,606.0	4,251,254.1	4,345,962.5
N_2O [c] (CO_2e)	19,344.1	17,363.8	19,868.3	21,170.2	19,479.3	18,354.0	18,616.1	20,519.2	20,324.7
CH_4 [c] (CO_2e)	9,009.5	8,087.2	9,254.0	9,860.6	9,072.8	8,548.3	8,670.6	9,557.3	9,466.7

[a] Assuming equal to PM_{10} emissions.

[b] Not reported in AORs - based on assuming 10% of SO_2 converts to SO_3, all of which converts to SAM.

[c] Calculated based on actual annual heat input - see Table 3.

Source: Annual Operating Report (AOR) for 2006 - 2010; EPA's Acid Rain database.

Table 7. Projected Actual Emissions for NGS Boiler Nos. 1 and 2 due to Biomass Firing

Pollutant	Proposed Biomass Usage [a] (tons/day)	Biomass Heating Value [b] (Btu/lb)	Daily Heat Input from Biomass (MMBtu/day)	Annual Heat Input from Biomass [c] (MMBtu/yr)	Emission Factor [d] (lb/MMBtu)	Uncontrolled Annual Emissions (TPY)	Estimated Control Efficiency [e] (%)	Annual Emissions (TPY)
NO_x	66.6	8,000.0	1,064.9	388,704	0.22	42.8	47.2	22.6
CO	66.6	8,000.0	1,064.9	388,704	0.60	116.6	94.3	6.7
SO_2	66.6	8,000.0	1,064.9	388,704	0.025	4.9	70.0	1.5
VOC	66.6	8,000.0	1,064.9	388,704	0.017	3.3	0.0	3.3
PM [e]	66.6	8,000.0	1,064.9	388,704	0.117	22.7	99.4	0.1
PM_{10} [e]	66.6	8,000.0	1,064.9	388,704	0.091	17.7	99.4	0.1
$PM_{2.5}$ [e]	66.6	8,000.0	1,064.9	388,704	0.082	15.9	99.4	0.1
SAM	66.6	8,000.0	1,064.9	388,704	0.004	0.7	0.0	0.7
GHGs								
CO_2	66.6	8,000.0	1,064.9	388,704	206.7	40,179.4	0.0	40,179.4
N_2O	66.6	8,000.0	1,064.9	388,704	9.26E-03	1.8	0.0	1.8
CH_4	66.6	8,000.0	1,064.9	388,704	7.05E-02	13.7	0.0	13.7

[a] Proposed daily wood chip usage at 1% of heat input using maximum over last 5-years; See Table 1 for 2007. (38,870,374 x 0.01 = 388,704 MMBtu/yr).

[b] Heating value based on Section 1.6 of AP-42. Dry wood heating value of 8,000 Btu/lb used as a conservative (high) value.

[c] Based on 365 days/yr operation.

[d] Tables 1.6-1, 1.6-2, and 1.6-3, Section 1.6, AP-42. SAM emission factor based on assumption that 10% of the SO_2 is further oxidized to SO_3, which is then converted to SAM (98/80).

[e] Current actual control efficiency calculated in Table 5.

Table 8. Increase/Decrease in Emissions, NGS Boiler Nos. 1 and 2: Biomass Firing

Pollutant	Baseline Emissions[a] (TPY)	Baseline 2-Year Period	Maximum 2-Year Period Average Heat Input[a] (MMBtu/yr)	Current Actual Emission Factors (lb/MMBtu)	Heat Input to be Replaced by Biomass[b] (MMBtu/yr)	Solid Fuel Emissions for 1% Heat Input Biomass[c] (TPY)	1% Heat Input Biomass Emissions[d] (TPY)	Increase/Decrease in Emissions (1% Biomass – Solid Fuel) (TPY)
NO_x	1,610	2010 - 2009	33,083,086	0.1015	388,704.0	19.7	22.6	2.8
CO	609	2007 - 2006	37,302,620	0.04	388,704.0	7.7	6.7	-1.0
SO_2	3,026	2008 - 2007	37,664,489	0.18	388,704.0	35.0	1.5	-33.5
VOC	47	2008 - 2007	37,664,489	0.0025	388,704.0	0.5	3.3	2.8
PM	54	2008 - 2007	37,664,489	0.0033	388,704.0	0.6	0.1	-0.5
PM_{10}	46	2010 - 2009	33,083,086	0.0028	388,704.0	0.5	0.1	-0.4
$PM_{2.5}$	46	2010 - 2009	33,083,086	0.0028	388,704.0	0.5	0.1	-0.4
SAM[e]	463	2008 - 2007	37,664,489	0.0276	388,704.0	5.4	0.7	-4.6
GHGs								
CO_2	4,345,962	2007 - 2006	37,302,620	243.3	388,704.0	47,294.0	40,179.4	
N_2O (CO_2e)	20,519	2008 - 2007	37,664,489	1.1	388,704.0	211.8	557.7	
CH_4 (CO_2e)	9,557	2008 - 2007	37,664,489	0.5	388,704.0	98.6	287.9	
Total GHGs (CO_2e)	4,376,039.0					47,604.4	41,025.0	-6,579.4

[a] Based on AOR data for the period 2006 - 2010, see Table 6.
[b] See Table 2 for heat input potential for biomass (wood chips), which is the potential amount of current actual heat input to be replaced by biomass burning.
[c] Solid fuel emissions equivalent to 1% heat input. This is the solid fuel emission that would be replaced by emissions using biomass, see Table 7.
[d] Projected annual emissions for annual biomass usage, see Table 7.
[e] SAM emissions data are not available (NA) in the AORs for 2005 - 2009.

Table A-1
JEA NGS
Summary of AOR Data for NGS Boiler Nos. 1 (EU ID 027) and 2 (EU ID 026)

Emission Unit 026

NGS Boiler #2 2010	Bituminous (Tons/year)	#2 Fuel Oil	Natural Gas	Coke	Total	Hours
NOx	87		1.2	814.5	**902.7**	**7177**
CO	19.3		0.3	180.7	**200.3**	
SO2	31.49		0	1576	**1607.49**	
VOC	1.95723		0.066	20.1091	**22.13233**	
PM	1.64		0.0912	14.5	**16.2312**	
PM10	2.03		0.0228	18.3	**20.3528**	
SAM	0		0	0	**0**	
Lead	0		0.000006	0	**0.000006**	

NGS Boiler #2 2009	Bituminous (Tons/year)	#2 Fuel Oil	Natural Gas	Coke	Total	Hours
NOx	74.8	0	1.8	727.5	**804.1**	**6332**
CO	14	0	0.3	136.2	**150.5**	
SO2	34.5	0	0	1353.4	**1387.9**	
VOC	1.70285	0	0.0935	18.2057	**20.00205**	
PM	5.8	0	0.1292	23.1	**29.0292**	
PM10	5.4	0	0.0323	21.6	**27.0323**	
SAM					**0**	
Lead	0.00215	0	0.000009	0.00861	**0.010769**	

NGS Boiler #2 2008	Bituminous (Tons/year)	#2 Fuel Oil	Natural Gas	Coke	Total	Hours
NOx	62.6	0	1.9	636.7	**701.2**	**6885**
CO	11.2	0	0.3	113.5	**125**	
SO2	33.33	0	0	1531.7	**1565.03**	
VOC	1.88838	0	0.121	19.1971	**21.20648**	
PM	6.7	0	0.1672	26.6	**33.4672**	
PM10	4.6	0	0.0418	18.3	**22.9418**	
SAM					**0**	
Lead	0.015862	0	0.000011	0.115182	**0.131055**	

NGS Boiler #2 2007	Bituminous (Tons/year)	#2 Fuel Oil	Natural Gas	Coke	Total	Hours
NOx	103.4	0	3.8	612.1	**719.3**	**7374**
CO	47.4	0	1.7	280.4	**329.5**	
SO2	69.98	0	0	1341.72	**1411.7**	
VOC	3.24965	0	0.2695	19.4989	**23.01805**	
PM	5.5	0	0.3724	31.7	**37.5724**	
PM10	4.1	0	0.0931	23.8	**27.9931**	
SAM					**0**	
Lead	0.027297	0	0.000025	0.116994	**0.144316**	

NGS Boiler #2 2006	Bituminous (Tons/year)	#2 Fuel Oil	Natural Gas	Coke	Total	Hours
NOx	140.3	0	2.2	639.5	**782**	**7411**
CO	57.3	0	0.9	261.1	**319.3**	
SO2	184.62	0	0	1413.38	**1598**	
VOC	3.5699	0	0.14025	18.7114	**22.42155**	
PM	6.6	0	0.1938	29.5	**36.2938**	
PM10	4.9	0	0.04845	22.1	**27.04845**	
SAM					**0**	
Lead	0.029987	0	0.000013	0.112268	**0.142268**	

Emission Unit 027

NGS Boiler #1 2010	Bituminous (Tons/year)	#2 Fuel Oil	Natural Gas	Coke	Total	Hours
NOx	67.8		1.4	634.8	**704**	**6816**
CO	29.1		0.6	272.5	**302.2**	
SO2	31.23		0	1553	**1584.23**	
VOC	1.86918		0.088	19.1972	**21.15438**	
PM	2.2		0.1216	19.4	**21.7216**	
PM10	2.7		0.0304	24.7	**27.4304**	
SAM	0		0		**0**	
Lead	0		0.000008	0.115183	**0.115191**	

NGS Boiler #1 2009	Bituminous (Tons/year)	#2 Fuel Oil	Natural Gas	Coke	Total	Hours
NOx	69.6	0	0.8	739.6	**810**	**6227**
CO	10.3	0	0.1	109.5	**119.9**	
SO2	32.94	0	0	1364.2	**1397.14**	
VOC	1.60678	0	0.0385	17.9395	**19.58478**	
PM	3.7	0	0.0532	14.9	**18.6532**	
PM10	3.5	0	0.0133	14	**17.5133**	
SAM					**0**	
Lead	0.00214	0	0.000004	0.107637	**0.109781**	

NGS Boiler #1 2007	Bituminous (Tons/year)	#2 Fuel Oil	Natural Gas	Coke	Total	Hours
NOx	71.2	0	2.9	744.6	**818.7**	**7940**
CO	17.7	0	0.66	185	**203.36**	
SO2	32.97	0	0	1532	**1564.97**	
VOC	2.13345	0	0.18425	22.3275	**24.6452**	
PM	5.2	0	0.2546	20.9	**26.3546**	
PM10	3.8	0	0.06365	15	**18.86365**	
SAM					**0**	
Lead	0.017921	0	0.000017	0.133965	**0.151903**	

NGS Boiler #1 2006	Bituminous (Tons/year)	#2 Fuel Oil	Natural Gas	Coke	Total	Hours
NOx	108.7	0	1.8	614.1	**724.6**	**7765**
CO	38.5	0	0.6	217.7	**256.8**	
SO2	70.49	0	0	1440	**1510.49**	
VOC	3.5499	0	0.12925	21.0676	**24.74675**	
PM	1.5	0	0.1786	8.6	**10.2786**	
PM10	1.5	0	0.04465	8.6	**10.14465**	
SAM					**0**	
Lead	0.029819	0	0.000012	0.126406	**0.156237**	

NGS Boiler #1 2006	Bituminous (Tons/year)	#2 Fuel Oil	Natural Gas	Coke	Total	Hours
NOx	113.3	0	2.1	594.6	**710**	**7105**
CO	49.9	0	0.9	262	**312.8**	
SO2	165.5	0	0	1270	**1435.5**	
VOC	3.02313	0	0.13475	18.2457	**21.40358**	
PM	1.4	0	0.1862	7.2	**8.7862**	
PM10	1.4	0	0.04655	7.2	**8.64655**	
SAM					**0**	
Lead	0.025394	0	0.000012	0.109474	**0.13488**	

	Fuel Usage Bituminous ton/yr	#2 Fuel Oil 1000 gal/yr	Natural Gas $MMft^3$/yr	Coke ton/yr	**Fuel Heat Content** Bituminous MMBtu/ton	#2 Fuel Oil MMBtu/1000gal	Natural Gas MMBtu/$MMft^3$	Coke MMBtu/ton	**Heat Input per Year** Bituminous MMBtu/yr	#2 Fuel Oil MMBtu/yr	Natural Gas MMBtu/yr	Coke MMBtu/yr	Total MMBtu/yr
NGS Boiler # 2													
2010	78289	0	24	574545	22	137	1030	29	1722358	0	24720	16661805	18408883
2009	68114	0	34	520162	22	137	1049	28	1498508	0	35666	14564536	16098710
2008	75535	0	44	548488	19.7	137	1050	28	1488040	0	46200	15357664	16891903.5
2007	129986	0	98	557112	21	137	1013	29	2729706	0	99274	16156248	18985228
2006	142796	0	51	534611	23	137	1029	28	3284308	0	52479	14969108	18305895
NGS Boiler # 1													
2010	74767	0	32	548491	22	137	1072	28	1644874	0	34304	15357748	17036926
2009	64271	0	14	512557	21	137	1043	28	1349691	0	14602	14351596	15715889
2008	85338	0	67	637928	19.9	137	1049	27.9	1698226	0	70283	17798191.2	19566700.4
2007	141996	0	47	601931	21	137	1046	28	2981916	0	49162	16854068	19885146
2006	120925	0	49	521305	23	137	1044	28	2781275	0	51156	14596540	17428971

Table A-2

CEM Reports from Acid Rain Database

Annual Reports

STATE	FACILITY_NAME	ORISPL_CODE	UNITID	OP_YEAR	ASSOC_STACKS	PRG_CODE	SUM_OP_TIME	NUM_MONTHS_REPORTED	GLOAD	SO2_MASS	NOX_RATE	NOX_MASS	CO2_MASS	HEAT_INPUT	UNIT_TYPE_INFO	PRIMARY_FUEL_INFO	SECONDARY_FUEL_INFO	CAPACITY_INPUT
FL	Northside	667	1A	2010		ARP	6921.99	12	1955060.98	1584.559	0.0698	704.294	2090362.297	19786440.76	Circulating flu	Coal		2764
FL	Northside	667	2A	2010		ARP	7254.77	12	2058348.45	1607.966	0.0888	902.675	2125872.527	20122700.55	Circulating flu	Coal		2672
									4013409.43			1606.969						

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