TAMPA ELECTRIC
A TECO ENERGY COMPANY

January 30, 1985

Mr. Steve Smallwood
Florida Department of Environmental
Regulation
Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32301

RE: Request for Permit Modification
Big Bend Station Unit 4
Tampa Electric Company
PSD-FL-040

Dear Mr. Smallwood:

As you are probably aware, Tampa Electric Company is in the final stages of constructing a 417 MW (net) coal fired electric generating unit at the Big Bend Station in Ruskin, Florida. The commercial operation date for this new unit, Big Bend Unit 4, is expected to be in March of 1985.

In anticipation of our upcoming commercial operation of Unit 4, Tampa Electric Company has been reviewing all permitting associated with the new unit. On reviewing the above referenced Prevention of Significant Deterioration (PSD) permit and associated application documents, a calculation error was identified in the PSD application emissions estimate for carbon monoxide (CO). In the application, an incorrect emission factor from the EPA document Compilation of Air Pollutant Emission Factors, AP-42, was inadvertently used to estimate the CO emissions. The use of the incorrect emission factor lead to an underestimation of the CO emissions by a factor of two. Attachment I contains the calculations for the corrected estimate.

As seen in Attachment I, the CO emission rate is expected to be approximately 124 lb/hr and 0.029 lb/MMbtu.

DER.
FEB 4 1985
BAQM

TAMPA ELECTRIC COMPANY
P.O. Box 111 Tampa, Florida 33601 (813) 228-4111

Tampa Electric Company requests a modification of the CO limits listed in Table 1 of permit number PSD-FL-040 to reflect the corrected estimate. Attachment II contains the corrected pages to our PSD application.

If you should have any questions please feel free to call me.

Sincerely,

Jerry L. Williams

Jerry L. Williams
Director
Environmental

JLW/jbj/047/1

Attachment

cc: Dr. Richard Garrity (DER)

Attachment I

CARBON MONOXIDE (CO) EMISSIONS ESTIMATE
BIG BEND STATION UNIT 4
PSD-FL-040

Fuel input rate at 100% load = 413,000 $\frac{\text{lbs coal}}{\text{hour}}$

Heat input rate at 100% load = 4330 $\frac{\text{MMbtu}}{\text{hour}}$

CO emission factor = 0.6 $\frac{\text{lbs CO}^{*}}{\text{ton coal}}$

(a) $413{,}000 \ \frac{\text{lbs coal}}{\text{hour}} \times \frac{1}{2000} \ \frac{\text{tons coal}}{\text{lbs coal}} \times 0.6 \ \frac{\text{lbs CO}}{\text{ton coal}}$ **

$= 123.9 \ \frac{\text{lbs CO}}{\text{hour}}$

(b) $123.9 \ \frac{\text{lbs CO}}{\text{hour}} \times \frac{1}{4330} \ \frac{\text{hour}}{\text{MMBtu}} = 0.0286 \ \frac{\text{lbs CO}}{\text{MMBtu}}$

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* Compilation of Air Pollutant Emission Factors, AP-42. See Table 1.1-1. attached.

** In the previously submitted and approved PSD application an emission factor of 0.3 $\frac{\text{KgCO}}{\text{Mg Coal}}$ was mistakenly used as 0.3 $\frac{\text{lb CO}}{\text{Ton Coal}}$. See Table 1.1-1. attached.

TABLE 1.1-1. EMISSION FACTORS FOR EXTERNAL BITUMINOUS AND SUBBITUMINOUS COAL COMBUSTION[a]

Firing Configuration	Particulate[b] kg/Mg	Particulate[b] lb/ton	Sulfur Oxides[c] kg/Mg	Sulfur Oxides[c] lb/ton	Nitrogen Oxides[d] kg/Mg	Nitrogen Oxides[d] lb/ton	Carbon Monoxide[e] kg/Mg	Carbon Monoxide[e] lb/ton	Nonmethane VOC[e,f] kg/Mg	Nonmethane VOC[e,f] lb/ton	Methane[e] kg/Mg	Methane[e] lb/ton
Pulverized coal fired												
Dry bottom	5A	10A	19.5S(17.5S)	39S(35S)	10.5(7.5)[g]	21(15)[g]	0.3	0.6	0.04	0.07	0.015	0.03
Wet bottom	3.5A[h]	7A[h]	19.5S(17.5S)	39S(35S)	17	34	0.3	0.6	0.04	0.07	0.015	0.03
Cyclone furnace	1A[h]	2A[h]	19.5S(17.5S)	39S(35S)	18.5	37	0.3	0.6	0.04	0.07	0.015	0.03
Spreader stoker												
Uncontrolled	30[i]	60[i]	19.5S(17.5S)	39S(35S)	7	14	2.5	5	0.04	0.07	0.015	0.03
After multiple cyclone												
With flyash reinjection from multiple cyclone	8.5	17	19.5S(17.5S)	39S(35S)	7	14	2.5	5	0.04	0.07	0.015	0.03
No flyash reinjection from multiple cyclone	6	12	19.5S(17.5S)	39S(35S)	7	14	2.5	5	0.04	0.07	0.015	0.03
Overfeed stoker[j]												
Uncontrolled	8[k]	16[k]	19.5S(17.5S)	39S(35S)	3.25	7.5	3	6	0.04	0.07	0.015	0.03
After multiple cyclone	4.5	9	19.5S(17.5S)	39S(35S)	3.25	7.5	3	6	0.04	0.07	0.015	0.03
Underfeed stoker												
Uncontrolled	7.5[l]	15[l]	15.5S	31S	4.75	9.5	5.5	11	0.65	1.3	0.4	0.8
After multiple cyclone	5.5	11	15.5S	31S	4.75	9.5	5.5	11	0.65	1.3	0.4	0.8
Handfired units	7.5	15	15.5S	31S	1.5	3	45	90	5	10	4	8

[a] Factors represent uncontrolled emissions unless otherwise specified and should be applied to coal consumption as fired.

[b] Based on EPA Method 5 (front half catch) as described in Reference 12. Where particulate is expressed in terms of the coal ash content (A), the factor is determined by multiplying the weight % ash content of the coal (as fired) by the numerical value preceding the "A". For example, if a coal having 8% ash is fired in a dry bottom unit, the particulate emission factor would be 5 x 8 or 40 kg/Mg (80 lb/ton). On average, the "condensible" material collected in the back half catch of EPA Method 5 is less than 5% of the front half, or "filterable", catch for pulverized coal and cyclone furnaces; about 10% for spreader stokers; about 15% for other stokers; and about 50% for handfired units (References 6, 19, and 49).

[c] Expressed as SO_2, including SO_2, SO_3 and gaseous sulfates. The factors in parentheses should be used to estimate gaseous sulfur oxide emissions for subbituminous coal. In all cases, "S" is the weight % sulfur content of the coal as fired. See Footnote b for an example calculation. On average for bituminous coal, 97% of the fuel sulfur is emitted as SO_2, whereas only about 0.7% of the fuel sulfur is emitted as SO_3 and gaseous sulfate. An equally small percent of the fuel sulfur is emitted as particulate sulfate (References 9, 13). Small quantities of sulfur are also retained in the bottom ash. With subbituminous coal, generally about 10% more fuel sulfur is retained in the bottom ash and particulate, because of the more alkaline nature of the coal ash. Conversion to gaseous sulfate appears to be about the same as for bituminous coal.

[d] Expressed as NO_2. Generally, 95 - 99 volume % of the nitrogen oxides present in combustion exhaust will be in the form of NO, the rest being NO_2 (Reference 11). To express these factors as NO, multiply by a factor of 0.66. All factors represent emissions at baseline operation (i.e., 60 - 110% load and no NO_x control measures, as discussed in the text).

[e] Nominal values achievable under normal operating conditions. Values one or two orders of magnitude higher can occur when combustion is not complete.

[f] Nonmethane volatile organic compounds (VOC), expressed as C_2 to C_{16} n-alkane equivalents (Reference 58). Because limited data on NMVOC were available to distinguish the effects of firing configuration, all data were averaged collectively to develop a single average for pulverized coal units, cyclones, spreader and overfeed stokers.

[g] Parenthetic value is for tangentially fired boilers.

[h] Uncontrolled particulate emissions, when no flyash reinjection is employed. When a control device is installed, and collected flyash is reinjected to the boiler, particulate from the boiler reaching the control equipment can increase by up to a factor of two.

[i] Accounts for flyash settling in an economizer, air heater or breeching upstream of a control device or stack. (Particulate directly at the boiler outlet typically will be twice this level.) This factor should be applied even when flyash is reinjected to the boiler from boiler, air heater or economizer dust hoppers.

[j] Includes traveling grate, vibrating grate and chain grate stokers.

[k] Accounts for flyash settling in the breeching or stack base. Particulate loadings directly at the boiler outlet typically can be 50% higher.

[l] Accounts for flyash settling in the breeching downstream of the boiler outlet.

Attachment II

Revised pages to:

VOLUME I

<u>Prevention of Significant Deterioration (PSD) Application - Tampa Electric Company</u>

(PSD-FL-040)