DEPARTMENT OF ENVIRONMENTAL PROTECTION
Marjory Stoneman Douglas Building
3900 Commonwealth Boulevard
Tallahassee, Florida 32399-3000

Fax Number ~~(904)~~ (850) 921-3000

FAX COVER SHEET

DATE: 10-13-98

TO: Bruce Mitchell **PHONE:** 8-1344
FAX: 922-6979

FROM: Jeff Brown **PHONE:** 9-9625

REGARDING: ____________

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Message ____________

Florida Department of Environmental Protection

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

Lawton Chiles
Governor

Virginia Wetherell
Secretary

FAX TRANSMITTAL SHEET

DATE: 10-12-98

TO: Robert Manning

PHONE: 222-7500 FAX: 224-8551

FROM: Bruce Mitchell PHONE: 921-9500

Division of Air Resources Management FAX: 850.922.6979

RE: JEA T-V permit

CC:

Total number of pages including cover sheet:

Message

Here are the pages that changed with a new effective date of 1-1-99.

If there are any problems with this fax transmittal, please call the above phone number.

"Protect, Conserve, and Manage Florida's Environmental and Natural Resources"

Printed on recycled paper

IN THE DISTRICT COURT OF APPEAL
FIRST DISTRICT, STATE OF FLORIDA

JACKSONVILLE ELECTRIC AUTHORITY

Appellant,

v.

1ST DCA Case No. 98-00441
OGC Case No. 98-0196

STATE OF FLORIDA DEPARTMENT OF
ENVIRONMENTAL PROTECTION,

Appellee.

/

SETTLEMENT STIPULATION AND
MOTION TO RELINQUISH JURISDICTION

Appellant Jacksonville Electric Authority ("JEA") and Appellee State of Florida Department of Environmental Protection ("DEP") stipulate to a settlement of this case and, pursuant to Fla. R. App. P. 9.300 and 9.350(a), move the court for an Order relinquishing jurisdiction in this matter to allow actions to be taken in furtherance of the settlement. Wherefore, JEA and DEP state:

1. This proceeding stemmed from DEP's issuance of Title V Permit No. 0310045-001-AV to JEA, pursuant to Chapter 403, Florida Statutes, and Chapter 62-213, Florida Administrative Code.

2. JEA and DEP have agreed that specific revisions of Title V Permit No. 0310045-001-AV will resolve all issues involved in this appeal. The revisions agreed to are reflected in the attached Final Permit Determination (stamped DRAFT), received by JEA's counsel on October 6, 1998. (Attachment A).

3. The Final Permit Determination, once issued, will supersede Final Title V Permit No. 0310045-001-AV, the effectiveness of which was stayed upon the filing of this appeal pursuant to Fla. R. App. P. 9.310(b)(2).

4. JEA and DEP agree that DEP will issue the Final Permit Determination, as reflected in Attachment A, as soon as possible after the filing of this Stipulation, with the following additional revisions: (1) the Effective Date will be changed to January 1, 1999, the Renewal Application Due Date will be changed to July 5, 2003, and the Expiration Date will be changed to December 31, 2003, and (2) the emissions unit/activities listed in Attachment B will replace Appendix I-1 in the Final Permit Determination.

5. Each party shall bear its own costs and attorney fees in this proceeding.

THEREFORE, the disputed issues having been resolved, JEA and DEP move the court for an Order relinquishing jurisdiction in this case so that the actions described above can be taken in furtherance of the settlement.

Dated this 13 day of October, 1998.

HOPPING GREEN SAMS & SMITH, P.A.

By: Robert A. Manning
James S. Alves
Florida Bar No. 443750
Robert A. Manning
Florida Bar No. 0035173
Post Office Box 6526
Tallahassee, FL 32314
(850) 222-7500

ATTORNEYS FOR JACKSONVILLE ELECTRIC AUTHORITY

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION

By:______________________
Jeffrey Brown
Assistant General Counsel
3900 Commonwealth Blvd.
Mail Station 35
Tallahassee, FL 32399-300
(850) 488-9314

113973.1

E.10. Particulate Matter. In accordance with Chapter 62-297, F.A.C., EPA Method 5 shall be used to determine compliance with the particulate matter emission limitations established in Revised Table 6, PSD-FL-010, for emissions units 4 thru 17 that exhaust through a stack. If the opacity limits are not met for those emissions units that exhaust through a stack, permit compliance shall be determined on the basis of mass emission rate tests. See specific condition **E.9**.
[Rules 62-4.070 and 62-213.440, F.A.C.; Part V, Rule 2.501, JEPB; and, PSD-FL-010]

E.11. Operating Rate During Testing. Testing of emissions shall be conducted with the emissions unit operation at permitted capacity, which is defined as 90 to 100 percent of the maximum operation rate allowed by the permit. If it is impracticable to test at permitted capacity, an emissions unit may be tested at less than the minimum permitted capacity; in this case, subsequent emissions unit operation is limited to 110 percent of the test load until a new test is conducted. Once the emissions unit is so limited, operation at higher capacities is allowed for no more than 15 consecutive days for the purpose of additional compliance testing to regain the authority to operate at the permitted capacity.

{Permitting note: The Revised Table 2 includes a summary of the various emissions points/ activities and their control systems for the Coal Storage Yard and Transfer Systems. The throughput rate amounts displayed represent approximately 74 percent of their maximum potential. Therefore, when any visible emissions test is being conducted, the emissions point/ activity being evaluated should be operating at or near its maximum potential throughput rate.}

[Rules 62-297.310(2) & (2)(b), 62-213.440(1) and 62-4.070(3), F.A.C.; Part XI, Rule 2.1101, JEPB]

E.12. Applicable Test Procedures.

(a) Required Sampling Time.

2. Opacity Compliance Tests. When either EPA Method 9 or DEP Method 9 is specified as the applicable opacity test method, the required minimum period of observation for a compliance test shall be sixty (60) minutes for emissions units which emit or have the potential to emit 100 tons per year or more of particulate matter, and thirty (30) minutes for emissions units which have potential emissions less than 100 tons per year of particulate matter and are not subject to a multiple-valued opacity standard. The opacity test observation period shall include the period during which the highest opacity emissions can reasonably be expected to occur. Exceptions to these requirements are as follows:

c. The minimum observation period for opacity tests conducted by employees or agents of the Department to verify the day-to-day continuing compliance of a unit or activity with an applicable opacity standard shall be twelve minutes.

[Rule 62-297.310(4)(a)2.c., F.A.C.; Part XI, Rule 2.1101, JEPB]

10-1-98

Bert,
As stated earlier, E.2. & E.3. are being deleted and the subsequent conditions renumbered. Please look at the "permitting note" drafted for E.11. (was E.13). Give me a call when you get a chance.
Thanks, Bruce

Table 2. Fugitive Emissions and Control Summary (Revised: from PSD Permit: PSD-FL-010)

	Process	Type	Amount	Factor	Control	Technique	Emissions (Grams/sec)
1.	Ship Unloading	2 Grab Buckets	2,200 Tons/hr	0.0016 lb/Ton+	70.0%	Suppression, Enclosure	0.13*
2.	Feeders to Conveyor A.	2 Points	2,200 Tons/hr	0.00039 lb/Ton	85.0%	Suppression, Enclosure	4.02
3.	Conveyor Transfers 1 and 2.	2 Points	2,200 Tons/hr	0.00087 lb/Ton**	85.0%	Suppression, Enclosure	0.07
4.	Conveyor Transfers 3, 4, 5 and D to D by-pass.	4 Points	2,200 Tons/hr	0.00118 lb/Ton**	75.0%	Enclosure, Conditioned Material	0.33
5	Conveyor Transfers 6 and 7.	2 Points	2,000 Tons/hr	0.00106 lb/Ton**	75.0%	Enclosure, Conditioned Material	0.13
6	Traveling Stacker	3 Points: 1 Point	2,200 Tons/hr	0.00031 lb/Ton	75.0%	Enclosure, Conditioned Material	0.02
		1 Point	2,200 Tons/hr	0.00039 lb/Ton	75.0%	Enclosure, Conditioned Material	0.03
		1 Point	2,200 Tons/hr	0.00017 lb/Ton	0.0%		0.05
7.	Bucket Wheel Reclaimer	2 Points	2,000 Tons/hr	0.00063 lb/Ton**	75.0%	Enclosure, Conditioned Material	0.0%
8.	Ship Unloading Facility Coal Surge Pile	Active	30 Acres	13 lb/Acre/day[a]	(90%)[a]	Wetting Agent	0.20
9.	Coal Handling Transfer Points Ship Unloading Facility Coal Pile*	8 Points	2,200 Tons/Hr.	0.00041 lb/Ton**	75.0%	Enclosure, Conditioned Material	0.23
10.	Rail Car Unloading	Rotary Dumper	10,000 Tons/Day	0.4 lb/Ton	(97%)[b]	Wet Suppression	0.63
11.	Coal Handling Transfer Points	2 Points	10,000 Tons/Day	0.2 lb/Ton[c]	(99.9%)[b]	Dry Collection	0.02
12.	Coal Handling Transfer Points	2 Points	3,300 Tons/Day	0.2 lb/Ton[c]	(99.9%)[b]	Dry Collection	0.01
13.	Coal Handling Transfer Points	6 Points	3,300 Tons/Day	0.2 lb/Ton[c]	(97%)[b]	Wet Suppression	0.62
14.	Coal Handling Transfer Points	7 Points	5,000 Tons/Day	0.2 lb/Ton[c]	(99 9%)[b]	Dry Collection	0.04
15.	Coal Storage At Plant*	Active	10 Acres	13 lb/Acre/day[a]	(90%)[a]	Wetting Agent	0.07
16.	Coal Storage At Plant*	Inactive Piles	13 Acres	3.5 lb/Acre/day	(99%)[a]	Wetting Agent	0.002
17.	Limestone Unloading	Rail Dumper	750 Tons/Day	0.4 lb/ton[a]	(97%)[b]	Wet Suppression	0.05
18.	Limestone Transfer	1 Point	750 Tons/Day	0.2 lb/Ton[a]	(99 9%)[b]	Dry Collection	0.001
19.	Cooling Towers	Drift	2 x 243,500 gal/min.	51,450 ppm solids (maximum) (40% < 50 microns diameter)	99.998%	Drift Elimination	12.66
20.	Solid Waste Disposal Area	Active	10 Acres	13 lb/Acre/day[a]	(90%)[a]	Wetting Agent	0.07

* Revised process or emissions, May 1986.
\+ Weighted average based on 1,500 and 700 STPH ship unloaders.
** Average of emission factors for individual sources.

a. Pedco, 1977.
b. Stoughton, 1980
c. EPA, 1979.

Table 6. Allowable Emission Limits (Revised: From PSD Permit: PSD-FL-010) (lb/hour; lb/MMBtu)

	Emission Unit	SO_2	NO_X	PM (Revised Original)	Opacity (Percent)
1.	Steam Generating Boiler No.1 (6,144 MMBtu/hr maximum heat input)	4,669.; 0.76 (30-day rolling average)	3.686; 0.6	184; 0.03	20
2.	Steam Generating Boiler No. 2 (6,144 MMBtu/hr maximum heat input)	4,669; 0.76 (30-day rolling average)	3,686; 0.6	184; 0.03	20
3.	Auxiliary boilers (254 MMBtu/hr maximum heat input total)	203; 0.8		25.0; 0.1	20
4.	Ship Unloading (2 Grab Buckets)			1.O	10
5.	Feeders to Conveyor A (2 Wet Suppression points)*			0.13	10
6.	Conveyor Transfers 1 & 2 (2 points)*			0.57	1O
7.	Conveyor Transfer 3, 4, 5 & D to D by-pass (4 points)*			2.6	10
8.	Conveyor Transfers 6 & 7 (2 points)*			1.0	10
9.	Traveling Stacker (3 points)*			0.8	10
10.	Bucket Wheel Reclaimer (2 points)*			0.6	10
11.	Ship unloading facility coal storage pile			1.6	10
12.	Coal handling transfer points ship unloading facility coal pile (8 points)*			1.8	10
13.	Rail car unloading (Rotary Dumper)			5	10
14.	Coal handling transfer points (6 wet suppression points)			5(each)	10
15.	Coal handling transfer points (11 dry collection)			0.1(each)	10
16.	Coal storage at plant. (10 acres active)			0.5	10
17.	Coal storage at plant* (2 to 13-acre inactive piles)			0.02	10
18.	Limestone unloading (rail dumper)			0.1	1O
19.	Limestone transfer points			0.4(each)	10
20.	Cooling towers			67(Each tower)	N/A

* Revised emission unit, May 1986.

Attention:	Bruce Mitchell	Date:	8/5/98
Company:	FDEP	Number of Pages:	2
Fax Number:	18509226979		
Voice Number:	19044881344		

From:	Liz Deken
Company:	
Fax Number:	573-785-2720
Voice Number:	573-785-2720

Subject: SJRPP Material Handling Permit Corrections

Comments:

Here is the list of points that actually exist at the SJRPP facility that Bert Giannaza indicated would be provided to you. A copy has also been provided to Syed Arif to look at for corrections that may be needed to the PSD permit.

You can call Bert or myself (573.785.2720) if you have questions.

Thanks

Liz Deken

Table 2. Fugitive Emissions and Control Summary (Revised: from PSD Permit: PSD-FL-010)

Process	Type	Amount	Factor	Control	Technique	Emissions (Grams/sec)
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3. Conveyor Transfers 1 and 2.	2 Points	2,200 Tons/hr	0.00087 lb/Ton**	85.0%	Suppression, Enclosure	0.07
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6 Traveling Stacker	3 Points:					
	1 Point	2,200 Tons/hr	0.00031 lb/Ton	75.0%	Enclosure, Conditioned Material	0.02
	1 Point	2,200 Tons/hr	0.00039 lb/Ton	75.0%	Enclosure, Conditioned Material	0.03
	1 Point	2,200 Tons/hr	0.00017 lb/Ton	0.0%		0.05
7. Bucket Wheel Reclaimer	2 Points	2,000 Tons/hr	0.00063 lb/Ton**	75.0%	Enclosure, Conditioned Material	0.0%
8. Ship Unloading Facility Coal Surge Pile	Active	30 Acres	13 lb/Acre/day[a]	(90%)[a]	Wetting Agent	0.20
9. Coal Handling Transfer Points Ship Unloading Facility Coal Pile*	8 Points	2,200 Tons/Hr.	0.00041 lb/Ton**	75.0%	Enclosure, Conditioned Material	0.23
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* Revised process or emissions, May 1986.
+ Weighted average based on 1,500 and 700 STPH ship unloaders.
** Average of emission factors for individual sources.

a. Pedco, 1977.
b. Stoughton, 1980
c. EPA, 1979.

Table 6. Allowable Emission Limits (Revised: From PSD Permit: PSD-FL-010) (lb/hour; lb/MMBtu)

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2.	Steam Generating Boiler No. 2 (6,144 MMBtu/hr maximum heat input)	4,669; 0.76 (30-day rolling average)	3,686; 0.6	184; 0.03	20
3.	Auxiliary boilers (254 MMBtu/hr maximum heat input total)	203; 0.8		25.0; 0.1	20
4.	Ship Unloading (2 Grab Buckets)			1.O	10
5.	Feeders to Conveyor A (2 Wet Suppression points)*			0.13	10
6.	Conveyor Transfers 1 & 2 (2 points)*			0.57	1O
7.	Conveyor Transfer 3, 4, 5 & D to D by-pass (4 points)*			2.6	10
8.	Conveyor Transfers 6 & 7 (2 points)*			1.0	10
9.	Traveling Stacker (3 points)*			0.8	10
10.	Bucket Wheel Reclaimer (2 points)*			0.6	10
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12.	Coal handling transfer points ship unloading facility coal pile (8 points)*			1.8	10
13.	Rail car unloading (Rotary Dumper)			5	10
14.	Coal handling transfer points (6 wet suppression points)			5(each)	10
15.	Coal handling transfer points (11 dry collection)			0.1(each)	10
16.	Coal storage at plant. (10 acres active)			0.5	10
17.	Coal storage at plant* (2 to 13-acre inactive piles)			0.02	10
18.	Limestone unloading (rail dumper)			0.1	1O
19.	Limestone transfer points			0.4(each)	10
20.	Cooling towers			67(Each tower)	N/A

* Revised emission unit, May 1986.

SJRPP Material Handling Transfer Points for Permitting

Limestone		**Points**
1)	Limestone receiving bin with 3 Unloading hoppers	1
2)	Unloading hoppers to FLD-1 Belt	3
3)	FLD-1 to L0	1
4)	L0 to L1	1
5)	L1 to L2	1
6)	L2 to Storage Pile	1
7)	Reclaim hopper	1
8)	Hopper to 9LC-02	1
9)	9LC-02 to Silos(2)	2
10)	Silos to 1LC-01,2LC-01 (to ball mills)	2
	Total	14

Coal-Yard		
1)	Receiving bin with 4 Unloading hoppers	1
2)	4 Unloading hoppers to FCD-1,2,3,4	4
3)	FCD-1,2,3,4 to CO	4
4)	C0 to C1	1
5)	C1 to C2	1
	C1 to emergency stackout	1
6)	C2 to C4	1
7)	C4 to C5	1
	C4 to CT6	1
8)	C5 to C6	1
9)	C6 to storage pile	1
	Reclaim to C6 (grab and dump)	2
	C6 to C4	1
10)	Surge Bins	
	C2 to Surge Bin	1
	C3 to Surge Bin	1
	C4 to Surge Bin	1
	Surge Bin to FCR-A,B	2
11)	FCR-A,B to Crushers (2)	2
	Crushers (2)	2
	Crushers to C7,8	2
12)	C7,8 to C9,10	2
13)	C9,10 to 14 Coal Storage Silos	14
	Total	47

Coal-Shipunloader		**Points**
14)	Bucket to Hopper (grab & dump)	2
15)	Hopper to Belt	1
16)	Hopper Belt to CT1	1
17)	CT1 to CT2	1
18)	CT2 to CT3	1
19)	CT3 to CT4	1
20)	Reclaimer to CT4 (grab, dump,dump)	3
21)	CT4 to CT5	1
	CT4 to S1 traveling conveyor	1
	S1 Traveling conv. to S2 boom conv.	1
	S2 boom conv to storage pile	1
22)	CT5 to C2	1
23)	CT6 to CT4	1
	Total	16

Coal-Petcoke Feeder System		
24)	Hopper	1
	Hopper to SPC-1	1
	SPC-1 to PC-1	1
	PC-1 to C4	1
	Total	4

Fly & Bottom Ash Handling System		
25)	Flyash	
	U#1-A&B Saleable silo Baghouse (2) & roof vents (2)	4
	U#1-1 Non-saleable Silo Baghouse & roof vent	2
	U#1-A loadout Silo discharge (2) & roof vent (1)	3
	U#1-B loadout Silo discharge (2) & roof vent (1)	3
	U#2-A&B Saleable silo Baghouse (2) & roof vents (2)	4
	U#2-A Non-saleable Silo Baghouse & roof vent	2
	U#2-A loadout Silo discharge (2) & roof vent (1)	3
	U#2-B loadout Silo discharge (2) & roof vent (1)	3
26)	Bottom Ash	
	U#1-A&B Silo to conveyor belt	2
	Conveyor belt to truck	1
	U#2-A&B Silo to conveyor belt	2
	Conveyor belt to truck	1
	Total	30

Grand Total 111

JACKSONVILLE ELECTRIC AUTHORITY

21 WEST CHURCH STREET • JACKSONVILLE, FL 32202-3139

July 7, 1998

RECEIVED
JUL 08 1998
BUREAU OF
AIR REGULATION

Mr. Bruce Mitchell
Environmental Administrator
Department of Environmental Protection
Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, FL 32399-2400

RE: Northside Generating Station
Title V Permit - Supplemental Information

Dear Mr. Mitchell:

Below please find additional comments relating to the Northside Generating Station Title V permit.

1. We request letter authorization, to be added to the Title V permit, to operate an auxiliary rental boiler rated at up to 300 HP. The primary fuel would be natural gas with #2 oil serving as backup in the event of gas curtailment.

2. We request clarifying language stating that the heat input value calculated by the CEMs is not the method of compliance with the heat input limit.

3. Attached please find a heat input curve for the Northside combustion turbines. Since manufacturer curves are unavailable, this curve is a regression curve developed empirically in-house. As such the heat input at each temperature is a nominal value (with approximately 50% of observations above the line and 50% of observations below the line) and should not be considered a limit, only a nominal value for determination of full load for VE testing purposes.

4. Attached please find an updated O&M plan for the Northside Generating Station.

5. In condition A.3.b. the sum of the oil inputs to units 1,2, and 3 listed as 1,440,000 is incorrect. Since each unit is limited, this limit is redundant and should be removed. Also, since fuel heat content varies, and the unit is limited on heat input as opposed to mass input, this redundant limit should be removed.

6. Attached please find the pertinent pages from our Title V permit application showing corrections to the stack heights and diameters.

7. On page 8, item A.11, please add a reference to item A.17.

If you have any questions with regard to this matter, please contact me at (904) 632-6247.

Sincerely,

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

NBG

bc: C. Maire
G. Connell
B. Wray
B. Gianazza
S. Stokes
File

PVADDN5

NORTHSIDE STATION COMBUSTION TURBINES
BASE LOAD MW vs TEMPERATURE

#	AMBIENT TEMP °F	GROSS MW (X)	x Coeff. Net MW	HEAT CONSUMED MBTU/HR	AMBIENT TEMP °F	GROSS MW (X)	x Coeff. Net MW	HEAT CONSUMED MBTU/HR
1	20	67.97	67.63	868	60	58.77	58.43	747
2	21	67.74	67.40	865	61	58.54	58.20	744
3	22	67.51	67.17	861	62	58.31	57.97	741
4	23	67.28	66.94	858	63	58.08	57.74	738
5	24	67.05	66.71	855	64	57.85	57.51	735
6	25	66.82	66.48	852	65	57.62	57.28	733
7	26	66.59	66.25	849	66	57.39	57.05	730
8	27	66.36	66.02	846	67	57.16	56.82	727
9	28	66.13	65.79	842	68	56.93	56.59	724
10	29	65.90	65.56	839	69	56.70	56.36	721
11	30	65.67	65.33	836	70	56.47	56.13	719
12	31	65.44	65.10	833	71	56.24	55.90	716
13	32	65.21	64.87	830	72	56.01	55.67	713
14	33	64.98	64.64	827	73	55.78	55.44	710
15	34	64.75	64.41	824	74	55.55	55.21	708
16	35	64.52	64.18	821	75	55.32	54.98	705
17	36	64.29	63.95	818	76	55.09	54.75	702
18	37	64.06	63.72	815	77	54.86	54.52	699
19	38	63.83	63.49	812	78	54.63	54.29	697
20	39	63.60	63.26	809	79	54.40	54.06	694
21	40	63.37	63.03	806	80	54.17	53.83	691
22	41	63.14	62.80	802	81	53.94	53.60	689
23	42	62.91	62.57	799	82	53.71	53.37	686
24	43	62.68	62.34	796	83	53.48	53.14	683
25	44	62.45	62.11	793	84	53.25	52.91	681
26	45	62.22	61.88	791	85	53.02	52.68	678
27	46	61.99	61.65	788	86	52.79	52.45	675
28	47	61.76	61.42	785	87	52.56	52.22	673
29	48	61.53	61.19	782	88	52.33	51.99	670
30	49	61.30	60.96	779	89	52.10	51.76	667
31	50	61.07	60.73	776	90	51.87	51.53	665
32	51	60.84	60.50	773	91	51.64	51.30	662
33	52	60.61	60.27	770	92	51.41	51.07	660
34	53	60.38	60.04	767	93	51.18	50.84	657
35	54	60.15	59.81	764	94	50.95	50.61	654
36	55	59.92	59.58	761	95	50.72	50.38	652
37	56	59.69	59.35	758	96	50.49	50.15	649
38	57	59.46	59.12	755	97	50.26	49.92	647
39	58	59.23	58.89	753	98	50.03	49.69	644
40	59	59.00	58.66	750	99	49.80	49.46	641
41	60	58.77	58.43	747	100	49.57	49.23	639

KSCT

Y INTERCEPT	72.576
SLOPE	0.2301

DISPATCH HEAT RATE CURVES

A =	1.78910E+02
B =	8.82453E+00
C =	-1.50705E-02
D =	5.30028E-04
AA =	3.40193E-01
BB =	9.99987E-01
CC =	1.79499E-07
DATE:	05/21/93

Jacksonville Electric Authority

Operation and Maintenance Plan

Operation and Maintenance

Following is a list of activities to be accomplished for the control of particulate emissions from units in or impacting the Duval County maintenance areas. These schedules apply to each on-line unit.

Daily:

1. Check and clean burners (renew tips as necessary) daily.
2. Conduct one complete soot-blowing cycle (or as needed).
3. Maintain optimum fuel oil temperature and pressure at all times.

Weekly:

1. Clean low pressure fuel oil strainers (more frequently if required).
2. Clean other fuel oil strainers as needed by monitoring the pressure drop.

Annually:

1. Clean the boiler and inspect baffles.
2. Inspect the:
   (a) wind box;
   (b) registers;
   (c) diffusers;
   (d) refractory throat;
   (e) scanners;
   (f) ignitors.
3. Adjust the air registers for optimum flame pattern with assistance from Engineering Services.
4. Replace burner tips (more frequently if required).

As Needed:

1. Wash furnace and air heaters.

Major Outages:

1. Overhaul the: (a) turbine/generator
   (b) boiler and auxiliary equipment.
2. Calibrate the: (a) flow meters including sensing line checks;
   (b) pneumatic controls;
   c) temperature gauges.

Performance Parameters

The following operational parameters are to be recorded on a bi-hourly basis.

1. Steam flow.
2. Burner oil pressure.
3. Burner oil temperature.

Fuel Type: Number 6 residual oil unless otherwise stated.

Records

Records of all operating data and maintenance procedures listed herein shall be retained at the Generating Station for review, upon request, for a period of five (5) years.

LB/O&MPlan.doc

04/29/98

Emissions Unit Information Section 1 of 6

E. EMISSION POINT (STACK/VENT) INFORMATION
(Regulated Emissions Units Only)

Emission Point Description and Type

1. Identification of Point on Plot Plan or Flow Diagram:

   Stack 1

2. Emission Point Type Code:
   [xx] 1 [ ] 2 [ ] 3 [ ] 4

3. Descriptions of Emissions Points Comprising this Emissions Unit for VE Tracking (limit to 100 characters per point):

   A single stack serving a single boiler

4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common:

   N/A

5. Discharge Type Code:
   [ ] D [ ] F [ ] H [ ] P
   [ ] R [xx] V [ ] W

6. Stack Height: 250 ~~160~~ feet

7. Exit Diameter: 16 ~~11.1~~ feet

8. Exit Temperature: approx. 286 °F

Emissions Unit Information Section 2 of 6

E. EMISSION POINT (STACK/VENT) INFORMATION
(Regulated Emissions Units Only)

Emission Point Description and Type

1. Identification of Point on Plot Plan or Flow Diagram: Stack 2	
2. Emission Point Type Code: [xx] 1 [ ] 2 [ ] 3 [ ] 4	
3. Descriptions of Emissions Points Comprising this Emissions Unit for VE Tracking (limit to 100 characters per point): A single stack serving a single boiler.	
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common: N/A	
5. Discharge Type Code: [ ] D [ ] F [ ] H [ ] P [ ] R [x] V [ ] W	
6. Stack Height: ~~195~~ 300	feet
7. Exit Diameter: ~~11.1~~ 16	feet
8. Exit Temperature: approx. 280	°F

Emissions Unit Information Section 3 of 6

E. EMISSION POINT (STACK/VENT) INFORMATION
(Regulated Emissions Units Only)

Emission Point Description and Type

1. Identification of Point on Plot Plan or Flow Diagram:	
Stack 3	
2. Emission Point Type Code:	
[x] 1 [ ] 2 [ ] 3 [ ] 4	
3. Descriptions of Emissions Points Comprising this Emissions Unit for VE Tracking (limit to 100 characters per point):	
a single stack serving a single boiler	
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common:	
5. Discharge Type Code:	
[ ] D [ ] F [ ] H [ ] P	
[ ] R [x] V [ ] W	
6. Stack Height: ~~235.3~~ 300	feet
7. Exit Diameter: ~~18.5~~ 23	feet
8. Exit Temperature: approx. 305	°F

REGULATORY AND ENVIRONMENTAL SERVICES DEPARTMENT

FAX COVER SHEET

AIR AND WATER QUALITY DIVISION

117 West Duval Street, Suite 225
Jacksonville, Florida 32202
(904) 630-3484 (Office)
(904) 630-3638 (Fax)

RECEIVED
MAY 29 1998
BUREAU OF
AIR REGULATION

DATE: 5/29/98 TIME: 11:25am

TO: Bruce Mitchell FAX #: 850-922-6979

MESSAGE: Al's letter

FROM: Dara Brown

NUMBER OF PAGES FAXED (Including cover): 3

PLEASE CALL (904) 630-3484 IF YOU DO NOT RECEIVE ALL THE PAGES OF THIS FAX OR IF TRANSMISSION IS UNCLEAR. OUR FAX NUMBER IS (904) 630-3638.

Department of Environmental Protection

Lawton Chiles
Governor

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

Virginia B. Wetherell
Secretary

September 10, 1997

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Mr. Wayne E. Tutt, Associate Engineer
Regulatory & Environmental Services
Department
Air & Water Quality Division
421 West Church Street, Suite 422
Jacksonville, Florida 32202-4111

Re: Site Certification No. PA 81-13
St. Johns River Power Park Units #1 & #2

Dear Mr. Tutt:

This correspondence is provided to address the July 30, 1997 letter to Buck Oven regarding semiannual testing for Carbon Monoxide (CO) and Sulfuric Acid Mist (H_2SO_4). The request to the Florida Department of Environmental Protection was related in the October 28, 1996 modifications to the Conditions of Certification for the St. Johns River Power Park (SJRPP). The modified conditions authorized the co-firing of petroleum coke and coal. Conditions I.A.2.h. and I.A.2.i. requires semiannual testing of CO and H_2SO_4 for the first two years of co-firing and annual testing for the next three years, as information demonstrating that the operational changes (i.e., co-firing petroleum coke and coal) did not result in a significant net increase in emissions. Additionally, quarterly continuous emission monitoring data for CO was required. The same conditions were included in the modification to the Prevention of Significant Deterioration (PSD) approval (PSD-FL-010(B), October 14, 1996).

The conditions in the modified PSD permit and the Conditions of Certification were included as a mechanism to assure that a significant increase in CO or H_2SO_4 emissions did not occur as a direct result of co-firing petroleum coke. Because of the variability of these pollutants during the combustion process, SJRPP is required by the Department to perform semiannual testing during the first two years to determine if significant emission increases have occurred. The intent of the conditions were to review emissions over a long term i.e., two years, to determine if an increase has occurred.

In order to compare whether a significant increase has occurred, the test data should be evaluated against all the baseline information provided by SJRPP. For CO, the single 1995 testing is not representative, since CO emissions can be highly variable based on combustion conditions and fuel properties such as Hardgrove Grindability Index. SJRPP provided information during the permitting process that indicated that CO emissions could be highly variable; during normal operation when firing coal could range from less than 10 ppm to 500 ppm. Therefore, a long-term baseline CO emissions level must be used for comparing semiannual or annual testing. The use of Appendix C is not an appropriate mechanism in determining significant increases. The June 1997 test data provided by SJRPP indicate CO emissions ranging between 75 and 120 ppm. These CO emissions are within the CO baseline emission when burning coal, therefore, there was no significant increase in CO emissions.

Similar to CO, H_2SO_4 emission were expected to vary due to combustion effects. While the 1995 baseline tests indicated a H_2SO_4 concentration of 6.19 ppm, further baseline tests conducted in February 1997 by SJRPP indicated a H_2SO_4 concentration of 8.16 ppm. The H_2SO_4 concentration for the June 1997 test was clearly below the baseline tests conducted for coal firing. Thus, no increase in emissions of H_2SO_4 has occurred.

Overall, no specific short-term emission limits were established for CO and H_2SO_4 as a result of petroleum coke use. The Department will make a future determination whether or not significant annual increases have occurred based on analysis of future actual representative annual emissions. This determination will be based on information provided by SJRPP through semi-annual tests, continuous emission monitoring data, etc.

For your information, the Sierra Club challenged issuance of the permit. SJRPP and the Sierra Club jointly obtained the independent assistance of Dr. William C. Zegel, now President of Air and Waste Management Association. He determined that CO and H_2SO_4 emissions increases are not occurring as a result of burning a petroleum coke blend. As a result, the Sierra Club dropped its request for an administrative hearing.

As more testing is conducted, similar test comparisons will be made. If there are any questions please call Syed Arif at (850) 488-1344.

Sincerely,

A A Linero 9/10

A. A. Linero, P.E., Administrator
New Source Review Section

AAL/sa

cc: H. Oven, DEP/SCO
W. Walker, RESD

Brown

0310045-002-AV

JACKSONVILLE ELECTRIC AUTHORITY

21 WEST CHURCH STREET • JACKSONVILLE, FL 32202-3139

POWER TO SERVE

April 20, 1998

Mr. Bruce Mitchell
Florida Dept. of Environmental Regulation
2600 Blair Stone Rd.
Tallahassee, FL.

RECEIVED

APR 23 1998

BUREAU OF
AIR REGULATION

RE: Jacksonville Electric Authority (JEA)
Northside Generating Station (NGS) / St. Johns River Power Park (SJRPP)
Title V Permit No. 0310045-001-AV

Dear Mr. Mitchell:

Pursuant to our telephone conversations concerning the above referenced permit, the following comments indicate discrepancies that have been identified in the final permit that are not consistent with existing SJRPP PSD permit (PSD-FL-010), SJRPP's Conditions of Certification (PA 81-13), or applicable regulations. In addition, several clarifying amendments are requested at the end of this letter.

REQUESTED REVISIONS: DISCREPANCIES

Section II. Facility-Wide Conditions

ok Condition 2. This Condition should be revised as follows: "No person shall ~~not~~ cause, suffer, allow, or permit . . . ."

Section III. Emissions Units and Conditions

D.3.c. This Condition states that the maximum weight of petroleum coke burned shall not exceed 100,000 pounds per hour. The language "averaged over 24 hours" should be changed to "30 day rolling average" to correspond to the basis of the emission limits and the fact that the pounds per hour limits are correspondent to such.

D.3.d. The third sentence in this provision prohibiting the use of used oil except when firing at "normal operating temperatures" is ambiguous and should be deleted. If this was intended to mean used oil could not be fired during startup and shutdown, this prohibition is included in the second sentence of this provision.

ok D.7.a. The maximum ash content of the coal is 18%, by weight and not 0.18% by weight.

ok D.10.a. The formula should read: SO_2 (lb/MMBtu) = (0.2 x C/100) + 0.4 PSD-FL-010(B) has it as 4.

No! D.10.c. The formula should read: SO_2 (lb/MMBtu) = [0.1653 x C x S - 0.4 x C + 4] x 1/100

ok D.11.(1) The phrase "and 90 percent reduction" should be included.

ok D.13.b. Limiting the petroleum coke sulfur content to no more than 4.0 percent, by weight, dry basis is not correct. This should read "The blend of petroleum coke and coal sulfur content shall not exceed 4.0 percent, by weight." The 4% limit applies to the fuel blend, not the petcoke individually. Also, there is no reference to "dry basis" in the existing permits and therefore it should be deleted here.

ok D.14.(2) This provision should be revised as follows: "If emissions of SO_2 to the atmosphere are <u>equal to or</u> less than . . . ."

ok D.18. This Condition should be deleted because there is no comparable condition in PSD-FL-010. PSD-FL-010 simply states that CO emissions will be minimized utilizing combustion controls.

ok D.19. This Condition should be deleted in its entirety because these provisions apply to 40 CFR Subpart D units, and the SJRPP units are subject to 40 CFR Subpart Da. Further, subparagraph (1) of Condition D.19 is redundant to Condition D.8.

D.20. D.21. These Conditions should be deleted because these emissions units are NSPS units subject to the excess emissions provisions of 40 CFR Part 60, which are applicable as a matter of Florida law because 40 CFR Part 60 is incorporated by reference in Rule 62-204.800, Fla. Admin. Code. Further, the applicable excess emissions provisions of 40 CFR Part 60 are already contained in this Title V permit under Condition D.25 and the Appendix containing selected provisions from 40 CFR 60 Subpart A.

D.44. ok D.XX. A Condition should be added allowing data from RATA tests to be utilized for performance test purposes. This request is similar to a request by Kissimmee Utility Authority which has already been approved by DEP without the need for an Alternate Sampling Procedure (ASP).

D.52(a)4. Subparagraph b. should be revised because there is no annual stack test requirement for units that utilize CEMs to determine compliance with specific pollutants (SO_2 and NO_x), and No! subparagraph c. should be deleted because this unit is not subject to a NESHAP. See comment on Condition D.53 below.

OK D.52(a)5. The sentence is incomplete and should read "does not burn liquid <u>and/or solid fuel</u>".

D.53. The Conditions of Certification were modified to remove stack tests for sulfur dioxide and nitrogen oxides in lieu of CEMS data which was based on the December 15, 1995 guidance document by Howard Rhodes - "Guidance Regarding Annual Compliance Testing Exemption for Facilities Utilizing CEMs." Therefore, these two parameters should be removed from this item. Note that the PSD permit does not specifically require a stack test.

D.67. This Condition should be revised as follows to reflect the fact that this unit does not burn gas, and that hourly records are only kept regarding the amounts of each fuel fired; other records should only be required on a per shipment basis: "The owner or operator shall create and maintain for each emissions unit hourly records of the amount of each fuel fired. ~~the ratio of fuel oil to gsa if co-fired~~ <u>Records regarding</u> the heating value, and sulfur and ash content, percent by weight, of each fuel fired <u>will either be provided by the vendor or prepared by the permittee, and maintained by the permittee for each shipment of fuel received</u>." OK No

D.68. There are no requirements to submit this data per SJRPP permit requirements and therefore should not be required. Records are maintained on site for agency review as needed.

Subsection E. Auxiliary Boilers

OK SJRPP Auxiliary Boilers have been removed from SJRPP and deleted from the Conditions of Certification. Therefore this section is not warranted and any reference to the auxiliary boilers throughout the permit should be deleted.

Subsection ~~F~~ E. Coal Storage Yard and Transfer Systems

~~F~~.8. Because this unit is subject to the NSPS under 40 CFR Part 60, Subpart Y, the excess emissions provisions contained in 40 CFR Part 60 are applicable for any NSPS emission limits for this unit. Accordingly, Conditions F.8 and F.9 should contain the following introductory language: "<u>For emission limits not derived from NSPS,</u> excess emissions . . . ." See comment on Conditions D.20 and D.21 above.

CLARIFYING AMENDMENTS

Table of Contents

Ok Section III. D. It is understood that the Megawatts are in the permit for informational purposes only.

Placard Page

There are numerous references in the Title V permit to the "attached" Tables in PSD-FL-010. These Tables should therefore be attached as part of the Title V permit, and so indicated on this page.

Section I. Facility Information

Subsection A. Facility Description: Petroleum coke should be referenced.

Section III. Subsection A.

Description. The commence operation date for unit 2 should be changed from "1972" to "November 16, 1966."

A permitting note should be included with the heat input numbers indicating that the heat input is included only for purposes of determining the capacity at which testing occurred, and that a heat input determination need only be made while testing.

No change

A.5. This Condition reflects an Order issued by the Department allowing annual compliance testing and a 40% opacity limit. This Order should be attached to this Title V permit and the language revised as follows: "For Boilers Nos. 1 and 3, visible emissions shall not exceed 40 percent opacity. DEP has determined that these units ~~Emissions units governed by this visible emissions limit~~ shall compliance test for particulate matter emissions annually . . . ." A copy of the Order is attached for your convenience.

see s.c. A.22.

A.8. This Condition should be revised to reflect the specified compliance test method as follows: "Particulate matter emissions shall not exceed 0.1 pound per million Btu heat input, as measured in accordance with Condition A.22. ~~by applicable compliance methods~~.

A.11.? did its removal cr.?

see s.c.s A.17, A.23 and A.24.

A.10. This Condition should be revised to reflect the specified compliance test method as follows: "SO_2 emissions shall not exceed 1.98 pounds per million Btu heat input, as measured in accordance with Conditions A.17, A.23 and A.24. ~~by applicable compliance methods~~.

see s.c. A.18.

A.12. This Condition should be revised to reflect the specified compliance test method as follows: "For Boiler No. 3, nitrogen oxides emissions shall not exceed 0.30 lb/mmBtu heat input, as measured in accordance with Condition A.18. ~~by applicable compliance methods~~.

how does it get there? no change!

A.13. This Condition states that JEA can only burn used oil that is generated by JEA, yet the compliance provisions in this Condition and throughout Subsection A. (e.g., A.34, A.38) refers to "delivery" of the used oil, and analysis by the vendor. These conditions should be clarified to reflect the fact that used oil is not "delivered."

JEA is still subject to all provisions even its getting used oil from its activities!

A.18. The citation to this Condition should be changed from "Rule 62-296.450(1)(e)4." to "Rule 62-296.405(1)(e)4."

Ok

No change (the rule)

A.31. This Condition should be revised as follows: "(a)4.a. visible emissions ~~if there is an applicable standard~~; b. particulate matter; c. sulfur dioxide; d. nitrogen oxide ~~Each of the following pollutants, if there is an applicable standard, and if the emissions unit emits or has the potential to emit: 5 tons per year or more of lead or lead compounds measured as elemental lead; 30 tons per year or more of acrylonitrile; or 100 tons per year or more of any other regulated pollutant; and c. Each NESHAP pollutant, if there is an applicable standard~~.

016 -583?? #1
017 #3
018 Aux Boiler A&B

Subsection B.

OK A permitting note should be included with the heat input numbers indicating that the heat input is included only for purposes of determining the capacity at which testing occurred, and that a heat input determination need only be made while testing.

B.1. In accordance with the Title V application and existing operating permit, the heat input when firing natural or LP gas should be 123.5, not 120.0. Also, the authority for this provision should state that the application was filed on June 14, 1996, rather than 1997. OK

Subsection C.

Ok Description. As indicated in the Title V application, CT No. 5 began commercial service in February of 1974, not December 1974.

FCG book shows 12/74.

Ok C.3. This Condition should be revised as follows: "Only ~~(virgin)~~ new No. 2 . . . ."

Subsection D.

March 86 May 88

FCG book is different. Ok The description should be revised to reflect the correct dates of initial operation as indicated in the application: boiler No. 1 (December 15, 1986), and boiler No. 2 (March 24, 1988).

OK A permitting note should be included with the heat input numbers indicating that the heat input is included only for purposes of determining the capacity at which testing occurred, and that a heat input determination need only be made while testing.

coal, petroleum coke blend

Ok D.15.(1) The reference to "bituminous coal" should be changed to "coal or ~~coal/coke blend~~."

did some edit Ok D.15.(2) The reference to "All other fuels - oil" is ambiguous and should be changed to "~~liquid fuels.~~" Fuel oil

Ok D.30. Last sentence "is experienced" is stated twice.

Ok D.37. The word "acceptable" in the last sentence should be capitalized.

D.70, D.71, D.72. The authority for these Conditions should reference the Conditions of Certification.

no; this is cited in D.44.; added a reference to D.44.)

did some edit Ok D.75. The authority for this Condition should cite to 40 CFR 60.48a(e)(1) and reference Condition D.44.

Subsection G. Limestone and Flyash Handling

OK The word "generally" should be removed from the last sentence in the system description.

OK G.6.c. This provision should be made consistent with the permit language as well as G.7a. which is "Limestone Silo," not "limestone day silo."

Subsection H. Cooling Towers

edited due to Tables 2 and 4, not BACT driven

What BACT does this description refer to?

Subsection IV. Acid Rain deleted

1. The description denotes MW. It is understood that this is for informational purposes only.

ok A.5. All references to the "Jacksonville Electric Company" should be changed to "Jacksonville Electric Authority." 2.

Tables 1-1, and 2-2

These Tables should be revised in accordance with the comments above.

If you have any questions regarding these comments, please contact Bert Gianazza at (904)665-6247 for issues relating to the Northside facility, and Jay Worley at (904)751-7729 for issues relating to the Power Park.

Sincerely,

M. Claudia Maire
Vice President
Environmental Health & Safety

Date: 3/23/98 9:01:14 AM
From: Hamilton Buck Oven TAL
Subject: Re: JEA Power Park

In my opinion the conditions do not need to be modified. There are specified limits for coal handling facilities and limits on limestone handling already in the conditions. the coal handling equipment on blount Island is an existing source. As long as the materials handled by that source and its control equipment don't exceed the emission limitations, no violation will occur. I am not sure how much coal is actually delivered at Blount island. I suspect that most of the coal comes in via rail directly to the plant. Yes, the conditons of certification provide for automatic modification of the conditions for amendments to the PSD or Title V permits. No new fees have been submitted, although some of the modification fee is still in our account. A letter can act as an amendment to the site certification application.

RECEIVED

MAR 23 1998

BUREAU OF
AIR REGULATION

st. johns river POWER PARK

EV 981603

March 16, 1998

Mr. Hamilton Oven, P.E.
Administrator, Power Plant Siting
Florida Dept. of Environmental Protection
2600 Blair Stone Rd.
Mail Station 48
Tallahassee, FL 32399-2400

RE: St. Johns River Power Park (SJRPP)
Jacksonville Electric Authority (JEA)
Coal Unloading Facility - Limestone / Equivalent Unloading

Dear Mr. Oven:

A notification concerning the above referenced limestone unloading operation and the evaluation of the potential emissions were submitted to your agency on 02-18-98. Pursuant to our 03/11/98 telephone conversation, your agency concurred with the notification and emissions evaluation, therefore, limestone or equivalent shall be made available through the SJRPP coal unloading facility.

Please contact me at (904)665-8729 if you have any questions.

Sincerely,

Jay Worley
Director Environmental & Safety

xc: M. Costello, FDEP
E. Frey, FDEP
A. Linero, FDEP
W. Tutt, RESD

EV 981802 CERTIFIED MAIL

st. johns river POWER PARK

February 18, 1998

Mr. Hamilton Oven, P.E.
Administrator, Power Plant Siting
Florida Dept. of Environmental Protection
2600 Blair Stone Rd.
Mail Station 48
Tallahassee, FL 32399-2400

RE: St. Johns River Power Park (SJRPP)
Jacksonville Electric Authority (JEA)
Conditions of Certification PA 81-13
PSD FL-010

Dear Mr. Oven:

The St. Johns River Coal Terminal (SJRCT), addressed in the above referenced Conditions of Certification and PSD, is a solid fuel unloading facility located on Blount Island on the St. Johns River. The facility unloads water-borne solid fuel shipments where it is conveyed to SJRPP for the generation of electricity.

SJRCT is located adjacent to the Jacksonville Port Authority (JPA), a major importer of materials. Pursuant to telephone conversations with you and Mr. Costello (Florida Dept. of Environmental Protection's Bureau of Air Regulation), SJRPP is formally notifying you that approximately 270,000 ton/year/unit annually of limestone or equivalent will be unloaded at the SJRCT using existing coal handling facilities. The limestone unloading operation will benefit SJRPP by taking advantage of the limestone market via water-borne suppliers in addition to our direct truck and rail deliveries.

The limestone or equivalent shall be conveyed via the existing enclosed conveyor system to SJRPP. The limestone or equivalent shall be temporarily stored in a designated area of the coal pile prior to movement by truck to the existing limestone storage area. Please find attached a document prepared by Kennard F. Kosky, P.E. (Golder Associates) which presents the results of an evaluation of the potential emissions of unloading limestone at the SJRCT. The TSP and PM_{10} emissions are well within the 2.85 tons/year (0.65 lb/hr) authorized by Specific Condition I.A.4.b. for the limestone rail/truck unloading and transfer system. The maximum potential emissions are also within those authorized in the PSD approval.

Please contact me at (904)665-8729 if you have any questions or require any additional information regarding this request.

Sincerely,

Jay Worley
Director, Environmental & Safety

xc: M. Costello, (FDEP) ✓
E. Frey, (FDEP)
A. Linero, (FDEP)
W. Tutt, (RESD)

RECEIVED
FEB 20 1998
BUREAU OF
AIR REGULATION

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

St. Johns River Power Park (SJRPP)
PSD-FL-010(B); PA 81-13
Ship Limestone Unloading and Conveyor Transfer
Emissions of Particulate Matter

This document presents the results of an evaluation of the potential emissions of unloading limestone at the St. Johns River Coal Terminal and the transfer of limestone by the existing coal conveyors to the plant site. The evaluation was conducted using US EPA Emission Factors for Aggregate Handling and Storage Piles (Section 13.2.4 of AP-42). The maximum potential emissions from conveyors and transfer points are estimated not to exceed 0.6 tons/year (0.14 lb/hr) for TSP and 0.3 tons/year (0.07 lb/hr) for PM_{10}. This estimate was based on a maximum potential limestone usage of about 270,000 ton/year/unit, 4 percent sulfur fuel and 100 percent capacity factor. The TSP and PM_{10} emissions are well within the 2.85 tons/year (0.65 lb/hr) authorized by Specific Condition I.A.4.b. for the limestone rail/truck unloading and transfer system. The maximum potential emissions are also within those authorized in the PSD approval.

Because the St. Johns River Coal Terminal commenced construction after August 31, 1983, the New Source Performance Standards relating to Nonmetallic Mineral Processing Plants (40 CFR 60.670-60.676) are applicable to the transfer of limestone. These NSPS cover both stack/vent emissions and fugitive emissions. Since the conveyors and transfer points are enclosed but do not have a stack or vent the opacity requirements of 60.672 apply. Initial performance tests using EPA Method 9 for opacity including provisions of 60.675(c) is required within 90 days of maximum production rate or 180 days from initial operation (i.e., limestone transfer).

Kennard F. Kosky

Kennard F. Kosky, P.E. SEAL
Principal
Florida Professional Engineer License No. 14996
February 13, 1998

9651109A/06

Best Available Control Technology (BACT) Determination

Jacksonville Electric Authority

Duval County

The proposed facility is the construction of two 600 megawatt coal-fired electric utility steam generating units to be located in Jacksonville, Florida. The units will be designed for possible conversion to oil, gas or refuse firing. There will be an oil fired auxiliary boiler rated at 200 million Btu/hr estimated to have an annual capacity factor of 5 percent compared to 74 percent for the two units.

The plant will be located in Duval County which is classified nonattainment for the pollutant Ozone (17-2.16(1)(c) F.A.C.). It will be located in the area of influence of the Jacksonville particulate nonattainment area (17-2.13(1)(b) F.A.C.), however, the plant will not significantly impact the nonattainment area and is therefore exempt from the requirements of Section 17-2, 17 & 18 & 19 with respect to particulate emissions. The facility must comply with the provisions of 17-2.04 F.A.C. (Prevention of Significant Deterioration).

BACT Determination Requested by the Applicant:

Pollutant	Emission Limit
Particulates	0.03 lb/million Btu input
SO_2	0.76 lb/million Btu input
NO_x	0.60 lb/million Btu input
CO	0.05 lb/million Btu input

Particulate emissions to be controlled using an Electrostatic Precipitator (ESP). SO_2 emissions to be controlled with a limestone wet scrubbing system. There is no specific control technology for control of NO_x and CO emissions. BACT to be manufacturer's guarantee for state-of-the-art burner design parameters to minimize emissions.

Flyash emissions to be controlled using a pneumatic transfer system and bottom ash using a wet transfer system. Emissions from coal and limestone handling to be controlled by use of enclosed conveying systems with baghouses rated at 99.9 percent efficiency. Water suppression to control dust to be used as required.

Date of Receipt of a Complete BACT Application:

February 27, 1981

Date of Publication in the Florida Administrative Weekly:

March 27, 1981

Review Group Members:

Steve Pace, Jacksonville Bio-Environmental Services
Johnny Cole, DER, St. Johns River Subdistrict
Buck Oven Power Plant Siting Section
Bob King, DER, Bureau of Air Quality Management
Tom Rogers, DER, Air Modeling Section

Bio-Environmental Services recommended a 65% reduction in NO_x emissions, or 0.5 lb/million Btu heat input. This was the only exception to unanimous acceptance of the NSPS emission limits as BACT.

BACT Determination by DER:

Pollutant	Emission Limit
Particulates	0.03 lb/million Btu input
SO_2	0.76 lb/million Btu input
NO_x	0.60 lb/million Btu input
CO	0.05 lb/million Btu input

Justification of DER Determination:

NSPS, Subpart Da, Standards of performance for electric utility steam generating units for which construction is commenced after September 18, 1978, is determined as BACT for the proposed project. The proposed control equipment is state-of-the-art and determined as BACT.

Emissions from the auxiliary boiler are minor compared to the main units. The auxiliary boiler will operate only when one of the main units is not in operation. Limited operation of the auxiliary boiler is determined as BACT.

Details of the Analysis May be Obtained by Contacting:

Edward Palagyi, BACT Coordinator
Department of Environmental Regulation
Bureau of Air Quality Management
2600 Blair Stone Road
Tallahassee, Florida 32301

Recommended By:

for Steve Smallwood, Chief, BAQM

Date:

5/6/81

Approved:

Victoria Tschinkel, Secretary

Date:

5/7/81

FLORIDA

Department of
Environmental Protection

Lawton Chiles
Governor

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

Virginia B. Wetherell
Secretary

Notice of Final Permit Amendment

In the Matter of an
Application for Permit Amendment

DEP File No. PSD-FL-010(B)

Mr. Richard Breitmoser, P.E.
Environmental Health & Safety Group
St. Johns River Power Park
11201 New Berlin Road
Jacksonville, Florida 32226

Enclosed is a letter that amends Permit Number PSD-FL-010(B). This letter amends the specific conditions related to sulfur dioxide (SO_2) emissions and fuel use in the subject Final Determination (dated March 12, 1982) pursuant to 40 CFR 52.21-Prevention of Significant Deterioration (PSD permit). This permit amendment is issued pursuant to Section 403, Florida Statutes.

Any party to this order (permit) has the right to seek judicial review of the permit pursuant to Section 120.68, F.S., by the filing of a Notice of Appeal pursuant to Rule 9.110, Florida Rules of Appellate Procedure, with the Clerk of the Department in the Legal Office; and by filing a copy of the Notice of Appeal accompanied by the applicable filing fees with the appropriate District Court of Appeal. The Notice of Appeal must be filed within 14 (fourteen) days from the date this Notice is filed with the Clerk of the Department.

Executed in Tallahassee, Florida.

A. A. Linero, P.E. 10/11 for
C. H. Fancy, P.E., Chief
Bureau of Air Regulation

CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this NOTICE OF FINAL PERMIT AMENDMENT (including the FINAL permit amendment) was sent by certified mail (*) and copies were mailed by U.S. mail before the close of business on 10-14-96 to the person(s) listed:

Mr. Richard Breitmoser*

Mr. Brian Beals, EPA
Mr. John Bunyak, NPS
Mr. Hamilton Oven, DEP
Mr. Chris Kirts, NED
Mr. Jim Manning, RESD
Mr. Ken Kosky, MKBN

Clerk Stamp

FILING AND ACKNOWLEDGMENT
FILED, on this date, pursuant to §120.52(11), Florida Statutes, with the designated Department Clerk, receipt of which is hereby acknowledged.

[signature] 10-14-96
(Clerk) (Date)

FLORIDA

Department of Environmental Protection

Lawton Chiles
Governor

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

Virginia B. Wetherell
Secretary

October 11, 1996

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Mr. Richard Breitmoser, P.E.
Vice President
Environmental Health and Safety Group
St. Johns River Power Park
11201 New Berlin Road
Jacksonville, Florida 32226

Dear Mr. Breitmoser:

Re: Permit Amendment - Petroleum Coke Cofiring
Jacksonville Electric Authority, St. Johns River Power Park
PSD-FL-010(B); Duval County

The Department hereby amends the specific conditions related to sulfur dioxide (SO_2) emissions and fuel use in the subject Final Determination (dated March 12, 1982) pursuant to 40 CFR 52.21 - Prevention of Significant Deterioration (PSD Permit). The PSD Permit, previously amended on March 30, 1995 is amended as follows:

Condition 2.A. (new)

i. When blends of petroleum coke and coal with a sulfur content of up to or equal to 2 percent are fired in Units 1 or 2, the SO_2 emissions shall not exceed 0.55 pound per million British thermal units (lb/MMBtu) and a minimum of 76 percent reduction shall be achieved in the flue gas desulfurization system.

ii. When co-firing petroleum coke with coals having a sulfur content between 2.00 and 3.63 percent, the emission limitation shall be based on the following formula:

$$SO_2 \text{ emission limit (lb/MMBtu)} = (0.2 \times C/100) + 4$$

where: C = percent of coal co-fired on a heat input basis.

Please note that C is on a heat input basis and not weight input basis, so appropriate conversions should be used.

Mr. Richard Breitmoser
October 11, 1996
Page Two

iii. When coals with a sulfur content greater than 3.63 percent are co-fired with petroleum coke, the SO_2 emissions shall not exceed the following formula:

$$SO_2 \text{ (lb/MMBtu)} = (0.1653 \times C \times S - 0.4 \times [C + 40]) \times 1/100$$

where: C = percent of coal co-fired on a heat input basis
S = weight percent sulfur in the coal

iv. The maximum SO_2 emission rate when firing petroleum coke and coal shall not exceed 0.676 lb/MMBtu.

v. Compliance with the SO_2 emissions limit shall be based on a 30-day rolling average for those days when petroleum coke is fired. Any use of petroleum coke during a 24-hour period shall be considered 1 day of the 30-day rolling average. The 30-day rolling average shall be calculated according to the New Source Performance Standards (NSPS) codified in 40 CFR 60 Subpart Da, except as noted above.

Condition 2.B. (new)

The petroleum coke-coal blends shall be limited to a maximum of 20 percent petroleum coke, by weight. The maximum weight of the petroleum coke burned shall not exceed 100,000 lb/hr. The maximum sulfur content of the petroleum coke-coal blend shall not exceed 4.00 percent, by weight.

Condition 3. A. (new)

The applicant shall maintain and submit to the Department on an annual basis for a period of five years from the date the unit is initially co-fired with petroleum coke, information demonstrating in accordance with 40 CFR 52.21(b)(21)(v) and 40 CFR 52.21(b)(33) that the operational changes did not result in emissions increases of nitrogen oxides and particulate matter.

Condition 3. B. (new)

The applicant shall maintain and submit to the Department on a semiannual basis for a period of two years from the date the unit is initially co-fired with petroleum coke, and then on an annual basis (if the first two years of data show no significant increase in carbon monoxide emissions) for an additional three years, information demonstrating that the operational changes did not result in a significant emissions increase of carbon monoxide. The carbon monoxide emissions shall be based on test results using EPA Method 10. Additionally, quarterly continuous emission monitoring data for carbon monoxide emissions shall be submitted to the Department for a period of two years to show the range of emissions experienced during each quarter.

<u>Condition 3. C. (new)</u>

The applicant shall maintain and submit to the Department on a semiannual basis for a period of two years from the date the unit is initially co-fired with petroleum coke, information demonstrating that the operational changes did not result in significant emissions increases of sulfuric acid mist. The sulfuric acid mist emissions shall be based on test results using EPA Method 8.

A copy of this amendment letter shall be attached to and shall become a part of Permit PSD-FL-010.

STATE OF FLORIDA DEPARTMENT
OF ENVIRONMENTAL PROTECTION

Howard L Rhodes

Howard L. Rhodes, Director
Division Air Resources Management

CERTIFIED MAIL

EV 960328

April 4, 1996

Mr. Al Linero
Bureau of Air Regulation
Florida Dept. of Environmental Protection
2600 Blair Stone Road
Mail Station 5505
Tallahassee, FL 32399-2400

RE: Jacksonville Electric Authority (JEA)
St. Johns River Power Park (SJRPP), Units 1 & 2
Permit File No. PSD-FL-010, PA 81-13
Petroleum Coke

Dear Mr. Linero:

We are in receipt of your March 25, 1996 letter requesting additional information in order to continue your processing of the petroleum coke application submitted to your agency on March 01, 1996. The application was submitted to amend the above referenced permit and to allow burning of up to 20 percent petroleum coke with coal in SJRPP Units 1 & 2.

The following is the listing of the requested information with responses:

1. The test burn of the petroleum coke-coal blends were limited to 20 percent petroleum coke, by weight. The application requests 20 percent of petroleum coke on heat input basis. Please provide the relationship between percent petroleum coke by weight and percent petroleum coke by heat.

   Response: We appreciate your pointing out the conflict on heat rate versus weight percent for establishing the petroleum coke to coal ratios. SJRPP proposes to determine petroleum coke input as a percentage of weight rather than heat input. It is noted that formulas for emission rates are based on heat input so no formulas in our submittal will change. Due to the heating value difference between petroleum coke and coal, a 20 percent by weight for petroleum coke is equivalent to 23.4 percent by heat input. For this reason emission rates will decrease slightly from our original submittal and scrubbing percentage will increase. This decrease in emission rate is due to the fact that we must maintain an emission rate of 0.4 lb/mmBtu for the petroleum coke portion and that 95 percent scrubbing is now required for 23.4 percent of the heat input as opposed to 20 percent. For example, when co-firing petroleum coke with coals having sulfur contents of 2 percent or less, the revised emission limit is 0.55 lb/mmBtu and a minimum 76 percent reduction based on 20 percent petroleum coke by weight. In contrast, based on 20 percent heat input, the proposed emission limit was 0.56 lb/mmBtu and a 75 percent reduction. We

11201 New Berlin Road (32226) • P.O. Box 26888 • Jacksonville, FL 32218-0888

have amended the applicable pages and tables of our application to reflect this change to weight percent. (See Attachment 1R)

2. The application states that a temporary hopper and conveyor will be used to load petroleum coke with coal on the reclaim conveyor prior to transporting the mixture to the crusher house and then to the coal storage silos. What assurances are provided to the Department that a maximum of 20 percent mix by heat of petroleum coke with coal is taking place once the blended fuel is sent to the coal storage silo.

   Response: Since we propose to change to weight percent for blending purposes, determining the percent of the blend will be straight forward. The petroleum coke will be fed onto the reclaim conveyor via the temporary hopper and conveyor. The petroleum coke will be blended, by weight, with coal at the transfer "crusher building" in the surge bin. The tonnage of petroleum coke to establish the percentage (up to 20%) will be determined based on the feeder rate. The petroleum coke will be weighed by belt scale to establish the feeder rate. The coal is fed to the transfer "crusher building" surge bin via a separate belt. The tonnage of coal will be determined based on the feeder rate. The coal will be weighed by belt scale to establish the feeder rate. Records will be kept on hourly petroleum coke and coal feed rates as well as belt scale calibrations. These records will be maintained on site.

3. Will the sulfur content of the petroleum coke or the blend ever exceed 4 percent, by weight?

   Response: Although the sulfur content of the petroleum coke may exceed 4 percent, SJRPP proposes that the sulfur content of the petroleum coke and coal blend shall not exceed 4 percent by weight to maintain consistency with the existing above referenced permits. (See pages 25, 26, 27, & 28 of the Application)

4. Please describe the procedures that can be implemented by the facility for an inspector to determine if the facility is in compliance with the different scenarios for SO2 removal efficiency. Describe how the proposed conditions for SO2 are enforceable as a practical matter.

   Response: SJRPP proposes to demonstrate compliance in the same manner as currently required by 40 CFR 60 subpart Da, (i.e. 30 day rolling average method). As referenced in Attachment 1 Section 2.1 Item 6 of the application, SJRPP Units 1 & 2 feature an inlet continuous emission monitoring system (CEMS) to monitor inlet SO2 levels prior to the flue gas desulfurization system (FGDS) as required by 40 CFR Subpart Da and an outlet CEMS which records SO2 emissions as required by Subpart Da and 40 CFR Part 75. These SO2 data are quality assured pursuant to Subpart Da and Part 75 requirements. The percent reduction requirements and the SO2 emissions limitations for coals blended with petroleum coke shall be ensured by operating in accordance with the data from the inlet and outlet CEMS. The sulfur content of the coal shall be ensured by utilizing the "as received" coal analytical data or on-site sampling and analysis.

FGDS unit operators monitor the real-time percent reductions and SO2 lb/MMBtu values from the quality assured inlet and outlet SO2 analyzers. The unit operators shall adjust removal efficiency based on these real-time inlet and outlet SO2 values as dictated by the coal's representative sulfur content

Please refer to Attachment 1, Section 2.1 a and b of the Application. Based on the coal's representative sulfur content, the FGDS unit operator shall adjust the real-time removal efficiency to ensure the combined emission limit based on Table 2 of the Application which will be available to the FGDS unit operator.

The above mentioned data will be available for inspectors on site. In addition quarterly CEMs submittals are made to the Department as part of our Title IV reporting requirements.

5. Please quantify the CO emissions in ppm, lb/hr and TPY for the past two years for the two units. Provide a range of CO emissions based on the historical data. How will you assure the Department that this range and the total annual emissions for the past two years are not exceeded when burning a blend of petroleum coke and coal?

Response: CO emissions from the SJRPP units vary greatly depending on the coal type and specific unit operating parameters. It should be noted that unlike many coal plants SJRPP burns a great variety of coals which results in a significant variability in CO emissions. 1995 data from non-certified CO-monitors indicate that daily maximum hourly CO values ranged from less than 10 ppm to 511 ppm for Unit 1 and less than 10 ppm to 484 ppm for Unit 2. It is noted that we did not optimize combustion parameters during our petroleum coke test burn and we expect a significant decrease in CO emissions during future petroleum coke burns. We are confident that these emissions will be well within the above mentioned ranges.

Currently, we do not feel that there is sufficient credible data to develop a meaningful TPY CO number for our units. It is noted, however, that 511 ppm corresponds to approximately to 3194 lb/hr. This CO issue is further addressed on page 6 of attachment one of our application.

Please contact Jay Worley at (904) 751-7729 if you have any additional questions. We appreciated your efforts to expedite the approval of this project.

Sincerely,

Robert H. Kaufman for

Richard Breitmoser, P.E.
Vice President
Environmental Health & Safety Group

/pja

cc: Hamilton S. Oven, Siting Coordinator, DEP
Jay Worley, SJRPP

bcc: S. Serrian w/o attachments
J. Jackson "
P. Smith "
A. Cobb "
L. Bradley "
B. Kappelmann "
C. Maire "
B. Para "
J. Alves, (HGSS) w/attachments
K. Koskey (KBN) "
S. Arif "
File "

Segment Description and Rate Information: Segment 2 of 2

1. Segment Description (Process/Fuel Type and Associated Operating Method/Mode): Coal and Petroleum Coke (Weight Basis)	
2. Source Classification Code (SCC): 1-01-001-04	
3. SCC Units: Tons	
4. Maximum Hourly Rate: 243	5. Maximum Annual Rate: 2,129,013
6. Estimated Annual Activity Factor:	
7. Maximum Percent Sulfur: 4	8. Maximum Percent Ash: 18
9. Million Btu per SCC Unit: 25	
10. Segment Comment: Maximum hourly and annual rate based on maximum percentage of petroleum coke when co-firing (i.e., 20% weight). Heat content and sulfur content of petroleum coke based on typical values of 29.6 MMBtu/ton and 6% sulfur. (See Segment 1 of 2 for coal values). Maximum Percent Ash: <18. Million Btu per SCC Unit: 25.3.	

E. POLLUTANT INFORMATION

For the emissions unit addressed in this Emissions Unit Information Section, a separate set of pollutant information must be completed for each pollutant required to be reported. See instructions for further details on this subsection of the Application for Air Permit.

Pollutant Potential/Estimated Emissions: Pollutant 1 of 1

1. Pollutant Emitted: SO_2
2. Total Percent Efficiency of Control: 95 %
3. Primary Control Device Code: 067
4. Secondary Control Device Code:
5. Potential Emissions: 575.5 lbs/hr 2,521 tons/yr
6. Synthetically Limited? [ ] Yes [x] No
7. Range of Estimated Fugitive/Other Emissions: [ ] 1 [ ] 2 [ ] 3 ________ to ________ tons/yr
8. Emission Factor: 0.4 lb/MMBtu Reference: See Comment
9. Emissions Method Code (check one): [ ] 1 [ ] 2 [ ] 3 [ ] 4 [ ] 5
10. Calculation of Emissions: 6,144 MMBtu/hr x 0.234 % heat input (Pet Coke) x 0.4 lb/MMBtu = 575.5 lb/hr
11. Pollutant Potential/Estimated Emissions Comment: Emission Factor Reference: Proposed Emission Limit for Petroleum Coke only. Potential emissions for petroleum coke only and based on assuring no increase in 'actual emissions' based on the definition in 62-212.200 (See Attachment 1).

Emissions Unit Information Section 1 of 2
Allowable Emissions (Pollutant identification on front page)

A.

1. Basis for Allowable Emissions Code:
   RULE
2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units:
   0.4 lb/MMBtu
4. Equivalent Allowable Emissions: 575.5 lbs/hr 2,521 tons/yr
5. Method of Compliance:
   CEMS
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode):
   Proposed emission limit for petroleum coke only. See Attachment 1R.

B.

1. Basis for Allowable Emissions Code:
2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units:
4. Equivalent Allowable Emissions: lbs/hr tons/yr
5. Method of Compliance:
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode):

Segment Description and Rate Information: Segment 2 of 2

1. Segment Description (Process/Fuel Type and Associated Operating Method/Mode): Coal and Petroleum Coke (Weight Basis)	
2. Source Classification Code (SCC): 1-01-001-04	
3. SCC Units: Tons	
4. Maximum Hourly Rate: 243	5. Maximum Annual Rate: 2,129,013
6. Estimated Annual Activity Factor:	
7. Maximum Percent Sulfur: 4	8. Maximum Percent Ash: 18
9. Million Btu per SCC Unit: 25	
10. Segment Comment: Maximum hourly and annual rate based on maximum percentage of petroleum coke when co-firing (i.e., 20% weight). Heat content and sulfur content of petroleum coke based on typical values of 29.6 MMBtu/ton and 6% sulfur. (See Segment 1 of 2 for coal values). Maximum Percent Ash: <18. Million Btu per SCC Unit: 25.3.	

E. POLLUTANT INFORMATION

For the emissions unit addressed in this Emissions Unit Information Section, a separate set of pollutant information must be completed for each pollutant required to be reported. See instructions for further details on this subsection of the Application for Air Permit.

Pollutant Potential/Estimated Emissions: Pollutant 1 of 1

1. Pollutant Emitted: SO2
2. Total Percent Efficiency of Control: 95 %
3. Primary Control Device Code: 067
4. Secondary Control Device Code:
5. Potential Emissions: 575.5 lbs/hr 2,521 tons/yr
6. Synthetically Limited? [ ] Yes [x] No
7. Range of Estimated Fugitive/Other Emissions: [ ] 1 [ ] 2 [ ] 3 ________ to ________ tons/yr
8. Emission Factor: 0.4 lb/MMBtu Reference: See Comment
9. Emissions Method Code (check one): [ ] 1 [ ] 2 [ ] 3 [ ] 4 [ ] 5
10. Calculation of Emissions: 6,144 MMBtu/hr x 0.234 % heat input (Pet Coke) x 0.4 lb/MMBtu = 575.5 lb/hr
11. Pollutant Potential/Estimated Emissions Comment: Emission Factor Reference: Proposed Emission Limit for Petroleum Coke only. Potential emissions for petroleum coke only and based on assuring no increase in 'actual emissions' based on the definition in 62-212.200 (See Attachment 1).

Allowable Emissions (Pollutant identification on front page)

A.

1. Basis for Allowable Emissions Code: RULE
2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: 0.4 lb/MMBtu
4. Equivalent Allowable Emissions: 575.5 lbs/hr 2,521 tons/yr
5. Method of Compliance: CEMS
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode): Proposed emission limit for petroleum coke only. See Attachment 1R.

B.

1. Basis for Allowable Emissions Code:
2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units:
4. Equivalent Allowable Emissions: lbs/hr tons/yr
5. Method of Compliance:
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode):

ATTACHMENT 1R

ATTACHMENT 1

1.0 PROJECT DESCRIPTION

The St. Johns River Power Park (SJRPP) proposes to co-fire a mixture of up to 20 percent petroleum coke by weight with coal in a manner that would ensure that there is not a significant net increase in actual emissions of any regulated pollutant and, therefore, the Prevention of Significant Deterioration (PSD) Rules in 62-212.400, Florida Administrative Code (F.A.C.) would not apply. This would be accomplished through a limitation on sulfur dioxide (SO_2) emissions when co-firing petroleum coke that includes both an emission limit and a percent SO_2 reduction requirement. In addition, SJRPP proposes to accept a condition for carbon monoxide (CO) that would demonstrate that an net significant emission increase would not occur.

This permit application is associated with a modification request of the site certification for the units (PA 81-13). Approval from the FDEP is being sought to use up to 20 percent (weight basis) of petroleum coke with coal. No new facilities or equipment are required to burn petroleum coke. Minor amendments to PSD permit are required. There will be no substantial changes made in the fuel handling facilities or the emission units to accommodate co-firing of petroleum coke. A temporary hopper and conveyor will be used to load petroleum coke with coal on the reclaim conveyor prior to transporting to the crusher house. From the crusher house, the blended fuel will be conveyed to the coal storage silos. Petroleum coke can be co-fired with coal as soon as approval is obtained from FDEP and it is received in the coal yard.

2.0 TRIAL BURN TEST RESULTS

A trial test burn for co-firing petroleum coke and coal was authorized by the Florida Department of Environmental Protection (FDEP) and conducted August 8-19, 1995. A copy of the trial test burn results is attached. A summary of the trial test burn results and a statistical comparison of the baseline tests (coal only) and co-firing petroleum coke and coal are presented in Table 1. A statistical analysis was performed using Appendix C to Part 60 (of 40 CFR).

The results of the trial test burn and the statistical analysis indicate that there are no emission rate increases for particulate matter or nitrogen oxides. The emission rates of sulfur dioxide, sulfuric acid mist, and CO were lower in the baseline tests than in the tests performed while the unit was co-firing petroleum coke and coal. The remainder of this attachment discusses these pollutants.

2.1 SULFUR DIOXIDE

A federally enforceable permit condition is proposed that prevents PSD applicability by preventing actual SO_2 emissions associated with the petroleum coke fraction of the blended fuel from exceeding past actual SO_2 emissions associated with burning coal. In this manner, there will be no prospective increase in SO_2 emissions caused by the proposed change (i.e., utilization of petroleum coke). Pursuant to EPA's June 21, 1992, WEPCO regulations (57 Federal Register 32314), increases in air emissions not caused by proposed changes must be excluded from steam electric power plants' future actual emissions in assessing PSD applicability. EPA emphasized in the preamble statement that new source review "applies only where the emissions increase is cause by the change" [57 Federal Register 32325]. The approach comports with the WEPCO regulations and corresponding state rules by eliminating the possibility that the petroleum coke portion of prospective fuel blends will exceed "past actual" SO_2 emissions associated with coal burning. Consistent with the WEPCO regulations, future increases in SO_2 emissions caused solely by enhanced electricity demand or caused by permissible variations in coal sulfur content should not count toward PSD applicability.

The emission limitation has the following components:

a. When blends of petroleum coke and coal with a sulfur content of up to or equal to 2 percent are fired in Units 1 or 2, the SO_2 emissions shall not exceed 0.55 pound per million British thermal units (lb/MMBtu) <u>and</u> a minimum of 76 percent reduction in the flue gas desulfurization system.

b. When co-firing petroleum coke with coals having a sulfur content between 2 and 3.63 percent, the emission limitation shall be based on the following formula:

SO_2 emission limit (lb/MMBtu) = (0.2 x C/100) + 0.4
where: C = percent of coal co-fired on a heat input basis.

c. When coals with a sulfur content greater than 3.63 percent are co-fired with petroleum coke, the SO_2 emissions shall not exceed the following formula:

SO_2 emission limit (lb/MMBtu) = (0.1653 x C x S - 0.4 x C + 40) x 1/100
where: C = percent of coal co-fired on a heat input basis

d. The maximum SO_2 emission rate when firing petroleum coke shall not exceed 0.676 lb/MMBtu.

e. Compliance with the SO_2 emissions limit shall be based on a 30-day rolling average for those days when petroleum coke is fired. Any use of petroleum coke during a 24-hour period shall be considered 1 day of the 30-day rolling average. The 30-day rolling average shall be calculated according to the New Source Performance Standards (NSPS) codified in 40 CFR Part 60 Subpart Da, except as noted above.

The proposed emission limits for SO_2 were developed from the two fundamental requirements of the PSD approval and the specific conditions of the site certification and to assure no net increase in annual emissions. The PSD approval and site certification require that the NSPS Subpart Da be met and that emissions do not exceed 0.76 lb/MMBtu (30-day rolling average). The emission limits proposed for co-firing are supported by the following rationale:

1. The NSPS codified in 40 CFR Part 60 Subpart Da requires, in the range of coals to be fired, either 0.6 lb/MMBtu or a 70 percent reduction in the potential SO_2 combustion concentration. For coals with a sulfur content greater than 1.2 percent, the 0.6 lb/MMBtu emission limit would govern. For coals with sulfur contents of 1.2 percent or less, the 70 percent reduction requirement would govern. This is illustrated in the attached Table 2 which presents in the sixth and seventh columns the NSPS emission limit and the percent SO_2 removals as a function of the coal sulfur content (first column). In terms of practical application, under Subpart Da: (1) when the inlet air to the scrubber has SO_2 concentrations under 2.0 lb/MMBtu, 70 percent SO_2 reduction is required; (2) when the inlet SO_2 concentration is higher than 2.0 but less than 6.0 lb/MMBtu, required SO_2 scrubbing must result in emissions of 0.6 lb/MMBtu or less; (3) at higher concentrations, 90 percent removal is required. It should be noted that the facility has a 0.76 lb SO_2/MMBtu emission limit established as BACT for coal firing. The proposed emission limit for co-firing petroleum coke and coal could not exceed this limit, since this is inherent in the proposed limit.
2. The representative actual annual SO_2 emission rate for Units 1 and 2 over the last 2 years has been 0.4 lb/MMBtu. By ensuring that the emission rate when firing petroleum coke does not exceed 0.4 lb/MMBtu, the "representative actual annual emissions" as defined in 40 CFR 52.21(b)(33) would not exceed the past actual

emissions. To achieve a 0.4 lb/MMBtu emission rate with the typical sulfur content for petroleum coke (e.g., 6 percent), a 95 percent reduction is required. This is shown on the last column of the Table 2.

3. Except for coals with a sulfur content of greater than 2 percent, the proposed percent reduction requirement and the emission limit are based on co-firing 20 percent petroleum coke with coal (on a weight basis). This is the worst-case mixture proposed and ensures that when co-firing lower percentages of petroleum coke with coal, the resulting emission rate would be lower than could be allowed by meeting only the NSPS and the "actual" emission rate. For example, if a 10 percent mixture of petroleum coke is co-fired with a 1.2 percent sulfur coal, then the resulting emissions rate to meet NSPS and 0.4 lb/MMBtu would be 0.58 lb/MMBtu. In contrast, the proposed condition would limit the SO_2 emissions to 0.55 lb/MMBtu.
4. The effect of the proposed SO_2 emission limitation is shown on Table 2 (second and third columns). As shown, for coals with sulfur content less than 1.2 percent, the 76 percent reduction requirement would produce emission rates less than 0.55 lb/MMBtu while meeting the NSPS reduction requirement of 70 percent and the "actual" emission rate of 0.4 lb/MMBtu for petroleum coke. For coals with a sulfur content of 1.2 to 2 percent, the proposed emission limit of 0.56 lb/MMBtu would meet the NSPS limit of 0.6 lb/MMBtu for coal and 0.4 lb/MMBtu for petroleum coke.
5. The equation for an SO_2 emission limit for coals above 2 percent sulfur content would allow some flexibility for petroleum coke/coal mixtures. This formula would be applicable for sulfur contents from 2.0 to 3.63 percent, since coals in this range would be required to meet the 0.6 lb/MMBtu limit in Subpart Da. The proposed equations for SO_2 emission limitations for coal above 2 percent sulfur content would allow some flexibility for petroleum coke/coal mixtures (see Table 3 for derivation of equations). The equation in Paragraph b above will achieve compliance with the governing Subpart Da limit of 0.6 lb/MMBtu and 0.4 lb/MMBtu for petroleum coke. The equation in Paragraph c above accounts for the governing Subpart Da requirement of 90 percent SO_2 reduction and 0.4 lb/MMBtu for petroleum coke. The maximum SO_2 emission rate associated with firing only coal, regardless of coal sulfur content, cannot exceed 0.76 lb/MMBtu as required by PSD and Power Plant Siting

Act (PPSA) approval. Therefore, mixtures of petroleum coke and coal can never exceed 0.676 lb/MMBtu.

6. SJRPP Units 1 and 2 feature an inlet continuous emission monitoring system to monitor inlet SO_2 levels prior to the flue gas desulfurization system as required by Subpart Da and an outlet continuous emission monitoring system which records SO_2 emissions as required by Subpart Da and 40 CFR Part 75. These SO_2 data are quality assured pursuant to Subpart Da and Part 75 requirements. The percent reduction requirements and the SO_2 emissions limitations for coals blended with petroleum coke that have a sulfur content less than 3.63 percent shall be ensured by operating in accordance with the data from the inlet and outlet continuous emissions monitoring system. The sulfur content of the coal shall be ensured by utilizing the "as received" coal analytical data or onsite sampling and analysis.

The proposed emission limitation meets the letter and intent of the WEPCO regulations. Also, this condition comports with EPA's "federal enforceability" guidance because it is enforceable both as a matter of law and as a practical matter; simply put, this condition obviates the possibility of an increase in actual emissions attributable to petroleum coke. Moreover, this proposal comports with good environmental policy. As shown in Figures 1 and 2, under the proposed permit condition, co-firing petroleum coke will be subject to lower emissions limitations than the limitations applicable when utilizing only coal. These graphs compare the emission limits and reduction percentages currently applicable to coal firing and proposed for petroleum coke co-firing. With the proposed permit condition, co-firing petroleum coke will not require PSD analysis pursuant to Rules 62-212.400 and 62.212.200(2)(d), F.A.C.

2.2 SULFURIC ACID MIST

The trial test values for sulfuric acid mist were a direct result of an associated increase in SO_2 emissions. Table 4 presents a comparison of the SO_2 and SO_3 emissions between the baseline tests and the co-firing test. The ratios of the blend to baseline test results are 1.78 and 1.70 for SO_2 and SO_3 emissions, respectively. This indicates that the SO_3 increase was in the relatively same proportion for both SO_3 and SO_2 (actually slightly greater for SO_2). In addition, the amount of SO_2 removal for both the baseline test and blend test was almost identical at about 73 percent.

The proposed SO_2 emission limit, if implemented during the test burn, would have ensured lower SO_2 emissions and concomitantly lower SO_3 emissions that would ensure no significant increase in the emission rates for both pollutants. Overall reduction in SO_2 emissions would have likely been 20 to 30 percent higher. For these reasons, no condition for sulfuric acid mist should be required.

2.3 ,CARBON MONOXIDE

The CO emissions during the baseline tests were lower than those observed during the blend tests. Since there was no attempt to control CO emissions during the co-firing tests, the combustion conditions were not "fine tuned" to optimize combustion of the petroleum coke and coal blend. Many factors, such as the grindability of the petroleum coke/coal blend and combustion controls (e.g., oxygen concentrations, NO_x control systems, load, etc.) can significantly influence CO concentrations. Data from other petroleum coke/coal co-firing test burns indicate no changes in CO emission rates. In addition, a review of the last several months of CO data from the SJRPP indicates CO values in the range reported for the co-firing test burn. For these reasons, SJRPP proposes to optimize combustion of co-firing petroleum coke and coal to ensure no net increase in emissions. A condition is proposed that has been issued in other Department permits approving co-firing of petroleum coke and coal:

(a) The applicant shall maintain and submit to the Department on an annual basis for a period of 5 years from the date the unit is co-fired with petroleum coke, information demonstrating that the co-firing did not result in significant emission increases of CO. The CO emissions shall be based on test results using EPA Method 10.

Table 1. Statistical Analysis of Petroleum Coke Trial Burn, St. John's River Power Park

Test Case	Date	PM (lb/hr)	SO3 (ppm)	CO (ppm)	NOx out (lb/MMBtu)	SO2 in (lb/MMBtu)	SO2 out (lb/MMBtu)
Baseline	07/18/95	44.14	6.96	10.29	0.468	1.029	0.283
Baseline	07/19/95	21.50	5.19	45.16	0.502	1.026	0.282
Baseline	07/20/95	64.92	5.55	67.00	0.474	1.031	0.282
Baseline	08/08/95	61.85	7.04	21.15	0.549	0.973	0.270
	Average	48.1	6.19	35.9	0.498	1.015	0.279
	Std. Dev.	20.0	0.95	25.3	0.0369	0.0279	0.0062
	Sample Var	398.4	0.91	642.1	0.0014	0.0008	0.0000
	n	4	4	4	4	4	4
Blend	08/11/95		7.54	312.96	0.502	1.636	0.457
Blend	08/12/95		9.21	497.58	0.494	1.709	0.485
Blend	08/13/95		14.03	745.64	0.463	1.728	0.482
Blend	08/14/95	80.76			0.498	1.757	0.477
Blend	08/15/95	42.95			0.503	1.730	0.471
Blend	08/16/95	28.98			0.535	1.720	0.477
Blend	08/17/95	63.28			0.559	1.938	0.521
Blend	08/18/95		11.37	467.90	0.498	2.244	0.566
Blend	08/19/95	23.47			0.470	2.376	0.545
	Average	47.9	10.54	506.0	0.502	1.871	0.498
	Std. Dev.	24.0	2.81	179.1	0.030	0.264	0.037
	Sample Var	573.9	7.88	32071.4	0.001	0.070	0.001
	n	5	4	4	9	9	9
Degrees of Freedom		7	6	6	11	11	11
	t prime at 95%	1.895	1.943	1.943	1.796	1.796	1.796
	Sp	22.33	2.10	127.89	0.032	0.225	0.032
	t calc	-0.0143188	2.937	5.198	0.220	6.322	11.406
	Result	OK	Sig Diff	Sig Diff	OK	Sig Diff	Sig Diff

Table 2. Combined Emissions Limit and Scrubber Efficiency for Co-firing Petroleum Coke and Coal at St. Johns River Power Park (Revised)

Coal Sulfur Content	Combined Emission Limit (lb/mmBtu)	Minimum Combined Scrubber Efficiency	Uncontrolled Emissions Coal SO2 (lb/mmBtu)	Uncontrolled Emissions Pet Coke SO2 (lb/mmBtu)	Coal SO2 NSPS Limit (lb/mmBtu)	Coal SO2 Removal (lb/mmBtu)	Pet Coke SO2 Removal (lb/mmBtu)
0.80%	0.40	75.87%	1.32	8.11	0.40	70.00%	95.07%
0.90%	0.44	75.87%	1.49	8.11	0.45	70.00%	95.07%
1.00%	0.47	75.87%	1.65	8.11	0.50	70.00%	95.07%
1.10%	0.51	75.87%	1.82	8.11	0.55	70.00%	95.07%
1.20%	0.55	75.87%	1.98	8.11	0.60	70.00%	95.07%
1.30%	0.55	77.46%	2.15	8.11	0.60	72.08%	95.07%
1.40%	0.55	78.99%	2.31	8.11	0.60	74.07%	95.07%
1.50%	0.55	80.31%	2.48	8.11	0.60	75.80%	95.07%
1.60%	0.55	81.47%	2.64	8.11	0.60	77.31%	95.07%
1.70%	0.55	82.49%	2.81	8.11	0.60	78.65%	95.07%
1.80%	0.55	83.40%	2.98	8.11	0.60	79.83%	95.07%
1.90%	0.55	84.21%	3.14	8.11	0.60	80.89%	95.07%
2.00%	0.55	84.95%	3.31	8.11	0.60	81.85%	95.07%
2.10%	0.55	85.61%	3.47	8.11	0.60	82.71%	95.07%
2.20%	0.55	86.21%	3.64	8.11	0.60	83.50%	95.07%
2.30%	0.55	86.76%	3.80	8.11	0.60	84.22%	95.07%
2.40%	0.55	87.26%	3.97	8.11	0.60	84.88%	95.07%
2.50%	0.55	87.72%	4.13	8.11	0.60	85.48%	95.07%
2.60%	0.55	88.15%	4.30	8.11	0.60	86.04%	95.07%
2.70%	0.55	88.55%	4.46	8.11	0.60	86.56%	95.07%
2.80%	0.55	88.92%	4.63	8.11	0.60	87.04%	95.07%
2.90%	0.55	89.26%	4.79	8.11	0.60	87.48%	95.07%
3.00%	0.55	89.58%	4.96	8.11	0.60	87.90%	95.07%
3.10%	0.55	89.88%	5.12	8.11	0.60	88.29%	95.07%
3.20%	0.55	90.16%	5.29	8.11	0.60	88.66%	95.07%
3.30%	0.55	90.42%	5.45	8.11	0.60	89.00%	95.07%
3.40%	0.55	90.67%	5.62	8.11	0.60	89.32%	95.07%
3.50%	0.55	90.90%	5.79	8.11	0.60	89.63%	95.07%
3.60%	0.55	91.12%	5.95	8.11	0.60	89.92%	95.07%
3.63%	0.55	91.19%	6.00	8.11	0.60	90.00%	95.07%
3.70%	0.56	91.19%	6.12	8.11	0.61	90.00%	95.07%
3.80%	0.57	91.19%	6.28	8.11	0.63	90.00%	95.07%
3.90%	0.59	91.19%	6.45	8.11	0.64	90.00%	95.07%
4.00%	0.60	91.19%	6.61	8.11	0.66	90.00%	95.07%

Assumptions:
- 12,100 Btu/lb for Coal
- 14,800 Btu/lb for Petroleum Coke
- 6% sulfur content of Petroleum Coke
- 20% Petroleum Coke firing (Weight basis)
- 0.40 lb/mmBtu for Petroleum Coke

Table 3. Derivation of Formulas (Page 1 of 2)

Fundamental Requirements:

1. Coal - Meet NSPS Subpart Da and BACT Emission Limit
   a. 0.6 lb / MMBtu or 70% SO_2 Reduction (NSPS),
   b. 1.2 lb / MMBtu or 90% SO_2 Reduction (NSPS), and
   c. 0.76 lb / MMBtu (30-day rolling average).

2. Petroleum Coke - Meet 0.4 lb / MMBtu; Equivalent to 95% Reduction

   Calculation: $\frac{0.06 \text{ lb S}}{\text{lb fuel}} \times \frac{\text{lb fuel}}{14{,}800 \text{ Btu}} \times \frac{2 \text{ lb } SO_2}{\text{lb S}} \times \frac{10^6}{\text{MM}} \times (1 - 0.95)$

   $= 0.4 \text{ lb / MMBtu}$

Proposed Limits:

1. Coals - ≤2% Sulfur; Assume 20% *(by weight)* Petroleum Coke Co-Firing at All Times
   a. NSPS = 0.6 lb / MMBtu

      Calculation: $\frac{0.0121 \text{ lb S}}{\text{lb fuel}} \times \frac{\text{lb fuel}}{12{,}100 \text{ Btu}} \times \frac{2 \text{ lb } SO_2}{\text{lb S}} \times \frac{10^6}{\text{MM}} \times (1 - 0.7)$

      $= 0.6 \text{ lb / MMBtu}$
   b. Petroleum Coke = 0.4 lb / MMBtu
   c. *Coal Heat Input = 0.8 x 12,100 Btu / lb = 9,680 Btu / lb-fuel (76.6%)*

      Petroleum Coke Heat Input = 0.2 x 14,800 Btu / lb = 2,960 Btu / lb-fuel (23.4%)

      12,640 Btu / lb-fuel (100%)
   d. *Result:* $\left(\frac{76.6}{100} \times 0.6 \text{ lb / MMBtu}\right) + \left(\frac{23.4}{100} \times 0.4 \text{ lb / MMBtu}\right)$

      = 0.55 lb / MMBtu and 76% reduction

2. Coals >2% Sulfur and ≤ 3.63% Sulfur; Variable Amount of Petroleum Coke
   a. NSPS = 0.6 lb / MMBtu

      Calculation: $\frac{3.63 \text{ lb S}}{100 \text{ lb fuel}} \times \frac{\text{lb fuel}}{12{,}100 \text{ Btu}} \times \frac{2 \text{ lb } SO_2}{\text{lb S}} \times \left(1 - \frac{90}{100}\right)$

      $= 0.6 \text{ lb / MMBtu}$
   b. Petroleum Coke = 0.4 lb / MMBtu

Table 3. Derivation of Formulas (Page 2 of 2)

Proposed Limits, continued:

c. Let C = % Coal Fired *(Btu basis)*

Equation: $$\left(\frac{C}{100} \text{ x } 0.6 \text{ lb / MMBtu}\right) + \left[\left(1 - \frac{C}{100}\right) \text{ x } 0.4 \text{ lb / MMBtu}\right]$$

$$SO_2 \text{ Limit} = \frac{0.6C}{100} - \frac{0.4C}{100} + 0.4 = \frac{0.2C}{100} + 0.4$$

3. Coals > 3.63% Sulfur; Variable Amount of Petroleum Coke
   a. NSPS = 90% Reduction
   b. Petroleum Coke = 0.4 lb / MMBtu
   c. Let C = % Coal Fired *(Btu basis)* and S = % Sulfur in Coal

Equation: $$\left[\frac{C}{100} \text{ x } \frac{S}{100} \text{ x } \frac{1}{12{,}100} \text{ x } 2 \text{ x } \left(1 - \frac{90}{100}\right) \text{ x } 10^6\right]$$

$$+ \left[\left(1 - \frac{C}{100}\right) \text{ x } 0.4\right]$$

$$= \left(\frac{C}{100} \text{ x S x } 0.1653\right) + \left(0.4 - 0.4 \text{ x } \frac{C}{100}\right)$$

$$SO_2 \text{ Limit} = \frac{1}{100} \text{ x } (0.1653 \text{ x C x S} - 0.4C + 40)$$

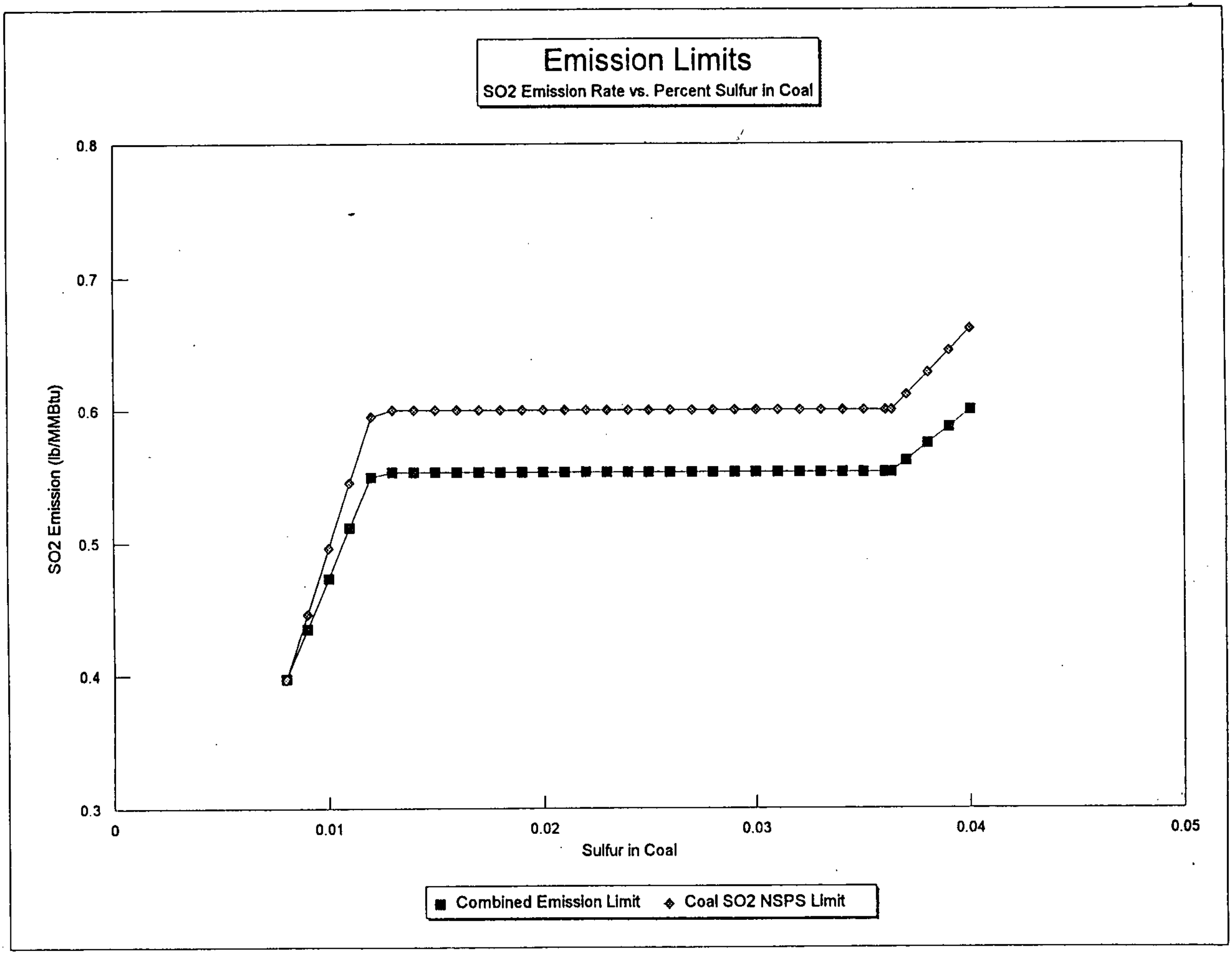
Example: 80% Coal *(Btu basis)* and 3.8% Sulfur

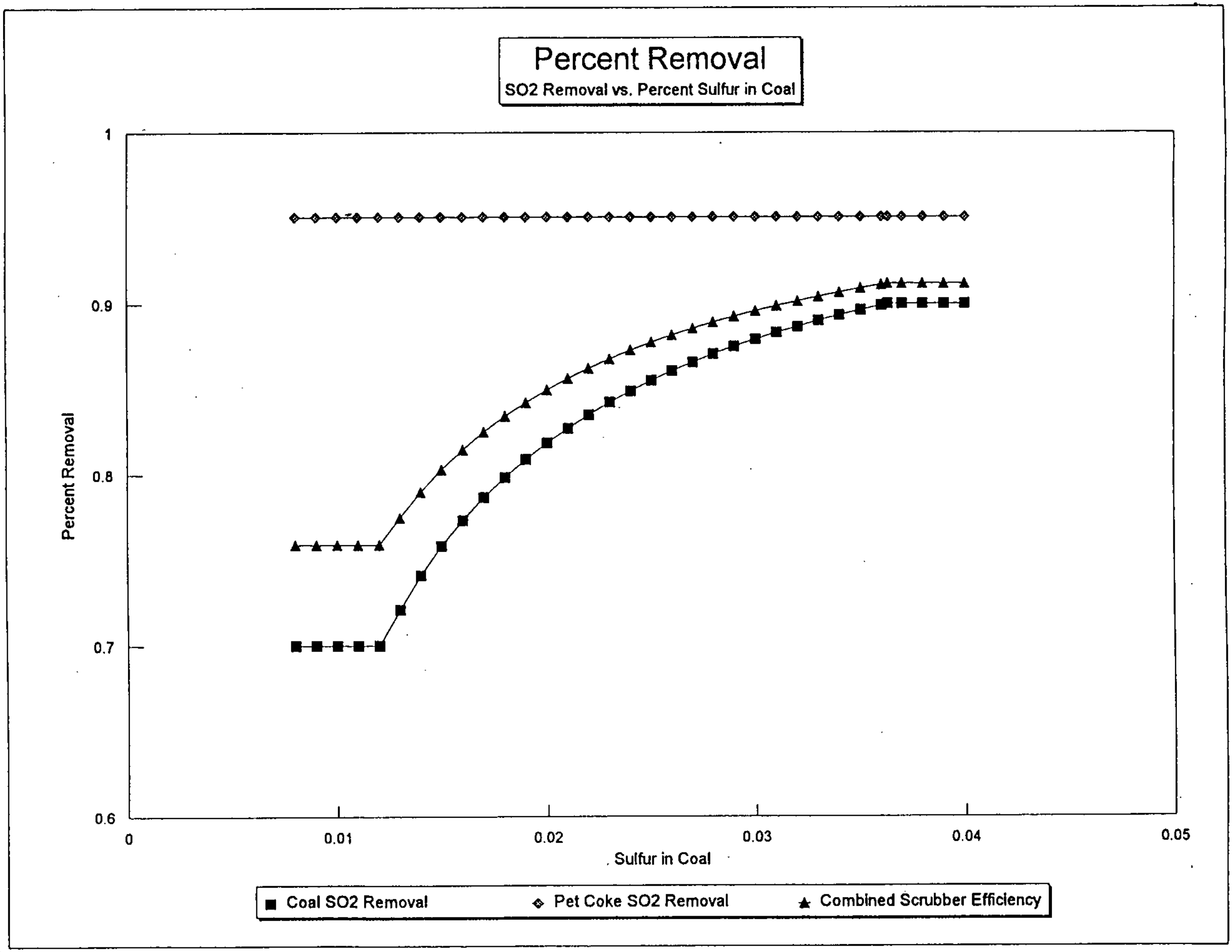
$$(0.1653 \text{ x } 80 \text{ x } 3.8 - 0.4 \text{ x } 80 + 40) \text{ x } \frac{1}{100} = 0.58 \text{ lb / MMBtu}$$

4. Maximum Limit When Co-Firing
   a. Coal at 0.76 lb / MMBtu, and
   b. Petroleum Coke at 0.4 lb / MMBtu

   Calculation:

$$\left(\frac{76.6}{100} \text{ x } 0.76 \text{ lb / MMBtu}\right) + \left(\frac{23.4}{100} \text{ x } 0.4 \text{ lb / MMBtu}\right) = 0.676 \text{ lb / MMBtu}$$


Emission Limits
SO2 Emission Rate vs. Percent Sulfur in Coal
SO2 Emission (lb/MMBtu)
0.8
0.7
0.6
0.5
0.4
0.3
0
0.01
0.02
0.03
0.04
0.05
Sulfur in Coal
Combined Emission Limit
Coal SO2 NSPS Limit



Percent Removal
SO2 Removal vs. Percent Sulfur in Coal
1
0.9
0.8
0.7
0.6
Percent Removal
0
0.01
0.02
0.03
0.04
0.05
Sulfur in Coal
Coal SO2 Removal
Pet Coke SO2 Removal
Combined Scrubber Efficiency