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BUREAU OF AIR REGULATION

March 26, 2010

093-87718

Mr. Jeffery F. Koerner, P.E.
New Source Review Section Administrator
Florida Department of Environmental Protection
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

**RE: REQUEST FOR ADDITIONAL INFORMATION DATED MARCH 3, 2010
PROJECT NO. 0310045-029-AC
ST. JOHNS RIVER POWER PARK UNITS 1 AND 2
REQUEST TO AUTHORIZE CONTINUOUS FIRING OF NATURAL GAS DURING NORMAL OPERATIONS**

Dear Mr. Koerner:

JEA has received a request for additional information (RAI) from the Florida Department of Environmental Protection (FDEP) dated March 3, 2010, regarding the air construction permit application (FDEP Project No. 0310045-029-AC) submitted on February 9, 2010, to authorize continuous firing of natural gas in St. Johns River Power Park (SJRPP) Units 1 and 2 during normal operations.

The RAI specifically asks for a regulatory applicability determination regarding the New Source Performance Standards (NSPS) Subpart Da for the firing of natural gas in Units 1 and 2. Subpart Da currently applies to Units 1 and 2, and the current Title V Operating Permit No. 0310045-016-AV lists the emissions standards, monitoring, reporting, and record keeping requirements pursuant to the Subpart. It is Golder's understanding that the particulate matter (PM) and sulfur dioxide (SO_2) standards of Subpart Da, as described in Title 40, Part 60.42Da of the Code of Federal Regulations (40 CFR 60.42Da), and 40 CFR 60.43Da, respectively, apply to gaseous fuel, which, as defined in 40 CFR 60.41Da, is different from natural gas. 40 CFR 60 Section 60.41Da defines gaseous fuel as "any fuel derived from coal or petroleum that is present as a gas at standard conditions and includes, but is not limited to, refinery fuel gas, process gas, coke-oven gas, synthetic gas, and gasified coal" and provides a separate definition for natural gas. The numerical emissions standards for PM and SO_2 in Subpart Da are described to be applicable during the combustion of solid, liquid, or gaseous fuels; however, natural gas has no regulatory precedent for limiting emission of PM or SO_2 under Subpart Da, as emissions of these air pollutants due to burning natural gas are negligible.

The emissions standards for nitrogen oxides (NO_x) as specified in 40 CFR 60.44Da(a)(1) and (2), are also described to be applicable to gaseous fuel and not to natural gas. However, NO_x has a historical basis as being applicable to natural gas prior to the definition of "gaseous fuel," which was first introduced in 2006. Pending clear guidance from the U.S. Environmental Protection Agency (EPA) on the reasons for separating natural gas from gaseous fuel, JEA proposes to accept the NO_x emissions standards for gaseous fuel as the emissions standards for natural gas.

It is proposed that Specific Conditions D.15 and D.16 of the current Title V Operating Permit No. 0310045-016-AV be revised as follows to include natural gas:

D.15. Nitrogen Oxides: No owner or operator subject to the provisions of 40 CFR 60, Subpart Da, shall cause to be discharged into the atmosphere from any affected facility any gases which contain nitrogen oxides in excess of the following emission limits, based on a 30-day rolling average.
(1) NO_x emissions limits.
   a. Coal or coal-petroleum coke blend: 0.60 lb/million Btu (260 ng/J) heat input;
   b. Fuel oil: 130 ng/J (0.30 lb/million Btu) heat input~~.~~;

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c. Natural gas: 86 ng/J (0.20 lb/million Btu) heat input.

(2) NO_x reduction requirement.

a. Solid fuels: 65 percent reduction of potential combustion concentration;

b. Liquid fuels: 30 percent reduction of potential combustion concentration~~.~~;

c. Gaseous fuel: 25 percent reduction of potential combustion concentration.

[40 CFR 60.44a(a)(1) and (2)]

D.16. Nitrogen Oxides: When two or more fuels [fuel oil, coal (or a blend of coal and petroleum coke), natural gas] are combusted simultaneously, the applicable standard is determined by proration using the following formula:

$PS_{NOX} = (130X + 260Y + 86Z) / 100$

where:

PS_{NOX} = the prorated standard for nitrogen oxides when multiple fuels [coal (or a blend of coal and petroleum coke), fuel oil, and natural gas] are combusted simultaneously (ng/J heat input)

X = the percentage of total heat input derived from the combustion of fuel oil

Y = the percentage of total heat input derived from the combustion of coal or a blend of coal and petroleum coke

Z = the percentage of total heat input derived from the combustion of natural gas

[40 CFR 60.44a(c) and PSD-FL-010]

Revised Tables 2 and 5 are provided in Attachment A, which shows future potential NO_x emissions due to natural gas combustion based on the Subpart Da NO_x limit of 0.20 pound per million British thermal units (lb/MMBtu). As a result, the revised potential decrease in NO_x emissions is shown as 1,351.6 tons per year (TPY). As described in the application, natural gas when used during normal operation is co-fired with coal and the resulting NO_x emissions are controlled using a selective catalytic reduction (SCR) system that will achieve a combined NO_x emission rate less than the Subpart Da NO_x emission limit.

Thank you for consideration of this information. If you have any questions, please do not hesitate to call us at (352) 336-5600 or via email (kkosky@golder.com and smohammad@golder.com).

Sincerely,

GOLDER ASSOCIATES INC.

Kennard Kosky, P.E.
Principal Engineer

Salahuddin Mohammad
Senior Project Engineer

cc: B. Gianazza, JEA

Enclosures

SKM/tz

TABLE 2 (Rev. 2)
FUTURE POTENTIAL EMISSIONS FOR UNITS 1 & 2 DUE TO NATURAL GAS FIRING

Pollutant	Potential Hourly Heat Input [a] (MMBtu/hr)	Potential Annual Heat Input [b] (MMBtu/yr)	Natural Gas Heat Content [c] ($MMBtu/10^6$ scf)	Natural Gas Consumption Hourly (10^6 scf/hr)	Natural Gas Consumption Annual (10^6 scf/yr)	Emission Factor [d]		Hourly Emissions (lb/hr)	Annual Emissions (TPY)
NO_x	1,400.0	12,264,000	1,022	1.37	12,000.0	0.20	lb/MMBtu	280.0	1,226.4
CO	1,400.0	12,264,000	1,022	1.37	12,000.0	84	$lb/10^6$ scf	115.1	504.0
SO_2	1,400.0	12,264,000	1,022	1.37	12,000.0	0.6	$lb/10^6$ scf	0.8	3.6
VOC	1,400.0	12,264,000	1,022	1.37	12,000.0	5.5	$lb/10^6$ scf	7.5	33.0
PM	1,400.0	12,264,000	1,022	1.37	12,000.0	1.9	$lb/10^6$ scf	2.6	11.4
PM_{10}	1,400.0	12,264,000	1,022	1.37	12,000.0	1.9	$lb/10^6$ scf	2.6	11.4
SAM	1,400.0	12,264,000	1,022	1.37	12,000.0	0.046	$lb/10^6$ scf	0.06	0.28

[a] Hourly heat input based on 28 igniters for each unit, each igniter rated at 25 MMBtu/hr.

[b] Potential annual heat input based on 8,760 hr/yr operation.

[c] Based on natural gas heat content of 1,022 Btu/scf.

[d] Tables 1.4-1 and 1.4-2, Section 1.4, AP-42. SAM emission factor based on AP-42 Section 1.3 for fuel oil burning - 5% (1 to 5%) of the SO_2 is further oxidized to SO_3, which then converts to SAM (98/80).

TABLE 5 (Rev. 2)
PSD APPLICABILITY - SJRPP UNITS 1 & 2
NATURAL GAS FIRING

Pollutant	Latest 2-Year (2007-2008) Average Emissions[a] (TPY)	Latest 2-Year (2007-2008) Average Heat Input[a] (MMBtu/yr)	Current Actual Emission Rates (lb/MMBtu)	Current Actual Emissions for Heat Input Potential of Natural Gas[c] (TPY)	Future Potential Emissions[d] (TPY)	Increase/Decrease in Emissions (Future – Current Actual) (TPY)	PSD Significant Emission Rates (TPY)
NO_x	19,282	91,727,403	0.42	2,578.0	1226.4	-1351.6	40
CO	7,978	91,727,403	0.17	1,066.6	504.0	-562.6	100
SO_2	10,943	91,727,403	0.24	1,463.1	3.6	-1459.5	40
VOC	121	91,727,403	0.0026	16.1	33.0	16.9	40
PM[e]	144	91,727,403	0.0035	21.5	11.4	-10.1	25
PM_{10}[f]	76	91,727,403	0.0029	18.0	11.4	-6.6	15
SAM[g]	NA	NA	NA	NA	0.3	0.3	7

[a] Based on AOR data for 2003 - 2008, see Table 4.

[b] Based on AOR data for 2003 - 2008, see Table 1.

[c] See Table 2 for heat input potential for natural gas, which is the potential amount of current actual heat input to be replaced by natural gas.

[d] Future potential emissions based on heat input potential of natural gas, see Table 2.

[e] Current actual PM emission rate in lb/MMBtu is based on stack test data from 2003-2008 from FDEP ARMS database.

[f] Current PM_{10} emission rate in lb/MMBtu is based on the ratio of PM to PM_{10} emission in Table 1.1-6 for dry bottom boilers with an ESP. Ratio is 0.054/0.064 = 84%.

[g] SAM emissions data are not available (NA) in the AORs for 2003 - 2008.