SEMINOLE ELECTRIC COOPERATIVE INCORPORATED

DEPARTMENT OF ENVIRONMENTAL PROTECTION

NOV 14 1996

RECEIVED

NOV 18 1996

BUREAU OF AIR REGULATION

November 11, 1996

Mr. Hamilton S. Oven, Administrator
Office of Siting Coordination
Department of Environmental Protection
2720 Blairstone Road, MS-48
Tallahassee, Florida 32399

Re: Seminole Electric Cooperative, Inc.
PA 78-10
Proposed Agreement to Modify Power Plant Certification

Dear Mr. Oven:

Pursuant to Section 403.516(1)(b), Florida Statutes, Seminole Electric Cooperative, Inc. ("SECI") respectfully files this Proposed Agreement to Modify the Power Plant Siting Act ("PPSA") Certification governing its existing Power Plant, Units 1 and 2, located north of Palatka in Putnam County. Enclosed also is a check for $10,000.00 as payment of the modification fee prescribed by Chapter 403.518, F.S.

The Governor and Cabinet, sitting as the Siting Board, on September 18, 1979 issued a Certification Order authorizing construction and operation of the referenced power plant, subject to specified conditions. The Conditions of Certification approved by the Siting Board have, from time to time, been the subject of modifications. With this Proposed Agreement to Modify Power Plant Certification, SECI seeks permission to combust a blend of petroleum coke (30% by weight) with coal in Units 1 and 2, and to utilize No. 2 fuel oil for emergency reserve capacity during statewide energy shortages and for limited supplemental load. An explanation of the air emission issues associated with petroleum coke utilization is contained in Attachment A. Moreover, data from the petroleum coke performance test burn conducted at the Palatka Plant from November 28, 1995 to January 9, 1996 is on file with DEP in the Tallahassee office of the Division of Air Resources Management. The rationale and explanation for No. 2 fuel oil utilization is set forth in Attachment B. Based on all of this information, we are optimistic that all concerned will concur that these requested modifications will result in compliance with all applicable requirements.

SECI also requests that a new condition be included confirming that prospective changes to the Palatka Plant federally delegated or approved PSD, NPDES, or Title V permits will operate automatically as changes to the corresponding Conditions of Certification, subject to specified notice requirements if relief mechanisms are invoked or permit limits are relaxed.

SECI's proposed changes to the existing Conditions of Certification are included herein in Attachment C.

We are hopeful that the Department and the agencies and persons that are parties to the certification proceedings will be amenable to these proposals. In accordance with Section 403.516(1)(b), Florida Statutes, the Department may modify the Conditions of Certification if no party objects in writing within 45 days after notice by mail, and if no other person whose substantial interests will be affected by the modifications objects in writing within 30 days after issuance of public notice. If you or any of the parties have questions or comments concerning the matter raised in this Proposed Agreement, please call me at the number indicated above or Jim Alves of Hopping Green Sams and Smith at 904/222-7500.

We have forwarded copies of this Proposed Agreement by certified U.S. mail to the parties in the original certification proceedings, as indicated in the attached list.

Very truly yours,

M.P. Opalinski

M. P. Opalinski
Director of Environmental Affairs

MPO/

Enclosures

ATTACHMENT A

PETCOKE UTILIZATION

The primary consideration is whether co-firing petroleum coke at the Seminole Power Plant will cause a significant increase in air emissions. Because the proposed use of petcoke at the Seminole Power Plant will replace the current use of coal (in amounts up to 30 percent by weight), a significant net increase due to the use of petcoke will not occur as long as the emissions resulting from petcoke combustion, for each PSD regulated air pollutant, do not exceed the 2 year historical average coal emission rates.

The pollutants addressed by the PSD regulatory program with respect to significant emission rates are listed in Chapter 62-212, Table 212.400-2, F.A.C; these pollutants and their significant emission rates are shown on Table E-1. For the Seminole Power Plant, measured historical emission rates are obtainable for sulfur dioxide (SO_2), nitrogen oxides (NO_x), and particulate matter (PM) for each unit. SO_2 and NO_x are monitored using continuous emissions monitoring systems (CEMS). PM is monitored on an annual basis using EPA Reference Method 5B.

A screening assessment of PSD applicability was first conducted by evaluating the potential for petcoke/coal blends to cause an increase in emission rates in comparison to baseline coal based on the test burn results and fuel characteristics. For emissions of PSD pollutants which do not have any potential to increase, no further analysis was necessary. A further detailed evaluation of potential PSD applicability was conducted for emissions of PSD pollutants identified as having the potential to increase.

Because year-to-year variations in operating hours, load, or coal sulfur content are generally *not* considered operational changes and therefore do *not* constitute modifications under the PSD regulatory program, the comparison of actual emission rates was made on a pound of pollutant per million British thermal unit (lb/MMBtu) heat input basis. As indicated previously, the Seminole Power Plant is a baseload facility. The use of petcoke will not change the electrical generation capacity of the facility nor change its operating hours from what would have occurred if petcoke were not utilized. Hence, a comparison of actual emissions on a lb/MMBtu basis is the most appropriate measure because it effectively excludes permissible variations in operating hours and production rate. To develop actual emission rate changes in terms of the tons per year (tpy) values shown in Chapter 62-212, Table 212.400-2, F.A.C, average load and operating hours for calender years 1994 and 1995 were used for both the historical and future representative actual annual emissions.

A discussion of the actual emission rate change for each of the PSD pollutants listed on Table E-1 is provided in the following sections.

Sulfur Dioxide (SO_2)

Because of the potentially higher sulfur content of petcoke in comparison to baseline coal, a detailed analysis of PSD applicability based on historical emission rates was conducted. The average 1994/1995 historical SO_2 emission rates obtained from SECI's Annual Operating Reports (AORs) for Units 1 and 2 are 0.740 and 0.715 lb/MMBtu, respectively. It is noted that these actual rates are approximately 25 percent lower than the maximum SO_2 emission rate (i.e., equivalent to 0.994 lb/MMBtu, based on 90 percent removal efficiency during maximum plant heat input) authorized by SECI's current permits. SECI proposes to limit petcoke SO_2 emission rates, on a 30-day rolling average basis, to the historical values noted above. Compliance with the historical emissions values can be verified through mutually acceptable permit conditions in conjunction with fuel blend monitoring. The *maximum* allowable SO_2 emission rates (based on 3.0 percent sulfur coal over a 30-day rolling average period) for a 70/30 coal/petcoke blend are summarized in the following tables. The tables also show current authorized allowable SO_2 emission rates demonstrating that maximum allowable rates will decrease due to the use of coal/petcoke blends.

Table E-1. Significant Emission Rates for PSD Review

Pollutant	Emission Rate (tpy)	(lb/yr)
CO	100	
NO_x	40	
SO_2	40	
Ozone	40 (as VOC)	
PM (TSP)	25	
PM (PM_{10})	15	
Total reduced sulfur (including H_2S)	10	
Reduced sulfur compounds (including H_2S)	10	
Sulfuric acid mist	7	
Fluorides	3	
Vinyl chloride	1	
Lead		1,200
Mercury		200
Asbestos		14
Beryllium		0.8

Source: Chapter 62-212, Table 212.400-2, F.A.C.

Unit 1:

Fuel Type	Maximum Allowable SO_2 Emission Rates		
	(lb/MMBtu)[1]	(lb/hr)	(tpy)
70% Coal	0.994	4,822	21,121
30% Petcoke	0.740	1,718	7,525
70%/30% Coal/Petcoke Blend	0.912	6,540	28,645
100% Coal	0.994	7,130	31,229

Unit 2:

Fuel Type	Maximum Allowable SO_2 Emission Rates		
	(lb/MMBtu)[1]	(lb/hr)	(tpy)
70% Coal	0.994	4,822	21,121
30% Petcoke	0.715	1,660	7,270
70%/30% Coal/Petcoke Blend	0.904	6,482	28,391
100% Coal	0.994	7,130	31,229

[1] Rates shown are based on the maximum coal SO_2 emission rate (7,130 lb/hr) and maximum heat input (7,172 MMBtu/hr) for each unit. Depending on the unwashed coal sulfur content and level of coal washing, SO_2 emission rates may increase up to 1.2 lb/MMBtu for the 70% and 100% coal fuel types, 1.05 lb/MMBtu for 70%/30% coal/petcoke blend (Unit 1), and 1.04 lb/MMBtu for 70%/30% coal/petcoke blend (Unit 2) under other, lower load operating conditions. However, maximum allowable lb/hr and tpy SO_2 emission rates will not exceed the rates shown in the above tables.

Details of the SO_2 emission rate calculations for the values shown in the above summaries are documented in Tables E-2 and E-3 for Units 1 and 2, respectively.

The allowable emission rate summaries shown above represent *maximum* allowable rates; i.e., use of coal containing the highest authorized sulfur content and a 70/30 coal/petcoke blend. Because Units 1 and 2 are subject to NSPS Subpart Da, the allowable SO_2 emission rate for any given 30-day rolling average period due to coal combustion will vary with the sulfur content of the coal; i.e., a 90 percent overall SO_2 removal efficiency is required (including coal washing credit). Therefore, although the allowable SO_2 emission rate in terms of lb/MMBtu for the petcoke portion of the coal/petcoke blend will be fixed at the

Table E-2. Allowable SO_2 Emissions For Unit 1

Parameter	Symbol	Value	Units	Formula
Average 94/95 Coal SO2 Emission Rate from AORs:	CSO2	0.740	lb/MMBtu	
Allowable Coal SO2 Emission Rate	ACSO2	0.994	lb/MMBtu	
Maximum Unit Heat Input:	UHI	7,172	MMBtu/hr	
Coal Heating Value (HHV, dry)	HHVC	27.40	MMBtu/ton	
Petcoke Heating Value (HHV, dry)	HHVP	30.60	MMBtu/ton	
70/30 Coal/Petcoke Blend Heating Value (HHV, dry)	HHVB	28.36	MMBtu/ton	
Coal Weight Fraction of 70/30 Coal/Petcoke Blend	FC	0.70		
Petcoke Weight Fraction of 70/30 Coal/Petcoke Blend	FP	0.30		
70/30 Coal/Petcoke Blend Consumption at Maximum Heat Input	BC	252.89	ton/hr	BC = UHI / ((HHVC * FC) + (HHVP * FP))
Petcoke Portion of 70/30 Coal/Petcoke Blend Consumption at Maximum Heat Input	PC	75.87	ton/hr	PC = BC * FP
Petcoke Portion of 70/30 Coal/Petcoke Blend Consumption at Maximum Heat Input	PCHI	2,322	MMBtu/hr	PCHI = PC * HHVP
Petcoke Portion of 70/30 Coal/Petcoke Blend Consumption at Maximum Heat Input	PCHI	2,322	MMBtu/hr	PCHI = UHI / (1 + ((HHVC * FC) / (HHVP * FP))) (consolidated formula)
Petcoke Portion of 70/30 Coal/Petcoke Blend Consumption at Maximum Heat Input		32.37	% by heat input	(PCHI / UHI) * 100
Maxmum Allowable Petcoke SO2 Emission Rate	PSO2HI PSO2H PSO2A	0.740 1,718 7,525	lb/MMBtu lb/hr ton/yr	CSO2 CSO2 * PCHI PSO2H * (8,760 / 2,000)
Coal Portion of 70/30 Coal/Petcoke Blend Consumption at Maximum Heat Input	CCHI	4,850	MMBtu/hr	UHI - PCHI
Coal Portion of 70/30 Coal/Petcoke Blend Consumption at Maximum Heat Input		67.63	% by heat input	(CCHI / UHI) * 100
Maximum Allowable Coal SO2 Emission Rate	ACSO2 CSO2H CSO2A	0.994 4,822 21,121	lb/MMBtu lb/hr ton/yr	ACSO2 ACSO2 * CCHI CSO2H * (8,760 / 2,000)
Maximum Allowable 70/30 Coal/Petcoke Blend SO2 Emission Rate	BSO2H BSO2A BSO2HI	6,540 28,645 0.912	lb/hr ton/yr lb/MMBtu	PSO2H + CSO2H BSO2H * (8,760 / 2,000) BSO2H / UHI

Source: ECT, 1996.

Table E-3. Allowable SO_2 Emissions For Unit 2

Parameter	Symbol	Value	Units	Formula
Average 94/95 Coal SO2 Emission Rate from AORs:	CSO2	0.715	lb/MMBtu	
Allowable Coal SO2 Emission Rate	ACSO2	0.994	lb/MMBtu	
Maximum Unit Heat Input:	UHI	7,172	MMBtu/hr	
Coal Heating Value (HHV, dry)	HHVC	27.40	MMBtu/ton	
Petcoke Heating Value (HHV, dry)	HHVP	30.60	MMBtu/ton	
70/30 Coal/Petcoke Blend Heating Value (HHV, dry)	HHVB	25.38	MMBtu/ton	
Coal Weight Fraction of 70/30 Coal/Petcoke Blend	FC	0.70		
Petcoke Weight Fraction of 70/30 Coal/Petcoke Blend	FP	0.30		
70/30 Coal/Petcoke Blend Consumption at Maximum Heat Input	BC	252.89	ton/hr	BC = UHI / ((HHVC * FC) + (HHVP * FP))
Petcoke Portion of 70/30 Coal/Petcoke Blend Consumption at Maximum Heat Input	PC	75.87	ton/hr	PC = BC * FP
Petcoke Portion of 70/30 Coal/Petcoke Blend Consumption at Maximum Heat Input	PCHI	2,322	MMBtu/hr	PCHI = PC * HHVP
Petcoke Portion of 70/30 Coal/Petcoke Blend Consumption at Maximum Heat Input	PCHI	2,322	MMBtu/hr	PCHI = UHI / (1 + ((HHVC * FC) / (HHVP * FP))) (consolidated formula)
Petcoke Portion of 70/30 Coal/Petcoke Blend Consumption at Maximum Heat Input		32.37	% by heat input	(PCHI / UHI) * 100
Maxmum Allowable Petcoke SO2 Emission Rate	PSO2HI PSO2H PSO2A	0.715 1,660 7,270	lb/MMBtu lb/hr ton/yr	CSO2 CSO2 * PCHI PSO2H * (8,760 / 2,000)
Coal Portion of 70/30 Coal/Petcoke Blend Consumption at Maximum Heat Input	CCHI	4,850	MMBtu/hr	UHI - PCHI
Coal Portion of 70/30 Coal/Petcoke Blend Consumption at Maximum Heat Input		67.63	% by heat input	(CCHI / UHI) * 100
Maximum Allowable Coal SO2 Emission Rate	ACSO2 CSO2H CSO2A	0.994 4,822 21,121	lb/MMBtu lb/hr ton/yr	ACSO2 ACSO2 * CCHI CSO2H * (8,760 / 2,000)
Maximum Allowable 70/30 Coal/Petcoke Blend SO2 Emission Rate	BSO2H BSO2A BSO2HI	6,482 28,391 0.904	lb/hr ton/yr lb/MMBtu	PSO2H + CSO2H BSO2H * (8,760 / 2,000) BSO2H / UHI

Source: ECT, 1996.

historical emission rates, the allowable rates for the coal portion of the blend will vary with coal sulfur content and the coal/petcoke blend ratio. The following algorithms are proposed to implement Subpart Da requirements during the combustion of coal/petcoke blends:

Unit 1:

$$E_{SO2} = [\ (\ \%C_{HI}\ /\ 100\ )\ *\ (P_S\ )\ *\ (\ 1 - (\ \%\ R_o\ /\ 100\ ))\ ] + [\ (\ 1 - (\ \%C_{HI}\ /\ 100\ ))\ *\ (\ 0.74\ \text{lb}\ SO_2\ /\ \text{MMBtu}\ )] \quad \text{(Eqn. E-1)}$$

Unit 2:

$$E_{SO2} = [\ (\ \%C_{HI}\ /\ 100\ )\ *\ (P_S\ )\ *\ (\ 1 - (\ \%\ R_o\ /\ 100\ ))] + [\ (\ 1 - (\ \%C_{HI}\ /\ 100\ ))\ *\ (\ 0.72\ \text{lb}\ SO_2\ /\ \text{MMBtu}\ )] \quad \text{(Eqn. E-2)}$$

where:

E_{SO2}	=	allowable SO_2 emission rate; lb SO_2/MMBtu, 30-day rolling average
$\%C_{HI}$	=	percent of coal used on a heat input basis
P_S	=	potential SO_2 combustion concentration (unwashed coal without emission control systems) as defined by NSPS Subpart Da; lb SO_2/MMBtu
$\%\ R_o$	=	overall percent SO_2 reduction from Equation 19-21 of EPA Reference Method 19. Per NSPS Subpart Da, $\%\ R_o$ must not be less than 90 percent, 30-day rolling average.

The first term in each equation is the allowable rate for the coal portion of the coal/petcoke blend while the second term addresses the allowable rate due to the petcoke portion of the blend. SECI intends to meet the proposed SO_2 emission limits while using petcoke containing up to 7.0 percent by weight sulfur by increasing the SO_2 removal efficiency of the existing FGD systems. The FGD systems have historically been operated at an average SO_2 removal efficiency of approximately 85 percent which, together with a coal washing credit, complies with the NSPS Subpart Da overall 90 percent SO_2 removal efficiency requirement. By adjusting operational variables such as the liquid to gas ratio (scrubbing liquid flow rate divided by the exhaust flow rate) and pH of the scrubbing liquid, SECI has demonstrated through past operations that the FGD SO_2 removal efficiency can be increased up to 10 percent above the historical average of 85 percent up to a maximum of 95 percent removal. To meet the proposed SO_2 emission limits, a maximum increase in FGD SO_2 removal efficiency of approximately 2 to 3 percent will be necessary. Therefore, the existing FGD control systems have adequate design capacity to meet the proposed SO_2 emission limits while using a 30 percent by weight petcoke/coal blend having petcoke and coal maximum 30-day average sulfur contents of 7.0 and 3.0 percent by weight, respectively.

Nitrogen Oxides (NO_x)

NO_x emission rates measured during the test burning show a decrease in rates for the 10 percent (12/8/95 test) and 20 percent (12/8/95 test) petcoke blend scenarios and a slight increase for the 30 percent (1/8/96 test) petcoke blend scenario in comparison to the NO_x emission rates obtained during the use of baseline coal (1/4/96 test). The difference in NO_x emission rates for the 30 percent petcoke blend scenario and baseline coal is not significant using the Student's *t* statistical test described in 40 CFR Part 60, Appendix C (reference Table E-4 for details). Other test burns of petcoke/coal blends conducted by Florida utilities also demonstrated that the use of petcoke/coal blends did not cause an increase in NO_x emission rates. Accordingly, the available test data provides reasonable assurance that the use of up to 30 percent by weight petcoke/coal blend at the Seminole Power Plant will not cause a significant increase in NO_x emissions.

Particulate Matter (PM)

The ash content of petcoke (approximately 0.5 percent by weight) is much lower than the ash content of baseline coal (approximately 9 percent by weight). Typically, eighty-five percent by weight of coal ash is contained in the furnace exhaust as fly ash with the remaining fifteen percent by weight found in the furnace bottom ash. Assuming, as a worst-case, that all of the petcoke ash is released as fly ash, use of a 30 percent by weight petcoke/coal blend will result in a decrease in the generation rate of fly ash due to the lower ash content of petcoke. All other factors remaining the same, a decrease in the

Table E-4. Analysis of NO_x Performance Test Data

A. Test Results

Fuel Type	Test Date	Emission Rates (lb NO_x/MMBtu, 3-Hr Averages)							
		Run No. 1	Run No. 2	Run No. 3	Run No. 4	Run No. 5	Run No. 6	Run No. 7	Run No. 8
Baseline Coal	1/4/96	0.543	0.566	0.491	0.552	0.553	0.558	0.547	0.557
30/70 Petcoke/Coal Blend	1/8/96	0.594	0.563	0.582	0.538	0.525	0.537	0.627	0.649

B. Calculations

Fuel Type	Arithmetic Mean (lb NO_x /MMBtu)	Sample Variance S^2	Pooled Estimate S_p	t Statistic
Baseline Coal	0.55	0.000541		
30/70 Petcoke/Coal Blend	0.58	0.002003		
Both Tests			0.0357	1.735
Degrees of Freedom				14
t' (95 percent confidence level)				1.761
Significant Increase (Y/N)				N

Source: ECT, 1996.

quantity of fly ash generated will also cause a decrease in PM emission rates. To illustrate, 100 lb of baseline coal will generate approximately 7.7 lb of fly ash. In contrast, 100 lb of a 30 percent by weight petcoke/coal blend will generate 0.15 lb of fly ash due to the petcoke portion of the blend (assuming all petcoke ash is released as fly ash) and 5.4 lb of fly ash due to the coal portion for a total of 5.55 lb. This total of 5.55 lb of fly ash generated is approximately 28 percent lower than the 7.7 lb value generated by baseline coal. Accordingly, it is concluded that the use of a 30 percent by weight petcoke/coal blend at the Seminole Power Plant will not cause a significant increase in PM emissions. The petcoke/coal test burn results confirm this conclusion; i.e., the use of 30 percent by weight petcoke/coal blend resulted in a lower PM emission rate in comparison to baseline coal.

Carbon Monoxide (CO) and Sulfuric Acid Mist (H_2SO_4)

Estimates of the actual emission rate change for these two air pollutants due to the use of petcoke was determined based on the petcoke test burn data. A summary of the baseline coal and 70/30 coal/petcoke blend test burn data for Unit No. 1 is provided in the following table:

Fuel Type	Test Date	Measured Emission Rates (lb/MMBtu)	
		CO	H_2SO_4
Baseline Coal	1/4/96	0.066	0.031
70%/30% Coal/Petcoke Blend	1/8/96	0.009	0.030

The petcoke test burn results demonstrate that emission rates of CO and H_2SO_4 during combustion of a 70/30 coal/petcoke blend were lower than the baseline coal emission rates. During these series of tests, the FGD SO_2 removal efficiency was approximately the same; i.e., 82.7 percent for the baseline coal test vs. 82.2 percent for the 30 percent petcoke/coal blend test. The measured decrease in H_2SO_4 emissions demonstrates that the FGD system is capable of maintaining H_2SO_4 emissions at or below baseline coal levels during the combustion of higher sulfur content coal/petcoke fuel blends.

Confirmation that future CO and H_2SO_4 emissions during the combustion of coal/petcoke blends are equal to or less than baseline coal levels will be made by conducting annual tests (for a five year period) while burning coal and coal/petcoke blends using EPA Reference Methods 10 (for CO) and 8 (for H_2SO_4).

Lead (Pb), Fluorides (F), Mercury (Hg), and Beryllium (Be)

Because emission rates of these air pollutants will be proportional to the element concentrations in the coal and petcoke fuels, estimates of actual emission rate changes for these air pollutants due to the use of petcoke was determined based on a comparison of baseline coal and petcoke fuel analyses. A summary of typical element concentrations, in lb/MMBtu, is provided in the following table for baseline coal and 100 percent petcoke:

Element	Fuel Concentration (lb/MMBtu)	
	Baseline Coal	100% Petcoke
Lead (Pb)	6.04E-04	3.38E-05
Fluoride (F)	5.28E-03	3.85E-04
Mercury (Hg)	6.04E-06	3.38E-06
Beryllium (Be)	7.55E-05	6.76E-07

The fuel compositions summarized above indicate that emission rates of lead, fluoride, mercury, and beryllium will be lower when petcoke is substituted for coal due to the lower concentrations of these elements present in petcoke.

Ozone [as volatile organic compounds (VOCs)]

Emissions of VOCs from fossil fuel combustion are the due to the partial oxidization of hydrocarbons contained in the fuel. As with most combustion processes, the Seminole Power Plant Unit Nos. 1 and 2 operate with excess air to ensure complete combustion. For this reason, emissions of VOCs from fossil fuel combustion are relatively low. For example, *total* actual VOC emissions from Unit Nos. 1 and 2 in 1995 (as indicated on

SECI's Annual Operating Report) were 108.2 tpy based on the application of AP-42 emission factors. Because emissions of VOCs depend primarily on process operations (i.e., extent of complete combustion) and not on fuel characteristics, no change in VOC emissions (in terms of lb VOC/ton of fuel combusted) is expected due to the substitution of petcoke for coal. This expectation is substantiated by the test burn results which showed lower CO emission rates during the use of coal/petcoke blends in comparison to baseline coal. The lower CO emissions are an indicator of high combustion efficiency; i.e., extent of complete combustion. The high combustion efficiency would also be expected to result in lower VOC emissions due to increased oxidation of fuel hydrocarbons. Actual emission rates of VOCs were estimated using EPA AP-42 emission factors.

Total Reduced Sulfur, Reduced Sulfur Compounds, Asbestos, and Vinyl Chloride

Emissions of these PSD regulated air pollutants due to the combustion of coal and petcoke are considered to be negligible. As mentioned previously, Unit Nos. 1 and 2 are operated with excess air to ensure complete combustion. Therefore, the formation of reduced sulfur or reduced sulfur compounds would be expected to be negligible in the oxidizing atmosphere of a fossil fuel combustion process. EPA reference material pertaining to toxic air pollutant emissions from coal combustion sources do not include any data for asbestos or vinyl chloride.

Summary of Actual Emission Changes for PSD Regulated Air Pollutants

As indicated in Table E-1, the significant emission rates for PSD review are expressed in units of tpy. Summaries of the actual emission rate changes due to the use of up to 30 weight percent petcoke as a replacement for coal for the Seminole Power Plant are shown on Tables E-5 through E-7.

Table E-5. Summary of Actual Emission Rate Changes
PSD Regulated Air Pollutants - Unit No. 1

Average 94/95 Heat Input for Unit No. 1: 41,838,863 MMBtu/yr
Percent of Total Heat Input Replaced by Petcoke : 32.37 %
(for 70/30 coal/petcoke blend)

Pollutant	Emission Factors		Actual Emission Rates[1]		Emission Rate Change[2] (tpy)
	Baseline Coal (lb/MMBtu)	Petcoke/Coal Blends (lb/MMBtu)	Baseline Coal (tpy)	Petcoke/Coal Blends (tpy)	
CO[3]	0.066	0.006	1,380.7	125.5	-1,255.2
NO_x[3]	0.550	0.480	11,505.7	10,041.3	-1,464.4
SO_2	0.740	0.740	15,480.4	15,480.4	0.0
Ozone (as VOC)[4]	0.0022	0.0021	46.0	44.7	-1.4
PM[5]	0.010	0.008	209.2	167.4	-41.8
PM10[5]	0.010	0.008	209.2	167.4	-41.8
Total Reduced Sulfur	Neg.	Neg.	Neg.	Neg.	Neg.
Reduced Sulfur Compounds	Neg.	Neg.	Neg.	Neg.	Neg.
Sulfuric Acid Mist[3]	0.031	0.028	648.5	585.7	-62.8
Fluorides[6]	0.0053	0.0036	110.5	74.9	-35.5
Vinyl Chloride	Neg.	Neg.	Neg.	Neg.	Neg.
Lead[6]	6.04E-04	4.19E-04	12.6	8.8	-3.86
Mercury[6]	6.04E-06	5.18E-06	0.126	0.108	-0.018
Asbestos	Neg.	Neg.	Neg.	Neg.	Neg.
Beryllium[6]	7.55E-05	5.13E-05	0.511	0.347	-0.164

1 [Emission Factor (lb/MMBtu)] * [Average Heat Input (MMBtu/yr)] * [(1 ton / 2,000 lb)]

2 [Petcoke (tpy) - Coal (tpy)]

3 Based on baseline coal (1/4/96) and average of petcoke/coal blend (12/8/95, 12/8/95, and 1/8/96) performance tests.

4 Based on AP-42 emission factor.

5 Based on baseline coal (1/4/96) and 30 percent by weight petcoke/coal blend (1/8/96) performance tests.

6 Based on typical fuel compositions and no credit for air pollution control system emission reduction.
Petcoke/coal blend value based on a 30 percent by weight petcoke/coal blend.

Table E-6. Summary of Actual Emission Rate Changes
PSD Regulated Air Pollutants - Unit No. 2

Average 94/95 Heat Input for Unit No. 2: 43,479,548 MMBtu/yr
Percent of Total Heat Input Replaced by Petcoke : 32.37 %
(for 70/30 coal/petcoke blend)

Pollutant	Emission Factors		Actual Emission Rates[1]		Emission Rate Change[2] (tpy)
	Baseline Coal (lb/MMBtu)	Petcoke/Coal Blends (lb/MMBtu)	Baseline Coal (tpy)	Petcoke/Coal Blends (tpy)	
CO[3]	0.066	0.006	1,434.8	130.4	-1,304.4
NO_x[3]	0.550	0.480	11,956.9	10,435.1	-1,521.8
SO_2	0.715	0.715	15,543.9	15,543.9	0.0
Ozone (as VOC)[4]	0.0022	0.0021	47.8	46.4	-1.4
PM[5]	0.010	0.008	217.4	173.9	-43.5
PM10[5]	0.010	0.008	217.4	173.9	-43.5
Total Reduced Sulfur	Neg.	Neg.	Neg.	Neg.	Neg.
Reduced Sulfur Compounds	Neg.	Neg.	Neg.	Neg.	Neg.
Sulfuric Acid Mist[3]	0.031	0.028	673.9	608.7	-65.2
Fluorides[6]	0.0053	0.0036	114.8	77.9	-36.9
Vinyl Chloride	Neg.	Neg.	Neg.	Neg.	Neg.
Lead[6]	6.04E-04	4.19E-04	13.1	9.1	-4.01
Mercury[6]	6.04E-06	5.18E-06	0.131	0.113	-0.019
Asbestos	Neg.	Neg.	Neg.	Neg.	Neg.
Beryllium[6]	7.55E-05	5.13E-05	0.531	0.361	-0.170

1 [Emission Factor (lb/MMBtu)] * [Average Heat Input (MMBtu/yr)] * [(1 ton / 2,000 lb)]
2 [Petcoke (tpy) - Coal (tpy)]
3 Based on baseline coal (1/4/96) and average of petcoke/coal blend (12/8/95, 12/8/95, and 1/8/96) performance tests.
4 Based on AP-42 emission factor.
5 Based on baseline coal (1/4/96) and 30 percent by weight petcoke/coal blend (1/8/96) performance tests.
6 Based on typical fuel compositions and no credit for air pollution control system emission reduction.
Petcoke/coal blend value based on a 30 percent by weight petcoke/coal blend.

Table E-7. Summary of Actual Emission Rate Changes PSD Regulated Air Pollutants - Unit Nos . 1 and 2

Pollutant	Emission Rate Change Unit No. 1 (tpy)	Emission Rate Change Unit No. 2 (tpy)	Emission Rate Change Unit Nos. 1and 2 (tpy)	PSD Significant Emission Rate (tpy)	Basis for Reasonable Assurance
CO	-1,255	-1,304	-2,560	100	1
NOx	-1,464	-1,522	-2,986	40	1
SO2	0	0	0	40	2
Ozone (as VOC)	-1	-1	-3	40	3
PM	-42	-43	-85	25	1
PM10	-42	-43	-85	15	1
Total Reduced Sulfur	Neg.	Neg.	Neg.	10	4
Reduced Sulfur Compounds	Neg.	Neg.	Neg.	10	4
Sulfuric Acid Mist	-63	-65	-128	7	1
Fluorides	-36	-37	-72	3	5
Vinyl Chloride	Neg.	Neg.	Neg.	1	6
Lead	-3.86	-4.01	-7.87	0.6	5
Mercury	-0.018	-0.019	-0.037	0.1	5
Asbestos	Neg.	Neg.	Neg.	0.007	6
Beryllium	-0.164	-0.170	-0.334	0.0004	5

Reasonable Assurance Footnotes:

[1] Test burn results
[2] Increase in FGD removal efficiency, as required
[3] AP-42 emission factor; continued high combustion efficiency
[4] Negligible emissions due to oxidizing atmosphere of combustion process
[5] Typical fuel composition
[6] Negligible emissions, if any

ATTACHMENT B

NO. 2 FUEL OIL UTILIZATION

REQUEST TO UTILIZE NO. 2 OIL
TO GENERATE ELECTRICAL CAPACITY

I. Introduction

Seminole Electric Cooperative, Inc. (Seminole) is permitted to operate two coal-fired electric generating units (Units 1 and 2) at the Seminole Power Plant near Palatka, Florida. Each unit has a design maximum generator rating of 714.6 MW and a normal continuous operating capacity of 659 MW in the summer and 670 MW in the winter. Each unit is equipped with coal handling and processing facilities that enable all loads to be achieved utilizing coal. Coal utilization has been about 3.6 million tons/year and is expected to be 4.0 million tons/year in the near future.

Units 1 and 2 are permitted to utilize No. 2 oil with a maximum sulfur content of 0.5% for start-up and for flame stabilization in all load ranges. Each unit is equipped with an oil ignitor system which has the potential to place enough oil BTU's into the boiler to generate only 45 MW per unit or about 6.3% of the design maximum generator rating. Use of oil is minimized to the extent possible due to its high cost ($5/mmBTU) as compared to coal ($2/mmBTU). In 1995, Units 1 and 2 used a total of 1.38 million gallons of No. 2 oil which was equal to approximately 0.22% of the heat input to each unit.

There are times when a combination of fuel quality, fuel conditions and/or required maintenance on either the coal ball mills (which pulverize coal to a talcum powder consistency prior to burning) or the burners themselves prevents the units from being able to meet all loads with coal only. For example, there are times when either wet coal or coal with a heat content at the low end of the design range could limit the BTU's placed in the boiler.

Each unit is equipped with six ball mills feeding six dedicated burners each, enabling the unit to meet the design rated capacity (714.6 MW). The normal operating load can be met with five mills (30 burners). There are times when one mill is out for scheduled maintenance and one or more burners from an operating mill may also be out of service, which, depending on which burners were out of service, could prevent the unit from meeting either the normal operating loads or emergency reserve loads.

Historically, when situations occur which prevent loads from being generated by coal, Seminole has purchased capacity from other utilities. The primary reasons are that Seminole Units 1 and 2 are not permitted to burn oil for load and alternative capacity at a lesser cost has been available.

II. Request to Burn Oil for Capacity

Seminole proposes to amend its Conditions of Certification and Prevention of Significant Deterioration (PSD) permit to allow the use of oil to meet Seminole's commitment to provide electrical reserve requirements as required by the Florida Public Service Commission (FPSC) and to meet electrical demand when coal quality, conditions and/or processing or burner equipment prevents meeting demand with coal only. Because Seminole does not propose to alter the existing ignitor system in any manner, oil use could not increase over its current capacity.

III. Rationale

A. Oil to Meet Reserve Capability Requirements

The Florida Public Service Commission (FPSC) requires that each electric utility in the State have reserve electrical capacity equal to at least 15% over its load obligations. Reserve capacity is required in the event that any of the operating generating units experience an outage, supplies from outside the State fail, transmission line(s) fail or customer demand is greater than the operating plants can produce. There are two types of reserve requirements; 1) operating (sometimes called spinning reserves), and 2) installed reserves. The major difference between the two types is that operating reserves have to be available in 10 minutes or less, and installed reserves have to be available in 30 minutes or less. In a statewide emergency requiring the use of reserve capacity, generally the lowest cost reserve capacity is used first and the highest cost capacity would be utilized last (economic dispatching).

Seminole is currently required to have 90 MW of operating reserve and 220 MW of installed reserve capacity to meet State requirements. Seminole currently obtains a portion of its reserve capacity from using the maximum generating capacity from Seminole Units 1 and 2 and the remainder from purchasing the right to call upon operating and installed reserve capacity from other utilities even though it may not be used in any given day.

As stated previously, Seminole Units 1 and 2 have a normal continuous operating capacity of 659/670 MW (summer/winter) and a maximum design rating of 714.6 MW. Historically, only a portion of the maximum design generator rating from Units 1 and 2 have been used for reserve capacity. There are two levels of maximum rated capacity for the two units. The first is the generating capacity obtained from running the unit with the turbine steam control valves wide open (VWO) and with 5% more steam pressure than normal. In this mode of operation, each unit is able to produce 685 MW in the summer and 696 MW in the winter months. The second mode of operation is VWO, the 5% additional steam pressure and taking the top feedwater heater out-of-service which will reliably produce 711 MW in the winter and summer.

Seminole has only relied on the Seminole Units for the first mode of maximum rated capability because there was concern that: 1) operating with the top feedwater heaters out-of-service for long periods would cause reduced unit availability; 2) the unit had to be operating under 600 MW before the top heater could be taken out of service, and the time necessary to reduce load, take out the heater and increase load would not qualify it as operating reserve capacity and only marginally as installed reserve, and 3) it was not always possible to rely on the coal ball mills to be able to put enough coal into the boilers to reach the maximum load due to ambient air conditions, fuel quality and mill availability.

Seminole has determined that it is economically prudent and technologically feasible to use the maximum rated capacity of Units 1 and 2 to meet its requirements for installed reserve capacity and eliminate the need to purchase reserve capacity. An operating evaluation has shown that: 1) the additional installed reserve capacity would be called upon for approximately 200 hours/year/unit on an annual basis, and that even on a worst case basis, this utilization should not adversely affect the availability of each unit; 2) the time needed to take the top feedwater heaters out-of-service could not be altered to meet the operating reserve requirement without installing additional steam valves, but the criteria for installed reserves could be reliably met without changes to the steam system, and 3) the fuel reliability needed to qualify as installed reserve capability could be met with the existing oil ignitor system in each unit.

B. Oil to Meet Load Capacity Requirements

As stated previously, situations may occur when Units 1 and 2 are unable to meet their normal continuous operating ratings (NCOR) of 659 MW (summer) and 670 MW (winter). When this condition has existed, Seminole has purchased the capacity to meet the NCOR. However, with the authority to burn oil to meet NCOR, Seminole would be able to generate this capacity if no other was available and be able to purchase the capacity through economy broker sales in lieu of a straight energy purchase.

Under the economy broker sales arrangement, utilities with the ability to generate capacity with a high cost can match up with a lower cost generator on an hourly basis and the strike price is one-half the difference between the two. This ability would allow Seminole to make hourly arrangements while the coal handling equipment is being maintained or repaired.

Seminole does not anticipate that this authority to burn oil will increase oil use in either case except in a statewide electrical emergency again due to the cost differential between No. 2 oil and any other fuel.

Impacts of Proposed Changes

While Seminole is requesting authority to use No. 2 oil to meet NCOR, it is not anticipated that No. 2 oil will be used due to the availability of other sources of more economic energy. Seminole does predict that Units 1 and 2 could be called upon to provide a maximum of 45 MW for 200 hours/year/unit to meet reserve capacity requirements. If it is assumed oil will be used to supply this capacity, air emissions would actually decrease.

Units 1 and 2 are permitted to burn No. 2 oil with a maximum sulfur content of 0.5%. Using 0.5%S No. 2 oil to generate 45 MW needed to reach 711 MW would reduce SO_2 emissions when compared to generating the electricity only from coal. The following is a per unit comparison of the hourly and annual SO_2 emissions from generating the reserve MW's with coal and No. 2 oil. The values reflect removing 84% of the SO_2 in each units' flue gas desulfurization system.

	Coal	Oil	Diff.
Hourly SO_2 (lbs/MMBTU)	0.76	0.08	-0.68
Annual SO_2 (tons)	34.2	3.6	-30.6

It is presumed that NO_x emissions would likewise be reduced since NO_x from oil is roughly one-half that from coal. However, even in a worst cast scenario of 45 MW being derived from oil, the oil would only constitute 6.3% of the hourly heat input to the boiler so the change in NO_x emissions would be undistinguishable. For the expected 200 hours/year of operation in this condition, the annual heat input to the boiler would be 0.14%.

Seminole is also requesting concurrence that the de minimis use of No. 2 oil in Units 1 and 2 not require Seminole to modify its current CEM program to derive new emission limitations as specified in 40 CFR 60, Subpart Da when different fuels are co-fired. As stated previously, in a worst cast scenario, oil would only constitute 6.3% of the instantaneous hourly heat input (0.14% annually). On an annual basis and again based on a worst case scenario, oil would only account for 0.43% of the annual heat input including start-up oil and flame stabilization oil. It would be impractical to modify the CEM program for the few hours oil is used for reserve capacity (if any is used at all) to determine supplemental fuel emission limits which, when calculated in a 30 DRA, would produce a non-detectable change.

For example, if 45 MW were generated by oil to meet reserve requirements for 5 hours/day for 4 consecutive days and oil constituted 6.3% of the heat input during the hours it was used, the daily NO_x emission limitation would change from 0.6 lbs/mmBTU to 0.596 lbs/mmBTU using the formula in 40 CFR 60.44a(c). Since Subpart Da standards are on a 30 day rolling average (DRA), the first day of use would change the 30 DRA from 0.6 lbs/mmBTU to 0.5999 lbs/mmBTU. At the end of the fourth day, the 30 DRA would be 0.5995 lbs/mmBTU. In each case, the results would be rounded to 0.6 lbs/mmBTU.

The SO_2 limitation results would have similar results. In the above example, 40 CFR 43a(h) requires that 90% removal from the FGD system be required, therefore, the change in the first day of the 30 DRA would be 1.1998 lbs SO_2/mmBTU and the fourth would be 1.1993 lbs SO_2/mmBTU and, therefore, rounded to 1.2 lbs/mmBTU.

ATTACHMENT C

PROPOSED CONDITIONS OF CERTIFICATION

1. **Add new section XXVII as follows:**

XXVII. Units No. 1 and 2 Burning Coal/Petroleum Coke Fuel Blends

Stack emissions from Units 1 and 2 shall not exceed the following when burning blends of coal and petroleum coke:

A. SO_2 Emissions: in accordance with the following equations:

Unit 1:

$$E_{SO2} = [(\%C_{HI}/100)*(1-(\%R_O/100))] + [(1-(\%C_{HI}/100))*(0.74 \text{ lb } SO_2/MMBtu)] \quad \text{(Eqn. 1)}$$

Unit 2:

$$E_{SO2} = [(\%C_{HI}/100)*(P_S)*(1-(\%R_O/100))] + [(1-(\%C_{HI}/100))*(0.72 \text{ lb } SO_2/MMBtu)] \quad \text{(Eqn.2)}$$

where:

E_{SO2}	=	allowable SO_2 emission rate; lb SO_2/MMBtu, 30-day rolling average
$\%C_{HI}$	=	percent of coal used on a heat input basis
P_S	=	potential SO_2 combustion concentration (unwashed coal without emission control systems) as defined by NSPS Subpart Da; lb SO_2/MMBtu, 30-day rolling average
$\%R_O$	=	overall percent SO_2 reduction from Equation 19-21 of EPA Reference Method 19. Per NSPS Subpart Da, $\%R_O$ must not be less than 90%, 30-day rolling average
0.74	=	historical 2-year annual average SO_2 emission rate for Unit No. 1; lb/MMBtu
0.72	=	historical 2-year annual average SO_2 emission rate for Unit No. 2; lb/MMBtu

B. NO_X - 0.60 lb. per million Btu heat input, and 35 percent of the potential combustion concentration (65 percent reduction). Compliance with the 0.60 lb. per million Btu heat input limitation constitutes compliance with the 65 percent reduction requirement.

C. Particulates - 0.03 lb. per million Btu heat input, and 1 percent of the potential combustion concentration (99 percent reduction). Compliance with the 0.03 lb. per million Btu heat input limitation constitutes compliance with the 99 percent reduction requirement.

D. Compliance with the emission limitations and percent reductions in Conditions XXVII A and B shall be determined on a 30-day rolling average.

E. Fuels fired shall consist of coal or a coal/petroleum coke blend containing a maximum of 30.0 percent petroleum coke by weight. The sulfur content of the petroleum coke shall not exceed 7.0 percent by weight dry basis.

F. Documentation verifying that the coal/petroleum coke blends combusted in Units No. 1 and 2 have not exceeded the 30.0 percent maximum petroleum coke by weight limit specified by Condition XXVII E. shall be maintained and submitted to the Department's Northeast District Office with each annual report.

G. The Permittee shall maintain and submit to the Department on an annual basis for a period five years from the date the units begin firing petroleum coke, data demonstrating that the operational change associated with the use of petroleum coke did not result in a significant emission increase pursuant to Rule 62-210.200(12)(d), F.A.C.

H. All prior conditions of certification that address coal handling shall also apply to the handling of petroleum coke.

2. <u>Add new section I.E. as follows:</u>

No. 2 fuel oil may be co-fired with solid fuel for start-ups, flame stabilization, emergency reserve capacity during statewide energy shortages, and limited (45 mw) supplemental load.

3. <u>Add new section XXV.c. as follows:</u>

This certification shall be automatically modified to conform to any subsequent amendments, modifications, or renewals made by DEP under a federally delegated or approved program to any separately issued Prevention of Significant Deterioration (PSD) permit, Title V Air Permit, or National Pollutant Discharge Elimination System (NPDES) permit for the certified facility. Permittee shall send each party to the original certification proceedings (at the party's last known address as shown in the record of such proceeding) notice of requests submitted by Permittee for modifications or renewals of the above listed permits if the request involves a relief mechanism (e.g., mixing zone, variance, etc.) from state standards, a relaxation of conditions included in the permit due to state permitting requirements, or the inclusion of less restrictive air emission limitations in the air permits. DEP shall notify all parties to the certification proceeding of any intent to modify conditions under this section prior to taking final agency action.

Mr. James S. Alves
Hopping, Green Sams & Smith
P. O. Box 6526
Tallahassee, FL 32314

Mr. David Jordan
Senior Attorney
Dept. Of Community Affairs
2740 Centerview Drive
Tallahassee, FL 32399-0450

Mr. Thornton J. Williams, Esq.
Assistant General Counsel
Department of Transportation
Haydon Burns Building
605 Suwannee Street, M.S. 58
Tallahassee, FL 32399-0450

Mr. Michael Palecki
Division of Legal Services
Florida Public Service Commission
101 East Gaines Street
Fletcher Building, Room 212
Tallahassee, FL 32399-0850

Mr. James Antista
General Counsel
Game and Fresh Water Fish Commission
Bryant Building
620 South Meridian Street
Tallahassee, FL 32399-1600

Mr. Robert Vandiver, Esq.
Public Service Commission
101 East Gaines Street
Tallahassee, FL 32399

Mr. Dan Stengle, Esq.
Department of Community Affairs
2740 Centerview Drive
Tallahassee, FL 32399-2100

Mr. Charles Harwood
Executive Director
Withlacoochee Regional Planning Council
1241 S.W. Tenth Street
Ocala, FL 34474-2798

Mr. Charles Justice
Executive Director
North Central Florida Planning Council
2009 N.W. 67th Place
Gainesville, FL 32606

Mr. Brian Temple
Executive Director
N.E. Florida Regional Planning Council
8649 Baypine Road, Suite 110
Jacksonville, FL 32256

Mr. Samuel Taylor
Board of County Commissioners
Putnam County
P. O. Box 758
Palata, FL 32178

Lynne C. Capehart, Esq.
1601 N.W. 35th Way
Gainesville, FL 32605

Mr. Henry Dean
Executive Director
St. Johns River Water Management District
P. O. Box 1429
Palata, FL 32178

Mr. Gordon B. Johnston
Marion County Attorney
601 S.E. 25th Avenue
Ocala, FL 34471

Mr. Jim Knox, Chairman
Board of County Commissioners
Columbia County Courthouse
P. O. Drawer 1529
Lake City, FL 32056

Mr. Patrick Gilligan
City of Ocala
Seven East Silver Springs Boulevard, Suite 405
Ocala, FL 34471

Mr. Mark Scruby
Clay County Attorney
P. O. Box 1366
Green Gove Springs, FL 32043

Honorable William A. Wilkes
825 North Orange Avenue
P. O. Box 1867
Green Gove Springs, FL 32043

Date: 11/20/96 8:00:44 AM
From: Martin Costello TAL
Subject: SECI
To: Alvaro Linero TAL
To: Martin Costello TAL

Insufficiency questions for Seminole Electric:

1. Table E5 incorrectly uses the baseline test data (instead of historic actual emission rates) to estimate emission rate changes for PSD pollutants for which there exists either stack test data or CEMS data. Please submit either 1994 or 1996 and 1995 averaged annual emission rates based on CEMS data for NO_X and SO_2 and based on stack test data for PM and VOC, H_2SO_4 and CO(if only have initial stack test data for CO, VOC, or H_2SO_4, then average this with the baseline test data). For pollutants which have not been tested in the past provide the rating and the date of the AP-42 emission factors. State how AOR emission rates were calculated for SO2.

2. The emission rates for the three blends are averaged in Table E5. Compare emission rates(tpy) for the 10%, 20% and 30% petcoke blends separately to the historic emission rates referenced in the above question.

3. The application does not provide measured SO_2 emission rates from the test burn. If not provided, please provide all measured emission rates from the test burn.

4. Appendix E states that SECI has demonstrated though past operation up to 95% removal efficiency for SO_2. Please provide date which demonstrates this.