Department of Environmental Protection

Jeb Bush
Governor

Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

David B. Struhs
Secretary

July 2, 2002

Mr. Gregg Worley, Chief
Air, Radiation Technology Branch
Preconstruction/HAP Section
U.S. EPA, Region 4
61 Forsyth Street
Atlanta, Georgia 30303

RE: Cedar Bay Cogeneration Facility
Co-firing Petroleum Coke with Coal
PSD-FL-137A Revision
DEP File No. 0310337-005-AC

Dear Mr. Worley:

Enclosed for your review and comment is an application submitted by U.S. Generating Company to allow permit the co-firing of up to 35 percent petroleum coke with coal in the three existing circulating fluidized bed boilers at the Cedar Bay cogeneration facility in Duval County, Florida.

Your comments may be forwarded to my attention at the letterhead address or faxed to the Bureau of Air Regulation at 850/922-6979. If you have any questions, please contact Mike Halpin, review engineer, at 850/921-9519.

Sincerely,

Patty Adams
for Al Linero, P.E.
Administrator
New Source Review Section

AAL/pa

Enclosure

Cc: Mike Halpin

FLORIDA
Jeb Bush
Governor

Department of Environmental Protection

Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

David B. Struhs
Secretary

July 2, 2002

Mr. John Bunyak, Chief
Policy, Planning & Permit Review Branch
NPS – Air Quality Division
Post Office Box 25287
Denver, Colorado 80225

RE: Cedar Bay Cogeneration Facility
Co-firing Petroleum Coke with Coal
PSD-FL-137A Revision
DEP File No. 0310337-005-AC

Dear Mr. Bunyak:

Enclosed for your review and comment is an application submitted by U.S. Generating Company to allow permit the co-firing of up to 35 percent petroleum coke with coal in the three existing circulating fluidized bed boilers at the Cedar Bay cogeneration facility in Duval County, Florida.

Your comments may be forwarded to my attention at the letterhead address or faxed to the Bureau of Air Regulation at 850/922-6979. If you have any questions, please contact Mike Halpin, review engineer, at 850/921-9519.

Sincerely,

Patty Adams
for Al Linero, P.E.
Administrator
New Source Review Section

AAL/pa

Enclosure

Cc: Mike Halpin

Golder Associates Inc.

6241 NW 23rd Street, Suite 500
Gainesville, FL 32653-1500
Telephone (352) 336-5600
Fax (352) 336-6603

Golder Associates

June 28, 2002

Mr. Michael P. Halpin, P.E.
New Source Review Section
Bureau of Air Regulation
Florida Department of Environmental Protection
Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

RECEIVED
JUL 01 2002
BUREAU OF AIR REGULATION

RE: REQUEST FOR ADDITIONAL INFORMATION
CEDAR BAY COGENERATION FACILITY
CO-FIRING PETROLEUM COKE WITH COAL
FILE NO. PA 88-24 (PSD-FL-137)

Dear Mr. Halpin:

This correspondence is being submitted on behalf of Cedar Bay Cogenerating Company, L.P. in reference to the Department's letter dated April 2, 2002 requesting additional information related to co-firing petroleum coke with coal at the facility. The additional information, along with calculations, is attached and follows the format of the Department's request. I am providing as part of this letter a professional engineer certification of the calculations contained with the additional information.

The Department's expeditious review of the application is appreciated. Please contact me if there are question on the information submitted with this correspondence.

Sincerely,

GOLDER ASSOCIATES INC.

Kennard F. Kosky

Kennard F. Kosky, P.E.
Principal
Professional Engineer Registration No. 14996

KFK

SEAL

cc: Bruce Smith, General Manager Cedar Bay Generating Company, L.P. (with enclosures)
Jeff Walker, Cedar Bay Generating Company, L.P. (with enclosures)
Michelle Golden, PG&E National Energy Group (with enclosures)
David Dee, Landers and Parsons (with enclosures)
Hamilton S. Oven, P.E., PPSO (with enclosures)
James L. Manning, Jacksonville RESD (with enclosures)
Chris Kirts, DEP NE District (with enclosures)
Stafford Campbell, Greater Arlington Civic Council
B. Worley, EPA
J. Bunyak, NPS

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ADDITIONAL INFORMATION FOR
CO-FIRING PETROLEUM COKE WITH COAL

File No. PA 88-24 (PSD-FL-137)
Cedar Bay Cogenerating Project

This document provides additional information requested by the Department in the letter dated April 2, 2002 related to co-firing petroleum coke with coal at the Cedar Bay Cogeneration facility. The information is presented in the same format as requested.

1. **FDEP Request/Comment:** The technical basis for the development of the "Representative Future Actual Emissions" in Table B is unclear. Rather, in each case, the "Representative Future Actual Emissions" appear to simply represent values that are slightly less than the past actual emissions plus the PSD Significant Emission Rates. Please provide the basis for the emission calculations, which Cedar Bay utilized in the development of this table. The Department notes that the basis for the original BACT emission calculation was a 93% capacity factor.

Additional Information: The "representative future actual emissions" were based on the average 1999/2000 actual emissions with an incremental addition for each pollutant to keep the emissions less than the PSD significant emission rates. The increment was added due to the potential variability of operations in any given year as well as pollutant variability. As indicated by the operation over the last five years, the facility operates at a high capacity given the requirement to provide power under contract to FPL and to supply steam to the host facility. Therefore, it is intended that the facility would operate in the same manner as in previous years with slight variability in operations and emission rates. Based on this premise, information on past actual performance and emissions when firing coal, and calculations of expected performance and emissions during the same period when co-firing petroleum coke with coal, were developed. This information and the associated calculations are presented in attached Tables 1 through 5. Each table is discussed below.

Table 1 presents information on the actual fuel and material used during operation of the facility from 1997 through 2001. This information was provided to the Department in the Annual Operating Reports (AORs) and includes fuel and limestone usage and generation of bed and fly ash. Information on the heat, ash and sulfur content of the fuel is also provided as these are used in subsequent calculations.

Table 2 presents operations information for coal firing during 1997 through 2001. The purpose of this table is for comparison with calculations for co-firing petroleum coke with coal. The information presented in this table is from the AORs and calculated based on data from the AORs. The far right column provides the basis of the information or the calculation. The amount of potential ash can be calculated directly. The amount of limestone required for SO_2 removal can be calculated based on the reaction of SO_2 with limestone ($CaCO_3$). The amount of byproduct formed by this reaction is calculated by assuming the formation of $CaSO_4$. The excess limestone is based on the actual limestone used minus that calculated for SO_2 removal. The CFB technology utilizes a reactant (i.e., limestone) to obtain high removal efficiencies. The total bed and fly ash, which includes ash from the fuel, excess reactant and $CaSO_4$, was also calculated. In this calculation, the CO_2 formed in the high temperature process of heating limestone is subtracted from the calculated total bed and fly ash. The table also includes a calculation of the lb/hr values for coal, limestone, bed ash and fly ash. This information is used to calculate the differences in fuel and material handling with regard to past actual emissions and future actual emissions.

Tables 3a and 3b present calculations representing the co-firing of petroleum coke with coal based on the same operation conditions as experienced in 1997 through 2001. As discussed previously, the facility will operate in basically the same manner. Cedar Bay Generating Company is proposing to limit the sulfur content of the total co-firing fuel to 3.2 lb/MMBtu or less. This approach would provide Cedar Bay with greater flexibility and would allow Cedar Bay to use a range of petroleum cokes. Specifically, the fuel used at Cedar Bay could range from approximately 20 percent petroleum coke (approximately 6 percent sulfur content) to approximately 35 percent petroleum coke (approximately 4 percent sulfur content). This approach would limit the maximum SO_2 removal in the CFB to approximately 95 percent when meeting a target emission rate of approximately 0.16 lb/MMBtu. To determine compliance with a 3.2 lb SO_2/MMBtu fuel input to the CFBs, daily as fired analyses would be performed.

To demonstrate the ability of the CFB to operate within this range, calculations were preformed using the 4.1 and 5.5 percent sulfur petroleum cokes identified in the Foster Wheeler report. The calculations in Table 3a are based on a 5.5 percent sulfur petroleum coke with the same heat input for the given year with 80 percent by weight of coal and 20 percent by weight of petroleum coke. Table 3b presents calculations based on a 4.1 percent petroleum coke with 65 percent by weight of coal and 35 percent by weight of petroleum coke supplying the heat input for the year. The coal fuel parameters (i.e., heat, sulfur and ash contents) are based on those for each year while the petroleum coke parameters are those used in the Foster Wheeler report provided with the original calculation (Coke #4). The calculations provided are identical to those for Table 2 including historical limestone requirements. Projections by Foster Wheeler of the amount of limestone required as a function of the amount of fuel at 35 percent petroleum coke in the total fuel suggest better limestone utilization due to improved bed combustion. This information was summarized in Table 1 of the application (i.e., 22,500 lb limestone/hr / 78,000 lb fuel/hr = 0.29). Therefore the calculations presented in Tables 3a and 3b are conservative. The tables also include calculations of the lb/hr values for coal, limestone, bed ash and fly ash for co-firing petroleum coke and coal. The projected lb/hr values in the Foster Wheeler are also provided for comparison. As noted, the calculated values are similar to and less than those provided in the Foster Wheeler report. Also presented in the tables are differences between coal and co-firing for fuel, fuel ash, limestone, total ash and fly ash. As shown, there would be decreases in fuel and fuel ash and increases in limestone and total bed and fly ash when co-firing 20 to 35 percent petroleum coke. It should be noted that the amount of increase in total ash is a direct result of the additional limestone; there is not an increase in fuel ash. The high calcium content of the ash would continue to help make this by-product a marketable soil supplement.

Tables 4a and 4b present calculations for each pollutant when co-firing coal and petroleum coke, with the actual emissions and net emissions increase. Each pollutant is discussed below.

- CO – The calculated emissions are based on projections of Foster Wheeler. As shown there is a net emission decrease.
- NO_x – Each CFB is equipped with Selective Non-Catalytic Reduction (SNCR), which will be used to limit NO_x emission rates to levels that would not increase annual emissions above the PSD significant emission rate of 40 tons/year. As noted from the Foster Wheeler report the co-firing of petroleum coke with coal would reduce uncontrolled emissions by about 25 percent (Figure 5) with the benefit of lower ammonia usage (Figure 6).
- PM/PM_{10} – The calculated emission are based on the average particulate emissions for each year. The emission rate from the baghouse for each CFB can be maintained because PM removal is not a function of loading, given the low loading rates to the baghouse. This information is provided in the ABB Emissions Control System Operations and Maintenance Manual, which is attached. As provided in the manual, the particulate emission rate can be maintained over a range of grain loading and flow rates. The baghouses are designed for an inlet grain loading o 19.5 grains/acf at 297,700 acfm. The grain loading (in grains/acf) for

coal and co-firing are presented in Tables 5a and 5b. As shown in the table, the increase loading to the baghouses resulting from co-firing is less than 1 grain/acf. In addition, the maximum grain loading projected in the Foster Wheeler report is 6.7 grains/acf, which is much less than the design condition. This conclusion is supported by information available from EPA regarding fabric filters. In the Air Pollution Technology Fact Sheets for fabric filters EPA states that: "the effluent particle concentration from a fabric filter is nearly constant"... and "fabric filters can be considered constant outlet devices rather than constant efficiency devices." The annual PM/PM_{10} emissions would be maintained with no increase above the PSD significant emission rate of 40 tons/year.

- Sulfuric Acid Mist (SAM) – The emissions for sulfuric acid mist when co-firing were based on the actual emissions determined during initial testing when firing coal, and increased proportionally for the increased sulfur content of the fuel when co-firing. The test data determined a emission rate of <0.00003 lb/MMBtu for all units. This was increased based on the sulfur content of the fuel and was about 0.00006 lb/MMBtu. While there is an projected increase in SAM emissions, the amount is less than the PSD significant emission rate of 7 tons/year.
- SO_2 – The removal of SO_2 would be increased by increasing the efficiency of removal through the use of more limestone. The Foster Wheeler report indicated that an emission rate of 0.16 lb/MMBtu can be maintained by increasing the use of limestone. The calculations presented in Tables 4a and 4b were based on meeting the annual emissions by controlling the outlet SO_2 emission. For each year, the required emission rates to keep emissions at past actual emissions ranges from 0.165 to 0172 lb/MMBtu. This is within the emission reduction predicted in Foster Wheeler Report. Thus, the annual SO_2 emissions would be maintained with no increase above the PSD significant emission rate of 40 tons/year.
- VOC – For VOC emissions, the tests suggest an emission rate ranging from 0.0014 lb/MMBtu (1994) to 0.0047 lb/MMBtu (2001) when firing coal, with and average of 0.003 lb/MMBtu. For VOC emissions, the calculation in Tables 4a and 4b show a comparison of the reported AOR emissions using the 1994 emission rate with the average emission rate for co-firing. The increase presented is an artifact of the calculation and is not expected. Given that the combustion process is improved when co-firing petroleum coke with coal, and that petroleum coke has lower volatile matter and hydrocarbons, no increase in VOCs is expected. The annual VOC emissions would be maintained with no increase above the PSD significant emission rate of 40 tons/year.

2. **FDEP Request/Comment:** Notwithstanding Cedar Bay's reference to 40 CFR 52.21(b)(33), it does not appear that the original question posed in the Department's letter dated September 28, has been fully answered. Within that request, the Department is attempting to obtain reasonable assurance as to whether a PSD Review is required. The relevant statutes expressly contemplate that projections of the impact of a change must be made before construction. Before a permit is issued, among other things, the owner or operator of the source must, using projections of post-change emissions, demonstrate that emissions from the modified source will not violate air quality requirements.

   Specifically, section 165 states that "[n]o major emitting facility ... may be constructed unless a permit has been issued for such proposed facility" [CAA § 165, 42 U.S.C. § 7475]. Further, the owner or operator must demonstrate to the administrator's satisfaction that "emissions from construction or operation of such facility will not cause, or contribute to, air pollution in excess of" the NAAQS, among other things [CAA § 165(a)(3), 42 U.S.C. § 7475(a)(3)].

This statutory and regulatory structure has two important features relevant to this application:

(1) the permit must be obtained *before* the physical change is made, and

(2) whether a physical change requires a permit is determined in part by reference to anticipated results or consequences, which necessarily would occur *after* the physical change is made.

Thus, the only way for the owner or operator of the source to know whether a permit is required for any particular physical change is for the owner or operator to make a prediction as to whether the emissions increase will occur. This observation was described by EPA in the 1992 preamble to amendments to the NSR regulations as follows:

> Applicability of the CAA's NSR provisions must be determined in advance of construction and is pollutant specific. In cases involving existing sources, this requires a pollutant-by-pollutant projection of the emissions increases, if any, which will result from the physical or operational change. [57 Fed. Reg. 32,314, 32,316 n.8 (1992.)]

Any other construction of the statute would allow sources to make modifications or changes without a permit, while they wait to see if it would be proven that emissions would increase. Clearly Congress did not intend such an outcome, which would effectively allow avoidance of the *preconstruction* dimension of the program.

Concerning the attendant application, should the Department gain reasonable assurance that the PSD thresholds are not triggered, a permit condition (similar to the one referenced within your response) may be able to be implemented, with additional restrictions as deemed appropriate by the Department.

Additional Information: The comment is acknowledged. As requested, Cedar Bay Cogenerating Company, L.P. will demonstrate on a continuing basis for the next 5-years when co-firing that there is not a significant increase in any PSD air pollutant.

3. **FDEP Request/Comment:** According to prior data reported to FDEP by Cedar Bay, past actual SO_2 has been controlled at 90% with limestone throughputs averaging 120,000 TPY. The application has estimated past actual sulfur capture at over 93% and annual limestone throughput at 152,753 TPY. As indicated below, the Department intends to revise all related calculations.

Additional Information: Comment acknowledged. The actual usage of limestone is presented in Table 1. Table 6 presents a update of the material usage for the project based on 35 percent petroleum coke co-fired with coal. The information on the fugitive emissions calculation presented in Appendix B of the application were based on an increase using 35 percent of the coal utilization and the use of a truck dump. A truck dump is no longer planned. Petroleum coke will be received within the enclosed coal unloading building. Since this building is partially enclosed and has a water spray system for controlling fugitive dust, overall emissions will be lower than those presented in the application. The limestone usage was based on the projection of Foster Wheeler for 35 percent petroleum coke with coal. Using this approach, these fugitive emissions estimates are greater than those using the revised calculations (e.g., 22,500 lb/hr/unit compared to a calculated of 19,000 lb/hr/unit in Table 6). Figure 3 has been updated to reflect the change in the use of the coal unloading building.

4. **FDEP Request/Comment:** According to prior data reported to FDEP by Cedar Bay, past actual throughputs of bed (bottom) ash have averaged over 70,000 TPY during years 1998 through 2000. The application has provided a calculated past value of 51,325 TPY. The Department intends to revise all related calculations, and notes that the existing permit limits the throughput to 88,000 TPY.

Additional Information: Comment acknowledged. Table 6 presents an update of actual and potential bed and fly ash.

5. **FDEP Request/Comment:** Based upon a preliminary analysis by the Department, the co-firing of petcoke at 35% will necessitate an increase in limestone feed by over 100% in order to ensure that SO_2 emissions are not increased. The Department specifically requires additional information (beyond that which has been submitted) in order to ensure that annual PM_{10} emissions remain below a 15 TPY increase, while simultaneously maintaining SO_2 emissions below a 40 TPY increase. Please provide assumed collection efficiencies within submitted calculations.

Additional Information: As presented in the response to FDEP Request/Comment 1, the PM/PM_{10} emission rate will be maintained by the baghouses on each CFB boiler. This conclusion is based on the design data in the manufacturer's manual and the relatively low increase in grain loading resulting from co-firing (i.e., less than 1 grain/acf) compared to the baghouse design. In addition, the SO_2 emission rate can be maintained based on increasing the rate of limestone usage. The ability to increase the limestone usage and concomitantly increase efficiency is based on the calculations supplied herein and the manufacturer's report, which was supplied as Appendix A of the application.

Table 1. Fuel and Material Handling Information from Annual Operating reports for Cedar Bay Cogeneration Facility

Material	Source of Information	Units	Year				
			1997	1998	1999	2000	2001
Total Fuel Usage	Coal	tons/yr	970,331	972,999	962,569	954,391	920,356
Coal Sulfur Content	Coal Sulfur Content	%	0.94	1.06	1.11	1.06	0.95
Coal Ash Content	Coal Ash Content	%	11.40	12.10	11.82	10.53	11.90
Coal Heat Content	Coal Heat Content	MMBtu/ton	23.80	23.40	23.90	23.90	23.80
Coal Heat Content	Coal Heat Content	Btu/lb	11,900.00	11,700.00	11,950.00	11,950.00	11,899.93
Total Limestone Throughput	Limestone Storage Bin 1	tons/yr	85,596	85,050	82,325	74,765	--
Total Limestone Throughput	Limestone Storage Bin 2	tons/yr	42,798	41,890	40,141	35,769	--
Total Limestone Throughput	Limestone Vib Pan Conv	tons/yr	66,337	66,337	--	--	--
Total Limestone Throughput	Pulv Limestone Feeders (6)	tons/yr	--	--	122,835	110,534	110,201
Total Lime Manufactured	Abs Dryer System Train 1	tons/yr	--	--	60,874	68,823	--
Total Lime Manufactured	Abs Dryer System Train 2	tons/yr	--	--	66,135	56,660	--
Total Bed Ash Throughput	Bed Ash Hopper	tons/yr	64,997	69,400	69,153	71,235	69,550
Total Bed Ash Throughput	Bed Ash Silo (Sep+Col)	tons/yr	64,997	69,340	69,153	71,235	69,550
Total Fly Ash Throughput	Fly Ash Silo (Sep+Col) 1	tons/yr	65,982	70,452	69,153	69,140	67,504
Total Fly Ash Throughput	Fly Ash Silo (Sep+Col) 2	tons/yr	65,982	70,452	69,153	69,140	67,504
Total Fly Ash Throughput	Fly Ash Silos	tons/yr	131,964	140,904	138,306	138,280	135,008
Total Fly/Bed Ash Processed	Dry Ash Rail Car Loadout	tons/yr	196,960	210,303	209,556	209,515	204,558

Table 2. Data and Calculation for Coal Firing at Cedar Bay Cogeneration Facility

Parameter	Units	Year 1997	1998	1999	2000	2001	Basis
Operation	hours	8,052.3	8,088.3	7,978.7	7,692.7	7,482.7	AOR
Coal	tons	970,331	972,999	962,569	954,391	920,356	AOR
Coal	MMBtu	23,093,878	22,768,177	23,005,399	22,809,945	21,904,349	AOR
Ash	%	11.40	12.10	11.82	10.53	11.90	AOR
Ash	tons	110,618	117,733	113,776	100,497	109,522	Coal (tons) x Ash (%)
Limestone total	tons	128,394	126,940	122,466	110,534	110,201	AOR
Sulfur	%	0.94	1.06	1.11	1.06	0.95	AOR
SO_2 total	tons	18,242.2	20,627.6	21,369.0	20,233.1	17,486.8	Coal (tons) x Sulfur (%)/100 x 2
SO_2 emitted	tons	1,909.0	1,935.6	1,926.2	1,965.1	1,901.5	AOR
SO_2 removed	tons	16,333.2	18,692.0	19,442.8	18,268.0	15,585.3	SO_2 total - SO_2 emitted
SO_2 removed	%	89.5%	90.6%	91.0%	90.3%	89.1%	SO_2 removed/SO_2 total
Limestone required for SO_2 removal	tons	25,520.7	29,206.2	30,379.4	28,543.7	24,352.0	SO_2 removed x 100/64
Limestone excess	tons	102,873.3	97,733.8	92,086.6	81,990.2	85,849.0	Limestone total - Limestone for SO_2
$CaSO_4$ Formed	tons	34,708.1	39,720.5	41,316.0	38,819.4	33,118.7	SO_2 removed x 130/64
CO_2 emitted from SO_2 removal	tons	11,229.1	12,850.7	13,367.0	12,559.2	10,714.9	SO_2 removed x 44/64
Ash and $CaSO_4$	tons	145,325.8	157,453.3	155,091.7	139,316.8	142,641.0	Ash (tons) + $CaSO_4$ formed (tons)
Actual Total Bed and Fly Ash	tons	196,960.0	210,303.0	209,556.0	209,515.0	204,558.0	AOR
Calculated Total Bed and Fly Ash	tons	202,934.9	212,184.3	206,660.2	185,231.3	190,716.5	Ash and $CaSO_4$ + Limestone excess x 44/100
Ratio of Ash & $CaSO_4$ to Total		1.36	1.34	1.35	1.50	1.43	
Ratio of Fly Ash to Total Ash		0.67	0.67	0.66	0.66	0.66	
Fuel	lb/hr	241,006.17	240,593.20	241,285.68	248,130.08	245,995.67	tons x 2,000/hours
Limestone	lb/hr	31,889.89	31,388.42	30,698.36	28,737.47	29,454.88	tons x 2,000/hours
Fly Ash	lb/hr	32,776.59	34,841.29	34,668.95	35,951.12	36,085.47	tons x 2,000/hours
Bed Ash	lb/hr	16,143.64	17,145.68	17,334.48	18,520.24	168,472.53	tons x 2,000/hours

Table 3a. Data and Calculation for 20% Co-firing Pet Coke (5.5% S) with 80% Coal at Cedar Bay Cogeneration Facility Based on Utilization

Parameter	Units	Year 1997	1998	1999	2000	2001	Basis
Co-firing Fuel	MMBtu	23,093,877.8	22,768,176.6	23,005,399.1	22,809,944.9	21,904,349.0	Same as AOR
Co-firing Fuel	tons	938,424.6	937,378.6	931,800.1	923,883.5	890,091.6	Coal + Pet Coke (tons)
Coal (80% by weight)	tons	750,739.7	749,902.9	745,440.1	739,106.8	712,073.3	Co-firing Fuel x 0.80
Coal (80% by weight)	MMBtu	17,867,604	17,547,728	17,816,018	17,664,653	16,947,251	Coal (tons) x Coal heat content (MMBtu/ton)
Coal	**%**	**80%**	**80%**	**80%**	**80%**	**80%**	minimum
Pet Coke (20% by weight)	MMBtu	5,226,274	5,220,449	5,189,381	5,145,292	4,957,098	Pet Coke (tons) x 27.846 MMBtu/ton
Pet Coke (20% by weight)	tons	187,685	187,476	186,360	184,777	178,018	Co-firing Fuel x 0 20
Pet Coke	**%**	**20%**	**20%**	**20%**	**20%**	**20%**	maximum
Pet Coke - sulfur	%	5.45	5.45	5.45	5.45	5.45	Foster Wheeler
Pet Coke - ash	%	0.37	0.37	0.37	0.37	0.37	Foster Wheeler
Coal - ash	tons	85,584.3	90,738.2	88,111.0	77,827.9	84,736.7	Coal (tons) x Ash (%)
Pet Coke - ash	tons	694.4	693.7	689.5	683.7	658.7	Pet Coke (tons) x Ash (%)
Total Ash	tons	86,278.8	91,431.9	88,800.5	78,511.6	85,395.4	Coal ash + Pet Coke ash
SO_2 coal	tons	14,113.9	15,897.9	16,548.8	15,669.1	13,529.4	Coal (tons) x Sulfur (%)/100 x 2
SO_2 pet coke	tons	20,457.7	20,434.9	20,313.2	20,140.7	19,404 0	Pet Coke (tons) x Sulfur (%)/100 x 2
SO_2 total	tons	34,571.6	36,332.8	36,862.0	35,809.7	32,933.4	Coal SO
SO_2 emitted	tons	1,909.0	1,935.6	1,926.2	1,965.1	1,901.5	AOR
SO_2 removed	tons	32,662.6	34,397.2	34,935.8	33,844.6	31,031.9	SO_2 total - SO_2 emitted
SO_2 removed	%	94.5%	94.7%	94.8%	94.5%	94.2%	SO_2 removed/SO_2 total
$CaSO_4$ Formed	tons	69,407.9	73,094.0	74,238.6	71,919.8	65,942.8	SO_2 removed x 130/64
Ash and $CaSO_4$	tons	155,686.7	164,525.9	163,039.2	150,431.4	151,338.2	Ash (tons) + $CaSO_4$ formed (tons)
Total Bed and Fly Ash	tons	270,891.1	265,242.4	255,699.9	235,496.1	247,061.4	Ash and $CaSO_4$ + Limestone excess x 44/100
Fly Ash	tons	181,498.2	177,713.7	168,760.7	155,427 5	163,060.7	Total Bed and Fly Ash x Ratio Fly to Total Ash
Bed Ash	tons	89,393.0	87,528.7	86,939.1	80,068.6	84,000.8	Total Ash - Fly Ash
Limestone for SO_2 removal	tons	51,035.3	53,745.6	54,587.2	52,882.2	48,487.3	SO_2 removed x 100/64
Limestone Utilization		**19.9%**	**23.0%**	**24.8%**	**25.8%**	**22.1%**	
Limestone -total	**tons**	**256,757.5**	**233,596.5**	**220,052.7**	**204,783.4**	**219,421.7**	**Based on Percent utilization**
Limestone excess	tons	205,722.2	179,850.8	165,465.5	151,901.2	170,934.4	Limestone total - Limestone for SO_2
Fuel	lb/hr	233,081.4	231,785.4	233,572.9	240,198.5	237,906.5	tons x 2,000/hours
Limestone	lb/hr	63,772.2	57,761.3	55,160.3	53,241.2	58,647.7	tons x 2,000/hours
Fly Ash	lb/hr	45,079.6	43,943.2	42,303.0	40,409.3	43,583.4	tons x 2,000/hours
Bed Ash	lb/hr	22,203.0	21,643.2	21,792.9	20,816.9	22,452.0	tons x 2,000/hours
Difference in Fuel	tons	-31,906.4	-35,620.4	-30,768.9	-30,507.5	-30,264.3	Co-firing Fuel - Coal (tons)
Difference in Fuel Ash	tons	-24,339.0	-26,301.0	-24,975.1	-21,985.8	-24,127.0	Co-firing Fuel - Coal (tons)
Difference in Limestone	tons	128,363.5	106,656.5	97,586.7	94,249.5	109,220.7	Co-firing Fuel - Coal (tons)
Difference in Total Ash	tons	73,931.1	54,939.4	46,143.9	25,981.1	42,503.4	Co-firing Fuel - Coal (tons)
Difference in Fly Ash	tons	49,534.2	36,809.7	30,454.7	17,147.5	28,052 3	Co-firing Fuel - Coal (tons)
Difference in Fly Ash	tons	46,146.3	29,902.0	23,766.7	12,238.1	23,642.5	Co-firing Fuel - Coal (tons)

Bottom Ash to Total Ash		33.00%	33.00%	34.00%	34.00%	34.00%

Table 3b. Data and Calculation for 35% Co-firing Pet Coke (4% S) with 65% Coal at Cedar Bay Cogeneration Facility Based on Utilization

Parameter	Units	Year 1997	1998	1999	2000	2001	Basis
Co-firing Fuel	MMBtu	23,093,877.8	22,768,176.6	23,005,399.1	22,809,944.9	21,904,349.0	Same as AOR
Co-firing Fuel	tons	901,104.9	897,501.5	895,381.7	887,774.5	854,693.3	Coal + Pet Coke (tons)
Coal (65% by weight)	tons	585,718.2	583,376.0	581,998.1	577,053.4	555,550.7	Co-firing Fuel x 0.65
Coal (65% by weight)	MMBtu	13,940,093	13,650,998	13,909,754	13,791,577	13,222,032	Coal (tons) x Coal heat content (MMBtu/ton)
Coal	**%**	**65%**	**65%**	**65%**	**65%**	**65%**	minimum
Pet Coke (35% by weight)	MMBtu	9,153,784	9,117,179	9,095,645	9,018,368	8,682,317	Pet Coke (tons) x 27.846 MMBtu/ton
Pet Coke (35% by weight)	tons	315,387	314,126	313,384	310,721	299,143	Co-firing Fuel x 0.35
Pet Coke	**%**	**35%**	**35%**	**35%**	**35%**	**35%**	maximum
Pet Coke - sulfur	%	4.09	4.09	4.09	4.09	4.09	Foster Wheeler
Pet Coke - ash	%	0.6	0.6	0.6	0.6	0.6	Foster Wheeler
Coal - ash	tons	66,771.9	70,588.5	68,792.2	60,763.7	66,110.5	Coal (tons) x Ash (%)
Pet Coke - ash	tons	1,892.3	1,884.8	1,880.3	1,864.3	1,794.9	Pet Coke (tons) x Ash (%)
Total Ash	tons	68,664.2	72,473.2	70,672.5	62,628.1	67,905.4	Coal ash + Pet Coke ash
SO_2 coal	tons	11,011.5	12,367.6	12,920.4	12,233.5	10,555.5	Coal (tons) x Sulfur (%)/100 x 2
SO_2 pet coke	tons	25,798.6	25,695.5	25,634.8	25,417.0	24,469.9	Pet Coke (tons) x Sulfur (%)/100 x 2
SO_2 total	tons	36,810.1	38,063.0	38,555.1	37,650.5	35,025.3	Coal SO
SO_2 emitted	tons	1,909.0	1,935.6	1,926.2	1,965.1	1,901.5	AOR
SO_2 removed	tons	34,901.1	36,127.4	36,628.9	35,685.4	33,123.8	SO_2 total - SO_2 emitted
SO_2 removed	%	94.8%	94.9%	95.0%	94.8%	94.6%	SO_2 removed/SO_2 total
$CaSO_4$ Formed	tons	74,164.9	76,770.8	77,836.5	75,831.4	70,388.1	SO_2 removed x 130/64
Ash and $CaSO_4$	tons	142,829.1	149,244.1	148,509.0	138,459.5	138,293.5	Ash (tons) + $CaSO_4$ formed (tons)
Total Bed and Fly Ash	tons	265,929.3	255,026.7	245,660.4	228,150.8	240,469.8	Ash and $CaSO_4$ + Limestone excess x 44/100
Fly Ash	tons	178,173.7	170,869.1	162,134.7	150,579.6	158,710.2	Total Bed and Fly Ash x Ratio Fly to Total Ash
Bed Ash	tons	87,755.6	84,157.6	83,525.6	77,571.2	81,759.6	Total Ash - Fly Ash
Limestone for SO_2 removal	tons	54,533.0	56,449.1	57,232.7	55,758.4	51,756.0	SO_2 removed x 100/64
Limestone Utilization		**19.9%**	**23.0%**	**24.8%**	**25.8%**	**22.1%**	
Limestone -total	**tons**	**274,354.7**	**245,346.8**	**230,717.3**	**215,921.5**	**234,213.5**	**Based on Percent utilization**
Limestone excess	tons	219,821.7	188,897.7	173,484.6	160,163.1	182,457.6	Limestone Total - Limestone for SO_2 removal
Fuel	lb/hr	223,812.1	221,924.9	224,443.9	230,810.6	228,445.2	tons x 2,000/hours
Limestone	lb/hr	68,142.9	60,666.8	57,833.6	56,137.0	62,601.3	tons x 2,000/hours
Fly Ash	lb/hr	44,253.9	42,250.8	40,642.1	39,148.9	42,420.6	tons x 2,000/hours
Bed Ash	lb/hr	21,796.3	20,809.6	20,937.2	20,167.6	21,853.0	tons x 2,000/hours
Difference in Fuel	tons	-69,226.1	-75,497.5	-67,187.3	-66,616.5	-65,662.6	Co-firing Fuel - Coal (tons)
Difference in Fuel Ash	tons	-41,953.5	-45,259.6	-43,103.2	-37,869.3	-41,617.0	Co-firing Fuel - Coal (tons)
Difference in Limestone	tons	145,960.7	118,406.8	108,251.3	105,387.6	124,012.5	Co-firing Fuel - Coal (tons)
Difference in Total Ash	tons	68,969.3	44,723.7	36,104.4	18,635.8	35,911.8	Co-firing Fuel - Coal (tons)
Difference in Fly Ash	tons	46,209.7	29,965.1	23,828.7	12,299.6	23,701.8	Co-firing Fuel - Coal (tons)
Difference in Fly Ash	tons	46,562.2	30,458.3	24,280.9	12,634.0	24,060.5	Co-firing Fuel - Coal (tons)

Bottom Ash to Total Ash		33.00%	33.00%	34.00%	34.00%	34.00%

Table 4a. Data and Calculation for Co-firing 20% Pet Coke (5.5%S) with Coal at Cedar Bay Cogeneration Facility

Parameter	Units	Year 1997	1998	1999	2000	2001	Basis
CO emission rate with co-firing	lb/MMBtu	0.04	0.04	0.04	0.04	0.04	Foster Wheeler Report
CO emissions when co-firing	tons/year	461.9	455.4	460.1	456.2	438.1	MMBtu x lb/MMBtu (assumes same heat input)
CO emissions with coal	tons/year	496	549.6	582.26	516.01	485.1	AOR
Net CO Emissions	tons/year	-34.1	-94.2	-122.2	-59.8	-47.0	Cofiring - Actual Coal
NO_x emission rate with co-firing	lb/MMBtu	0.15	0.15	0.15	0.15	0.15	Foster Wheeler Report
NO_x emissions with co-firing	tons/year	1,732.0	1,707.6	1,725.4	1,710.7	1,642.8	MMBtu x lb/MMBtu (assumes same heat input)
NO_x emissions with coal	tons/year	1,726.0	1,716.4	1,741.5	1,779.0	1,656.9	AOR
Net NO_x emissions	tons/year	6.0	-8.8	-16.1	-68.3	-14.1	Cofiring - Actual Coal
PM_{10} emission rate with co-firing	lb/MMBtu	0.0129	0.0160	0.0150	0.0147	0.0157	average of actual test data
PM_{10} emissions with co-firing	tons/year	149.3	182.5	172.5	167.3	171.6	MMBtu x lb/MMBtu (assumes same heat input)
PM_{10} emissions with coal	tons/year	149.5	178.3	193.7	165.2	201.9	AOR
Net PM_{10} emissions	tons/year	-0.16	4.22	-21.20	2.05	-30.32	Cofiring - Actual Coal
SAM emission rate with co-firing	lb/MMBtu	5.69E-05	5.28E-05	5.18E-05	5.31E-05	5.65E-05	Test data increased for increased sulfur in fuel
SAM emissions with co-firing	tons/year	0.66	0.60	0.60	0.61	0.62	MMBtu x lb/MMBtu (assumes same heat input)
SAM emissions with coal	tons/year	0.35	0.35	0.35904	0.34617	0.3	AOR
Net SAM emissions	tons/year	0.31	0.25	0.24	0.26	0.32	Cofiring - Actual Coal
SO_2 emission rate with co-firing	lb/MMBtu	0.165	0.17	0.167	0.172	0.172	rate adjusted to meet past actuals
SO_2 emissions with co-firing	tons/year	1,905.2	1,935.3	1,921.0	1,961.7	1,883.8	MMBtu x lb/MMBtu (assumes same heat input)
SO_2 emissions with coal	tons/year	1909	1935.6	1926.19	1965.13	1901.5	AOR
Net SO_2 emissions	tons/year	-3.8	-0.3	-5.2	-3.5	-17.7	Cofiring - Actual Coal
VOC emission rate with co-firing	lb/MMBtu	0.0030	0.0030	0.0030	0.0030	0.0030	Test data from 1994 and 2001
VOC emissions when co-firing	tons/year	35.0	34.5	34.8	34.5	33.2	MMBtu x lb/MMBtu (assumes same heat input)
VOC emissions with coal	tons/year	14.8	14.7	17.89104	17.250215	48.7	AOR
Net VOC Emissions	tons/year	20.2	19.8	16.9	17.3	-15.5	Cofiring - Actual Coal

Table 4b. Data and Calculation for Co-firing 35% Pet Coke (4.1%S) with Coal at Cedar Bay Cogeneration Facility

Parameter	Units	Year 1997	1998	1999	2000	2001	Basis
CO emission rate with co-firing	lb/MMBtu	0.035	0.035	0.035	0.035	0.035	Foster Wheeler Report
CO emissions when co-firing	tons/year	404.1	398.4	402.6	399.2	383.3	MMBtu x lb/MMBtu (assumes same heat input)
CO emissions with coal	tons/year	496	549.6	582.26	516.01	485.1	AOR
Net CO Emissions	tons/year	-91.9	-151.2	-179.7	-116.8	-101.8	Cofiring - Actual Coal
NO_x emission rate with co-firing	lb/MMBtu	0.15	0.15	0.15	0.15	0.15	Foster Wheeler Report
NO_x emissions with co-firing	tons/year	1,732.0	1,707.6	1,725.4	1,710.7	1,642.8	MMBtu x lb/MMBtu (assumes same heat input)
NO_x emissions with coal	tons/year	1,726.0	1,716.4	1,741.5	1,779.0	1,656.9	AOR
Net NO_x emissions	tons/year	6.0	-8.8	-16.1	-68.3	-14.1	Cofiring - Actual Coal
PM_{10} emission rate with co-firing	lb/MMBtu	0.0129	0.0160	0.0150	0.0147	0.0157	average of actual test data
PM_{10} emissions with co-firing	tons/year	149.3	182.5	172.5	167.3	171.6	MMBtu x lb/MMBtu (assumes same heat input)
PM_{10} emissions with coal	tons/year	149.5	178.3	193.7	165.2	201.9	AOR
Net PM_{10} emissions	tons/year	-0.16	4.22	-21.20	2.05	-30.32	Cofiring - Actual Coal
SAM emission rate with co-firing	lb/MMBtu	6.05E-05	5.54E-05	5.41E-05	5.58E-05	6.01E-05	Test data increased for increased sulfur in fuel
SAM emissions with co-firing	tons/year	0.70	0.63	0.62	0.64	0.66	MMBtu x lb/MMBtu (assumes same heat input)
SAM emissions with coal	tons/year	0.35	0.35	0.35904	0.34617	0.3	AOR
Net SAM emissions	tons/year	0.35	0.28	0.26	0.29	0.36	Cofiring - Actual Coal
SO_2 emission rate with co-firing	lb/MMBtu	0.165	0.17	0.167	0.172	0.172	rate adjusted to meet past actuals
SO_2 emissions with co-firing	tons/year	1,905.2	1,935.3	1,921.0	1,961.7	1,883.8	MMBtu x lb/MMBtu (assumes same heat input)
SO_2 emissions with coal	tons/year	1909	1935.6	1926.19	1965.13	1901.5	AOR
Net SO_2 emissions	tons/year	-3.8	-0.3	-5.2	-3.5	-17.7	Cofiring - Actual Coal
VOC emission rate with co-firing	lb/MMBtu	0.0030	0.0030	0.0030	0.0030	0.0030	Test data from 1994 and 2001
VOC emissions when co-firing	tons/year	35.0	34.5	34.8	34.5	33.2	MMBtu x lb/MMBtu (assumes same heat input)
VOC emissions with coal	tons/year	14.8	14.7	17.89104	17.250215	48.7	AOR
Net VOC Emissions	tons/year	20.2	19.8	16.9	17.3	-15.5	Cofiring - Actual Coal

Table 5a. Data and Calculation for Inlet Loading to Baghouses when Co-firing 20% Pet Coke (5.5%S) with Coal at Cedar Bay Cogeneration Facility

Parameter	Units	Year					Basis
		1997	1998	1999	2000	2001	
Fly Ash - Coal Firing	lb/hr/facility	32,776.59	34,841.29	34,668.95	35,951.12	36,085.47	Table 2, based on actual fly ash
Fly Ash - Coal Firing	lb/hr/unit	10,925.53	11,613.76	11,556.32	11,983.71	12,028.49	divided by 3 CFBs
PM Emission Rate with coal	grains/acfm	4.28	4.55	4.53	4.70	4.71	lb/hr x 7,000 grains/lb x 1/acfm x 1/60
Fly Ash - Co-Firing	lb/hr/facility	45,079.64	43,943.21	42,302.99	40,409.27	43,583.38	Table 2, based on actual fly ash
Fly Ash - Co-Firing	lb/hr/unit	15,026.55	14,647.74	14,101.00	13,469.76	14,527.79	divided by 3 CFBs
PM Emission Rate with coal	grains/acfm	5.89	5.74	5.53	5.28	5.69	lb/hr x 7,000 grains/lb x 1/acfm x 1/60
PM Emission Rate Increase	grains/acfm	1.61	1.19	1.00	0.58	0.98	Co-firing - Coal (grains/acf)
Maximum Projected	lb/hr/unit	17,000.00					Foster Wheeler Report (Figure 12)
Maximum Projected	grains/acfm	6.66					lb/hr x 7,000 grains/lb x 1/acfm x 1/60
Flow Rate of Unit	acfm	297,700					

Table 5b. Data and Calculation for Inlet Loading to Baghouses when Co-firing 20% Pet Coke (5.5%S) with Coal at Cedar Bay Cogeneration Facility

Parameter	Units	Year					Basis
		1997	1998	1999	2000	2001	
Fly Ash - Coal Firing	lb/hr/facility	32,776.59	34,841.29	34,668.95	35,951.12	36,085.47	Table 2, based on actual fly ash
Fly Ash - Coal Firing	lb/hr/unit	10,925.53	11,613.76	11,556.32	11,983.71	12,028.49	divided by 3 CFBs
PM Emission Rate with coal	grains/acfm	4.28	4.55	4.53	4.70	4.71	lb/hr x 7,000 grains/lb x 1/acfm x 1/60
Fly Ash - Co-Firing	lb/hr/facility	44,253.93	42,250.76	40,642.06	39,148.88	42,420.56	Table 2, based on actual fly ash
Fly Ash - Co-Firing	lb/hr/unit	14,751.31	14,083.59	13,547.35	13,049.63	14,140.19	divided by 3 CFBs
PM Emission Rate with coal	grains/acfm	5.78	5.52	5.31	5.11	5.54	lb/hr x 7,000 grains/lb x 1/acfm x 1/60
PM Emission Rate Increase	grains/acfm	1.50	0.97	0.78	0.42	0.83	Co-firing - Coal (grains/acf)
Maximum Projected	lb/hr/unit	17,000.00					Foster Wheeler Report (Figure 12)
Maximum Projected	grains/acfm	6.66					lb/hr x 7,000 grains/lb x 1/acfm x 1/60
Flow Rate of Unit	acfm	297,700					

Table 6. Material Usage of Coal, Limestone, Bottom Ash and Fly Ash for Co-firing 35% Petroleum Coke with Coal at Cedar Bay Cogeneration Facility

		1999-2000					
	Units	Coal	Co-Firing	Difference	Co-Firing[d]	Permit Limits	Title V Permit Condition
Fuel	lb/hr/unit[a]	81,569	75,876	-5,694	78,000	104,000	Section III. A.3.
	lb/hr/plant[b]	244,708	227,627	-17,081	234,000	312,000	Section III. A.3.
	tons/month[c]	88,095	81,946	-6,149	84,240	117,000	Section III. A.3.
	tons/year[b]	958,480	891,579	-66,902	953,176	1,170,000	Section III. A.3.
Limestone	lb/hr/unit[a]	9,906	18,995	9,089	22,500	NA	
	lb/hr/plant[b]	29,718	56,985	27,267	67,500	NA	
	tons/month[c]	10,698	20,515	9,816	24,300	27,000	Section III. B.1.
	tons/year[b]	116,685	223,320	106,635	274,955	320,000	Section III. B.1.
Fly Ash	lb/hr/unit[a]	11,770	13,299	1,529	15,500	NA	
	lb/hr/plant[b]	35,310	39,896	4,586	46,500	NA	
	tons/month[c]	12,712	14,362	1,651	16,740	28,000	Section III. B.1.
	tons/year[b]	138,293	156,358	18,065	189,413	336,000	Section III. B.1.
Bottom Ash	lb/hr/unit[a]	5,976	6,851	875	7,000	NA	
	lb/hr/plant[b]	17,927	20,552	2,624	21,000	NA	
	tons/month[c]	6,454	7,399	945	7,560	8,000	Section III. B.1.
	tons/year[b]	70,194	80,549	10,355	85,541	88,000	Section III. B.1.

Footnotes:
[a] average for three CFB units.
[b] Coal from Table 2 and Co-firing from Table 3.
[c] based on 24 hour/day and 30 days/month per permit condition.
[d] based on Foster Wheeler Report for a single CFB unit co-firing 35 percent petroleum coke.

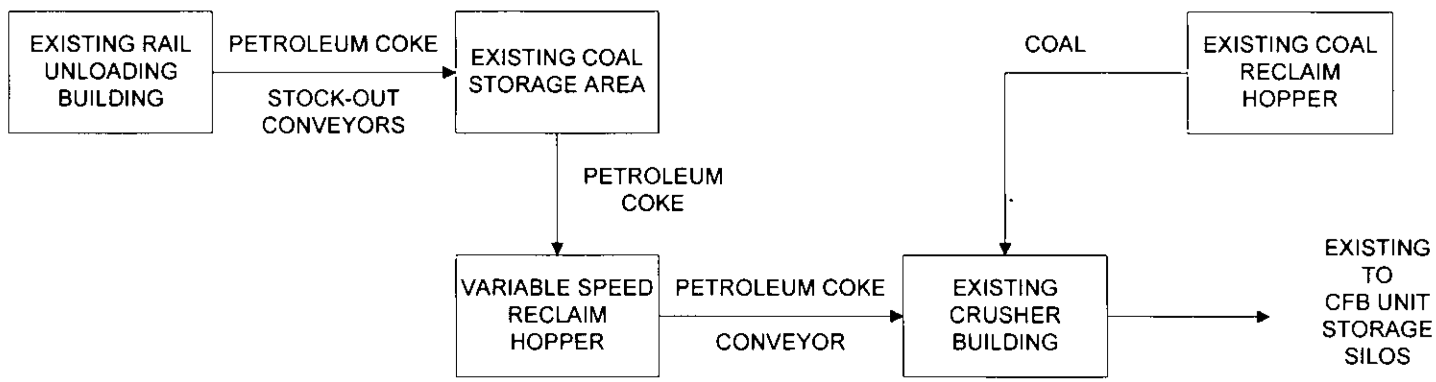


Figure 3
Process Flow Diagram for Petroleum Coke Unloading
Cedar Bay Cogeneration Facility
Jacksonville, Florida

Golder Associates

3.0 EQUIPMENT DESCRIPTION/INSTALLATION

3.1 DESIGN CONDITIONS

3.1.1 Unit Operating Conditions

The Flakt baghouses are for a circulating fluidized bed (CFB) boiler cogeneration plant.

3.1.2 Induced Draft Fans

Owner furnished induced draft fans will be used by the owner to maintain the baghouse at below atmospheric pressure. Discharge from these fans will be into the Owner's stack.

3.1.3 Flue Gas Condition

1. Inlet dust load to collector system - 19.5 grains/ACF (including flyash re-injection).
2. Flue gas volume - 297,700 ACFM at 265°F per baghouse and -15" W.G.
3. Maximum flue gas temperature at baghouse inlet - 450°F.
4. Normal flue gas operating temperature - 265°F.
5. Raw material analysis - see Figure 1.

3.2 BAGHOUSE DESIGN DESCRIPTION

3.2.1 Basic Design:

Number of baghouses	3
Number of compartments/baghouse	8
Number of bags per compartment	264
Total number of bags/baghouse	2,112
Bag diameter, inches	12"
Bag length, ft-in.	33'-0" O.A.
Bag area, sq. ft.	99.01
Total area sq. ft./compartment	26,139
Total area sq. ft. for baghouse	209,112
Reverse air volume, ACFM	54,742

FIGURE 1

CEDAR BAY FUELS

COAL DATA PROXIMATE ANALYSIS	PERFORMANCE	RANGE/MAXIMUMS
MOISTURE, %		5.0 - 10.0
ASH, %		6.0 - 14.0
VOLATILE, %		33.0 - 37.0
FIXED CARBON, %		47.0 - 53.0
HEATING VALUE, BTU/LB	12,200	11,500 - 12,600
SULFUR, %		0.6 - 1.7

ULTIMATE ANALYSIS	PERFORMANCE	RANGE/MAXIMUMS
MOISTURE, %	7.51	5.0 - 9.0
CARBON, %	68.5	68.0 - 76.0
HYDROGEN, %	4.35	4.2 - 5.2
NITROGEN, %	1.14	1.0 - 1.7
CHLORINE, %	0.08	0.01 - 0.1
SULFUR, %	1.20	0.6 - 1.7
ASH, %	11.31	6.0 - 12.0
OXYGEN, %	5.91	3.5 - 7.0

MINERAL ANALYSIS OF ASH, %	PERFORMANCE	RANGE/MAXIMUMS
PHOSPHATE PENTOXIDE (P_2O_5		0.05 - 0.15
SILICA (SiO_2)		50.0 - 60.0
FERRIC OXIDE (Fe_2O_3)		3.5 - 7.5
ALUMINA (Al_2O_3)		25.0 - 32.0
TITANIA (TiO_2)		0.75 - 1.2
LIME (CaO)		1.5 - 3.0
MAGNESIA (MgO)		0.5 - 0.8
SULFUR TRIOXIDE (SO_3)		1.5 - 3.0
POTASSIUM OXIDE (K_2O) AND SODIUM OXIDE (Na_2O)		5.0 MAX COMBINED

CB SECONDARY FUEL

In addition to other fuels the steam generators will burn bark at a rate of up to 10 percent of the total heat input of the steam generators.

Typical bark analysis is as follows.

FUEL ANALYSIS	TYPICAL
Btu/lb (Dry Basis)	6,971
Carbon (Dry Basis)	50.11%
Hydrogen (Dry Basis)	6.08%
Nitrogen (Dry Basis)	0.26%
Sulfur (Dry Basis)	0.012%
Chloride (Dry Basis)	0.061%
Oxygen	41.67%
Ash (Dry Basis)	1.804%
Moisture (As required)	34.89%

CEDAR BAY LIMESTONE	PERFORMANCE	RANGE/MAXIMUMS
$CaCO_3$		90%
$MgCO_3$		3.0%
MOISTURE		1.0%

CEDAR BAY SUPPLEMENTAL FUEL

NO. 2 COMMERCIAL GRADE FUEL OIL IN ACCORDANCE WITH ASTM D396 OR SIMILAR FUEL.

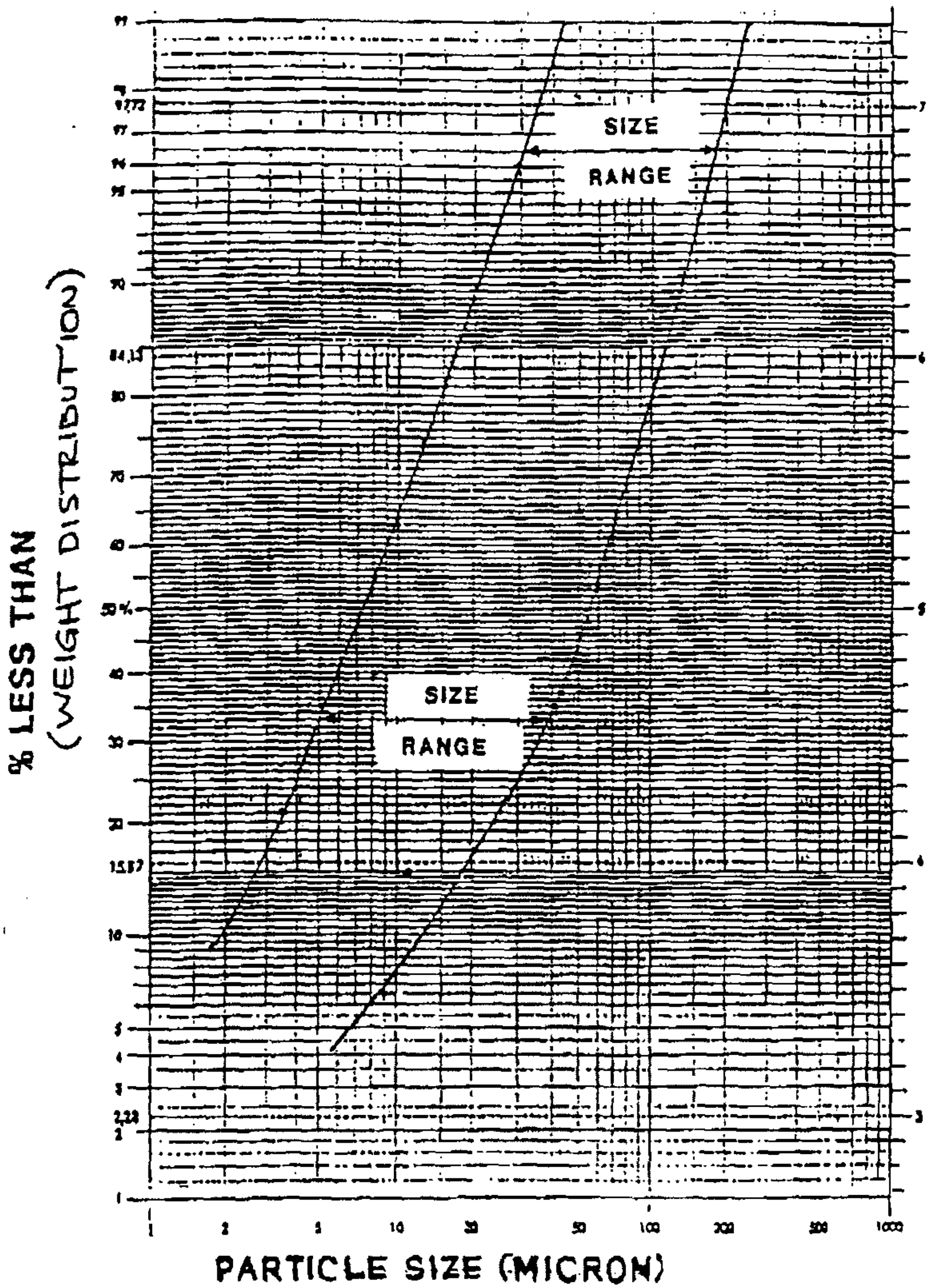
FLYASH RE-INJECTION

THE FLYASH RE-INJECTION SYSTEMS WILL BE PLACED IN SERVICE OR REMOVED FROM SERVICE AT THE OWNER'S DISCRETION AND BASED ON THE AVAILABILITY OF FLYASH FOR RE-INJECTION. THE UNITS MAY BE OPERATED FOR EXTENDED PERIODS OF TIME WITH OR WITHOUT FLYASH RE-INJECTION. AN ASH PARTICLE SIZE DISTRIBUTION CURVE IS ATTACHED. THIS CURVE IS REPRESENTATIVE OF OPERATION WITHOUT ASH RE-INJECTION. SMALLER PARTICLES MAY RESULT WHEN RE-INJECTION IS EMPLOYED.

ASH COMPOSITION (Estimated -- will vary depending on operations and fuel)

	LOW S COAL	HIGH S COAL
CaO %	15-24	21-30
CaSO4 %	10-17	22-31
Lmstn Inert %	2-7	3-5
Coal Ash %	44-65	28-48
Unburnt Fuel %	6-11	5-7

FLYASH PARTICLE SIZE RANGE (BAGHOUSE INLET)



3.2.2 Air-to-Cloth Ratios

Gross air-to-cloth ratio	1.4:1
Net air-to-cloth ratio, one compartment out for cleaning and one compartment out for maintenance.	2.2:1

3.2.3 Filter Fabric Bag Construction

Material	Woven fiberglass w/teflon finish.
Diameter	12 inches
Bag length	33.0 feet
Weight (oz/sq.yd.)	10.3 oz.
Weave	3 X 1 twill
Permeability, CFM/sq. ft.	1/2" W.G., 35-60 CFM sq. ft.
Top suspension method -----	"J" Hook, compression spring and cap. Compression band sewn into top of bag for retainment over cap.
Bottom Attachment ---------	Filter bag slip over thimble and is secured with stainless steel clamp.
Filter Tube Rings ---------	3/16" dia. cadmium plated steel are sewn into bag so that the bag does not collapse upon itself during reverse air cleaning, eight (8) rings per bag.
Installation, Tension and Adjustment ------------	Tension is shown by deflection of spring. 75# tension is initial setting. (See Drawing No. 325-11-00-E-01, Section 10).

3.3 INSTALLATION

3.3.1 Preliminary Inspection

3.3.1.1 Before installing or storing this equipment, inspect all items for shipping damage. Check the delivery list to determine that all parts are accounted for.

CAUTION: OBSERVE ALL APPLICABLE NATIONAL AND LOCAL CODES WHEN PERFORMING ELECTRICAL INSTALLATION.

3.3.1.2 Installation of Fabric Filter System must conform to the arrangement drawings (Section 10) and the instructions supplied with system components in Section 11.

3.3.2 Storage Requirements

3.3.2.1 In the event this Fabric Filter System or its components are not installed immediately, attention must be directed to proper methods of storage. The table below lists shelf life requirements under specific conditions for Flakt supplied equipment.

EQUIPMENT	0 - 6 MONTHS	7 - 18 MONTHS	19 - 36 MONTHS
ELECTRICAL COMPONENTS, CONTROL EQUIPMENT	3	4	4
GATES, MECHANICAL ASSEMBLY, MACHINE CASTINGS	2	3	4
CLOSED CRATES AND BOXES	2	3	
STRUCTURAL STEEL	1	1	3
BAGS (IN CARTONS)	5	5	

CODE:
1 - UNPROTECTED OUTDOOR STORAGE
2 - PROTECTED OUTDOOR STORAGE (ELEVATED AND COVERED)
3 - UNHEATED INDOOR STORAGE
4 - HEATED INDOOR STORAGE
5 - HEATED INDOOR STORAGE FOR NOT MORE THAN 12 MONTHS

3.3.1.1.1 Always store components and equipment in an upright position.

NOTE: INDOOR STORAGE IS PREFERABLE

3.3.1.1.2 Remove all fan belts and store in a heated enclosed area.

3.3.1.1.3 Rotate fans and motors once a month.

3.3.1.1.4 Filter bags are shipped in cartons. DO NOT remove filter bags from their protective carton until ready to install.

CAUTION: DO NOT STACK PALLETS OF BAG CARTONS.

3.3.3 Filter Bags

CAUTION: SHARP CREASES IN A BAG ARE POTENTIAL LEAKS. DO NOT STEP ON BAGS OR DRAPE THEM OVER STEEL MEMBERS OR PLANKS. DO NOT REMOVE BAGS FROM THEIR PROTECTIVE CARTONS UNTIL READY TO HANG.

3.3.3.1 Transport bags in protective cartons to bag tube sheet elevation of compartment.

3.3.3.2 Installation should proceed from the far corners os each compartment. Maintenance crews must avoid standing on bags during installing.

3.3.3.3 Apply a great deal of caution in handling of bags to ensure long life.

3.3.3.4 Remove bag carefully from cartons.

3.3.3.5 When removing bag, visually inspect for holes, heavy creases, abrasion damages, etc. Do not install the bag in less than perfect condition!

3.3.3.6 Attach hoisting line from bag cap and raise per Step 2, Drawing 326-11-00-E-01.

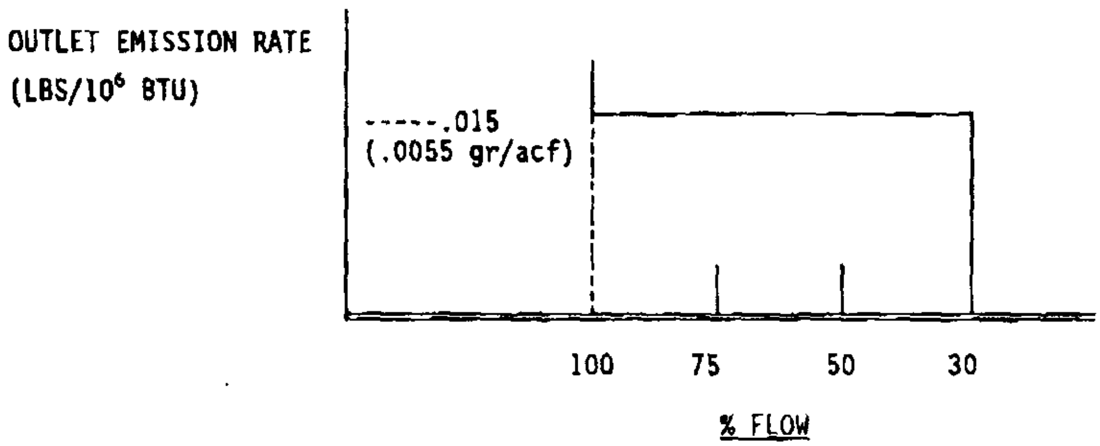
3.3.3.7 After raising bag, attach to bag support steel per Step 3, Drawing 326-11-00-E-01.

CAUTION: THE BAG SEAM MUST ALWAYS BE FACING THE CENTER AISLE OF THE COMPARTMENT (SEE DRAWING 326-11-00-E-01 FOR CORRECT ORIENTATION). DO NOT POSITION CLAMP SCREW HOLDER DIRECTLY OVER BAG SEAM. PERMANENT BAG DAMAGE MAY RESULT IF THE CLAMP SCREW HOLDER IS INSTALLED ON THE BAG SEAM.

3.3.3.8 Adjust bag to remove any noticeable slack.

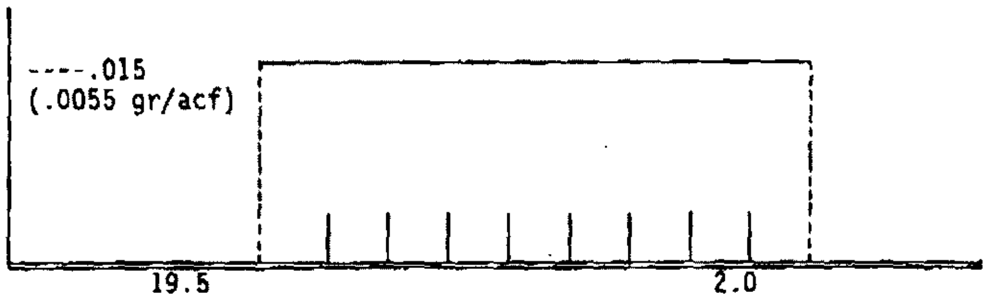
3.4 PERFORMANCE CURVES

OUTLET EMISSION RATE VS. FLUE GAS FLOW RATE



PERFORMANCE CURVE

OUTLET EMISSION RATE VS. INLET PARTICULATE LOAD



PARTICULATE LOAD (GRAINS/ACF)

Department of Environmental Protection

Jeb Bush
Governor

Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

David B. Struhs
Secretary

April 2, 2002

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Mr. Bruce Smith
Cedar Bay Cogenerating Company, L.P.
P.O. Box 26324
Jacksonville, FL 32226

Re: Request for Additional Information
Co-firing Petroleum Coke with Coal
File No. PA 88-24 (PSD-FL-137)
Cedar Bay Cogenerating Project

Dear Mr. Smith:

The Department is in receipt of your reply to our September 28, 2001 request for additional information. The application remains incomplete. In order to continue processing your application, the Department will need the additional information below. Should your response to any of the below items require new calculations, please submit the new calculations, assumptions, reference material and appropriate revised pages of the application form.

1. The technical basis for the development of the "Representative Future Actual Emissions" in Table B is unclear. Rather, in each case, the "Representative Future Actual Emissions" appear to simply represent values that are slightly less than the past actual emissions plus the PSD Significant Emission Rates. Please provide the basis for the emission calculations, which Cedar Bay utilized in the development of this table. The Department notes that the basis for the original BACT emission calculation was a 93% capacity factor.

2. Notwithstanding Cedar Bay's reference to 40 CFR 52.21(b)(33), it does not appear that the original question posed in the Department's September 28th letter has been fully answered. Within that request, the Department is attempting to obtain reasonable assurance as to whether a PSD Review is required. The relevant statutes expressly contemplate that projections of the impact of a change must be made before construction. Before a permit is issued, among other things, the owner or operator of the source must, using projections of post-change emissions, demonstrate that emissions from the modified source will not violate air quality requirements.

   Specifically, section 165 states that "[n]o major emitting facility … may be constructed unless a permit has been issued for such proposed facility" [CAA § 165, 42 U.S.C. § 7475]. Further, the owner or operator must demonstrate to the administrator's satisfaction that "emissions from construction or operation of such facility will not cause, or contribute to, air pollution in excess of" the NAAQS, among other things [CAA § 165(a)(3), 42 U.S.C. § 7475(a)(3)].

   This statutory and regulatory structure has two important features relevant to this application:
   (1) the permit must be obtained *before* the physical change is made, and
   (2) whether a physical change requires a permit is determined in part by reference to anticipated results or consequences, which necessarily would occur *after* the physical change is made.

   Thus, the only way for the owner or operator of the source to know whether a permit is required for any particular physical change is for the owner or operator to make a prediction as to whether the emissions increase will occur. This observation was described by EPA in the 1992 preamble to amendments to the NSR regulations as follows:

> Applicability of the CAA's NSR provisions must be determined in advance of construction and is pollutant specific. In cases involving existing sources, this requires a pollutant-by-pollutant projection of the emissions increases, if any, which will result from the physical or operational change. 57 Fed. Reg. 32,314, 32,316 n.8 (1992).

Any other construction of the statute would allow sources to make modifications or changes without a permit, while they wait to see if it would be proven that emissions would increase. Clearly Congress did not intend such an outcome, which would effectively allow avoidance of the *preconstruction* dimension of the program.

Concerning the attendant application, should the Department gain reasonable assurance that the PSD thresholds are not triggered, a permit condition (similar to the one referenced within your response) may be able to be implemented, with additional restrictions as deemed appropriate by the Department.

3. According to prior data reported to FDEP by Cedar Bay, past actual SO_2 has been controlled at 90% with limestone throughputs averaging 120,000 TPY. The application has estimated past actual sulfur capture at over 93% and annual limestone throughput at 152,753 TPY. As indicated below, the Department intends to revise all related calculations.

4. According to prior data reported to FDEP by Cedar Bay, past actual throughputs of bed (bottom) ash have averaged over 70,000 TPY during years 1998 through 2000. The application has provided a calculated past value of 51,325 TPY. The Department intends to revise all related calculations, and notes that the existing permit limits the throughput to 88,000 TPY.

5. Based upon a preliminary analysis by the Department, the co-firing of petcoke at 35% will necessitate an increase in limestone feed by over 100% in order to ensure that SO_2 emissions are not increased. The Department specifically requires additional information (beyond that which has been submitted) in order to ensure that annual PM_{10} emissions remain below a 15 TPY increase, while simultaneously maintaining SO_2 emissions below a 40 TPY increase. Please provide assumed collection efficiencies within submitted calculations.

Rule 62-4.050(3), F.A.C. requires that all applications for a Department permit must be certified by a professional engineer registered in the State of Florida. This requirement also applies to responses to Department requests for additional information of an engineering nature. Please note that per Rule 62-4.055(1): *"The applicant shall have ninety days after the Department mails a timely request for additional information to submit that information to the Department.......... Failure of an applicant to provide the timely requested information by the applicable date shall result in denial of the application."*

If you have any questions, please call Michael P. Halpin, P.E. at 850/921-9519.

Sincerely,

Michael P. Halpin

Michael P. Halpin, P.E. FDEP/DARM
New Source Review Section

Ken Kosky, P.E. Golder Associates
Hamilton S. Oven, P.E. PPSO
James L. Manning, P.E. RESD
Chris Kirts, DEP-NED
Stafford Campbell, Greater Arlington Civic Council

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1. Article Addressed to:

Mr. Bruce Smith
Cedar Bay Cogenerating Co., LP
PO Box 26324
Jacksonville, FL 32226

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B. Date of Delivery 4/5/02

C. Signature X Debra L Sumner ☐ Agent ☐ Addressee

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APR - 5 2002 USPS

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Street, Apt. No.; or PO Box No.
PO Box 26324

City, State, ZIP+4
Jacksonville, FL 32226

PS Form 3800, January 2001 See Reverse for Instructions al

PG&E National Energy Group

Cedar Bay
Generating Plant
Owner: Cedar Bay Generating Company L P

RECEIVED

MAR 08 2002

BUREAU OF AIR REGULATION

POB 26324
Jacksonville, FL 32226-6324

904.751.4000
Fax: 904.751.7320

March 7, 2002

Mr. C. H. Fancy, P.E., Chief
Bureau of Air Regulation
Florida Department of Environmental Protection
Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

RE: Cedar Bay Cogeneration Facility
Co-firing Petroleum Coke with Coal
Revision of PSD-FL-137A

Dear Mr. Fancy:

In a letter dated September 28, 2001, the Department requested additional information related to the request to co-fire petroleum coke with coal at the Cedar Bay Cogeneration Facility. The Department subsequently granted an extension to Cedar Bay on January 14, 2002. The information requested was an analysis of the facility's past actual emissions, future emissions and a comparison with the Prevention of Significant Deterioration (PSD) significant emission rates in Table 62-212.400(5).

The applicable FDEP rule for determining actual emissions is 62-210.200(11), FAC, and is attached to this letter for reference. The Cedar Bay Cogeneration Facility consists of three boilers and associated electric generator, which is an electric utility steam generating unit as defined in 62-210.200(11)(d). Therefore, the use of representative actual annual emissions is appropriate when making annual emission comparisons. The definition of "representative actual annual emissions" in 40 CFR 52.21(b)(33) is also attached for reference.

EPA has provided guidance for electric utility units on what it considers "representative" operation. The current PSD regulation promulgated in 1992 and adopted by FDEP clearly recognized the use of any consecutive two years within the 5-year period preceding a change for utility units. This is clearly stated in the preamble to the EPA regulations as follows:

> *Under the proposed action, the administrator would presume that any 2 consecutive years within the 5 years prior to a proposed change is representative of normal source operation for a utility. This presumption is consistent with the 5-year period for "contemporaneous" emission increases and decreases in 40 CFR 52.21(b)(3)(i)(b). [57 FR 32,314]*

The historical emissions from the Cedar Bay Cogeneration Facility were provided in Table 2 of the application and summarized in the attached Table A. Table A also contains an emissions summary for 2001 because this is the last full year of available data. This table also provides information related to Equivalent Forced Outage Rate (EFOR) for the facility for the last 5-years, i.e., 1997 through 2001. The EFOR is based on outages that are unplanned and occur as a result of unforeseen mechanical and electrical failures, and other causes. As shown in Table A, the EFOR in 2001 was considerably higher than previous years and significantly different than the average EFOR over the 5-year period.

The average emissions for 1999 and 2000 are the most appropriate as the "actual emissions" because these years represent two consecutive years out of the last 5 years and are representative of the operation of the facility. The "representative actual annual emissions" were based on emission increases slightly less than the PSD significant emission rates for CO, NOx, PM/PM_{10}, H_2SO_4, SO_2, VOC, Fl, Pb and Hg and are essentially the upper bound on emissions proposed by Cedar Bay. However, any future comparison would exclude any emissions due to increased utilization as a result of increased electricity demand growth for the utility system.

Table B presents the past actual emissions, representative actual annual emissions proposed for the co-firing of petroleum coke with coal and the PSD significant emission rates. This table shows that the project emission increase of all pollutants is less than the applicable PSD significant emission rate.

To ensure that the co-firing of petroleum coke with coal is restricted in a manner that is consistent with PSD regulations, the following permit condition is requested, which is nearly identical to the condition authorizing four other facilities to co-fire petroleum coke with coal (i.e., Tampa Electric Company' Big Bend Generating Station, St. Johns River Power Park, City of Lakeland McIntosh Unit 3 and Seminole Electric Cooperative, Inc. Seminole Plant

> CO, NOx, PM/PM_{10}, H_2SO_4, and SO_2. The permittee shall maintain and submit to the Department and RESD, on an annual basis for a period of 5-years from the date each emission unit begins co-firing petroleum coke, data demonstrating in accordance with 40 CFR 52.21(b)(21)(v) and 40 CFR 52.21(b)(33) that the operational change associated with the use of petroleum coke did not result in a significant emission increases for CO, NOx, PM/PM_{10}, H_2SO_4, and SO_2.

Table B also presents the current permit emission limits and the representative actual annual emissions. As shown, the representative future actual emissions are less than maximum potential emissions for each pollutant authorized in the PSD and PPSA approvals for firing coal. As a result, there will be no emissions increase over that currently authorized by FDEP for the facility.

The Department's expeditious review of the application is appreciated. Please contact me if there is any further information needed.

Sincerely,

Bruce Smith, General Manager
Cedar Bay Generating Company, LP

Cc: A.A Linero, DEP
Scott Gorland, DEP
Jonathan Holtom, DEP
Ernest Frye, DEP NE District
Steve Pace, Jacksonville RESD
Hamilton S. Oven, Jr.
Ken Kosky
David Dee

Definitions of Actual Emissions and Representative Actual Annual Emissions

62-210.200(11) F.A.C. "Actual Emissions" - The actual rate of emission of a pollutant from an emissions unit as determined in accordance with the following provisions:

(a) In general, actual emissions as of a particular date shall equal the average rate, in tons per year, at which the emissions unit actually emitted the pollutant during a two year period which precedes the particular date and which is representative of the normal operation of the emissions unit. The Department may allow the use of a different time period upon a determination that it is more representative of the normal operation of the emissions unit. Actual emissions shall be calculated using the emissions unit's actual operating hours, production rates and types of materials processed, stored, or combusted during the selected time period.

(b) The Department may presume that unit-specific allowable emissions for an emissions unit are equivalent to the actual emissions of the emissions unit provided that, for any regulated air pollutant, such unit-specific allowable emissions limits are federally enforceable.

(c) For any emissions unit (other than an electric utility steam generating unit specified in subparagraph (d) of this definition) which has not begun normal operations on a particular date, actual emissions shall equal the potential emissions of the emissions unit on that date.

(d) For an electric utility steam generating unit (other than a new unit or the replacement of an existing unit) actual emissions of the unit following a physical or operational change shall equal the representative actual annual emissions of the unit following the physical or operational change, provided the owner or operator maintains and submits to the Department on an annual basis, for a period of 5 years representative of normal post-change operations of the unit, within the period not longer than 10 years following the change, information demonstrating that the physical or operational change did not result in an emissions increase. The definition of "representative actual annual emissions" found in 40 CFR 52.21(b)(33) is adopted and incorporated by reference in Rule 62-204.800, F.A.C.

40 CFR 52.21(b)(33) Representative actual annual emissions means the average rate, in tons per year, at which the source is projected to emit a pollutant for the two-year period after a physical change or change in the method of operation of a unit, (or a different consecutive two-year period within 10 years after that change, where the Administrator determines that such period is more representative of normal source operations), considering the effect any such change will have on increasing or decreasing the hourly emissions rate and on projected capacity utilization. In projecting future emissions the Administrator shall:

(i) Consider all relevant information, including but not limited to, historical operational data, the company's own representations, filings with the State or Federal regulatory authorities, and compliance plans under title IV of the Clean Air Act; and

(ii) Exclude, in calculating any increase in emissions that results/from the particular physical change or change in the method of operation at an electric utility steam generating unit, that portion of the unit's emissions following the change that could have been accommodated during the representative baseline period and is attributable to an increase in projected capacity utilization at the unit that is

unrelated to the particular change, including any increased utilization due to the rate of electricity demand growth for the utility system as a whole.

Table A. Annual Emissions and Equivalent Forced Outage Rate (EFOR) 1997-2001
Cedar Bay Cogeneration Facility

	Units	Year				
		1997	1998	1999	2000	2001
CO emissions	tons/yr	496.0	549.6	582.3	516.0	485.1
NOx emissions	tons/yr	1,726.0	1,716.4	1,741.5	1,779.0	1,656.9
PM10 emissions	tons/yr	149.5	178.3	193.7	165.2	201.9
Sulfuric Acid Mist	tons/yr	0.4	0.4	0.4	0.3	0.3
SO2 emissions	tons/yr	1,909.0	1,935.6	1,926.2	1,965.1	1,901.5
VOC	tons/yr	14.8	14.7	17.9	17.3	48.7
EFOR		2.08%	1.74%	4.91%	6.87%	11.87%
EFOR Statistics:		Average	Std Dev	Upper CI	Lower CI	
		5.49%	0.041423339	9.44%	1.54%	

Std Dev = Standard Deviation; CI = Confidence Interval
Note: Upper and Lower CI based on Student's "t" statistic at the 95 percent confidence level.

Table B. Actual Emissions and Representative Actual Annual Emissions when Cofiring Petroleum Coke with Coal Compared to PSD Significant Emission Rate and Permitted Emission Limitations - Cedar Bay Cogeneration Facility

Pollutant	1999 & 2000 Annual Emissions (tons/year)	Representative Future Actual Emissions (tons/year)	Difference for Co-Firing Pet Coke w/Coal (tons/year)	PSD Significant Emission Rate (tons/year)	PPSA & PSD Emission Limitations (tons/year)	Difference from Emission Limitations (tons/year)
CO	549.1	648.1	99.0	100.0	2,273.0	-1,624.9
NOx	1,760.3	1,799.3	39.0	40.0	2,208.0	-408.7
PM10	179.5	193.5	14.0	15.0	234.0	-40.5
Sulfuric Acid Mist	0.4	6.0	5.6	6.0	6.1	-0.1
SO2	1,945.7	1,984.7	39.0	40.0	2,598.0	-613.3
VOC	17.6	56.7	39.1	40.0	195.0	-138.3
Fl	1.5	3.5	2.0	3.0	9.7	-6.2
Pb	0.006	0.5	0.5	0.6	0.8	-0.3

Table B. Actual Emissions and Representative Actual Annual Emissions when Cofiring Petroleum Coke with Coal Compared to PSD Significant Emission Rate and Permitted Emission Limitations - Cedar Bay Cogeneration Facility

Pollutant	1999 & 2000 Annual Emissions (tons/year)	Representative Future Actual Emissions (tons/year)	Difference for Co-Firing Pet Coke w/Coal (tons/year)	PSD Significant Emission Rate (tons/year)	PPSA & PSD Emission Limitations (tons/year)	Difference from Emission Limitations (tons/year)
CO	549.1	648.1	99.0	100.0	2,273.0	-1,624.9
NOx	1,760.3	1,799.3	39.0	40.0	2,208.0	-408.7
PM10*	179.5	193.5	14.0	15.0	234.0	-40.5
Sulfuric Acid Mist	0.4	6.0	5.6	6.0	6.1	-0.1
SO2	1,945.7	1,984.7	39.0	40.0	2,598.0	-613.3
VOC*	17.6	56.7	39.1	40.0	195.0	-138.3
Fl	1.5	3.5	2.0	3.0	9.7	-6.2
Pb	0.006	0.5	0.5	0.6	0.8	-0.3

* Data reflects use of most recent stack testing data

Table 4b. Maximum Predicted Concentrations of Styrene Emissions, Sea Ray Boats, Inc. Cape Canaveral Plant Compared to Florida Air Reference Concentrations (ARC)

Averaging Time	Year	Site Boundary (ug/m^3)	Residential Boundary (ug/m^3)	Florida ARC (ug/m^3)	Site Boundary (ppb)	Residential Boundary (ppb)	Florida ARC (ppb)
Single Stack (75 feet high)-Original Concept							
Annual	1987	2.2	1.5	1,000.0	0.5	0.4	235.0
	1988	2.1	1.7	1,000.0	0.5	0.4	235.0
	1989	2.0	1.6	1,000.0	0.5	0.4	235.0
	1990	2.6	1.5	1,000.0	0.6	0.4	235.0
	1991	2.4	1.4	1,000.0	0.6	0.3	235.0
Highest 24-hour	1987	27.7	27.7	507.0	6.5	6.5	119.2
	1988	32.1	32.1	507.0	7.5	7.5	119.2
	1989	27.3	27.3	507.0	6.4	6.4	119.2
	1990	26.1	21.9	507.0	6.1	5.1	119.2
	1991	29.3	22.0	507.0	6.9	5.2	119.2
Highest 8-hour	1987	53.3	48.7	2,130.0	12.5	11.4	500.6
	1988	50.7	46.5	2,130.0	11.9	10.9	500.6
	1989	58.0	58.0	2,130.0	13.6	13.6	500.6
	1990	58.3	54.3	2,130.0	13.7	12.8	500.6
	1991	54.4	47.3	2,130.0	12.8	11.1	500.6
Single Stack (75 feet high)-Final Design							
Annual	1987	1.3	0.7	1,000.0	0.3	0.2	235.0
	1988	1.3	0.7	1,000.0	0.3	0.2	235.0
	1989	1.2	0.7	1,000.0	0.3	0.2	235.0
	1990	1.5	0.7	1,000.0	0.4	0.2	235.0
	1991	1.4	0.6	1,000.0	0.3	0.1	235.0
Highest 24-hour	1987	15.9	10.3	507.0	3.7	2.4	119.2
	1988	20.8	10.4	507.0	4.9	2.4	119.2
	1989	17.1	9.3	507.0	4.0	2.2	119.2
	1990	15.4	10.1	507.0	3.6	2.4	119.2
	1991	17.3	9.0	507.0	4.1	2.1	119.2
Highest 8-hour	1987	31.8	28.3	2,130.0	7.5	6.6	500.6
	1988	29.8	22.7	2,130.0	7.0	5.3	500.6
	1989	32.2	21.9	2,130.0	7.6	5.2	500.6
	1990	33.5	27.2	2,130.0	7.9	6.4	500.6
	1991	29.4	22.4	2,130.0	6.9	5.3	500.6

Notes: ug/m^3 per ppb = 4.254567
ug/m^3 = micrograms per cubic meter
ppb = parts per billion

Table 5. Maximum 1-Hour Predicted Concentrations of Styrene Emissions, Sea Ray Boats, Inc. Cape Canaveral Plant Compared to Environmental Protection Agency (EPA) Recommended Odor Threshold for Styrene

Averaging Time	Year	Site Boundary (ug/m^3)	Residential Boundary (ug/m^3)	EPA Odor Threshold[a] (ug/m^3)	Site Boundary (ppb)	Residential Boundary (ppb)	EPA Odor Threshold[a] (ppb)
6 Vents (55 feet high)							
Highest 1-hour	1987	680	540	638	160	127	150
	1988	673	530	638	158	125	150
	1989	658	509	638	155	120	150
	1990	738	526	638	173	124	150
	1991	676	538	638	159	127	150
Single Stack (60 feet high)							
Highest 1-hour	1987	241	188	638	57	44	150
	1988	260	183	638	61	43	150
	1989	255	182	638	60	43	150
	1990	235	180	638	55	42	150
	1991	259	181	638	61	43	150
Single Stack (75 feet high)-Original Design							
Highest 1-hour	1987	103	103	638	24	24	150
	1988	103	98	638	24	23	150
	1989	109	98	638	26	23	150
	1990	123	98	638	29	23	150
	1991	102	94	638	24	22	150
Single Stack (75 feet high)-Final Design							
Highest 1-hour	1987	67	59	638	16	14	150
	1988	67	60	638	16	14	150
	1989	73	58	638	17	14	150
	1990	72	61	638	17	14	150
	1991	72	57	638	17	13	150

Notes: ug/m^3 per ppb = 4.254567 ; ug/m^3 = micrograms per cubic meter
ppb = parts per billion.

[a]Source: EPA, 1992. Reference Guide to Odor Thresholds for Hazardous Air Pollutants Listed in the Clean Air Act Amendments of 1990. EPA/600/R-92/047.

Department of
Environmental Protection

Jeb Bush
Governor

Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

David B. Struhs
Secretary

January 14, 2002

CERTIFIED MAIL – Return Receipt Requested

Mr. Bruce Smith
Cedar Bay Generating Company, L.P.
P.O. Box 26324
Jacksonville, Florida 32226

Re: Extension of Time to Respond to Additional Information Request Regarding Application for Revision of PSD-FL-137A to Allow Co-firing of Petcoke, DEP Project #: 0310337-005-AC

Dear Mr. Smith:

The Department received your letter, dated January 11, 2002, requesting an extension of time to respond to our request for additional information regarding your application to burn petcoke, which was sent to you on September 28, 2001.

In accordance with the provisions of Rule 62-4.055, F.A.C., "...If an applicant requires more than ninety days in which to respond to a request for additional information, the applicant may notify the Department in writing of the circumstances, at which time the application shall be held in active status for one additional period of up to ninety days. Additional extensions shall be granted for good cause shown by the applicant. A showing that the applicant is making a diligent effort to obtain the requested additional information shall constitute good cause. Failure of an applicant to provide the timely requested information by the applicable deadline shall result in denial of the application."

A 90-day extension of time to respond is hereby granted. Failure to submit the requested additional information by March 27, 2002, shall be grounds for denial of the application.

If you should have any questions regarding this extension, please contact Jonathan Holtom, P.E., at (850) 921-9531.

Sincerely,

for C. H. Fancy, P.E.
Chief
Bureau of Air Regulation

cc: Jeff Walker, CBGC
Kennard Kosky, P.E., Golder Associates
Hamilton S. Oven, Jr.
Ernest Frye, DEP NE District
Steve Pace, Jacksonville RESD

Mailed 1/14/02

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1. Article Addressed to:

1r. Bruce Smith
edar Bay Generating Company, L.P
.O. Box 26324
acksonville, Florida 32226

COMPLETE THIS SECTION ON DELIVERY

A. Received by *(Please Print Clearly)* Shelly Arnold

B. Date of Delivery

C. Signature

X

☐ Agent
☐ Addressee

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Mr. Bruce Smith

Postage	$	Postmark Here
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Total Postage & Fees	$	

***Recipient's Name** (Please Print Clearly) (To be completed by mailer)*
Mr. Bruce Smith
Street, Apt. No.; or PO Box No.
P.O. Box 26324
City, State, ZIP+ 4
Jacksonville, Florida 32226

PS Form 3800, February 2000 See Reverse for Instructions

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1. Article Addressed to: 031033?-005-PC Extension

Mr. Bruce Smith
General Manager
Cedar Bay Generating Company, L.P.
9640 Eastport Road
Jacksonville, Florida 32226

2.

PS

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4. Restricted Delivery? (*Extra Fee*) ☐ Yes

PG&E National Energy Group

Cedar Bay
Generating Plant
Owner Cedar Bay Generating Company, L.P.

POB 26324
Jacksonville, FL 32226-6324

904.751.4000
Fax: 904.751.7320

January 11, 2002

Mr. C. H. Fancy, P.E., Chief
Bureau of Air Regulation
Florida Department of Environmental Protection
Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

RE: Cedar Bay Cogeneration Facility
Co-firing Petroleum Coke with Coal
Revision of PSD-FL-137A

Dear Mr. Fancy:

In a letter dated September 28, 2001, the Department requested additional information related to the request to co-fire petroleum coke with coal at the Cedar Bay Cogeneration Facility. Cedar Bay Generating respectfully request an extension of time to respond to the request pursuant to Rule 62-4.055.

As you know the request to co-fire petcoke is directly related to the bankruptcy of our long-term coal supply contractor and the subsequent termination of our coal contract. Our main focus has been maintaining our coal supply in the short term and securing coal supply and delivery contracts for a longer period. Petcoke remains a technically viable fuel alternative, which we do intend to pursue, however we require additional time to complete our analysis and respond to your request.

Rule 62-4.055 authorizes the Department to grant one additional period of up to ninety days. We will respond in the near future and well within the additional ninety-day period.

If you have any questions, please do not hesitate to contact Jeff Walker of my staff at (904) 751-4000 extension 22.

Sincerely,

Bruce Smith, General Manager
Cedar Bay Generating Company, LP

Cc: A.A Linero, DEP
Scott Gorland, DEP
Jonathan Holtom, DEP
Ernest Frye, DEP NE District
Steve Pace, Jacksonville RESD
Hamilton S. Oven, Jr.
Ken Kosky
David Dee

Department of Environmental Protection

Jeb Bush
Governor

Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

David B. Struhs
Secretary

September 28, 2001

CERTIFIED MAIL – Return Receipt Requested

Mr. Bruce Smith
Cedar Bay Generating Company, L.P.
P.O. Box 26324
Jacksonville, Florida 32226

Re: Revision of PSD-FL-137A to Allow Co-firing of Petcoke

Dear Mr. Smith:

The Department received the application that you submitted, requesting approval to co-fire up to 35% petcoke in your boilers, on August 29, 2001. Based on a telephone conversation with Mr. Jeffery Walker, it is our understanding that this project is undergoing additional evaluation as to its overall economic feasibility. Because of potential adjustments to the scope of the project, or the potential withdrawal of the project, as a result of these evaluations, raises questions about the accuracy and completeness of the application that has been submitted.

Based on the evaluation of the application, it is considered incomplete. Please provide the following information and the Department will resume review of the application. Also, please provide all assumptions, calculations and reference material.

1. Provide a pollutant emissions analysis that compares the facility's past actual pollutant emissions, pursuant to Rule 62-210.200, F.A.C., Definitions – Actual Emissions, to future allowable pollutant emissions that show there is no significant pollutant emissions increase pursuant to Table 400-2, F.A.C. If there is a significant increase for any pollutant, please submit the information and evaluation(s) required pursuant to Rule 62-212.400(5), F.A.C.

This information requires a written response to the Department within ninety days of receipt of this notice unless additional time is requested pursuant to Rule 62-4.055, F.A.C. If you should have any questions, please contact Jonathan Holtom, P.E., at (850) 921-9531.

Sincerely,

C. H. Fancy, P.E.
Chief
Bureau of Air Regulation

cc: Kennard Kosky, P.E., Golder Associates
Jeff Walker, CBGC

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1. Article Addressed to:

Mr. Bruce Smith
Cedar Bay Generating Company, L.P.
P.O. Box 26324
Jacksonville, FL 32226

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C. Signature
X Debra S Dunnell ☐ Agent ☐ Addressee

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PS Form 3811, July 1999 Domestic Return Receipt 102595-00-M-0952

U.S. Postal Service
CERTIFIED MAIL RECEIPT
(Domestic Mail Only; No Insurance Coverage Provided)

7000 0520 0020 9371 1618

Mr. Bruce Smith

Postage	$	Postmark Here
Certified Fee		
Return Receipt Fee (Endorsement Required)		
Restricted Delivery Fee (Endorsement Required)		
Total Postage & Fees	$	

Recipient's Name (Please Print Clearly) (To be completed by mailer)
Mr. Bruce Smith
Street, Apt. No.; or PO Box No.
P.O. Box 26324
City, State, ZIP+4
Jacksonville, Florida 32226

PS Form 3800, February 2000 See Reverse for Instructions

PG&E National Energy Group.
Cedar Bay Generating Plant
Owner Cedar Bay Generating Company, L.P.

RECEIVED
SEP 1 0 2001
BUREAU OF

POB 26324
Jacksonville, FL 32226-6324
904.751.4000
Fax: 904.751.7000

Reflected in Site Cert. Superseded in PSD/TS? Handle with Pet coke

September 18, 2001

Mr. Scott Sheplak, P.E.
Florida Department of Environmental Protection
Division of Air Resource Management
Bureau of Air Regulation
Mail Station #5505
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Re: Cedar Bay Draft Air Construction/PSD Permit No.

Dear Mr. Sheplak:

Cedar Bay Generating Company, L.P. would like to take the opportunity to provide written comments to the proposed Air Construction/PSD Permit Revision during the Public Notice period.

Material Handling Handling and Treatment

The previous PSD modification that became effective in March 2000 is now identified as PSD-FL-137D. One of the items in the original modification request was a request to modify the material handling and usage rates of the coal and limestone/aragonite. Due to the modification's intensive focus on SO2 limits and supporting air dispersion modeling, this particular item was apparently overlooked during the draft and final permit issuance.

Coal and limestone are staged in lined storage piles. Coal is supplied via rail and limestone/aragonite is supplied via ship, then truck. Cedar Bay Generating Company, L.P. is concerned that current PSD permit conditions do not allow sufficient material handling capacity to allow the facility to weather catastrophic events or business interruptions. It would be prudent to have the ability to increase the amount of coal and limestone "handled" at the facility.

Given that:

- Coal unloading and storage , as well as limestone/aragonite unloading and storage, represent fugitive particulate emissions for which no emission rate limits are set;
- There is no federal or state regulation limiting the quantities of these material or emissions on a monthly basis; and
- Compliance with a rigorous interpretation of the current monthly conditions would, in theory, render the storage piles to be eventually depleted if the boilers ran at full capacity for an extended period with even intermittent cessation of supply periods;

Cedar Bay therefore requests doubling the monthly limitations for coal and limestone/aragonite unloading and storage, and increasing the annual usage rate by one month's capacity. This would require separating the limits for these sources from the other material handling sources.

Thus, Cedar Bay proposes to modify Conditions II.B.2 as follows:

2. Material Handling and Usage Rate

a. The material handling/usage rates for coal unloading and storage and for limestone/aragonite unloading and storage shall not exceed the following:

	Handling/Usage Rate	
Material	TPM	TPY
Coal	234,000	1,287,000
Limestone/Aragonite	54,000	347,000

b. For fly ash and bed ash handling sources, the handling/usage rates shall not exceed the following:

	Handling/Usage Rate	
Material	TPM	TPY
Fly Ash	28,000	336,000
Bed Ash	8,000	88,000

Note: TPM is tons per month based on 30 consecutive days; and, TPY is tons per year

It is important to note that the latest version of Cedar Bay's Conditions of Certification reflect these changes as requested in the PSD modification application although the material handling changes were not part of the proposed changes in the draft PSD permit.

Addition of language for a Pug Mill

As explained in a letter to the Department dated August 21, 2001, Cedar Bay desires to improve the flexibility for ash handling and transportation from the site with the installation of a pug mill. The pug mill will mix ash and water in an enclosed system and enable the removal of ash by other than sealed trucks. This process will enable the ash to be loaded, transported, and disposed in a Class 1 landfill while minimizing fugitive emissions.

While the PSD Modification Application in 1994 explicitly detailed "Dry Ash Unloading in Sealed Trucks", the resulting modification, PSD-FL-137(B), did not specifically reference the use of trucks as a means to remove ash from the site. Instead, Section II.B.4.added a stipulation that requires the Project site to option prior approval of the DEP and RESD for removal of bottom and fly ash by any other means other than rail. Cedar Bay has since obtained such permission once it was clear that long-term beneficial re-use opportunities were available.

The use of the pug mill will alter the process of loading the trucks but will enable the project to meet the visible emission limitation (VE) of five per cent (5%) opacity in accordance with rule 62-296.711, F.A.C. By wetting and blending the ash, the pug mill will produce a more uniform ash with less opportunity for dusting. There are no new vents or other air emission sources associated with the pug mill itself.

Therefore, Cedar Bay requests to modify PSD-FL-137(B) (in conjunction with the retirement of the pelletizer emission units) as follows:

From

II.1.B.4 Material handling sources shall be regulated as follow:

a. The material handling and treatment area sources with either fabric filter or baghouse controls are as follows:

Coal Crusher Building	Limestone Pulverizer (2)/Conveyor
Coal Silo Conveyor	Limestone Storage Bins(2)
Bed Ash Hopper	Fly Ash Silo Vent
Bed Ash Separator	Fly Ash Separators(2)
Bed Ash Silo Vent	Pellet Vibratory System
Bed Ash Receiver Bin	Pellet Recycle tank
Fly Ash Receiver Bin	Cured Pellet Screening Conveyor System
	Pellet Recycle System
	Pelletizing Rail Loadout

The emissions from the above listed sources are subject to the particulate emission limitation requirement of 0.003 gr./disc (applicant requested limitation which is more stringent than what is allowed by Rule 62-296.711, F.A.C. Since these sources are RACT standard type, then a one-time verification test on each source shall be required for PM mass emissions to demonstrate that the baghouse control systems can achieve the 0.003 gr/dscf. The performance tests shall be conducted using EPA method 5 pursuant to Chapter 62-297, F.A.C. and 40 CFR 60, Appendix A.

b. The PM emissions from the following process equipment and/or facility in the material handling and treatment area sources shall be controlled as follows:

Ash Pellet Hydrator:	Scrubber
Ash Pellet Curing Silos:	Scrubber
Ash Pelletizing Pan:	Scrubber

The above listed sources are subject to a visible emissions (VE) and a particulate matter (PM) emissions limitation requirement of 5 percent opacity and a 0.01 gr/dscf(applicant requested limitation, which is more stringent than what is allowed by rule) , respectively, in accordance with Rule 62-296.711, F.A.C. Initial and subsequent compliance tests shall be conducted for VE and PM using EPA methods 9 and 5, respectively, in accordance with Rule 62-297, D=F.A.C. and 40 CFR 60, Appendix A.

c. Fugitive emissions from the following material handling and transport sources shall be controlled as follows:

Coal Car Unloading:	Wet Suppression using continuous water sprays during unloading
Dry Ash Rail Car Loadout:	Using closed or covered containers under negative air pressures during ash loadout; and using water sprays prior to removal of railcar loadout cap when loading open rail cars

The above listed sources are subject to a visible emission (VE) limitation requirement of five percent (5%) opacity in accordance with Rule 62-296.711, F.A.C. Initial and subsequent compliance test shall be conducted for VE using EPA Method 9 or other FDEP approved methods in accordance with Rule 62-297, F.A.C. and 40 CFR 60, Appendix A (July, 1992 version). Initial visible emission testing shall be conducted within 90 days after final DEP approval of these facilities or within 90 days after completion of construction of the source, whichever occurs last. Ash shipped in open rail cars will either be pelletized or be sprayed with water to create a crust on the top layer of non-pelletized ash. Removal of bottom and fly ash from the Project site by any means other than by rail shall require the prior approval of DEP and RESD of the method(s) of fugitive emissions control.

To:

II.1.B.4 Material handling sources shall be regulated as follow:

The material handling and treatment area sources with either fabric filter or baghouse controls are as follows:

Coal Crusher Building	Limestone Pulverizer (2)/Conveyor
Coal Silo Conveyor	Limestone Storage Bins(2)
Bed Ash Hopper	Fly Ash Silo Vent
Bed Ash Separator	Fly Ash Separators(2)
Bed Ash Silo Vent	

The emissions from the above listed sources are subject to the particulate emission limitation requirement of 0.003 gr./disc (applicant requested limitation which is more stringent than what is allowed by Rule 62-296.711, F.A.C. Since these sources are RACT standard type, then a one-time verification test on each source shall be required for PM mass emissions to demonstrate that the baghouse control systems can achieve the 0.003 gr/dscf. The performance tests shall be conducted using EPA method 5 pursuant to Chapter 62-297, F.A.C. and 40 CFR 60, Appendix A.

b.Fugitive emissions from the following material handling and transport sources shall be controlled as follows:

Coal Car Unloading:	Wet Suppression using continuous water sprays during unloading
Dry Ash Rail Car Loadout:	Using closed or covered containers under negative air pressures during ash loadout; and using water sprays prior to removal of railcar loadout cap when loading open rail cars
Dry Ash Truck Loadout:	Using sealed trailers under negative air
Wet Ash Truck Loadout:	Using a pug mill to mix water with ash

The above listed sources are subject to a visible emission (VE) limitation requirement of five percent (5%) opacity in accordance with Rule 62-296.711, F.A.C. Initial and subsequent compliance test shall be conducted for VE using EPA Method 9 or other FDEP approved methods in accordance with Rule 62-297, F.A.C. and 40 CFR 60, Appendix A (July, 1992 version). Initial visible emission testing shall be conducted within 90 days after final DEP approval of these facilities or within 90 days after completion of construction of the source, whichever occurs last. Ash shipped in open rail cars will either be pelletized or be sprayed with water to create a crust on the top layer of non-pelletized ash. ~~Removal of bottom and fly ash from the Project site by any means other than by rail shall require the prior approval of DEP and RESD of the method(s) of fugitive emissions control.~~

We hope that these proposed changes are satisfactory to you and we look forward to working with you to ensure that we can operate the Cedar Bay facility in a reliable, environmentally responsible, and cost-effective manner. Please contact me at 904-751-4000 extension 22 with any questions or comments.

Sincerely,

Jeffrey A. Walker

Jeffrey A. Walker
Environmental Manager, Cedar Bay

cc: Robert Dehart, PG&E National Energy Group
Bruce Smith, Cedar Bay

0310337-005-AC / PSD-FL-137 G(7)

PG&E National Energy Group
Cedar Bay Generating Plant
Owner: Cedar Bay Generating Company, L.P.

POB 26324
Jacksonville, FL 32226-6324
904.751.4000
Fax: 904.751.7320

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AUG 29 2001
BUREAU OF AIR REGULATION

August 28, 2001

Clair H. Fancy, Chief
Bureau of Air Regulation
Florida Department of Environmental Protection
Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, FL 32399-2400

RE: Request to Modify PSD Permit (PSD-FL-137) To Allow Co-Firing of Petroleum Coke with Bituminous Coal at Cedar Bay Cogeneration Facility

Dear Mr. Fancy:

On behalf of Cedar Bay Generating Company, L.P. (Cedar Bay), I have enclosed an original and three copies of an Application for Air Permit – Title V Source (Form 62-210.900(1)) and supporting documentation for Cedar Bay's request for approval to co-fire limited amounts of petroleum coke (pet coke) with bituminous coal at the Cedar Bay Cogeneration Facility (Facility) in Jacksonville, Florida. Although a change to the Facility's PSD permit is being requested, the limited use of pet coke will not cause any significant net emissions increase at the Facility and, therefore, the requirements of the PSD review process will not be triggered by this request.

The enclosed materials are being submitted in support of Cedar Bay's request to modify the Facility's PSD permit. In the near future, Cedar Bay will submit a separate request to modify the Conditions of Certification for the Facility, so that the Conditions of Certification and the PSD permit will be revised in a consistent manner.

Since operations began, Cedar Bay has been obtaining its fuel (bituminous coal) from Lodestar, a Kentucky-based mining company, pursuant to a long-term contract which requires Cedar Bay to purchase all of its coal from Lodestar. Unfortunately, Lodestar has filed for protection under Chapter 11 of the Bankruptcy Code. Under Chapter 11 of the Bankruptcy Code, Lodestar may terminate its contract with Cedar Bay for economic reasons. The price for coal under the contract is currently less than the price that Lodestar could obtain in the spot market. As a result, Cedar Bay has evaluated various options for obtaining fuel (including alternate suppliers of coal), while continuing its negotiations with Lodestar.

Options under consideration in the event the Lodestar rejects the Cedar Bay contract include:

- 100% Domestic Coal
- Domestic Coal and up to 35% petroleum coke
- 100% foreign coal
- Foreign coal and up to 35% petroleum coke

Currently, Lodestar continues to supply coal and remove ash for disposal.

At this time, the limited use of pet coke is a promising alternative for Cedar Bay and consequently, Cedar Bay is seeking authorization to co-fire pet coke because Cedar Bay must take steps to ensure that it has a sufficient and suitable fuel supply for the Facility.

Cedar Bay has asked Foster Wheeler Energy Services, Inc. (Foster Wheeler), to evaluate the feasibility of using pet coke as a supplemental fuel at the Facility. Foster Wheeler is knowledgeable about the use of pet coke at other electrical power plants in Florida, the specific design of the Facility, and other relevant factors. Based on its professional experience and its site-specific analyses, Foster Wheeler concluded that pet coke could be co-fired at the Cedar Bay Facility and, subject to certain qualifications, the use of pet coke could even improve the performance of the Facility's boilers. Foster Wheeler specifically addressed the fuel blend (up to 35% pet coke) that is being proposed in the attached application. Foster Wheeler's report is attached hereto as an appendix to the PSD application.

We would be happy to answer any questions that the Department may have about the Facility or this application. If you have questions about the Facility, please contact Mr. Jeff Walker, our Project Manager, at 904-751-4000 x22. If you have questions about the application, you may wish to contact Mr. Ken Kosky, our consultant, at 352-336-5600 or Mr. David Dee, our environmental counsel, at 850-681-0311.

We look forward to working with you and the other members of the Department on this project.

Sincerely,

Bruce Smith, General Manager
Cedar Bay Generating Company, LP

Cc: A.A Linero, DEP (w/o enclosures)
Scott Gorland, DEP (w/o enclosures)
Jonathan Holtom, DEP (w/o enclosures)
Ernest Frye, DEP NE District (w/ enclosures)
Steve Pace, Jacksonville RESD (w/ enclosures)
Hamilton S. Oven, Jr. (w/o enclosures)
Ken Kosky (w/ enclosures)
David Dee (w/ enclosures)