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(813) 499-6603

Farzie Shelton
ENVIRONMENTAL COORDINATOR, Ch E.

December 1, 1994

VIA HAND DELIVERY

Clair Fancy, Chief
Bureau of Air Regulation
Department of Environmental Protection
Magnolia Park Courtyard
Tallahassee, FL 32301

RE: C.D. McIntosh Power Plant, Unit No. 3
Cofiring of Petroleum Coke

Dear Clair:

As you may recall, the City of Lakeland wrote to you on November 10, 1994, requesting Prevention of Significant Deterioration (PSD) and New Source Performance Standards (NSPS) applicability determinations. Your response dated November 18, 1994, indicated that a complete application for permit modification would need to be submitted prior to the Department making such determinations. Submittal of a complete application should not, however, be required before an applicability determination is made.

The federal NSPS rules, which the Florida Department of Environmental Protection has incorporated by reference, state that "when requested to do so by an owner or operator," the agency will make a determination of whether an intended action would constitute construction or modification (within 30 days of receipt of the request). 40 CFR § 60.5, incorporated by reference in Rule 62-296.800(3)(b), Florida Administrative Code.[1] This rule does *not* include a requirement that the request be accompanied by a completed permit modification application, and to be consistent, the Department should not require the City of Lakeland to submit a completed permit application before it makes an NSPS determination regarding the cofiring of petroleum coke. In addition, the Department's own rules actually "encourage" applicants to consult with the Department *before* submitting an application regarding the modification of any

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[1] In addition to this federal rule being incorporated by reference in the Department's rules, the State's delegation by the U.S. Environmental Protection Agency (EPA) is conditioned upon the Department issuing applicability determinations that are consistent with those made by EPA in the past. Letter from Bruce P. Miller, Chief, Air Programs Branch, Air, Pesticides, and Toxics Management Division, EPA Region IV, to Steve Smallwood, Chief, Bureau of Air Quality Management, dated May 2, 1988, page 3.

facility or concerning the need for pollution control equipment. Rule 62-4.060, Florida Administrative Code.

Consistent with the approach set forth under the federal NSPS and its own rules, the Department has historically made NSPS and PSD applicability determinations without requiring that a completed application be submitted. One of the primary purposes of a requested NSPS or PSD applicability determination is to allow the owner or operator to decide whether he or she wishes to proceed with a formal permit application. In addition, such determinations clarify the type of information that must be included in the application, which reduces the need for future requests for information once the application has been submitted. We recognize, however, that if information ultimately provided in an application is materially inconsistent with that provided in a request for applicability determination, the Department could revise its determination accordingly. Because of the importance of pre-application applicability determinations, the City of Lakeland respectfully requests that the Department make formal PSD and NSPS applicability determinations for the cofiring of petroleum coke at the McIntosh Power Plant, Unit No. 3. If specific information is needed, in addition to what is being provided in the subsequent portions of this letter and what was provided in the November 10, 1994, letter, please let us know and we will provide it to you.

As stated in the November 10 letter to you, the City of Lakeland plans to seek authorization for its McIntosh Unit No. 3 to cofire petroleum coke with coal (or coal and refuse) at a maximum rate of 20 percent by weight. As the test burn results indicated, when petroleum coke is blended in the appropriate amounts, the particulate matter, sulfur dioxide, nitrogen oxides, and opacity limits will not be exceeded. (A complete copy of the test burn results, which had previously been submitted to the Department in March of 1994, is included as Attachment 1.) Prior to submitting a permit revision application to allow the cofiring of petroleum coke, the City of Lakeland seeks confirmation that the planned use of petroleum coke will not trigger applicability of NSPS Subpart Da. In addition, if PSD review is required, the City of Lakeland seeks confirmation from the Department that control technology review will not be required for the boiler. The Department should be able to make both of these determinations based on information provided in this letter and in the November 10 letter.

New Source Performance Standard - Subpart Da

The City of Lakeland's McIntosh Unit No. 3 is an "existing" unit and not subject to NSPS Subpart Da. This is supported by correspondence from the U.S. Environmental Protection Agency (EPA). In December of 1978, the City of Lakeland wrote to EPA Region IV seeking a determination as to whether NSPS Subpart Da applied to the new McIntosh Power Plant Unit No. 3, which had been under a continuous program of construction for a period of time well in excess of one year prior to September 19, 1978 (the relevant date for Subpart Da applicability). See letter from Stephen C. Watson, Assistant City Attorney, City of Lakeland, to William R. Phillips, General Counsel, EPA Region IV, dated December 13, 1978 (Attachment 2). Apparently based on a request for additional information, the City of Lakeland supplemented the December 1978 letter with a January 9, 1979, letter (Attachment 3). In response, William R. Phillips, Assistant General Counsel for EPA Region IV, prepared a memorandum dated January 11, 1979, which found that McIntosh Unit No. 3 was *not* subject to Subpart Da (Attachment 4). This conclusion was restated in a letter from Sanford W. Harvey, Jr., Regional Counsel, EPA Region IV, to the City of Lakeland dated March 2, 1979 (Attachment 5), and in a letter from the Chief of the Air Facilities Branch, EPA Region IV, to the City of Lakeland dated January 30, 1981 (Attachment 6). As you can see from these attached letters, McIntosh Unit No. 3 was not subject to NSPS Subpart Da when it was constructed and is therefore considered an "existing facility." What is more, the cofiring of petroleum coke in the unit should not trigger Subpart Da applicability.

The federal NSPS rules, which have been incorporated by reference by the Department, provide that physical or operational changes to an existing facility which result in an increase in the emission rate of any pollutant to which a standard applies are considered a "modification." Upon such a modification, the NSPS for the appropriate source category becomes applicable to the existing facility. 40 CFR § 60.14(a), incorporated by reference in Rule 62-296.800(3)(k), Florida Administrative Code. Under Subpart Da, an affected "facility" is an electric utility steam generating *unit* (not the entire plant site). Because the emission rates of the pollutants regulated under Subpart Da (sulfur dioxide, nitrogen oxides, particulate matter, and opacity) do not increase when petroleum coke is cofired at a maximum rate of 20 percent (based on total heat input) with coal (or coal and refuse) in Unit No. 3, the use of petroleum coke should not constitute a "modification" under NSPS.

Moreover, even if the emission rates of any regulated air pollutant were increased, the change would not constitute a "modification" because of the exception for the use of alternative fuels. Section 60.14(e) provides that where an existing facility is designed to accommodate an alternative fuel prior to the effective date of a standard, the use of the alterative fuel will not be considered a modification. A unit is considered to be "designed to accommodate" an alternative fuel if it could use the alternative fuel under its construction specifications. 40 CFR § 60.14((e)(4). Subpart Da became effective for electric utility steam generating units in September of 1978, and because petroleum coke is so similar in substance to coal, Unit No. 3 can easily burn petroleum coke without changes to its design, as demonstrated by the recent test burn. Because the Unit was therefore designed to accommodate petroleum coke, the NSPS definition of "modification" should not be triggered and Subpart Da should not apply.

Furthermore, EPA has consistently determined that the use of an alternative fuel in a unit that was designed to accommodate such fuel does not constitute a modification, and, as stated previously in footnote 1, the Department is required by EPA under the State's NSPS delegation to issue applicability determinations that are consistent with those made by EPA in the past.

Letter from Bruce P. Miller, Chief, Air Programs Branch, Air, Pesticides, and Toxics Management Division, EPA Region IV, to Steve Smallwood, Chief, Bureau of Air Quality Management, Florida Department of Environmental Protection, dated May 2, 1988, page 3. For examples of EPA NSPS applicability determinations based on the alternative fuels exemption, see letter from Director, Division of Stationary Source Enforcement, EPA Region VI, to Arkansas Power & Light Company, dated March 22, 1974 (Attachment 7) and letter from Jewell A. Harper, Chief, Air Enforcement Branch, EPA Region IV, to Clair H. Fancy, P.E., Chief, Bureau of Air Regulation, Florida Department of Environmental Regulation, dated May 22, 1990 (finding that the exemption at 40 CFR § 60.14(e)(4) was applicable because, as originally constructed, the unit could accommodate an alternative fuel) (Attachment 8).

To be consistent with the Department's own Rule 62-296.800(3)(k), Florida Administrative Code, 40 CFR § 60.14, and earlier EPA determinations, the City of Lakeland respectfully requests that the Department concur in its analysis that because the McIntosh Unit No. 3 is not currently subject to NSPS Subpart Da (i.e., it is an "existing unit") and because the Unit was designed to accommodate petroleum coke, the NSPS definition of "modification" is not triggered and Subpart Da does not become applicable. As stated above, if additional information is needed for the Department to make this determination, please let us know.

PSD Review

As stated in the November 10 letter to you, it is the City of Lakeland's position that the cofiring of petroleum coke in Unit No. 3 should not constitute a "modification" under Rule 62-212.200(46), Florida Administrative Code. The Department defines modification to be a physical change or change in the method of operation which causes an increase in actual emissions of any regulated air pollutant.[2] As demonstrated by the recent test burn, the burning of petroleum coke does not require any physical or operational changes. Petroleum coke has slightly different characteristics than coal, but it is so similar substantively that no changes to the plant are necessary for its use. Petroleum coke can be burned in Unit No. 3 without any changes to the fuel transportation and handling systems or to the boiler itself. Unlike a typical fuel switch situation, the cofiring of petroleum coke, which is so similar to coal, will not require changes at the plant. Because no physical or operational changes are required for the use of petroleum coke, the definition of modification should not be triggered.

Even if the Department finds that the use of petroleum coke constitutes an operational change, the use should not constitute a modification since it will not result in an increase in the

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2 The definition includes certain limited exceptions for routine maintenance, repair, or replacement of component parts and changes in the hours of operation or production rate, none of which apply.

actual emissions of any regulated air pollutant. In fact, when petroleum coke is cofired with other fuels at a maximum rate of 20 percent by weight, the potential emissions are actually decreased. Currently, Unit No. 3 is allowed to use coal that contains up to 3.3% sulfur. As proposed by the City of Lakeland, only a small amount of petroleum coke, which has a sulfur content of approximately 5%, will be cofired with medium sulfur coal (2.5%) at a maximum cofiring rate of 10 percent, and with low sulfur coal (1%) at a maximum cofiring rate of 20 percent. As a result, the total sulfur content would be a maximum of 2.75 percent, which is lower the sulfur content allowed for coal alone and which would therefore be environmentally beneficial. In addition to the reduction in potential sulfur dioxide emissions, the test results indicate that, at these cofiring percentages, all regulated air pollutant emissions would be within the permitted limits.

In determining whether an increase in actual emissions has occurred, the Department's rules generally require that past actual emissions be compared to future potential emissions or, for electric utilities, to representative (future) actual emissions. Alternatively, the Department's rules allow the Department to *presume* that *federally enforceable allowable emissions* are equivalent to an emission unit's *actual* emissions, even where a source has begun normal operations. Rule 62-212.200(2)(a), (b), Florida Administrative Code. If the federally enforceable allowable emissions for Unit No. 3 are presumed to be the actual emissions, then no increase will occur. Certainly the City of Lakeland could burn a high sulfur coal (maximum of 3.3% sulfur) at any time, and the use of a lower emitting fuel in recent years should not be used to the detriment of the City when determining whether a modification has occurred. Any increase in actual emissions based on historical data where low sulfur coal has been used would artificially indicate an increase in actual emissions when compared to allowable emissions (regardless of whether coal is fired alone or coal is cofired with petroleum coke). The increase in emissions is therefore not caused by the use of petroleum coke as much as it is caused by the comparison between historical emissions and allowable emissions. The City of Lakeland therefore respectfully requests that the Department exercise its discretion to presume that Unit No. 3's allowable emissions are equivalent to the actual emissions. If this presumption is made, then no increase in actual emissions will occur because the emissions during petroleum coke cofiring will not exceed the allowable emissions.

As stated in the City of Lakeland's December 10 letter, Dennis Crumpler of EPA's Office of Air Quality Planning Standards generally agreed that the proposed cofiring of petroleum coke would not constitute a modification, and that neither PSD nor NSPS would apply. Likewise, Greg Worley of EPA Region IV stated that EPA would likely adopt a state determination that the cofiring of petroleum coke did not constitute a modification and that neither PSD nor NSPS were triggered.

If the Department rejects this analysis and determines that use of petroleum coke would constitute a "modification" and that PSD review applies, control technology review should nevertheless *not* be required for Unit No. 3. The City of Lakeland requests the Department's concurrence that Best Available Control Technology (BACT) review should not be required for Unit No. 3 since it is capable of accommodating petroleum coke and since no physical or operational changes are necessary to the boiler. Such a determination would be completely consistent with the coal conversion policy developed by EPA over a decade ago. That policy exempted boilers designed to accommodate an alternative fuel from BACT review where the individual boiler was capable of firing the new fuel with minimal physical changes (e.g., change of burners only). BACT analysis was not required for the boilers since, individually, they were designed to accommodate the alternative fuel and therefore were not undergoing a physical change or change in the method of operation. Letter from Chief, Air Management Branch, EPA Region IV, to Steve Smallwood, Chief, Bureau of Air Quality Management, Florida Department of Environmental Regulation, dated June 7, 1983 (Attachment 9).

Consistent with this determination, EPA's Office of Air Quality Planning and Standards issued a determination in 1990 stating that even if the use of an alternative fuel triggered PSD review for the facility (plant site), the use of an alternative fuel in a boiler (even if slight changes to the burners were required) is not "a physical change or change in the method of operation in the unit, and, consequently, would not subject the boiler to a BACT review." EPA stated that if the sole change to a boiler were the addition of new burners (gas canes) then the only requirements necessary for a PSD permit would be "an air quality analysis, additional impacts analysis, and (if applicable) a Class I impact analysis." Specifically, the application of BACT to the boiler was *not required.* Letter from Gerald A. Emison, Director, Office of Air Quality Planning and Standards, EPA, to Detroit Edison Company, dated January 18, 1990 (attached as Attachment 10). Later that same year, EPA issued yet another determination that where a boiler itself is capable of accommodating an alternative fuel, the applicant is not required to perform a BACT analysis. Letter from EPA Region IV to the Florida Department of Environmental Regulation, dated May 22, 1990 (Attachment 8).

Like the boilers in these determinations, the McIntosh Unit No. 3 boiler is capable of accommodating an alternative fuel and, even if PSD review is required for the facility, BACT review should not be required for the boiler. The McIntosh Unit No. 3 boiler is completely capable of accommodating petroleum coke--not even minor changes are required, as evidenced by the recent test burn. The City of Lakeland therefore requests the Department's concurrence that, because the McIntosh Unit No. 3 boiler is capable of accommodating petroleum coke and no physical or operational changes are necessary, no BACT analysis will be required for the unit. Again, if additional information is needed for the Department to make its determination, please let us know.

Thank you for your continued cooperation and for your consideration of this request. We look forward to meeting with you on Thursday, December 1, 1994, at 3:30 p.m. to discuss these issues with you in greater detail. If you have any questions prior to that time, please do not hesitate to contact me.

Sincerely,

Shelton

Farzie Shelton

cc: Dennis Crumpler, EPA/OAQPS
Greg Worley, EPA/Region IV
Ken Kosky, KBN
Angela Morrison, HBGS

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Farzie Shelton
ENVIRONMENTAL COORDINATOR, Ch E.

January 17, 1995

VIA HAND DELIVERY
Clair Fancy, Chief
Bureau of Air Regulation
Department of Environmental Protection
2600 Blair Stone Road
Tallahassee, FL 32399

Re: City of Lakeland--C.D. McIntosh Power Plant, Unit No. 3
Request to Amend PSD Permit No. PSD-FL-8

Dear Clair:

Please make the following corrections to the package submitted to the Department On January 4, 1995, in the above-referenced matter:

1. Please remove the "seventh" page 26. (Ref. No. 14262Y1/F3/TVD-S16 (12/30/94) (bottom right corner)) The previous page, which also provides information regarding natural gas and includes a max sulfur content of 1%, is correct.

2. Please replace page 28 (Ref. no. 14262Y1/F3/TVE-PI1 (12/30/94)). Line no. 5 should read "Method of Compliance: Annual Stack Test <u>if > 400 hours of operation.</u>

3. Please replace page 28 (Ref. no. 14262Y2/F3/TVE-PI3a (01/04/95) with the enclosed page (poor copy quality).

Thank you for your assistance in this matter. Please call me if you have any questions.

Sincerely,

Farzie Shelton

Allowable Emissions (Pollutant identified on front page)

A.

1. Basis for Allowable Emissions Code: Rule	
2. Future Effective Date of Allowable Emissions: Not applicable	
3. Requested Allowable Emissions and Units: 0.1 lb/MMBtu	
4. Equivalent Allowable Emissions: 364 lbs/hr	1,594 tons/yr
5. Method of Compliance: Annual Stack Test if >400 hours of operation	
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode): The allowable emission limit is based on FDEP Rule 62-296.800; 40 CFR Part 60, Subpart D (see also Attachment 1).	

B. Not Applicable

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):	

Allowable Emissions (Pollutant identified on front page)

C. Natural gas firing

1. Basis for Allowable Emissions Code: Rule	
2. Future Effective Date of Allowable Emissions: Not applicable	
3. Requested Allowable Emissions and Units: 0.2 lb/MMBtu	
4. Equivalent Allowable Emissions: 728 lbs/hr	3,188.6 tons/yr
5. Method of Compliance: Annual stack test if > 400 hours operation	
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode): The allowable emission limit is based on FDEP Rule 62-296.800; 40 CFR Part 60, Subpart D, Section 60.44(a)(1) (see also Attachment 1).	

D.

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):	

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Farzie Shelton
ENVIRONMENTAL COORDINATOR, Ch E.

January 4, 1995

Clair H. Fancy, Chief
Bureau of Air Regulation
Division of Air Resources Management
Department of Environmental Protection
2600 Blair Stone Road
Tallahassee, FL 32399

RE: City of Lakeland--C.D. McIntosh Power Plant, Unit No. 3
Request to Amend PSD Permit No. PSD-FL-8

Dear Clair:

The City of Lakeland ("Lakeland") requests minor amendments to the above-referenced prevention of significant deterioration (PSD) permit (and corresponding application) for its McIntosh Power Plant, Unit No. 3. Lakeland originally submitted a PSD permit application to the U.S. Environmental Protection Agency (EPA) in February of 1978, and EPA subsequently issued the permit on December 27, 1978, authorizing construction of the coal-, municipal refuse-, and oil-fired steam electric generation unit. Consistent with its permit, the unit was later constructed and actual start-up occurred on September 1, 1982. As a result of the final unit design, the City has identified several needed changes to the PSD permit and corresponding application:

- Adjust particulate matter limits to 0.1 lb/mmBtu heat input (regardless of the fuel being burned);
- Clarify that the minimum sulfur dioxide (SO_2) removal efficiency of 85 percent applies only when high sulfur coal is burned;
- Delete the requirement to install an SO_2 monitor at the inlet to the scrubber, since the monitor at the stack is sufficient for use in determining SO_2 removal efficiencies; and
- Recognize that natural gas and low sulfur oil may be used as startup fuels or at any other time.

In addition, based on a successful test burn of petroleum coke, the City requests that the PSD permit be amended to specifically allow such fuel to be cofired with permitted fuels. When petroleum coke is blended in the appropriate amounts with coal (or coal and refuse), the particulate matter, sulfur dioxide, nitrogen oxides, and opacity limits will not be exceeded. The total amount of petroleum coke will not exceed 20 percent (by weight).

As we stated in our December 1, 1994, letter to you, neither New Source Performance Standard Subpart Da applicability nor Prevention of Significant Deterioration (PSD) review should be triggered by the requested permit revisions. Based on recent telephone conversations with Bruce Mitchell of the Department's Bureau of Air Regulation, I understand that the Department has concurred with our analysis, except that it may be appropriate to require PSD review for carbon monoxide and sulfur acid mist emissions. As the information from the test burn indicates, however, no increase in sulfuric acid mist emissions should occur as a result of cofiring petroleum coke with other permitted fuels.

The test burn data indicates only a slightly higher emission rate for sulfuric acid mist when cofiring petroleum coke with coal than when coal with a sulfur content of 2.5 percent is burned alone; however, the student "t" test indicates that there is no statistical difference between these emission rates. This approach for determining emission rate changes is consistent with 40 CFR Part 60, Appendix C. Further, while the emission rate for carbon monoxide when petroleum coke was cofired during the test burn is statistically higher than when coal was burned alone during the test, the higher rate is attributable to the differences in grindability between the high and low sulfur coals used and to combustion conditions, as opposed to the characteristics of petroleum coke. (See memorandum from Timothy C. Bates, Acting Plant Manager for McIntosh Power Plant, dated December 29, 1994, included as Attachment C.)

Because no increase in regulated air pollutant emissions will occur as a result of cofiring petroleum coke with other permitted fuels, PSD review should not be triggered for any pollutants. Moreover, even if PSD review is required, control technology review for the boiler should not be required since no physical or operational changes are being made to the boiler to cofire petroleum coke.

The City of Lakeland respectfully requests that the Department accept the requested changes to the PSD application and make the requested changes to the PSD permit. In support of Lakeland's requested permit revisions and to illustrate the requested changes to its application, a permit application has been prepared on the Department's new form and is enclosed as Attachment A. (Some of the information requested on the application form will be submitted within the next few months when the Title V application for the McIntosh Plant is submitted.) In addition, the PSD permit, as proposed to be revised, is enclosed as Attachment B and is also being provided on a computer disk, WordPerfect 5.1 format.

In support of its request, Lakeland provides the following information.

Particulate Matter Limits

The particulate matter limits included in the PSD permit should be changed to 0.1 lb/mmBtu heat input (regardless of the type of fuel burned), consistent with the corresponding Site Certification and New Source Performance Standard (NSPS) Subpart D. The lower limits were included in the permit because it was anticipated that the Unit might be subject to NSPS Subpart Da (40 CFR 60.40a-60.49a), which was proposed on September 19, 1978--just three months prior to issuance of the permit. The Subpart Da requirements would have applied to the Unit *if* it had commenced construction on or after the proposal date of September 19, 1978, even though the rules were not finalized until the following year. After the Unit's permit had been issued, the U.S. Environmental Protection Agency determined in March of 1979 that the Unit had commenced construction on March 21, 1978, *prior* to the effective date of Subpart Da. The Unit was therefore subject only to Subpart D and *not* Subpart Da. The particulate matter limits should therefore be appropriately adjusted to the Subpart D limit of 0.1 lb/mmBtu heat input. 40 CFR § 60.42(a)(1). This limit is also consistent with Rule 62-296.405(1)(b), Florida Administrative Code.

Accordingly, the City requests that Condition No. 1 of the permit be changed as follows:

A. Particulate matter emitted to the atmosphere from the boiler shall not exceed 0.1 lb/mmBtu heat input, regardless of the fuel burned.

~~Mode of Firing~~	~~lb/10^6 Btu Heat Input~~
~~Coal~~	~~0.044~~
~~Coal/Refuse~~	~~0.050~~
~~Oil~~	~~0.070~~
~~Oil/Refuse~~	~~0.075~~

Sulfur Dioxide Removal Efficiency

The City of Lakeland proposed a removal efficiency of 85 percent of the sulfur dioxide from the stack gases through installation of a limestone scrubber based on the expectation of utilizing "high sulfur" coal (sulfur content of 3.3 percent). Because the City's application was based on a proposed revision to the New Source Performance Standards for power plants under Subpart Da and Unit No. 3 is *not* subject to Subpart Da standards, the Unit should *not* be required to comply with an 85 percent removal rate when lower sulfur fuels are burned. *See* letter from the U.S. Environmental Protection Agency to the City of Lakeland dated March 2,

1979. Further, the limit of 1.2 lb/mmBtu heat input applies, regardless of the removal efficiency.

The actual sulfur dioxide emissions will be much less than 1.2 lb/mmBtu even when the 85 percent removal rate is not achieved because the desulfurization unit will continue to operate even when lower sulfur coal (or coal/refuse/petroleum coke combinations) is burned. In other words, the resultant sulfur dioxide emissions when burning a lower sulfur fuel (sulfur content of less than 3.3 percent) and operating the desulfurization unit will be less than the sulfur dioxide emissions would be if high sulfur coal (3.3 percent sulfur) were burned, even with the desulfurization unit operating at an 85 percent removal efficiency. An 85 percent removal efficiency should therefore not be required when lower sulfur fuels are burned.

Accordingly, Condition 2.B. should be changed as follows:

> A flue gas desulfurization system will be installed to treat all exhaust gases. The desulfurization system ~~and~~ will operate at a minimum SO_2 removal efficiency of 85 percent whenever high sulfur (3.3% sulfur) coal is burned.

Monitor for Sulfur Dioxide Removal Efficiency

The PSD permit for McIntosh Unit No. 3 required the installation and operation of sulfur dioxide (SO_2) continuous emissions monitors (CEMs), both before and after the flue gas desulfurization unit, to calculate sulfur removal efficiencies. Consequently, when Unit No. 3 was constructed, SO_2 CEMs were installed both before and after the flue gas desulfurization unit. Subsequent to installation however, the CEM located before the flue gas desulfurization unit has not performed as consistently as desired (and has in fact malfunctioned) due to the high level of sulfuric acid in the flue gas prior to the desulfurization unit. Sulfur removal efficiencies can be determined by calculating the sulfur dioxide emission rate prior to the desulfurization unit based on the sulfur content of the fuel being burned and comparing that rate to the sulfur dioxide emission rate recorded by the CEM installed *after* the desulfurization unit. Because this alternative method of determining the sulfur removal efficiency exists and because it is impracticable to successfully operate a CEM prior to the desulfurization unit, the City respectfully requests that Condition No. 6 be revised as follows:

> Continuous monitors shall be installed and operated in accordance with 40 CFR 60.45 and 60.13. ~~In addition, a continuous SO_2 monitor shall be installed prior to the flue gas desulfurization system for purposes of calculating SO_2 removal efficiencies.~~

Startup Fuels

Because, like all other coal units, Unit No. 3 must be started on natural gas or fuel oil, Lakeland requests that the PSD permit be revised to reflect that natural gas and low sulfur fuel oil may be burned during startup. Further, because these fuels are "clean fuels," Lakeland also requests that the PSD permit be revised to clarify that these fuels may be burned at any time.

Petroleum Coke

As stated above, the City of Lakeland recently conducted a successful test burn of petroleum coke blended with coal. In an effort to use the most cost-effective fuels while not increasing emissions above allowable limits, the City of Lakeland requests that its PSD permit be revised to allow petroleum coke to be burned when blended with coal. Because continuous emissions monitors are installed for sulfur dioxide, nitrogen oxides, and opacity, as required by the PSD permit (Condition No. 6) and NSPS (40 CFR § 60.45), the City can ensure that the emission limits for these pollutants are not exceeded when petroleum coke is blended with coal (or coal and refuse) and burned in Unit No. 3. The City accordingly requests that a Condition No. 8 be added as follows:

8. The following fuels may be burned:

   Coal only
   Oil only
   Coal and up to 10% refuse (based on heat input)
   Oil and up to 10% refuse (based on heat input)
   Coal and up to 20% petroleum coke (based on weight)
   Coal and up to 20% petroleum coke (based on weight) and 10% refuse (based on heat input)

In addition to this request to amend the PSD permit and application, Lakeland is seeking a separate modification of the site certification for Unit No. 3, which was issued pursuant to the Florida Power Plant Siting Act (PA-74-06) on December 7, 1978. The request for modification of the site certification, dated December 7, 1994, is attached to the enclosed permit application as Attachment SI-1.

Thank you for your consideration of this request. If you have any questions, please contact me at 813-499-6603.

Sincerely,

Farzie Shelton

arm/ Farzie Shelton
Environmental Affairs
Department of Electric & Water Utilities

(4 copies enclosed)

cc: Hamilton S. Oven, Jr., DEP
Bill Thomas, DEP SW District
Mike Hickey, DEP SW District
Jewell Harper, EPA Region IV
Brian Beals, EPA Region IV
Ken Kosky, KBN
Angela Morrison, HBGS

45193

CITY OF LAKELAND C.D. MCINTOSH UNIT 3
REVISED APPLICATION FOR CO-FIRING PETROLEUM COKE

This correspondence provides information on the City's application to co-fire petroleum coke and coal at McIntosh Unit 3. The information presented herein addresses the issues raised in the Department's September 11, 1995, correspondence. The information is organized according to each pollutant addressed in the Department's letter. For completeness, portions of the previous application have been revised and are enclosed herein.

Sulfur Dioxide Emissions

As noted in the September 11, 1995, correspondence, the Department proposes that the determination of actual sulfur dioxide (SO_2) emissions for comparison the future representative actual annual emissions should be based on the recently revised SO_2 emission limits.

The City proposes to co-fire petroleum coke and coal at a calculated allowable 1994 and 1995 emission rate based on the information presented in the application on heat input, coal heat content, 1994 and 1995 coal sulfur contents and annual usage rates, and allowable emission rate. The calculated allowable emission rate is as follows:

Design Data:

Coal usage for Unit 3 = 159.6 tons coal/hour

Heat input for Unit 3 = 3,640 MMBtu/hour

Note: Coal usage and heat input are the design basis provided in the application and the recently revised BACT determination.

Uncontrolled SO_2 Emissions:

1994 sulfur content = 1.12 percent (see attachment)

1995 sulfur content = 1.22 percent (see attachment)

1994/1995 average sulfur content = 1.17 percent

Note: Coal quality data are attached.

159.6 tons coal/hr x 0.0117 ton sulfur/ton coal x 2 tons SO_2 /ton sulfur

= 3.7346 tons SO_2

Calculated allowable SO_2 emission rate (based on revised BACT):

3.7346 tons SO_2 x (1 - 0.65) = 1.3071 tons/hr

1.3071 tons/hr x 2,000 lb/ton x 1 hr/3,640 MMBtu = 0.7182 lb/MMBtu

Calculated annual allowable SO_2 emissions:

1994 usage = 991,351 tons/year

1995 usage = 949,553 tons/year (prorated from January through September)

(Usage through September = 710,213.75 tons; days in October, November, and December = 92; prorated usage = 710,213.75 tons x 365 x 1/273)

Actual emissions = 970,452 tons/year x 0.0117 ton sulfur/ton coal x 2 tons SO_2/ton sulfur x (1 - 0.65) = 7,948.0 tons/year

The City proposes an emission limit of 0.7182 lb/MMBtu (30-day rolling average) when burning 10 to 20 percent petroleum coke. Because of the complexity of determining the exact proportions of coal at percentages less than 10 percent (this would usually occur at the beginning and end of blending), the emission limit in the revised BACT would govern.

The proposed emission limit is also supported by the coal quality of the 1994 and 1995 compliance tests. The allowable SO_2 emission rate is calculated as follows:

<u>1994 Coal Quality</u>

1.26% S/100 x 2 lb SO_2/lb S x 1/12,847 Btu/lb x 10^6 x 0.35 = 0.687 lb/MMBtu

<u>1995 Coal Quality</u>

1.29% S/100 x 2 lb SO_2/lb S x 1/12,806 Btu/lb x 10^6 x 0.35 = 0.705 lb/MMBtu

<u>1994/95 Average</u>

(0.687 + 0.705)/2 = 0.696 lb/MMBtu

The coal quality data are attached.

The City also proposes to co-fire petroleum coke and coal so that emissions when co-firing do not exceed 7,948.0 tons/year which represents the calculated actual allowable emissions for 1994/1995. Taking together the proposed SO_2 emissions limit when co-firing and the actual hours of operation, the calculated actual annual SO_2 emissions and the "representative future SO_2 emissions" would be equal for PSD purposes. Therefore, PSD review would not be necessary according to Rule 62-212.200(2)(d), F.A.C. and 40 CFR 52.21(b)(33).

Sulfuric Acid Mist Emissions

The co-firing test data do not support the Department's contention that the presence of vanadium in petroleum coke increases sulfuric acid mist emissions over the range of petroleum coke to be fired (i.e., up to 20 percent). As discussed in Attachment 1, statistical analysis clearly demonstrated that there was no statistically significant difference between any of the test conditions. As shown in Table 1 of Attachment 1, all tests were determined to be not statistically different based on the procedures in 40 CFR Part 60 Appendix C for determining increases in emission rates (see attached Appendix C). Moreover, the test condition using 10 percent petroleum coke with 90 percent coal was 11.25 percent *lower* than the coal-only test. The 20 percent petroleum coke with 80 percent coal was only 6.25 percent higher than the coal-only test. If there was an effect of vanadium in petroleum coke, then the effect should be consistent between test runs which is clearly not the case.

The conclusion that vanadium concentrations did not affect sulfuric acid mist concentrations in the range requested (up to 20 percent) is also supported by analyses of vanadium in the 10 percent and 20 percent petroleum coke and coal mixtures. The average vanadium concentrations were:

10 percent petroleum coke and high sulfur coal	311 ppm
20 percent petroleum coke and low sulfur coal	177 ppm

Again, if sulfuric acid mist emissions are directly proportional to vanadium, then the tests demonstrated the opposite effect.

Carbon Monoxide Emissions

The information previously presented supports the City's position that CO was a result of factors other than the use of petroleum coke. The data presented in Attachment 1 clearly suggest that the grindability and oxygen concentration are the major factors for the difference between coal-only and coal with 20 percent petroleum coke. Indeed, the effect of petroleum coke would appear to lower CO concentrations since the 10 percent petroleum coke with 90 percent high-sulfur coal was 7.4 percent *lower* than the high-sulfur coal-only test. If petroleum coke had an effect, it would have been apparent in this test comparison. The major difference using a slightly higher percentage of petroleum coke was the kind of coal, i.e., high sulfur versus low sulfur.

would have been apparent in this test comparison. The major difference using a slightly higher percentage of petroleum coke was the kind of coal, i.e., high sulfur versus low sulfur.

As noted in Attachment 1, oxygen concentration was quite different and lower during the low sulfur coal/20 percent petroleum coke test burn. This difference was about 0.8 percent O_2 or about 10 percent lower than the high sulfur coal test condition. Changes in oxygen concentration of this magnitude can have a significant influence on CO concentrations. Difference of several 100 ppm CO has been observed with oxygen concentrations of as little as 0.1 percent change.

Taking together the test data and engineering principals of CO formation, it is concluded that using up to 20 percent petroleum coke will not increase emissions of CO.

Nitrogen Oxides Emissions

The City does not believe additional tests of NO_x emissions are necessary and co-firing petroleum coke will not cause an increase in NO_x emissions. As discussed in Attachment 1, statistical analysis clearly demonstrated that there was no statistically significant difference or increase in NO_x emissions between any of the test conditions. While the test condition using 10 percent petroleum coke with 90 percent coal was 1.4 percent *higher* than the coal-only test, the 20 percent petroleum coke with 80 percent coal was 23.5 percent *lower* than the coal-only test. If there was an effect on NO_x emissions using petroleum coke, then the effect should be consistent between test runs, which was not the case. Indeed, there is more variability within the test method itself than the 1.4 percent difference detected.

Moreover, the 1995 CEM data support the variability in NO_x emissions that occur. The monthly NO_x emissions for 1995 are as follows: January - 0.50 lb/MMBtu; February - 0.47 lb/MMBtu; March - 0.45 lb/MMBtu; April - 0.51 lb/MMBtu; May - 0.49 lb/MMBtu; June - 0.54 lb/MMBtu; July - 0.56 lb/MMBtu. The NO_x emissions during the 1995 compliance test averaged 0.63 lb/MMBtu while low-sulfur coal was being used. During the test burn, the NO_x emission rates were 0.55 and 0.41 lb/MMBtu, respectively, for the 10 percent and 20 percent petroleum coke test burns. Clearly, the NO_x emission rate when firing coal or a blend of coal and petroleum coke within the proposed range is a function of combustion conditions and not the fuel.

Particulate Matter Emissions

Emissions of particulate when firing petroleum coke were all less than when firing coal. Therefore, no effect of co-firing petroleum coke on the emission rate was observed, and PSD is not applicable since there is no increase in emissions.

Summary

The City proposes that the Department approve the co-firing of up to 20 percent petroleum coke with coal at an emission rate not to exceed 0.718 lb/MMBtu and no more than 7,948 tons per year when co-firing petroleum coke and coal. This would effectively produce no net increase in actual emissions. For the other pollutants, no increase in emissions is attributable to firing petroleum coke. The test results for NO_x and sulfuric acid mist were determined to be not different based on 40 CFR Part 60 Appendix C. Emissions of CO are attributable to combustion conditions and not petroleum coke firing.

Professional Engineer's Statement

This revision to the original application is submitted under the same certification provided with the original application.

Kennard F. Kosky — 10/16/95 — KS SEAL

Signature — Date

Professional Engineer Registration No. 14996

REVISED APPLICATION PAGES

(Note: The previous pollutant information pages are not relevant to the requested change. Only SO_2 will be affected by co-firing.)

Category II: All Air Operation Permit Applications Subject to Processing Under Rule 62-210.300(2)(b), F.A.C.

This Application for Air Permit is submitted to obtain:

[ ] Initial air operation permit under Rule 62-210.300(2)(b), F.A.C., for an existing facility seeking classification as a synthetic non-Title V source.

Current operation/construction permit number(s): ______________________

____

[ ] Renewal air operation permit under Rule 62-210.300(2)(b), F.A.C., for a synthetic non-Title V source.

Operation permit to be renewed: ______________________

[ ] Air operation permit revision for a synthetic non-Title V source. Give reason for revision; e.g., to address one or more newly constructed or modified emissions units.

Operation permit to be revised: ______________________

Reason for revision: ______________________

____

Category III: All Air Construction Permit Applications for All Facilities and Emissions Units

This Application for Air Permit is submitted to obtain:

[X] Air construction permit to construct or modify one or more emissions units within a facility (including any facility classified as a Title V source).

Current operation permit number(s), if any: PA 74-06-SR (PPSA); PSD-FL-008

[ ] Air construction permit to make federally enforceable an assumed restriction on the potential emissions of one or more existing, permitted emissions units.

Current operation permit number(s): ______________________

[ ] Air construction permit for one or more existing, but unpermitted, emissions units.

Professional Engineer Certification

1. Professional Engineer Name: Kennard F. Kosky Registration Number: 14996	
2. Professional Engineer Mailing Address: Organization/Firm: KBN Engineering and Applied Sciences, Inc. Street Address: 6241 NW 23rd Street, Suite 500 City: Gainesville State: FL Zip Code: 32653-1500	
3. Professional Engineer Telephone Numbers: Telephone: (904) 336-5600 Fax: (904) 336-6603	

4. Professional Engineer Statement:

I, the undersigned, hereby certify, except as particularly noted herein, that:*

(1) To the best of my knowledge, there is reasonable assurance (a) that the air pollutant emissions unit(s) and the air pollution control equipment described in this Application for Air Permit, when properly operated and maintained, will comply with all applicable standards for control of air pollutant emissions found in the Florida Statutes and rules of the Department of Environmental Protection; or (b) for any application for a Title V source air operation permit, that each emissions unit described in this Application for Air Permit, when properly operated and maintained, will comply with the applicable requirements identified in this application to which the unit is subject, except those emissions units for which a compliance schedule is submitted with this application;

(2) To the best of my knowledge, any emission estimates reported or relied on in this application are true, accurate, and complete and are either based upon reasonable techniques available for calculating emissions or, for emission estimates of hazardous air pollutants not regulated for an emissions unit addressed in this application, based solely upon the materials, information and calculations submitted with this application; and

(3) For any application for an air construction permit for one or more proposed new or modified emissions units, the engineering features of each such emissions unit described in this application have been designed or examined by me or individuals under my direct supervision and found to be in conformity with sound engineering principles applicable to the control of emissions of the air pollutants characterized in this application.

Kennard F. Kosky

Signature

October 16, 1995

Date

KK (seal)

* Attach any exception to certification statement.

Application Contact

1. Name and Title of Application Contact: **Ms. Farzie Shelton, Environmental Coordinator**	
2. Application Contact Mailing Address: Organization/Firm: **Lakeland Department of Electric and Water Utilities** Street Address: **501 East Lemon Street** City: **Lakeland** State: **FL** Zip Code: **33801-5099**	
3. Application Contact Telephone Numbers: Telephone: **(941) 499-6603** Fax: **(941) 499-6688**	

Application Comment

This application is being submitted to obtain FDEP recognition that petroleum coke can be burned in McIntosh Unit 3. There will be no new construction of facilities or changes in the current procedures when petroleum coke is being fired in Unit 3. The application also addresses minor amendments to the PSD approval and previous application.

II. FACILITY INFORMATION

A. GENERAL FACILITY INFORMATION

Facility Name, Location, and Type

1. Facility Owner or Operator: City of Lakeland, Department of Electric and Water Utilities			
2. Facility Name: C.D. McIntosh Power Plant			
3. Facility Identification Number: 40TPA530004 [ ] Unknown			
4. Facility Location Information: Facility Street Address: 3030 East Lake Parker Drive City: Lakeland County: Polk Zip Code: 33805			
5. Facility UTM Coordinates: Zone: 17 East (km): 408.5 North (km): 3,105.8			
6. Facility Latitude/Longitude: Latitude (DD/MM/SS): Longitude (DD/MM/SS):			
7. Governmental Facility Code: 4	8. Facility Status Code: A	9. Relocatable Facility? [ ] Yes [X] No	10. Facility Major Group SIC Code: 49
11. Facility Comment:			

Facility Contact

1. Name and Title of Facility Contact: Ms. Farzie Shelton, Environmental Coordinator
2. Facility Contact Mailing Address: Organization/Firm: City of Lakeland, Department of Electric and Water Utilities Street Address: 501 East Lemon Street City: Lakeland State: FL Zip Code: 33801-5099
3. Facility Contact Telephone Numbers: Telephone: (941) 499 - 6303 Fax: (941) 499 - 6688

Emissions Unit Operating Capacity

1. Maximum Heat Input Rate:	3,640 mmBtu/hr
2. Maximum Incineration Rate:	Not applicable lbs/hr tons/day
3. Maximum Process or Throughput Rate: **Not Applicable**	
4. Maximum Production Rate: **Not Applicable**	
5. Operating Capacity Comment: **Emissions unit burns coal and refuse-derived fuel (RDF); The emissions unit is authorized to burn residual oil.**	

Emissions Unit Operating Schedule

Requested Maximum Operating Schedule: **Co-firing of coal (and coal/refuse) with petroleum coke.**			
	hours/day		days/week
	weeks/yr	8,760	hours/yr

<u>Segment Description and Rate Information:</u> Segment 5 of 7

1. Segment Description (Process/Fuel Type and Associated Operating Method/Mode): Coal and petroleum coke (80/20 weight basis)	
2. Source Classification Code: 10100101	
3. SCC Units: Tons	
4. Maximum Hourly Rate: 152.6	5. Maximum Annual Rate: 970,452
6. Estimated Annual Activity Factor: Not applicable	
7. Maximum Percent Sulfur: 3.3	8. Maximum Percent Ash: < 15
9. Million Btu per SCC Unit: 23.85	
10. Segment Comment: Maximum hourly rates and percent sulfur will vary depending upon mixture. Coal and petroleum coke will be blended to a maximum sulfur content of 3.3 percent. Typical sulfur content of petroleum is 5 percent. Maximum hourly rate based on 122.1 TPH coal and 30.5 TPH petroleum coke. Heat content of mixture based on maximum hourly rate (TPH) and maximum heat input rating for unit of 3,640 MMBtu/hr. Maximum annual rate based on calculated actual allowable emissions for 1994 and 1995. Heat contents of coal and petroleum coke are 22.81 and 28.0 MMBtu/ton (see also FA-1).	

Emissions Unit Information Section 1 of 1

Segment Description and Rate Information: Segment 6 of 7

1. Segment Description (Process/Fuel Type and Associated Operating Method/Mode): Coal, petroleum coke, and RDF; coal/coke. (80/20 weight basis at 90% of heat input; RDF at 10% heat input)	
2. Source Classification Code: 10100101	
3. SCC Units: Tons	
4. Maximum Hourly Rate: 168.8	5. Maximum Annual Rate: 1,020,452
6. Estimated Annual Activity Factor: Not applicable	
7. Maximum Percent Sulfur: 3.3	8. Maximum Percent Ash: < 15
9. Million Btu per SCC Unit: 21.56	
10. Segment Comment: Maximum hourly rates and percent sulfur will vary depending upon mixture. Coal, RDF, and petroleum coke will be blended to a maximum sulfur content of 3.3 percent for coal/ petroleum mixture. Maximum hourly rate based on 100.9 TPH coal, 40.4 TPH RDF, and 27.5 TPH petroleum coke. Heat content of mixture based on maximum hourly rate (TPH) and maximum heat input rating for unit of 3,640 MMBtu/hr. Maximum annual rate based on calculated actual annual allowable emissions for 1994 and 1995, and 50,000 tons/year of RDF usage.	

Emissions Unit Information Section 1 of 1

Segment Description and Rate Information: Segment 7 of 7

1. Segment Description (Process/Fuel Type and Associated Operating Method/Mode): Natural gas	
2. Source Classification Code: 10100601	
3. SCC Units: Million cubic feet	
4. Maximum Hourly Rate: 3.529	5. Maximum Annual Rate: 30,914
6. Estimated Annual Activity Factor: Not applicable	
7. Maximum Percent Sulfur: 0.003	8. Maximum Percent Ash: Negligible
9. Million Btu per SCC Unit: 1,031.4	
10. Segment Comment: Natural gas is proposed as a supplementary fuel. Heat content of mixture based on maximum hourly rate (TPH) and maximum heat input rating for unit of 3,640 MMBtu/hr.	

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: 87.0 %

3. Primary Control Device Code: 067

4. Secondary Control Device Code: Not applicable

5. Potential Emissions: 2,613.5 lbs/hr 7,948 tons/yr

6. Synthetically Limited? [ ] Yes [X] No

7. Range of Estimated Fugitive/Other Emissions: Not applicable

   [ ] 1 [ ] 2 [ ] 3 _____ to _____ tons/yr

8. Emission Factor: 0.718 lb/MMBtu

   Reference: Proposed emission limit

9. Emissions Method Code:
   [ ] 1 [X] 2 [ ] 3 [ ] 4 [ ] 5

10. Calculation of Emissions:
    3,640 MMBtu/hr x 0.718 lb/MMBtu = 2,613.5 lb/hour

    0.033 lb sulfur/lb coal x 2 lb SO_2/lb sulfur x 2,000 lb/ton x ton/23.85 MMBtu x (1 - 0.87) = 0.718 lb/MMBtu

11. Pollutant Potential/Estimated Emissions Comment: The overall efficiency of sulfur dioxide removal (i.e, 87.0 percent) applies to using a maximum 3.3 percent for the co-firing mixture.

<u>Allowable Emissions</u> (Pollutant identified on front page)

A. Co-Firing

1. Basis for Allowable Emissions Code: **ESCPSD**	
2. Future Effective Date of Allowable Emissions: **Not applicable**	
3. Requested Allowable Emissions and Units: **0.718 lb/MMBtu (30-day rolling average)**	
4. Equivalent Allowable Emissions: **2,613.5** lbs/hr	**7,948** tons/yr
5. Method of Compliance: **Annual stack test**	
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode): **The allowable emission limit is based on FDEP Rule 62-212.200(2)(d) F.A.C. and 40 CFR Part 52.21(b)(33) and calculated actual allowable emissions to limit the emission rate and actual emissions below PSD significant emission rate.**	

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):	

2. Increment Consuming for Nitrogen Dioxide?

If the emissions unit addressed in this section emits nitrogen oxides, answer the following series of questions to make a preliminary determination as to whether or not the emissions unit consumes PSD increment for nitrogen dioxide. Check first statement, if any, that applies and skip remaining statements.

[ ] The emissions unit addressed in this section is undergoing PSD review as part of this application, or has undergone PSD review previously, for nitrogen dioxide. If so, emissions unit consumes increment.

[ ] The facility addressed in this application is classified as an EPA major source pursuant to paragraph (c) of the definition of "major source of air pollution" in Chapter 62-213, F.A.C., and the emissions unit addressed in this section commenced (or will commence) construction after February 8, 1988. If so, baseline emissions are zero, and emissions unit consumes increment.

[ ] The facility addressed in this application is classified as an EPA major source, and the emissions unit began initial operation after February 8, 1988, but before March 28, 1988. If so, baseline emissions are zero, and emissions unit consumes increment.

[ ] For any facility, the emissions unit began (or will begin) initial operation after March 28, 1988. If so, baseline emissions are zero, and emissions unit consumes increment.

[X] None of the above apply. If so, the baseline emissions of the emissions unit are nonzero. In such case, additional analysis, beyond the scope of this application, is needed to determine whether changes in emissions have occurred (or will occur) after the baseline date that may consume or expand increment.

3. Increment Consuming/Expanding Code:			
PM	[X] C	[ ] E	[ ] Unknown
SO2	[X] C	[ ] E	[ ] Unknown
NO2	[ ] C	[ ] E	[ ] Unknown

4. Baseline Emissions:		
PM	lbs/hr	tons/yr
SO2	lbs/hr	tons/yr
NO2		11,160 tons/yr

5. PSD Comment: **Potential emissions assumed for NO_x baseline.**

I. EMISSIONS UNIT SUPPLEMENTAL INFORMATION

This subsection of the Application for Air Permit form provides supplemental information related to the emissions unit addressed in this Emissions Unit Information Section. Supplemental information must be submitted as an attachment to each copy of the form, in hard-copy or computer-readable form.

Supplemental Requirements for All Applications

1. Process Flow Diagram [X] Attached, Document ID: PFD-1 [ ] Not Applicable	[ ] Waiver Requested
2. Fuel Analysis [X] Attached, Document ID: FA-1 [ ] Not Applicable	[ ] Waiver Requested
3. Detailed Description of Control Equipment [ ] Attached, Document ID: ____________ [X] Not Applicable	[ ] Waiver Requested
4. Description of Stack Sampling Facilities [ ] Attached, Document ID: ____________ [X] Not Applicable	[ ] Waiver Requested
5. Compliance Test Report [ ] Attached, Document ID: ____________ [ ] Previously Submitted, Date: __________	[X] Not Applicable
6. Procedures for Startup and Shutdown [ ] Attached, Document ID: __________	[X] Not Applicable
7. Operation and Maintenance Plan [ ] Attached, Document ID: ____________	[X] Not Applicable
8. Supplemental Information for Construction Permit Application [X] Attached, Document ID: SI-1	[ ] Not Applicable
9. Other Information Required by Rule or Statute [ ] Attached, Document ID: ________	[X] Not Applicable

ATTACHMENT 1

DISCUSSION OF TEST BURN

ATTACHMENT 1 - DISCUSSION OF TEST BURN

The City of Lakeland requested in August 1993 authorization from the Florida Department of Environmental Protection (FDEP) to conduct a trial test burn of co-firing petroleum coke and coal (see August 16, 1993 letter from Ms. Farzie Shelton, Environmental Coordinator for Lakeland Department Electric and Water Utilities to Mr. Buck Oven of FDEP). FDEP authorized the trial burn in January 1994 (see letter from Mr. Oven to Ms. Shelton dated January 31, 1994). The trial test burn was conducted in February 1994 with a report of the results furnished to FDEP (see Emission Test Report by Environmental Science & Engineering, Inc. dated February 1994). Three operating conditions were evaluated during the trial test burn:

Condition 1. High-sulfur coal only,

Condition 2. A 90/10 percent blend of high-sulfur coal and petroleum coke, and

Condition 3. A 80/20 percent blend of low-sulfur coal and petroleum coke.

Note: High-sulfur in this context refers to coal with a sulfur content of 2.5 percent. Low-sulfur refers to 1 percent sulfur coal.

Measurements were conducted using U.S. Environmental Protection Agency (EPA) and FDEP sampling procedures for particulate matter, sulfur dioxide, nitrogen oxides, carbon monoxide, and sulfuric acid mist.

The potential applicability of the Prevention of Significant Deterioration (PSD) rules [Rules 62-212.400(2)(d)4, Florida Administrative Code (F.A.C.)] as they may apply to modifications are related to whether a source has a significant increase in actual emissions. The results of the trial test can be used to determine if an emissions increase has occurred. In order to determine any differences in emissions rate for the pollutants that were sampled during the trial test burn, confidence intervals using the student "t" test were performed and are presented in Table 1. Calculations are attached. The results of the evaluation indicated that, except for CO, there was either no statistical difference between emissions from the three test conditions or that emissions when co-firing petroleum were lower than when firing high-sulfur coal. Unit 3 is currently authorized to burn coal with 3.3 percent sulfur content. While the emission rate for sulfuric acid mist under Condition 3 was higher than the emission rate for high-sulfur coal only test condition (Condition 1), the differences were not statistically significant. This was confirmed using the approach outlined in Appendix C of 40 Code of Federal Regulations (CFR) Part 60 for determination of emission rate change (see calculations).

The emission rate of carbon monoxide for Condition 3 was statistically higher than Condition 1. The increase in CO emission was not due to petroleum coke in the coal/petroleum coke mixture. The primary and most important factor causing this increase was due to the hardness measured by the Hardgrove Grindability Index (HGI) of the coal that was being used for the trial test mixture in test condition 3. The petroleum coke used in the test burn had a high HGI. The higher the number, the softer the fuel. The 2.5 percent S coal used in test conditions 1 and 2 (alone and in combination with the coke) had a hardness of 43 HGI. The efficiency of fuel combustion is directly related to the particle size of pulverized coal; the softer (higher HGI) the coal, the greater amount of small particles which will produce overall better combustion and less CO concentrations.

Attached is a graph (Insert A) to show the effect of hardness on the performance of the pulverizers on coal particle size referred to as "fineness." As an example, both mixtures have been plotted based on a feed rate of 70,000 lb/hr. At this feed rate, the lower hardgrove mixture would be expected to give a fineness of ≈ 67 percent passing 200 mesh while the higher hardgrove mixture would be expected to give a fineness of ≈ 85 percent passing 200 mesh. This results in better fuel distribution and combustion and concomitantly lower CO generation. Insert B shows the hardness for the two mixtures used during the tests and an analysis of the petroleum coke used in the mixtures. If the fineness is reduced (i.e., a lower amount of small particles) it reduces the combustion efficiency and degrades the fuel distribution in the combustion zone, thus forming more CO. Therefore, the change in the CO noted during testing is primarily due to the difference between the high sulfur and low sulfur coal hardness and thus grindability.

The higher CO can also be affected by the oxygen (O_2) concentrations observed during the each test condition. The O_2 concentrations during Condition 3 (80/20 coal petroleum coke blend) averaged 6.9 percent. In contrast, the O_2 concentrations during Condition 1 (high-sulfur coal only) averaged 7.7 percent. CO and O_2 concentrations are inversely proportional, suggesting that the higher CO concentrations were a result of combustion conditions and not the fuel. This observation is confirmed by the results for Condition 2 in which O_2 concentrations were the highest (7.8 percent) and CO emission rate was the lowest [0.05 pound per million British thermal units (lb/MMBtu)].

Table 1. Statistical Evaluation of Trial Test Burn for Co-Firing Petroleum Coke at City of Lakeland McIntosh Plant - Unit 3

Pollutant	Test Condition (a)	Average	"t" - distribution Lower 90% C.I.	Upper 90% C.I.	Conclusions (b)
Particulate	1. HSC Only	0.0481	0.0381	0.0582	1=2>3
	2. HSC w/10% PC	0.0459	0.0329	0.0589	2=1>3
	3. LSC w/20% PC	0.0141	0.0096	0.0187	3<1&2
Sulfur Dioxide	1. HSC Only	1.0866	1.0639	1.1094	1=2>3
	2. HSC w/10% PC	1.1087	1.0618	1.0618	2=1>3
	3. LSC w/20% PC	0.8935	0.8585	0.9284	3<1&2
Nitrogen Oxides	1. HSC Only	0.5391	0.5353	0.5428	1=2>3
	2. HSC w/10% PC	0.5466	0.5329	0.5602	2=1>3
	3. LSC w/20% PC	0.4126	0.4052	0.4199	3<1&2
Carbon Monoxide	1. HSC Only	0.0054	0.0044	0.0064	1=2<3
	2. HSC w/10% PC	0.0050	0.0047	0.0053	2=1<3
	3. LSC w/20% PC	0.0890	0.0231	0.1549	3>1&2
Sulfuric Acid Mist	1. HSC Only	0.0240	0.0166	0.0315	1=2=3
	2. HSC w/10% PC	0.0213	0.0167	0.0258	2=1=3
	3. LSC w/20% PC	0.0255	0.0174	0.0336	3=1=2

(a) HSC = High Sulfur Coal; LSC = Low Sulfur Coal; PC = Petroleum Coke
(b) "1, 2, and 3" refer to test conditions; "=" means no significant difference between test conditions; "< and >" refers to a significant difference betwen test conditions.

Calculations for Table 1

Calculations:

PM HSC Only		PM-HSCw/10%PC		PM-LSCw/20%PC	
Run 2	0.054	Run 5	0.0399	Run 8	0.0151
Run 3	0.0483	Run 6	0.0432	Run 9	0.0162
Run 4	0.0421	Run 7	0.0546	Run 10	0.0111
Mean	0.04813333	Mean	0.0459	Mean	0.01413333
STD. DEV.	0.00485958	STD. DEV.	0.00629762	STD. DEV.	0.0021914
V	2	V	2	V	2
ta/2	2.92	ta/2	2.92	ta/2	2.92
C.I.	0.01003383	C.I.	0.01300302	C.I.	0.00452469

SO2 HSC Only		SO2-HSCw/10%PC		SO2-LSCw/20%PC	
Run 1	1.0744	Run 4	1.1399	Run 7	0.9113
Run 2	1.1011	Run 5	1.0865	Run 8	0.8707
Run 3	1.0844	Run 6	1.0997	Run 9	0.8984
Mean	1.08663333	Mean	1.1087	Mean	0.89346667
STD. DEV.	0.01101403	STD. DEV.	0.02271035	STD. DEV.	0.01693799
V	2	V	2	V	2
ta/2	2.92	ta/2	2.92	ta/2	2.92
C.I.	0.02274124	C.I.	0.04689124	C.I.	0.03497275

NOx HSC Only		NOx-HSCw/10%PC		NOx-LSCw/20%PC	
Run 1	0.5385	Run 4	0.5544	Run 7	0.4104
Run 2	0.5372	Run 5	0.5382	Run 8	0.4097
Run 3	0.5415	Run 6	0.5471	Run 9	0.4176
Mean	0.53906667	Mean	0.54656667	Mean	0.41256667
STD. DEV.	0.00180062	STD. DEV.	0.00662437	STD. DEV.	0.00357056
V	2	V	2	V	2
ta/2	2.92	ta/2	2.92	ta/2	2.92
C.I.	0.00371783	C.I.	0.01367767	C.I.	0.00737232

CO HSC Only		CO-HSCw/10%PC		NOx-LSCw/20%PC	
Run 1	0.0061	Run 4	0.0051	Run 7	0.0845
Run 2	0.005	Run 5	0.0048	Run 8	0.1301
Run 3	0.0051	Run 6	0.0051	Run 9	0.0523
Mean	0.0054	Mean	0.005	Mean	0.08896667
STD. DEV.	0.00049666	STD. DEV.	0.00014142	STD. DEV.	0.03191837
V	2	V	2	V	2
ta/2	2.92	ta/2	2.92	ta/2	2.92
C.I.	0.00102547	C.I.	0.000292	C.I.	0.06590351

Calculations for Table 1

H2SO4 HSC Only		H2SO4-HSCw/10%PC		H2SO4-LSCw/20%PC	
Run 1	0.0248	Run 4	0.0204	Run 7	0.0208
Run 2	0.028	Run 5	0.0243	Run 8	0.0304
Run 3	0.0193	Run 6	0.0191	Run 9	0.0254
Mean	0.02403333	Mean	0.02126667	Mean	0.02553333
STD. DEV.	0.00359289	STD. DEV.	0.00220958	STD. DEV.	0.00392032
V	2	V	2	V	2
ta/2	2.92	ta/2	2.92	ta/2	2.92
C.I.	0.00741843	C.I.	0.00456222	C.I.	0.00809448

40 CFR Part 60, Appendix C Calculation

H2SO4 HSC Only		H2SO4-LSCw/20%PC	
Run 1	0.0248	Run 7	0.0208
Run 2	0.028	Run 8	0.0304
Run 3	0.0193	Run 9	0.0254
Mean	0.02403333	Mean	0.02553333
Sa^2	0.00001936	Sa^2	0.00002305
Sp^2	0.00460525		
t	0.39891799		
t'	2.132		

no significant difference

40 CFR Part 60, Appendix C Calculation - Test

Run A		Run B	
Run 1	100	Run 7	115
Run 2	95	Run 8	120
Run 3	110	Run 9	125
Mean	101.666667	Mean	120
Sa^2	58.3333333	Sb^2	25
Sp^2	6.45497224		
t	3.47850543		
t'	2.132		

significant difference-same as CFR Example

Note: CFR example has round-off which produces slightly different values.

INSERT A

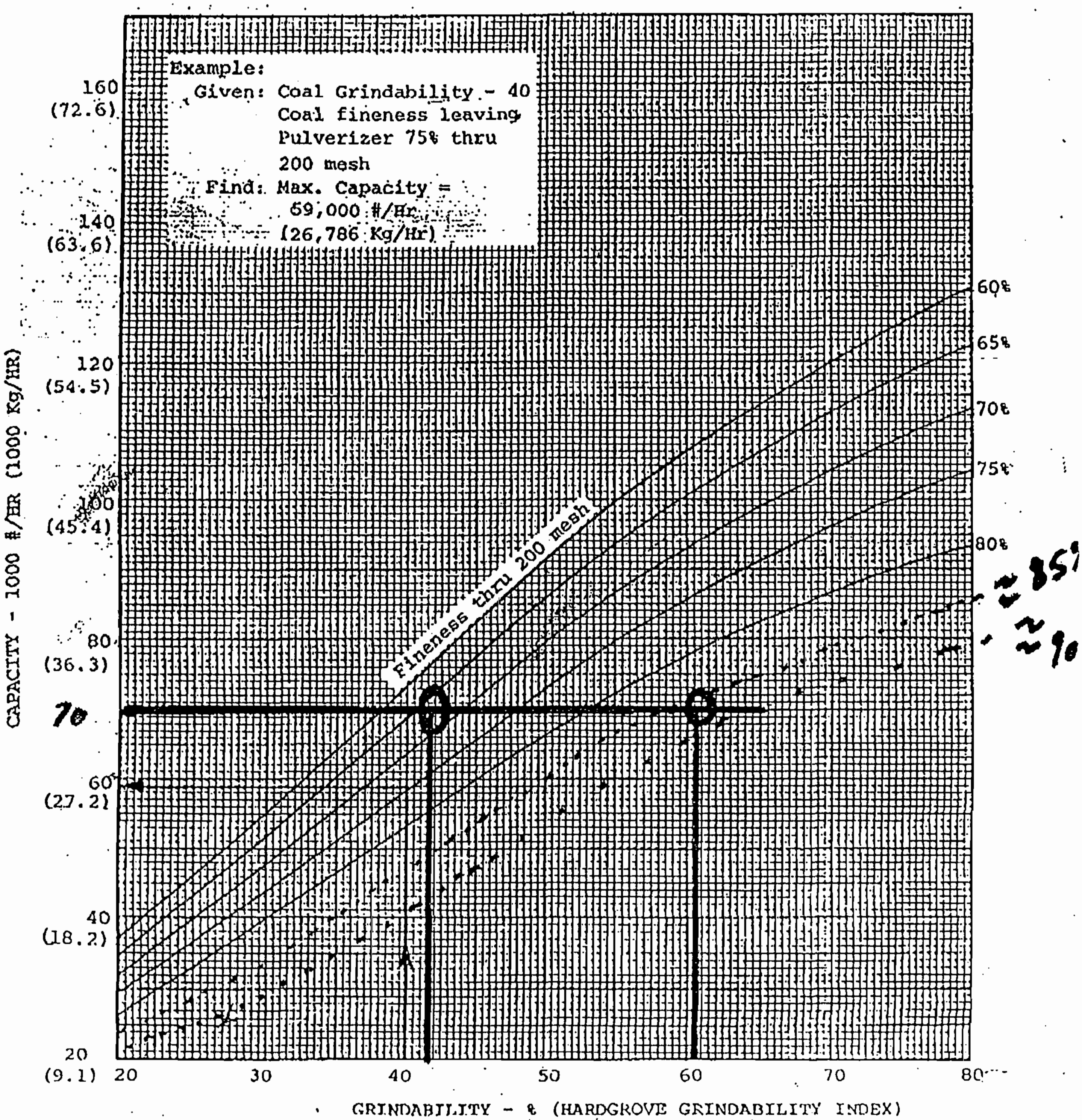
9P1 (FPG)
6R211 -(75)
7A3
57/10-5-77

THE BABCOCK & WILCOX COMPANY
FOSSIL POWER GENERATION DIVISION

ATTACHMENT A

PULVERIZED FUEL SYSTEMS
TYPE MPS 75 PULVERIZER
OPERATING INSTRUCTIONS

FIG. 8 MPS-75 PULVERIZER EXPECTED PERFORMANCE (NOT CORRECTED FOR MOISTURE)



INSERT B

ATTACHMENT B
PAGE 1

COAL ANALYSIS

McINTOSH POWER PLANT

DATE ANALYZED 2/17/94

DATE SAMPLED 2/15/94

SAMPLE POINT C-3 Auto Sampler

DATE RECEIVED 2/16/94

SAMPLE ID # 112-94

SAMPLED BY Grundy

ANALYZED BY Grundry / Parish

RELEASED BY SEP

PROXIMATE ANALYSIS

	AS RECEIVED	DRY BASIS	A-M FREE
% MOISTURE (TOTAL)	7.18		
% ASH	7.34	7.90	
% VOLATILE MATTER	32.25	34.74	37.72
% FIXED CARBON	53.24	57.36	62.28
BTU/LB	12,962	13,965	15,163
% SULFUR	1.54	1.66	1.81

HARDGROVE GRINDABILITY INDEX 43

COAL ANALYSIS

McINTOSH POWER PLANT

DATE ANALYZED	2/14/94	DATE SAMPLED	2/9/94
SAMPLE POINT	C-5 Auto Sampler	DATE RECEIVED	2/10/94
SAMPLE ID #	107-94	SAMPLED BY	unknown
ANALYZED BY	Steven Parrish	RELEASED BY	SEP

PROXIMATE ANALYSIS

	AS RECEIVED	DRY BASIS	A-M FREE
% MOISTURE (TOTAL)	10.64		
% ASH	11.32	12.66	
% VOLATILE MATTER	23.38	26.17	29.96
% FIXED CARBON	54.66	61.17	70.04
BTU/LB	11,698	13,091	14,989
% SULFUR	2.83	3.17	3.63

HARDGROVE GRINDABILITY INDEX 61

SGS Commercial Testing & Engineering Co.

January 18, 1994

1212 N. 39th Street
Suite 323
Tampa, Florida 33605
Tel: (813) 248-6566
Fax: (813) 247-2562

KOCH CARBON, INC.
P. O. Box 2219
Wichita, KS 67201

CERTIFICATE OF ANALYSIS

KIND OF SAMPLE:	PETROLEUM COKE
SAMPLE TAKEN AT:	TECO, BIG BEND TERMINAL, TAMPA, FLORIDA
SAMPLE TAKEN BY:	CT&E, TAMPA FROM BARGE "WANDA WHEELOCK"
DATED SAMPLED:	JANUARY 16, 1994
DATE RECEIVED:	JANUARY 17, 1994.

ANALYSIS REPORT NO. 08-1680

	AS RECEIVED	DRY BASIS
Moisture	10.35 %	xxxx
Ash	0.28 %	0.31 %
Volatile Matter	9.11 %	10.16 %
Fixed Carbon (by difference)	80.26 %	89.53 %
Sulfur	4.46 %	4.97 %
Gross Calorific Value	13761 Btu/lb	15339 Btu/lb
Moisture Ash Free Btu		15387

Hardgrove Grindability Index = 69

TRACE ELEMENTS P.P.M.

Silicon, Si	330
Calcium, Ca	155
Iron, Fe	130
Nickle, Ni	218
Vanadium, V	1090

SIZE ANALYSIS (Square Hole)

Over 3	Inch	3.79%
3 x 2	Inch	5.69%
2 x 1	Inch	16.63%
1 x 1/2"	Inch	15.53%
Under 1/2"	Inch	58.36%

COMMERCIAL TESTING & ENGINEERING CO.

Edward B. Linde
Branch Manager

EBL/vl

COAL ANALYSIS DATA

UNIT TRAIN ANALYSIS SHEET				1994
City of Lakeland C.D. McIntosh Unit Number 3				
DATE	U.T.#	SULFUR	TONS	TONS/DATE
JAN				
4	1	0.96	9184.90	9,184.90
8	2	0.99	9552.97	18,737.87
11	3	0.94	9442.30	28,180.17
14	4	0.98	9487.57	37,667.74
26	5	0.94	9460.90	47,128.64
				47,128.64
JAN	5	0.96		
YTD	5	0.96		
FEB				
2	6	1.00	9472.62	56,601.26
3	7	2.60	9504.00	66,105.26
7	8	0.97	9306.60	75,411.86
7	9	1.73	9000.00	84,411.86
9	10	1.07	9177.00	93,588.86
10	11	0.98	9484.75	103,073.61
14	12	0.99	9661.97	112,735.58
16	13	1.00	9446.10	122,181.68
16	14	1.06	9336.00	131,517.68
23	15	1.38	9533.80	141,051.48
23	16	1.36	8966.60	150,018.08
				150,018.08
FEB	11	1.28		
YTD	16	1.18		
MAR				
1	17	0.96	9239.70	159,257.78
15	18	1.03	9566.10	168,823.88
15	19	1.02	9279.70	178,103.58
20	20	1.01	9564.00	187,667.58
22	21	1.02	9526.60	197,194.18
25	22	1.05	9559.47	206,753.65
28	23	0.86	9444.90	216,198.55
				216,198.55
MAR	7	0.99		
YTD	23	1.12		
APRIL				
1	24	1.09	9458.60	225,657.15
4	25	0.99	9431.40	235,088.55
8	26	0.90	9513.97	244,602.52
10	27	1.01	9305.20	253,907.72
13	28	1.04	9575.07	263,482.79
15	29	0.98	9134.80	272,617.59
21	30	1.05	9567.32	282,184.91
24	31	0.88	9510.07	291,694.98
27	32	1.00	9128.85	300,823.83
				300,823.83
APRIL	9	0.99		
YTD	32	1.09		

UNIT TRAIN ANALYSIS SHEET 1994

City of Lakeland C.D. McIntosh Unit Number 3

DATE	U.T.#	SULFUR	TONS	TONS/DATE
MAY				
1	33	1.00	9570.00	310,393.83
4	34	0.97	9332.10	319,725.93
8	35	1.04	9529.10	329,255.03
10	36	0.98	9358.30	338,613.33
14	37	1.03	9573.55	348,186.88
15	38	0.87	9553.32	357,740.20
21	39	0.89	9513.87	367,254.07
22	40	0.86	9513.45	376,767.52
28	41	0.70	9501.65	386,269.17
				386,269.17
MAY	9	0.93		
YTD	41	1.05		
JUNE				
3	42	1.22	9530.50	395,799.67
3	43	0.99	9249.40	405,049.07
8	44	1.03	9535.00	414,584.07
9	45	0.96	9269.70	423,853.77
13	46	1.06	9566.95	433,420.72
14	47	1.34	9544.50	442,965.22
18	48	1.10	9428.30	452,393.52
21	49	1.34	9410.00	461,803.52
24	50	1.38	9322.46	471,125.98
				471,125.98
JUNE	9	1.16		
YTD	50	1.07		
JULY				
2	51	1.30	9614.90	480,740.88
2	52	1.09	9506.10	490,246.98
9	53	1.07	9050.17	499,297.15
9	54	1.26	9512.40	508,809.55
16	55	1.26	9946.50	518,756.05
17	56	0.93	8566.30	527,322.35
21	57	1.26	9639.50	536,961.85
22	58	1.08	9573.00	546,534.85
27	59	0.99	9264.80	555,799.65
				555,799.65
JULY	9	1.14		
YTD	59	1.08		
AUG				
1	60	1.30	9469.10	565,268.75
1	61	1.08	9569.27	574,838.02
6	62	1.28	9515.50	584,353.52
8	63	1.00	9127.10	593,480.62
10	64	1.30	9604.50	603,085.12
13	65	1.05	9545.37	612,630.49
16	66	1.06	9574.25	622,204.74
18	67	1.34	9116.90	631,321.64
22	68	0.99	9255.80	640,577.44

UNIT TRAIN ANALYSIS SHEET 1994

City of Lakeland C.D. McIntosh Unit Number 3

DATE	U.T.#	SULFUR	TONS	TONS/DATE
24	69	0.99	9251.40	649,828.84
				649,828.84
AUG	10	1.14		
YTD	69	1.09		
SEPT				
6	70	1.01	9145.40	658,974.24
6	71	1.06	9580.17	668,554.41
11	72	1.07	9571.80	678,126.21
12	73	1.05	9238.50	687,364.71
16	74	1.10	9590.02	696,954.73
18	75	1.01	9123.40	706,078.13
26	76	0.99	9308.90	715,387.03
				715,387.03
SEPT	7	1.04		
YTD	76	1.09		
OCT				
1	77	0.99	9204.70	724,591.73
2	78	1.26	9845.80	734,437.53
6	79	1.30	9587.80	744,025.33
7	80	1.08	9375.55	753,400.88
12	81	1.24	9357.40	762,758.28
14	82	1.09	9575.57	772,333.85
17	83	1.06	9594.72	781,928.57
20	84	1.26	9418.70	791,347.27
22	85	0.99	9324.60	800,671.87
				800,671.87
OCT	9	1.14		
YTD	85	1.09		
NOV				
1	86	0.99	9850.50	810,522.37
1	87	1.34	9511.30	820,033.67
7	88	1.40	9472.90	829,506.57
7	89	1.04	9462.60	838,969.17
13	90	1.07	9565.10	848,534.27
13	91	1.04	9969.20	858,503.47
19	92	1.07	9588.55	868,092.02
20	93	1.36	9428.60	877,520.62
25	94	1.40	9609.90	887,130.52
28	95	1.68	9404.95	896,535.47
				896,535.47
NOV	10	1.24		
YTD	95	1.11		
DEC				
3	96	1.85	9565.20	906,100.67
4	97	1.06	9561.22	915,661.89
9	98	1.40	9524.20	925,186.09
10	99	1.05	9498.27	934,684.36
15	100	1.28	9599.00	944,283.36
15	101	1.10	9583.40	953,866.76

UNIT TRAIN ANALYSIS SHEET			1994	
City of Lakeland C.D. McIntosh Unit Number 3				
DATE	U.T.#	SULFUR	TONS	TONS/DATE
20	102	1.02	9460.70	963,327.46
21	103	1.42	9424.20	972,751.66
29	104	1.28	9180.00	981,931.66
30	105	1.34	9419.40	991,351.06
				991,351.06
DEC	10	1.28		
YTD	105	1.12		

UNIT TRAIN ANALYSIS SHEET 1995				
City of Lakeland				
C.D. McIntosh		Unit Number 3		
DATE	U.T.#	SULFUR	TONS	TONS/DATE
JAN				
4	1	0.98	9500.70	9,500.70
5	2	1.38	9642.20	19,142.90
9	3	0.96	9489.80	28,632.70
10	4	1.32	9432.90	38,065.60
14	5	1.49	9425.40	47,491.00
14	6	1.14	9350.00	56,841.00
19	7	1.48	9510.20	66,351.20
24	8	1.00	9436.10	75,787.30
25	9	0.98	9411.60	85,198.90
30	10	1.42	9496.80	94,695.70
31	11	0.99	9276.50	103,972.20
				103,972.20
JAN	11	1.20		
YTD	11	1.20		
FEB				
5	12	1.01	9362.50	113,334.70
6	13	1.38	9359.50	122,694.20
10	14	0.99	9499.90	132,194.10
13	15	1.40	9418.70	141,612.80
16	16	1.05	9223.75	150,836.55
18	17	1.36	9650.10	160,486.65
21	18	1.34	9340.40	169,827.05
24	19	1.01	9536.60	179,363.65
28	20	1.34	9617.20	188,980.85
				188,980.85
FEB	9	1.21		
YTD	20	1.20		
MAR				
1	21	0.99	9222.95	198,203.80
5	22	1.00	9259.00	207,462.80
8	23	1.34	9430.70	216,893.50
13	24	1.02	9422.30	226,315.80
14	25	1.18	9255.40	235,571.20
19	26	0.99	9320.90	244,892.10
20	27	1.34	9743.50	254,635.60
25	28	1.34	9700.40	264,336.00

UNIT TRAIN ANALYSIS SHEET 1995				
City of Lakeland				
C.D. McIntosh		Unit Number 3		
DATE	U.T.#	SULFUR	TONS	TONS/DATE
26	29	1.34	9659.30	273,995.30
				273,995.30
MAR	9	1.17		
YTD	29	1.19		
APRIL				
				273,995.30
APRIL	0	0.00		
YTD	29	1.19		
MAY				
1	30	1.30	9611.10	283,606.40
1	31	0.90	9166.50	292,772.90
6	32	1.32	9451.20	302,224.10
9	33	1.39	9247.25	311,471.35
11	34	1.28	9506.00	320,977.35
16	35	0.94	9445.00	330,422.35
18	36	1.30	9497.40	339,919.75
22	37	0.97	9388.80	349,308.55
23	38	0.92	9279.00	358,587.55
30	39	0.91	9214.20	367,801.75
31	40	0.97	9296.70	377,098.45
				377,098.45
MAY	11	1.11		
YTD	40	1.17		
JUNE				
1	41	1.34	9608.30	386,706.75
7	42	0.95	9444.40	396,151.15
10	43	1.40	9748.60	405,899.75
12	44	1.42	9586.30	415,486.05
16	45	1.50	9605.00	425,091.05
17	46	1.48	9721.40	434,812.45
21	47	1.50	9626.00	444,438.45
23	48	1.48	9602.50	454,040.95
26	49	1.42	9552.60	463,593.55
30	50	1.42	9627.00	473,220.55
				473,220.55
JUNE	10	1.39		
YTD	50	1.22		

UNIT TRAIN ANALYSIS SHEET 1995				
City of Lakeland				
C.D. McIntosh		Unit Number 3		
DATE	U.T.#	SULFUR	TONS	TONS/DATE
JULY				
2	51	1.40	9690.00	482,910.55
6	52	1.44	9353.00	492,263.55
9	53	1.42	9525.30	501,788.85
11	54	1.01	9321.90	511,110.75
16	55	1.40	9301.70	520,412.45
17	56	0.99	9366.20	529,778.65
21	57	0.98	9362.40	539,141.05
22	58	1.34	9383.10	548,524.15
				548,524.15
JULY	8	1.25		
YTD	58	1.22		
AUG				
2	59	1.44	9513.80	558,037.95
4	60	1.44	9459.10	567,497.05
7	61	0.98	9585.60	577,082.65
11	62	1.42	9543.60	586,626.25
12	63	1.40	9478.80	596,105.05
16	64	0.99	9510.50	605,615.55
18	65	1.40	9573.60	615,189.15
22	66	1.30	9399.70	624,588.85
23	67	1.34	9465.10	634,053.95
28	68	0.97	9526.70	643,580.65
				643,580.65
AUG	10	1.27		
YTD	68	1.23		
SEPT				
2	69	1.32	9529.10	653,109.75
8	70	0.93	9536.30	662,646.05
13	71	1.28	9449.10	672,095.15
16	72	0.92	9501.70	681,596.85
19	73	1.34	9639.80	691,236.65
22	74	0.92	9494.00	700,730.65
27	75	1.29	9483.10	710,213.75
				710,213.75
SEPT	7	1.14		
YTD	75	1.22		

UNIT TRAIN ANALYSIS SHEET 1995				
City of Lakeland				
C.D. McIntosh		Unit Number 3		
DATE	U.T.#	SULFUR	TONS	TONS/DATE
OCT				
5	76	0.00	9396.80	719,610.55
9	77		9349.60	728,960.15
				728,960.15
OCT	2	0.00		
YTD	77	1.19		
NOV				
1	0	0.00	0.00	728,960.15
				728,960.15
NOV	1	0.00		
YTD	78	1.19		
DEC				
0	0	0.00	0.00	728,960.15
				728,960.15
DEC	1	0.00		
YTD	79	1.19		

LAKELAND ELECTRIC & WATER

Excellence Is Our Goal, Service Is Our Job

MCINTOSH ~~POWER PLANT~~
3030 E. ~~LAKE PARKER~~ DR.
LAKELAND, FLORIDA 33805

Ph. (813) 499-6600
FAX (813) 499-6686

July 14, 1994

McIntosh Power Plant C-3 Stack Test

Date of Composite Coal Sample: June 08, 1994
Lab I.D. 461-94
Sulfur %WT.: 1.26 Method: Parr 1760

BTU per lb.: 12,847 Method: D-2015

DOUGLAS DOERR
E&W ENGINEER

$$\frac{1.26}{100} \times 2 \times \frac{1}{12,847} \times 10^6 = 1.96151b/mmBTU$$

0.6865

Excellence Is Our Goal, Service Is Our Job

FAX (813) 499-6686

July 31, 1995

McIntosh Power Plant C-3 Stack Test

Date of Composite Coal Sample: June 15, 1995

Lab I.D. 549-95

Sulfur %WT.: 1.29 Method: Parr 1760

BTU per Lb.: 12,806 Method: D-2015

John O'Mahony
Power Production Foreman

$$\frac{1.29}{100} \times 2 \times \frac{1}{12{,}806} \times 10^6 = 2.0147 \text{ lb/MMBTU uncontrolled}$$

0.705 lb/MMBTU

$$\begin{array}{l} 0.705 \\ 0.687 \\ \hline \bar{x} = 0.696 \text{ lb/MMBTU} \end{array}$$

40 CFR PART 60

APPENDIX C

[redacted] Tests, and Calculations. This is the same as PS 2, Sections 7.1, 7.2, 7.3, and 7.5, respectively. Note: For Method 16, a sample is made up of at least three separate injects equally spaced over time. For Method 16A, a sample is collected for at least 1 hour.

3.2 Reference Methods. Unless otherwise specified in an applicable subpart of the regulations, Method 16, Method 16A, or other approved alternative, shall be the RM for TRS.

4. *Bibliography*

1. Department of Commerce. Experimental Statistics. National Bureau of Standards. Handbook 91. 1963. Paragraphs 3-3.1.4, p. 3-31.

2. A Guide to the Design, Maintenance and Operation of TRS Monitoring Systems. National Council for Air and Stream Improvement Technical Bulletin No. 89. September 1977.

3. Observation of Field Performance of TRS Monitors on a Kraft Recovery Furnace. National Council for Air and Stream Improvement Technical Bulletin No. 91. January 1978.

PERFORMANCE SPECIFICATION 6—SPECIFICATIONS AND TEST PROCEDURES FOR CONTINUOUS EMISSION RATE MONITORING SYSTEMS IN STATIONARY SOURCES

1. Applicability and Principle

1.1 Applicability. The applicability for this specification is the same as Section 1.1 of Performance Specification 2 (PS 2), except this specification is to be used for evaluating the acceptability of continuous emission rate monitoring systems (CERMS's). The installation and measurement location specifications, performance specification test procedure, data reduction procedures, and reporting requirements of PS 2, Section 3, 5, 8, and 9, apply to this specification.

1.2 Principle. Reference method (RM), calibration drift (CD), and relative accuracy (RA) tests are conducted to determine that the CERMS conforms to the specification.

2. Definitions

The definitions are the same as in Section 2 of PS 2, except that this specification refers to the continuous emission rate monitoring system rather than the continuous emission monitoring system. The following definitions are added:

2.1 Continuous Emission Rate Monitoring System (CERMS). The total equipment required for the determination and recording of the pollutant mass emission rate (in terms of mass per unit of time).

2.2 Flow Rate Sensor. That portion of the CERMS that senses the volumetric flow rate and generates an output proportional to flow rate. The flow rate sensor shall have provi[redacted]si[redacted]chec[redacted]CD for each flow rate parameter that it measures individually (e.g., velocity pressure).

3. Performance and Equipment Specifications

3.1 Data Recorder Scale. Same as Section 4.1 of PS 2.

3.2 CD. Since the CERMS includes analyzers for several measurements, the CD shall be determined separately for each analyzer in terms of its specific measurement. The calibration for each analyzer used for the measurement of flow rate except a temperature analyzer shall not drift or deviate from either of its reference values by more than 3 percent of 1.25 times the average potential absolute value for that measurement. For a temperature analyzer, the specification is 1.5 percent of 1.25 times the average potential absolute temperature. The CD specification for each analyzer for which other PS's have been established (e.g., PS 2 for SO_2 and NO_x) shall be the same as in the applicable PS.

3.3 CERMS RA. The RA of the CERMS shall be no greater than 20 percent of the mean value of the RM's test data in terms of the units of the emission standard, or 10 percent of the applicable standard, whichever is greater.

4. CD Test Procedure

The CD measurements are to verify the ability of the CERMS to conform to the established CERMS calibrations used for determining the emission rate. Therefore, if periodic automatic or manual adjustments are made to the CERMS zero and calibration settings, conduct the CD tests immediately before these adjustments, or conduct them in such a way that CD can be determined.

Conduct the CD tests for pollutant concentration at the two values specified in Section 4.1 of PS 2. For each of the other parameters that are selectively measured by the CERMS (e.g., velocity pressure), use two analogous values: one that represents zero to 20 percent of the high-level value (a value that is between 1.25 and 2 times the average potential value) for that parameter, and one that represents 50 to 100 percent of the high-level value. Introduce, or activate internally, the reference signals to the CERMS (these need not be certified). Record the CERMS response to each, and subtract this value from the respective reference value (see example data sheet in Figure 6–1).

5. RA Test Procedure

5.1 Sampling Strategy for RM's Tests, Correlation of RM and CERMS Data, Number of RM's Tests, and Calculations. These are the same as PS 2, Sections 7.1, 7.2, 7.3, and 7.5, respectively. Summarize the results on a data sheet. An example is shown in Figure 6–2. The RA test may be conducted during the CD test period.

[redacted]

3.2 Reference Methods (RM's). Unless otherwise specified in the applicable subpart of the regulations, the RM for the pollutant gas is the appendix A method that is cited for compliance test purposes, or its approved alternatives. Methods 2, 2A, 2B, 2C, or 2D, as applicable are the RM's for the determination of volumetric flow rate.

6. Bibliography

1. Brooks, E.F., E.C. Beder, C.A. Flegal, D.J. Luciani, and R. Williams. Continuous Measurement of Total Gas Flow Rate from Stationary Sources. U.S. Envionmental Protection Agency. Research Triangle Park, NC. Publication No. EPA-650/2-75-020. February 1975. 248 p.

PERFORMANCE SPECIFICATION 7—SPECIFICATIONS AND TEST PROCEDURES FOR HYDROGEN SULFIDE CONTINUOUS EMISSION MONITORING SYSTEMS IN STATIONARY SOURCES

1. Applicability and Principle

1.1 *Applicability*. 1.1.1 This specification is to be used for evaluating the acceptability of hydrogen sulfide (H_2S) continuous emission monitoring systems (CEMS's) at the time of or soon after installation and whenever specified in an applicable subpart of the regulations.

1.1.2 This specification is not designed to evaluate the installed CEMS performance over an extended period of time nor does it identify specific calibration techniques and other auxiliary procedures to assess CEMS performance. The source owner or operator, however, is responsible to calibrate, maintain, and operate the CEMS. To evaluate CEMS performance, the Administrator may require, under Section 114 of the Act, the source owner or operator to conduct CEMS performance evaluations at other times besides the initial test. *See* §60.13(c).

1.1.3 The definitions, installation specifications, test procedures, data reduction procedures for determining calibration drifts (CD) and relative accuracy (RA), and reporting of Performance Specification 2 (PS 2), Sections 2, 3, 5, 6, 8, and 9 apply to this specification.

1.2 Principle. Reference method (RM), CD, and RA tests are conducted to determine that the CEMS conforms to the specification.

2. Performance and Equipment Specifications

2.1 *Instrument zero and span*. This specification is the same as Section 4.1 of PS 2.

2.2 *Calibration drift*. The CEMS calibration must not drift or deviate from the reference value of the calibration gas or reference source by more than 5 percent of the established span value for 6 out of 7 test days (e.g., the established span value is 300 ppm for subpart J fuel gas combustion devices).

2.3 *Relative accuracy*. The RA of the CEMS shall be no greater than 20 percent of the mean value of the RM test data in terms of the units of the emission standard or 10 percent of the applicable standard, whichever is greater.

3. Relative Accuracy Test Procedure

3.1 Sampling Strategy for RM Tests, Correlation of RM and CEMS Data Number of RM Tests, and Calculations. These are the same as that in PS 2, §7.1, 7.2, 7.3, and 7.5, respectively.

3.2 Reference Methods. Unless otherwise specified in an applicable subpart of the regulation, Method 11 is the RM for this PS.

4. Bibliography

1. U.S. Environmental Protection Agency. Standards of Performance for New Stationary Sources; Appendix B; Performance Specifications 2 and 3 for SO_2, NO_x, CO_2, and O_2 Continuous Emission Monitoring Systems; Final Rule. 48 CFR 23608. Washington, DC, U.S. Government Printing Office. May 25, 1983.

2. U.S. Government Printing Office. Gaseous Continuous Emission Monitoring Systems—Performance Specification Guidelines for SO_2, NO_x, CO_2, O_2, and TRS. U.S. Environmental Protection Agency. Washington, DC, EPA-450/3-82-026. October 1982. 26p.

3. Maines, G.D., W.C. Kelly (Scott Environmental Technology, Inc.), and J.B. Homolya. Evaluation of Monitors for Measuring H_2S in Refinery Gas. Prepared for the U.S. Environmental Protection Agency. Research Triangle Park, NC, Contract No. 68-02-2707. 1978. 60 p.

4. Ferguson, B.B., R.E. Lester (Harmon Engineering and Testing), and W.J. Mitchell. Field Evaluation of Carbon Monoxide and Hydrogen Sulfide Continuous Emission Monitors at an Oil Refinery. Prepared for the U.S. Environmental Protection Agency. Research Triangle Park, NC. Publication No. EPA-600/4-82-054. August 1982. 100 p.

[48 FR 13327, Mar. 30, 1983 and 48 FR 23611, May 25, 1983, as amended at 48 FR 32986, July 20, 1983; 51 FR 31701, Aug. 5, 1985; 52 FR 17556, May 11, 1987; 52 FR 30675, Aug. 18, 1987; 52 FR 34650, Sept. 14, 1987; 53 FR 7515, Mar. 9, 1988; 53 FR 41335, Oct. 21, 1988; 55 FR 18876, May 7, 1990; 55 FR 40178, Oct. 2, 1990; 55 FR 47474, Nov. 14, 1990; 56 FR 5526, Feb. 11, 1991]

APPENDIX C TO PART 60—DETERMINATION OF EMISSION RATE CHANGE

1. *Introduction*.

1.1 The following method shall be used to determine whether a physical or operational change to an existing facility resulted in an increase in the emission rate to the atmosphere. The method used is the Student's *t* test, commonly used to make inferences from small samples.

2. *Data.*

2.1 Each emission test shall consist of n runs (usually three) which produce n emission rates. Thus two sets of emission rates are generated, one before and one after the change, the two sets being of equal size.

2.2 When using manual emission tests, except as provided in §60.8(b) of this part, the reference methods of appendix A to this part shall be used in accordance with the procedures specified in the applicable subpart both before and after the change to obtain the data.

2.3 When using continuous monitors, the facility shall be operated as if a manual emission test were being performed. Valid data using the averaging time which would be required if a manual emission test were being conducted shall be used.

3. *Procedure.*

3.1 Subscripts a and b denote prechange and postchange respectively.

3.2 Calculate the arithmetic mean emission rate, E, for each set of data using Equation 1.

$$E = \frac{\sum_{i=1}^{n} E_i}{n} = \frac{E_1 + E_2 \ldots + E_n}{n} \qquad (1)$$

Where:

E_i=Emission rate for the i th run.

n=number of runs.

3.3 Calculate the sample variance, S^2, for each set of data using Equation 2.

$$S^2 = \frac{\sum_{i=1}^{n} (E_i - E)^2}{n-1} = \frac{\sum_{i=1}^{n} E_i^2 - \left(\sum_{i=1}^{n} E_i\right)^2 \Big/ n}{n-1} \qquad (2)$$

3.4 Calculate the pooled estimate, S_p, using Equation 3.

$$S_p = \left[\frac{(n_a - 1)\, S_a^2 + (n_b - 1)\, S_b^2}{n_a + n_b - 2}\right]^{1/2} \qquad (3)$$

3.5 Calculate the test statistic, t, using Equation 4.

$$t = \frac{E_b - E_a}{S_p \left[\frac{1}{n_a} + \frac{1}{n_b}\right]^{1/2}} \qquad (4)$$

4. *Results.*

4.1 If $E_b > E_a$ and $t > t'$, where t' is the critical value of t obtained from Table 1, then with 95% confidence the difference between E_b and E_a is significant, and an increase in emission rate to the atmosphere has occurred.

TABLE 1

Degrees of freedom (n_a+n_b-2)	t' (95 percent confidence level)
2	2.920
3	2.353
4	2.132
5	2.015
6	1.943
7	1.895
8	1.860

For greater than 8 degrees of freedom, see any standard statistical handbook or text.

5.1 Assume the two performance tests produced the following set of data:

Test a	Test b
Run 1. 100	115
Run 2. 95	120
Run 3. 110	125

5.2 Using Equation 1—

$$E_a=100+95+110/3=102$$
$$E_b=115+120+125/3=120$$

5.3 Using Equation 2—

$$S_a^2=(100-102)^2+(95-102)^2+(110-102)^2/3-1=58.5$$
$$S_b^2=(115-120)^2+(120-120)^2+(125-120)^2/3-1=25$$

5.4 Using Equation 3—

$$S_p=[(3-1)(58.5)+(3+1)(25)/3+3-2]^{1/2}=6.46$$

5.5 Using Equation 4—

$$t = \frac{120-102}{6.46\left[\frac{1}{3}+\frac{1}{3}\right]^{1/2}} = 3.412$$

5.6 Since $(n^1+n^2-2)=4$, $t'=2.132$ (from Table 1). Thus since $t>t'$ the difference in the values of E_a and E_b is significant, and there has been an increase in emission rate to the atmosphere.

6. *Continuous Monitoring Data.*

6.1 Hourly averages from continuous monitoring devices, where available, should be used as data points and the above procedure followed.

[40 FR 58420, Dec. 16, 1975]

APPENDIX D TO PART 60—REQUIRED EMISSION INVENTORY INFORMATION

(a) Completed NEDS point source form(s) for the entire plant containing the designated facility, including information on the applicable criteria pollutants. If data concerning the plant are already in NEDS, only that information must be submitted which is necessary to update the existing

NEDS record for that plant. Plant and point identification codes for NEDS records shall correspond to those previously assigned in NEDS; for plants not in NEDS, these codes shall be obtained from the appropriate Regional Office.

(b) Accompanying the basic NEDS information shall be the following information on each designated facility:

(1) The state and county identification codes, as well as the complete plant and point identification codes of the designated facility in NEDS. (The codes are needed to match these data with the NEDS data.)

(2) A description of the designated facility including, where appropriate:

(i) Process name.

(ii) Description and quantity of each product (maximum per hour and average per year).

(iii) Description and quantity of raw materials handled for each product (maximum per hour and average per year).

(iv) Types of fuels burned, quantities and characteristics (maximum and average quantities per hour, average per year).

(v) Description and quantity of solid wastes generated (per year) and method of disposal.

(3) A description of the air pollution control equipment in use or proposed to control the designated pollutant, including:

(i) Verbal description of equipment.

(ii) Optimum control efficiency, in percent. This shall be a combined efficiency when more than one device operates in series. The method of control efficiency determination shall be indicated (e.g., design efficiency, measured efficiency, estimated efficiency).

(iii) Annual average control efficiency, in percent, taking into account control equipment down time. This shall be a combined efficiency when more than one device operates in series.

(4) An estimate of the designated pollutant emissions from the designated facility (maximum per hour and average per year). The method of emission determination shall also be specified (e.g., stack test, material balance, emission factor).

[40 FR 53349, Nov. 17, 1975]

APPENDIX E TO PART 60—[RESERVED]

APPENDIX F TO PART 60—QUALITY ASSURANCE PROCEDURES

PROCEDURE 1. QUALITY ASSURANCE REQUIREMENTS FOR GAS CONTINUOUS EMISSION MONITORING SYSTEMS USED FOR COMPLIANCE DETERMINATION

1. Applicability and Principle

1.1 Applicability. Procedure 1 is used to evaluate the effectiveness of quality control (QC) and quality assurance (QA) procedures and the quality of data produced by any continuous emission monitoring system (CEMS) that is used for determining compliance with the emission standards on a continuous basis as specified in the applicable regulation. The CEMS may include pollutant (e.g., SO_2 and NO_x) and diluent (e.g., O_2 or CO_2) monitors.

This procedure specifies the minimum QA requirements necessary for the control and assessment of the quality of CEMS data submitted to the Environmental Protection Agency (EPA). Source owners and operators responsible for one or more CEMS's used for compliance monitoring must meet these minimum requirements and are encouraged to develop and implement a more extensive QA program or to continue such programs where they already exist.

Data collected as a result of QA and QC measures required in this procedure are to be submitted to the Agency. These data are to be used by both the Agency and the CEMS operator in assessing the effectiveness of the CEMS QC and QA procedures in the maintenance of acceptable CEMS operation and valid emission data.

Appendix F, Procedure 1 is applicable December 4, 1987. The first CEMS accuracy assessment shall be a relative accuracy test audit (RATA) (see section 5) and shall be completed by March 4, 1988 or the date of the initial performance test required by the applicable regulation, whichever is later.

1.2 Principle. The QA procedures consist of two distinct and equally important functions. One function is the assessment of the quality of the CEMS data by estimating accuracy. The other function is the control and improvement of the quality of the CEMS data by implementing QC policies and corrective actions. These two functions form a control loop: When the assessment function indicates that the data quality is inadequate, the control effort must be increased until the data quality is acceptable. In order to provide uniformity in the assessment and reporting of data quality, this procedure explicitly specifies the assessment methods for response drift and accuracy. The methods are based on procedures included in the applicable performance specifications (PS's) in appendix B of 40 CFR part 60. Procedure 1 also requires the analysis of the EPA audit samples concurrent with certain reference method (RM) analyses as specified in the applicable RM's.

Because the control and corrective action function encompasses a variety of policies, specifications, standards, and corrective measures, this procedure treats QC requirements in general terms to allow each source owner or operator to develop a QC system that is most effective and efficient for the circumstances.

2. Definitions

2.1 Continuous Emission Monitoring Systems. The ...

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Farzie Shelton
ENVIRONMENTAL COORDINATOR, Ch E.

November 9, 1995

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AIR REGULATION

VIA HAND DELIVERY

Clair H. Fancy, Chief
Bureau of Air Regulation
Florida Department of Environmental Protection
Magnolia Park Courtyard
Tallahassee, Florida 32301

RE: City of Lakeland; C.D. McIntosh Unit No. 3;
Proposed Permit Amendment to PSD Permit PSD-FL-8

Dear Clair:

The City of Lakeland very much appreciates the Department of Environmental Protection's timely review of the City's request for permit amendment recently submitted regarding the above-referenced Prevention of Significant Deterioration (PSD) permit for the C.D. McIntosh Unit No. 3. The meeting last week between representatives from the Department and the City was very beneficial, and we appreciate the Department's efforts in quickly responding to the City's permit amendment request. Al Linero, Administrator of the Division of Air Resources Management's New Source Review Section, has diligently worked with the City to accomplish the permit amendment, and his efforts have been very much appreciated. While the proposed permit amendment is largely satisfactory to the City, in reviewing the proposed language, the City noted that a few of the proposed conditions may need to be clarified or revised.

Condition 2.B.

Under Condition 2.B., the draft permit amendment language requires that emissions information, including not only the pound-per-million-Btu emission rates but also the percentages of sulfur dioxide reductions, be provided to the Department on a quarterly basis. The City believes that it may be more appropriate to simply keep such records on site and available should the Department request to review the data. Any excess emissions or other potential non-compliance situations would, of course, need to be reported to the Department immediately. The City does not object to maintaining the information but is concerned that the paperwork burden may be unnecessary since the data would be available to the Department if requested. Because any excess emissions or other potential non-compliance situations would be reported immediately, the Department should not be as concerned with day-to-day information.

In addition, the language in Condition 2.B. should also be clarified to indicate that the emission limit of 0.718 pounds per million Btu heat input applies whenever blends of petroleum coke and other fuels are cofired. While this is the intent of the language, it could be misinterpreted to mean that whenever coal and refuse are cofired, this limit would apply. We understand that this is not the intent of the language, and a simple clarification may be helpful.

To accomplish these changes, the City suggests the following language:

> Compliance with the sulfur dioxide emission limitation of 0.75 pound per million Btu heat input and percent reduction requirement shall be determined on a 30-day rolling average. ~~and submitted to the Department on a quarterly basis.~~ This compliance information shall be retained for a period of three years and made available upon request by the Department. Whenever blends of ~~coal and~~ petroleum coke with other fuels ~~or refuse~~ are cofired ~~burned~~, sulfur dioxide emissions shall not exceed 0.718 pounds per million Btu heat input based on a 30-day rolling average.

Conditions 2.C. and 2.D.

While the current Conditions 2.C. and 2.D. have not been proposed to be changed by the Department, it may be helpful to clarify that the "oil" referred to in these conditions relates to "high sulfur oil." Otherwise, these conditions could be interpreted to conflict with the new Condition 2.E. As stated below, it would also be helpful to indicate in new Condition 9 that high sulfur oil can also be used, consistent with Conditions 2.C. and 2.D. Additionally, "high sulfur oil" should be defined as oil with a sulfur content above 0.5 percent, based on weight. These changes are technical in nature and should help clarify future interpretations of the permit.

Condition 5.B.

In Condition 5.B., the Department is including additional reference methods for performing sulfur dioxide and nitrogen oxides tests. While these additional reference methods are appropriate, the PSD permit requirement to conduct performance tests applies only to the initial performance tests--not annual tests. In addition, because the sulfur dioxide emission limits are now based on a 30-day rolling average, it would not be appropriate to conduct a 3-hour annual stack test to determine compliance; rather, compliance must be determined based on the continuous emissions monitoring data. It may be helpful therefore to delete references to sulfur dioxide stack testing requirements.

Condition 6

In Condition 6, the proposed permit amendment clarifies that the fuel sampler will be used to analyze "solid fuel." While this language makes it clear that gaseous and liquid fuels would not be sampled and analyzed, it is not clear that "refuse" would not need to be sampled and analyzed. It may therefore be better to include the word "fossil," so that the condition would clearly require that "solid fossil fuels" be sampled and analyzed.

Condition 8

It may be helpful to clarify that in Condition 8 that higher sulfur fuel may also be used, consistent with Conditions 2.C. and 2.D. In addition, while Condition 2.E. clarifies that low sulfur oil can be cofired with natural gas, it may be helpful to indicate in Condition 8 that natural gas may be cofired with any of the other fuels and fuel combinations. To accomplish these simple clarifications, the City suggests the following language:

Coal only
Low sulfur fuel oil only (≤ 5 percent sulfur by weight)
Coal and up to 10 percent refuse (based on heat input)
Low sulfur fuel oil and up to 10 percent refuse (based on heat input)
Coal and up to 20 percent petroleum coke (based on weight)
Coal and up to 20 percent petroleum coke (based on weight) and 10 percent refuse (based on heat input)
High sulfur oil (> 0.5 percent sulfur by weight) consistent with Conditions 2.C. or 2.D.
Natural gas only or in combination with any of the other fuels or fuel combinations listed above

Condition 9

The City questions whether it is necessary to demonstrate that the use of petroleum coke will not result in emission increases of carbon monoxide or sulfuric acid mist. As the City has explained previously, based on available information, carbon monoxide and sulfuric acid mist emissions are not expected to increase due to the use of petroleum coke--any increases in carbon monoxide emissions would be due to coal quality and combustion practices and there is no indication that sulfuric acid mist emissions will increase. At the most, because no increase in the emission factor is expected, it would be appropriate, and consistent with the federal rules cited, to provide information to the Department indicating that utilization of the unit has not increased due to the use of petroleum coke. The City respectfully requests, therefore, that carbon monoxide and sulfuric acid mist be deleted from the language in Condition 9.

The City would like to thank you and the Department's air staff again for your continued cooperation and assistance in this permit amendment process. We hope to receive a final permit amendment after the public comment period, which should expire on December 10, 1995. Once the final permit has been issued, we understand that the new or revised permit conditions from this amendment along with the September 5, 1995, amendment will be incorporated into the Conditions of Certification during the current Site Certification Modification process. The City hopes that this process can also be completed within the next several weeks. To assist in this effort, Site Certification Conditions, as proposed to be revised, are attached to this letter and are included on a computer disk as well (WordPerfect 5.1 format).

If you or any of the Department's air staff have any questions regarding the clarification language being requested or other issues related to the PSD permit or Site Certification, please do not hesitate to contact me at (813) 499-6603 or (813) 254-3998.

Sincerely,

Farzie Shelton/arm

Farzie Shelton
Environmental Coordinator

cc: Howard Rhodes, FDEP
Al Linero, FDEP
Martin Costello, FDEP
Hamilton Oven, FDEP
Ken Kosky, KBN
Angela Morrison, HGSS

State of Florida Department of Environmental Regulation
City of Lakeland
C.D. McIntosh, Jr. Power Plant - Unit No. 3
Case No. PA 74-06-SR
CONDITIONS OF CERTIFICATION

GENERAL

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State of Florida Department of Environmental Regulation
City of Lakeland
C.D. McIntosh, Jr. Power Plant - Unit No. 3
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CONDITIONS OF CERTIFICATION

GENERAL

1. Change in Discharge

All discharges or emissions authorized herein shall be consistent with the terms and conditions of this certification. The discharge of any regulated pollutant not identified in the application, or any discharge more frequent than, or at a level in excess of that authorized herein, shall constitute a violation of the certification. Any ~~anticipated~~ proposed ~~facility~~ expansions, production increases, or process modifications which will result in new, different or increased discharges or expansion in steam generating capacity of Unit No. 3 will require a submission of a new or supplemental application pursuant to Chapter 403, Florida Statutes.

2. Noncompliance Notification

If, for any reason, the permittee does not comply with or will be unable to comply with any limitation specified in this certification, the permittee shall notify the Southwest District Manager of the Department by telephone during the working day during which said noncompliance occurs and shall confirm this situation in writing within seventy-two (72) working-day hours of first becoming aware of such conditions, supplying the following information:

a. A description and cause of noncompliance; and

b. The period of noncompliance, including exact dates and times; or, if not corrected, the anticipated time the noncompliance is expected to continue, and steps being taken to reduce, eliminate and prevent recurrence of the noncomplying event.

3. ~~Facilities~~ Unit No. 3 Operation

The permittee shall at all times maintain in good working order and operate as efficiently as possible all treatment or control facilities or systems installed or used by the permittee to achieve compliance with the terms and conditions of this certification. Such systems are not to be bypassed without prior department approval.

4. Adverse Impact

The permittee shall take all reasonable steps to minimize any adverse impact resulting from noncompliance with any limitation specified in this certification, including but not limited to such accelerated or additional monitoring as necessary to determine the nature and impact of the noncomplying event.

5. Right of Entry

The permittee shall allow the Secretary of the Florida Department of Environmental Protection ~~Regulation~~ and/or authorized representatives, upon the presentation of credentials:

a. To enter upon the permittee's premises where an effluent source is located or in which records are required to be kept under the terms and conditions of this permit; and

b. To have access to and copy all records required to be kept under the conditions of this certification; and

c. To inspect and test any monitoring equipment or monitoring method required in this certification and to sample any discharge or pollutants, and

d. To assess any damage to the environment or violation of ambient standards.

6. Revocation or Suspension

This certification may be suspended or revoked pursuant to Section 403.512, Florida Statutes, or for violations of any General or Special Condition.

7. Civil and Criminal Liability

This certification does not relieve the permittee from civil or criminal responsibility or liability for noncompliance with any conditions of this certification, applicable rules or regulations of the Department, or Chapter 403, Florida Statutes, or regulations thereunder.

Subject to Section 403.511, Florida Statutes, this certification shall not preclude the institution of any legal action or relieve the permittee from any responsibilities or penalties established pursuant to any other applicable State Statutes or regulations.

8. Property Rights

The issuance of this certification does not convey any property rights in either real or personal property tangible or intangible, nor any exclusive privileges, nor does it authorize any injury to public or private property or any invasion of personal rights, nor any infringement of Federal, State or local laws or regulations. The applicant will obtain title, lease or right of use from the State of Florida, to any sovereign submerged lands occupied by plant, transmission line structures, or appurtenant facilities.

9. Severability

The provisions of this certification are severable, and if any provision of this certification, or the application of any provision of this certification to any circumstances, is held invalid, the application of such provision to other circumstances and the remainder of the certification shall not be affected thereby.

10. Definitions

The meaning of terms used herein shall be governed by the definitions contained in Chapter 403, Florida Statutes, and any regulation adopted pursuant thereto. In the event of any dispute over the meaning of a term used in these general or special conditions which is not defined in such statutes or regulations, such dispute shall be resolved by reference to the most relevant definitions contained in any other state or federal statute or regulation or, in the alternative by the use of the commonly accepted meaning as determined by the Department.

11. Review of Site Certification

The certification shall be final unless revised, revoked or suspended pursuant to law. At least every five years from the date of issuance of this certification or any National Pollutant Discharge Elimination System Permit issued pursuant to the Federal Water Pollution Control Act Amendments of 1972, for the plant units, the Department shall review all monitoring data that has been submitted to it during the preceding five-year period, for the purposes of determining the extent of the permittee's compliance with the conditions of this certification and the environmental impact of this ~~facility~~ unit. The Department shall submit the results of its review and recommendations to the permittee. Such review will be repeated at least every five years thereafter.

12. Modification of Conditions

The conditions of this certification may be modified in the following manner:

a. The Board hereby delegates to the Secretary the authority to modify, after notice and opportunity for hearing, any conditions pertaining to monitoring or sampling.

b. All other modifications shall be made in accordance with Section 403.516, F.S.

State of Florida Department of Environmental Protection ~~Regulation~~
City of Lakeland
C.D. McIntosh, Jr. Power Plant Unit No. 3
Case No. PA 74-06-SR
CONDITIONS OF CERTIFICATION

SPECIAL

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State of Florida Department of Environmental Protection ~~Regulation~~
City of Lakeland
Power Plant No. 3 - Unit No. 3
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CONDITIONS OF CERTIFICATION

SPECIAL

I. Air

The construction and operation of the Unit No. 3 at the McIntosh Plant shall be in accordance with all applicable provisions of the Chapters ~~17-2, 17-5, and 17-7~~ 62-210 - 62-297, Florida Administrative Code. The permittee shall comply with the following conditions of certification:

A. Emission Limitations

1. Stack emissions shall not exceed those specified in Chapter ~~17-2.04(6)(e)-1.~~ 62-296.405, FAC.

2. ~~The permittee shall not burn a fuel oil containing more than an average of 0.7% sulfur unless it can be demonstrated that either, a) heat efficiency is such as to insure compliance with all applicable emission limitations, or b) that a flue gas desulfurization unit is installed that will insure compliance with applicable emission limitations.~~

   a. Continuous burning of natural gas, low sulfur fuel oil (less than or equal to 0.5 percent sulfur by weight), or combinations of these two fuels with or without the use of SO_2 scrubber will be allowed.

   b. The burning of high sulfur oil or a combination of high sulfur oil and municipal refuse as an emergency fuel without the use of the SO_2 scrubber will be allowed only when the flue gas desulfurization system malfunctions to the extent that the burning of coal would cause emission limitations to be exceeded. Sulfur dioxide emitted to the atmosphere from the boiler shall not exceed 0.8 pound per million Btu under this condition.

   c. During malfunctions of equipment which cause an interruption of the coal feed to the boiler, the burning of high sulfur oil or a combination of high sulfur oil and municipal refuse will be allowed only if all flue gases are fully scrubbed by the SO_2 scrubber. Sulfur dioxide emitted to the atmosphere from the boiler shall not exceed 0.8 pound per million Btu under this condition.

3. The height of the boiler exhaust stack for Unit 3 shall be not less than 250 feet above grade. The height of stacks for future units shall be determined after review of supplemental applications.

4. Particulate emissions from the coal handling facilities:

a. The applicant shall not cause to be discharged into the atmosphere from any coal processing or conveying equipment, coal storage system, or coal transfer and loading system ~~processing coal~~, visible emissions which exceed 20 percent opacity.

b. The applicant must submit to the Department within five (5) working days after it becomes available, copies of technical data pertaining to the selected particulate emissions control for the coal handling facility. These data should include, but not be limited to, a copy of the formal bid from the successful bidder, guaranteed efficiency and emission rates, and major design parameters such as air/cloth ratio and flow rate. The Department may, upon review of these data, disapprove the use of such device if the Department determines the selected control device to be inadequate to meet the visible emission limit specified in 5 (a) above.

5. Particulate matter emitted into the atmosphere from the boiler shall not exceed:

Mode of Firing	$lb/10^6$ Btu Heat Input
Coal	0.044
Coal/Petcoke	0.044
Coal/Refuse	0.050
Coal/Petcoke/Refuse	0.050
Oil	0.070
Oil/Refuse	0.075

6. A flue gas desulfurization system will be installed to treat exhaust gases and will operate such that whenever coal or blends of coal and petroleum coke or refuse are burned, sulfur dioxide in gases discharged to the atmosphere from the boiler shall not exceed 1.2 pounds per million Btu heat input and 10 percent of the potential combustion concentration (90 percent reduction), or 35 percent of the potential combustion concentration (65 percent reduction), when emissions are less than 0.75 pounds per million Btu heat input. Compliance with the sulfur dioxide emission limitation of 0.75 pound per million Btu heat input and percent reduction requirement shall be determined on a 30-day rolling average. This compliance information shall be retained for a period of three years and made available upon request by the Department. Whenever blends of petroleum coke and with other fuels are cofired, sulfur dioxide emissions shall not exceed 0.718 pound per million Btu heat input based on a 30-day rolling average.

B. Air Monitoring Program

1. The permittee shall install and operate continuously ~~ly~~ monitoring devices for the Unit No. 3 boiler exhaust for sulfur dioxide, nitrogen dioxide and opacity. The monitoring devices shall meet the applicable requirements of ~~17-2.08, FAC~~ 40 CFR 60.45 and 60.13. In addition, the ASTM-certified automatic solid fossil fuel sampler shall be installed which produces a representative daily sample for analysis of sulfur, moisture, heating value and ash. The solid fossil fuel analysis data shall be used in conjunction with emission factors and the continuous monitoring data to calculate SO_2 reduction.

2. The permittee shall operate the ambient monitoring device for sulfur dioxide in accordance with EPA reference methods in 40 CFR Part 53 and two ambient monitoring device for suspended particulates. New and existing monitoring devices shall be located as designated by the Department. The frequency of operation shall be every six days or as specified by the Department.

3. The permittee shall maintain a daily log of fuels used and copies of fuel analyses containing information on sulfur content, ash content and heating values to facilitate calculations of emissions.

4. The permittee shall provide sampling ports into the stack and shall provide access to the sampling ports, in accordance with Standard Sampling Techniques and Methods of Analysis for The Determination of Air Pollutants from Point Sources, July 1975.

5. The ambient monitoring program may be reviewed annually beginning two years after start-up of Unit No. ~~2~~3 by the Department and the permittee.

6. Emission Control Systems:

   Prior to operation of the source, the owner or operator shall submit to the Department a standardized plan or procedure that will allow the company to monitor emission control equipment efficiency and enable the company to return malfunctioning equipment to proper operation as expeditiously as possible.

C. Stack Testing:

1. Within 60 days after achieving the maximum capacity at which the facility will be operated, but no later than 180 days after initial startup, the owner or operator shall conduct performance tests for particulates and SO_2 and promptly furnish the Department a written report of the results of such performance tests.

2. Performance tests shall be conducted and data reduced in accordance with methods and procedures in accordance with EPA or DEP-approved test methods. ~~Standard Sampling Techniques and Methods of the Determination on Air Pollutants from Point Sources, July 1975.~~

3. Performance tests shall be conducted under such conditions as the Department shall specify based on representative performance of the facility. The owner or operator shall make available to the Department such records as may be necessary to determine the conditions of the performance tests.

4. The owner or operator shall provide the Department with 30 days prior notice of the performance tests and afford the Department the opportunity to have an observer present.

5. Stack tests for particulates and NO_x ~~and SO_2~~ shall be performed annually in accordance with conditions 2, 3 and 4 above.

D. Reporting

1. Stack monitoring~~, fuel usage and fuel analysis~~ data shall be reported to the Department on a quarterly basis in accordance with 40 CFR, Part 60, Section 60.7(c),(d) and in accordance with ~~17-2.08~~ 62-297.405(1)(g), FAC. Fuel usage and fuel analysis data shall be reported to the Department on an annual basis.

2. Ambient air monitoring data shall be reported to the Department quarterly by the last day of the month following the quarterly reporting period utilizing the SAROAD or other format approved by the Department in writing.

E. Coal Characteristics and Contracts

Before approval can be granted by the Department for use of control devices, characteristics of the coal to be fired must be known. Therefore, before these approvals are granted, the applicant must submit to the Department copies of coal contracts which should include the expected sulfur content, ash content, and heat content of the coal to be fired. These data will be used by the Department in its evaluation of the adequacy of the control devices.

F. Coal Information

As an alternative to the submittal of contracts for purchase of coal under condition E above, the applicant may submit the following information:

1. The name of the coal supplier;

2. The sulfur content, ash content, and heat content of the coal as specified in the purchase contracts;

3. The location of the coal deposits covered by the contract (including mine name and seam);

4. The date by which the first delivery of coal will be made;

5. The duration of the contract; and

6. An opinion of counsel for the applicant that the contract(s) are legally binding and enforceable.

G. Reporting:

Beginning one month after certification the applicant shall submit to the Department a quarterly status report briefly outlining progress made on engineering design and purchase of major pieces of equipment (including control equipment). All reports and information required to be submitted under this condition shall be submitted to Mr. Hamilton S. Oven, Jr., Administrator of Power Plant Siting, Department of Environmental Protection ~~Regulation~~, 2600 Blair Stone Road, Tallahassee, Florida 32301.

H. Fuels:

The following fuels may be burned:

Coal only
Low sulfur fuel oil only (< 5 percent sulfur by weight)
Coal and up to 10 percent refuse (based on heat input)
Low sulfur fuel oil and up to 10 percent refuse (based on heat input)
Coal and up to 20 percent petroleum coke (based on weight)
Coal and up to 20 percent petroleum coke (based on weight) and 10 percent refuse (based on heat input)
High sulfur oil (> 0.5 percent sulfur by weight) consistent with Conditions I.A.2.b. or I.A.2.c.
Natural gas only or in combination with any of the other fuels or fuel combinations listed above

II. Water Discharges

Discharges during construction and operation of the Unit No. 3 shall be in accordance with all applicable provisions of Chapter 62-302 ~~17-3~~, Florida Administrative Code and 40 CFR 423, Effluent Guidelines and Standards for Steam Electric Power Generating Point Source Category. In addition, the permittee shall comply with the following conditions of certification:

A. Pretreatment Standards

Wastewater discharges from Unit No. 3 to the Lakeland wetlands treatment system shall comply with the effluent limitation guidelines contained in 40 CFR~~, Part~~ § 423.16 ~~423.12~~ and amendments. The specific standards applicable to the facilities as planned are:

1. Cooling Tower Blowdown

There shall be no detectable amounts of materials added for corrosion inhibition containing zinc and chromium in cooling tower blowdown discharged to the City of Lakeland wetland treatment system. ~~On an emergency basis the on site Marsh Treatment System may be used to treat cooling tower blowdown.~~

2. pH

The pH of all discharges shall be within the range of 6.0 to 9.0.

3. Polychlorinated Biphenyl Compounds

There shall be no release to the environment of polychlorinated biphenyl compounds.

4. Chemical Wastes and Boiler Blowdown

All low volume wastes (demineralizer regeneration, cooling tower basin cleaning wastes, floor drainage, sample drains and similar wastes), metal cleaning wastes (including preheater and fireside wash) and boiler blowdown shall be treated as required for pH adjustment and removal of chemical constituents. These wastewaters will be treated in an process wastewater treatment system capable of complying with 40 CFR~~, Part~~ § 423.16 ~~423.12~~ and discharged with the cooling tower blowdown via a return pipeline to the Lakeland wetlands treatment system. The remaining sludge shall be disposed of in the on site FGD stabilized sludge landfill.

5. Sluice Pond Overflow

Sluice pond overflow (coal pile runoff from less than 10-year, 24-hour rainfall and bottom and fly ash transport water) shall be treated if necessary ~~required~~ to meet the requirements of 40 CFR § ~~Part~~ 423.16 ~~423.12~~ and discharged with the cooling tower blowdown to the Lakeland wetlands treatment system.

6. Flue Gas Desulfurization Sludge Pond Overflow

The flue gas desulfurization sludge pond overflow shall be treated if required to meet the requirements of 40 CFR § ~~Part~~ 423.16 ~~423.12~~ in a process waste system and discharged with the cooling tower blowdown to the Lakeland wetlands treatment system.

~~B. In-Plant Water Monitoring Program~~

~~A monitoring program shall be undertaken by the City of Lakeland on each effluent stream within the facility to determine compliance by Unit 3 with the applicable effluent guidelines of 40 CFR, Part 423.12~~ § 423.16 ~~for those wastewaters discharged to the Lakeland wetlands treatment system. This monitoring program may be reviewed annually to determine the necessity for its continuance.~~

III. Groundwater

A. General

The use of groundwater shall be minimized to the greatest extent practicable.

B. Well Criteria

The well locations shall be approved by the Southwest Florida Water Management District. Design and construction of new wells shall be in accordance with the applicable rules of the Department of Environmental Protection ~~Regulation~~ and Southwest Florida Water Management District.

C. Groundwater Use Limitations

1. Groundwater used for makeup for the cooling tower for Unit No. 3 shall be limited to emergency use only, not to exceed 0.2166 million gallons per day on an average annual basis or 5.271 mgd on a maximum daily basis from 3 new wells.

2. Daily water use from the new wells shall be reported quarterly to the Southwest Florida Water Management District.

IV. Leachate

A. Compliance

Leachate from coal storage piles, settling and treatment ponds, ~~artificial marsh, rapid infiltration beds,~~ secure land fills and flue gas desulfurization sludge ponds (FGD) shall not contaminate waters of the State (including both surface and groundwaters) in excess of the limitations of Chapters 62-302 and 62-520 ~~17-3~~, FAC.

B. Monitoring

A monitoring well system shall be used to determine whether or not leachate from the treatment ponds, ~~artificial marsh,~~ secure landfill, ash sluice ponds, and the flue gas desulfurization sludge ponds is reaching the groundwater.

1. Permittee shall collect background samples monthly commencing at least two months prior to construction of the waterwater treatment system sampling the following parameters: specific conductance, chlorides, sulfates, pH, zinc and iron.

2. The permittee shall annually monitor Arsenic, Barium, Cadmium, Lead, Mercury, Nitrates, Gross Alpha, Selenium and Silver beginning with commencement of construction of the wastewater treatment system.

3. The permittee shall monthly monitor specific conductance, chlorides, sulfates, pH, zinc and iron beginning with commencement of operation of the wastewater treatment system.

4. If any the monitoring parameters listed in paragraph 3 above exceed the average background levels by 35%, the permittee shall commence monthly monitoring on the parameters listed in paragraph 2 above.

5. A quarterly summary of the results of the monitoring shall be provided by the permittee to the Southwest District of the Department of Environmental Protection ~~Regulation~~ and to the Southwest Florida Water Management District.

6. The permittee shall keep a monthly record of the monitoring results and shall notify the Department's Southwest District Manager and the Southwest Florida Water Management District when said measurements reach 90% of the levels permitted in the water quality standards of Rule 62-520.420 ~~17-3.101~~, F.A.C.

C. Corrective Action

When the leachate monitoring system indicates significant leakage to the groundwater in the shallow aquifer, the appropriate ponds (settling spray or sludge) shall be sealed, relocated or closed, or the operation of the affected pond shall be altered in such a manner as to assure the Department that no significant contamination of the groundwater will occur.

V. Control Measures During Construction

A. Stormwater Runoff

During construction and plant operation, necessary measures shall be used to settle, filter, treat or absorb silt containing or pollutant laden stormwater runoff to limit the suspended solids to 50 mg/1 or less during rainfall periods not exceeding the 10-year, 24-hour rainfall, and to prevent an increase in turbidity to more than 29 NTUs ~~50 Jackson Turbidity Units~~ above background in waters of the State.

Control measures shall consist at the minimum, of filters, sediment traps, barriers, berms or vegetative planting. Exposed or disturbed soil shall be protected as soon as possible to minimize silt and sediment laden runoff. The pH shall be kept within the range of 6.0 to 8.5.

B. Sanitary Wastes

Disposal of sanitary wastes from construction toilet facilities shall be in accordance with applicable regulations of the Department and appropriate local health agency.

C. Environmental Control Program

An environmental control program shall be established under the supervision of a qualified person to assure that all construction activities conform to good environmental practices and the applicable conditions of certification.

The permittee shall notify the Department if unexpected harmful effects or evidence of irreversible environmental damage are detected during construction, shall immediately cease work and shall provide an analysis of the problem and a plan to eliminate or significantly reduce the harmful effects or damage, and to prevent reoccurrence.

VI. Solid Wastes

Solid Wastes resulting from construction or operation shall be disposed of in accordance with the applicable regulations of Chapter ~~17-7~~ 62-701, FAC.

Open burning in connection with land clearing shall be in accordance with Chapter ~~71-5~~ 62-256, FAC, no additional permits shall be required, but the Division of Forestry shall be notified. Open burning shall not occur if the Division of forestry has issued a ban on burning due to fire hazard conditions.

VII. Operation Safeguards

The overall design and layout of the facilities shall be such as to minimize hazards to humans and the environment. Security control measures shall be utilized to prevent exposure of the public to hazardous conditions.

VIII. Solid Waste Utilization System

The solid waste utilization facility shall be designed and operated in compliance with all applicable regulations of the Department, including but not limited to Chapter ~~71-7~~ 62-701, FAC.

IX. Screening

The permittee shall provide screening of the site through the use of aesthetically acceptable structures, vegetated earthen walls and/or existing or planted vegetation.

X. Potable Water Supply System

The potable water supply system shall be designed and operated in conformance with Chapter ~~17-22~~ 62-550, 62-551, 62-555, and 62-560, FAC. ~~Information as required in 17-22.05 shall be submitted to the Department prior to construction and operation. The operator of the potable water supply system shall be certified in accordance with Chapter 17-16, FAC.~~

XI. Transformer and Electric Switching Gear

The foundations for transformers, capacitors, and switching gear necessary for McIntosh Unit 3 to the existing distribution system shall be constructed of an impervious material and shall be constructed in such a manner to allow complete collection and recovery of any spills or leakage of oily, toxic, or hazardous substances.

XII. Toxic, Deleterious, or Hazardous Materials

The spill of any toxic, deleterious, or hazardous materials shall be reported in the manner specified by General Condition 2.

XIII. Transmission Line

Directly associated transmission lines shall be constructed and maintained in a manner to minimize environmental impacts in accordance with Chapter 403, F.S., and Chapter ~~22~~27F-6, FAC.

A. Construction

1. Filling and construction in waters of the State shall be minimized to the extend practicable. No such activities shall take place without obtaining lease or title from the Board of Trustees of the Internal Improvement Trust Fund ~~Department of Natural Resources.~~

2. Placement of fill in wetland areas shall be minimized by spanning such areas with the maximum transmission lines span practicable. Such areas should be bridged by maintenance or access roads.

3. Construction and access roads should avoid wetlands and be located in surrounding uplands. Any fill required in wetlands for construction but not required for maintenance purposes shall be removed and the ground restored to its original contours after transmission line placement.

4. Keyhole fills from upland areas are preferable to a single road and should be oriented as nearly parallel to surface water flow lines as possible.

5. Sufficient culverts shall be placed through fill causeways to maintain sheet flow. The number and locations of such culverts will be determined in the field by consultation with DE~~R~~P field inspectors.

6. Maintenance roads shall be planted with native species to prevent erosion and subsequent water quality degradation.

7. Construction activities should proceed as much as possible during the dry season.

8. Turbidity control measures, where needed, shall be employed to prevent violation of water quality standards.

9. Good environmental practices as described in Environmental Criteria for Electric Transmission Systems or published by the U.S. Department of Interior and the U.S. Department of Agriculture should be followed.

10. Any archaeological sites discovered during construction of the transmission line shall be disturbed as little as possible and such discovery shall be communicated to the Department of State, Division of Archive History and Records Management.

B. Maintenance

1. Vegetative removal for maintenance should be carried out in the following manner:

   Vegetation within the right-of-way may be cut or removed no lower than the soil surface under the conductor, and for a distance up to 20 feet to either side of the outermost conductor, while maintaining the remainder of the project right-of-way by selectively clearing vegetation which has an expected mature height above 14 feet. Brazilian pepper, Australian pine and Melaleuca shall be eradicated throughout the wetland portion of the right-of-way.

2. Herbicides registered with the U.S. Environmental Protection Agency may be used for vegetation control within the transmission line easement without prior approval of the Department.

XIV. Construction in Waters of the State

No construction in waters of the State shall commence without obtaining lease or title from the Board of Trustees of the Internal Improvement Trust Fund ~~Department of Natural Resources~~.

XV. Cooling Water Treatment

A study to determine the presence of pathogenic organisms in the sewage treatment plant effluent shall be performed to determine the degree of treatment required prior to use in cooling towers. A plan or study will be developed by the Department and the Department of Health & Rehabilitative Services. Based on the number of pathogenic organisms detected, the final degree of treatment and amount of chlorination to be required will be determined by the Department.

XVI. Sanitary Waste Disposal

Sanitary waste from operating plant facilities shall be disposed of in a septic tank system, as approved by the ~~Health~~ Department of Health & Rehabilitative Services, as long as the average daily flow does not exceed 2,000 gallons per day. If the sanitary waste exceeds 2000 gpd, a properly designed treatment system shall be constructed upon receipt of approval by the Department.

LAKELAND
ELECTRIC & WATER

Excellence Is Our Goal, Service Is Our Job

(813) 499-6603

Farzie Shelton
ENVIRONMENTAL COORDINATOR, Ch E.

March 9, 1995

RECEIVED
MAR 9 1995
Bureau of
Air Regulation

VIA HAND DELIVERY
Hamilton S. Oven, Jr., Administrator
Power Plant Siting Section
Department of Environmental Regulation
3900 Commonwealth Boulevard
Tallahassee, FL 32399-3000

Re: City of Lakeland; C.D. McIntosh Unit No. 3; Responses to Requests for Additional Information and Supplement to Requests to Modify Site Certification (PA-78-06) and to Revise PSD Permit (PSD-FL-8)

Dear Buck:

As you know, the City of Lakeland submitted a request to modify the above-referenced Site Certification on December 7, 1994, and a request to revise the above-referenced air permit on January 4, 1995. The Department of Environmental Protection promptly reviewed these applications and requested additional information by letters dated January 11 and January 27, 1995. We have subsequently prepared responses, and are providing additional information with this letter. The responses to the January 11 and 27 requests are included as Exhibits 1 and 2, respectfully. In addition, supplemental and replacement pages for the air permit application form are included as Exhibit 3.

While the City of Lakeland does not concur with the Department's position that the use of petroleum coke in Unit No. 3 would trigger Prevention of Significant Deterioration (PSD) and Best Available Control Technology (BACT) review, the requested information has been provided in an effort to expedite the Department's review and anticipated authorization to utilize petroleum coke. You may notice that PSD and BACT review information is being provided only for carbon monoxide. The City of Lakeland is proposing limits on the hours of operation when petroleum coke is cofired to prevent any significant net emissions increases of other pollutants, based on the Department's methodology for emission comparisons. The Department's methodology was explained to us at a meeting on February 7 by Clair Fancy and his staff, and based on this methodology and a limit on the hours of operation, PSD and BACT review information is being submitted only for carbon monoxide.

As a result, it is the City's understanding that the Department will issue a BACT determination only for carbon monoxide. The City would like to confirm that this BACT determination and the limitation on the hours of operation will apply only during periods when petroleum coke is cofired. The City of Lakeland will continue to be permitted to operate 8760 hours per year when Unit No. 3 utilizes fuels other than petroleum coke.

Thank you for your prompt attention to this matter. Once you and your staff have had an opportunity to review the attached information, please let us know whether any additional clarification is needed. Your cooperation and assistance with this matter is very much appreciated.

Sincerely,

Farzie Shelton

Farzie Shelton /arm
Environmental Coordinator
Department of Electric and Water Utilities

cc: Clair Fancy, FDEP (Exhibit 2 and 3)
Al Rushanan, FDEP (Exhibit 1)
Jan Mandrup-Poulsen, FDEP (Exhibit 1)
Don Kell, FDEP (Exhibit 1)
Michael Hickey, FDEP (Exhibit 1)
Richard Garrity, FDEP (Exhibit 1)
Angela Morrison, HGSS
Ken Kosky, KBN

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(813) 499-6603

Farzie Shelton
ENVIRONMENTAL COORDINATOR, Ch E.

January 17, 1995

VIA HAND DELIVERY
Clair Fancy, Chief
Bureau of Air Regulation
Department of Environmental Protection
2600 Blair Stone Road
Tallahassee, FL 32399

Re: City of Lakeland--C.D. McIntosh Power Plant, Unit No. 3
Request to Amend PSD Permit No. PSD-FL-8

Dear Clair:

Please make the following corrections to the package submitted to the Department On January 4, 1995, in the above-referenced matter:

1. Please remove the "seventh" page 26. (Ref. No. 14262Y1/F3/TVD-S16 (12/30/94) (bottom right corner)) The previous page, which also provides information regarding natural gas and includes a max sulfur content of 1%, is correct.

2. Please replace page 28 (Ref. no. 14262Y1/F3/TVE-PI1 (12/30/94)). Line no. 5 should read "Method of Compliance: Annual Stack Test <u>if > 400 hours of operation.</u>

3. Please replace page 28 (Ref. no. 14262Y2/F3/TVE-PI3a (01/04/95) with the enclosed page (poor copy quality).

Thank you for your assistance in this matter. Please call me if you have any questions.

Sincerely,

Farzie Shelton

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JAN 17 1995
Bureau of
Air Regulation

Allowable Emissions (Pollutant identified on front page)

C. Natural gas firing

1. Basis for Allowable Emissions Code: Rule	
2. Future Effective Date of Allowable Emissions: Not applicable	
3. Requested Allowable Emissions and Units: 0.2 lb/MMBtu	
4. Equivalent Allowable Emissions: 728 lbs/hr	3,188.6 tons/yr
5. Method of Compliance: Annual stack test if > 400 hours operation	
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode): The allowable emission limit is based on FDEP Rule 62-296.800; 40 CFR Part 60, Subpart D, Section 60.44(a)(1) (see also Attachment 1).	

D.

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):	

Allowable Emissions (Pollutant identified on front page)

A.

1. Basis for Allowable Emissions Code: **Rule**	
2. Future Effective Date of Allowable Emissions: **Not applicable**	
3. Requested Allowable Emissions and Units: **0.1 lb/MMBtu**	
4. Equivalent Allowable Emissions: **364** lbs/hr	**1,594** tons/yr
5. Method of Compliance: **Annual Stack Test if >400 hours of operation**	
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode): **The allowable emission limit is based on FDEP Rule 62-296.800; 40 CFR Part 60, Subpart D (see also Attachment 1).**	

B. Not Applicable

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):	

Department of
Environmental Protection

DIVISION OF AIR RESOURCES MANAGEMENT

APPLICATION FOR AIR PERMIT - LONG FORM

See Instructions for Form No. 62-210.900(1)

I. APPLICATION INFORMATION

This section of the Application for Air Permit form provides general information on the scope of this application, the purpose for which this application is being submitted, and the nature of any construction or modification activities proposed as a part of this application. This section also includes information on the owner or authorized representative of the facility (or the responsible official in the case of a Title V source) and the necessary statements for the applicant and professional engineer, where required, to sign and date for formal submittal of the Application for Air Permit to the Department. If the application form is submitted to the Department on diskette, this section of the Application for Air Permit must also be submitted in hard-copy.

<u>Identification of Facility Addressed in This Application</u>

Enter the name of the corporation, business, governmental entity, or individual that has ownership or control of the facility; the facility name, if any; and a brief reference to the facility's physical location. If known, also enter the ARMS or AIRS facility identification number. This information is intended to give a quick reference, on the first page of the application form, to the facility addressed in this application. Elsewhere in the form, numbered data fields are provided for entry of the facility data in computer-input format.

City of Lakeland, Department of Electric and Water Utilities; C.D. McIntosh Power Plant; Unit 3; Lakeland, Polk County, 40TPA50004

<u>Application Processing Information (DEP Use)</u>

1. Date of Receipt of Application:	
2. Permit Number:	
3. PSD Number (if applicable):	
4. Siting Number (if applicable):	

Owner/Authorized Representative or Responsible Official

1. Name and Title of Owner/Authorized Representative or Responsible Official:
   Ronald W. Tomlin, Assistant Managing Director

2. Owner/Authorized Representative or Responsible Official Mailing Address:

   Organization/Firm: **City of Lakeland, Department of Electric and Water Utilities**
   Street Address: **501 East Lemon Street**
   City: **Lakeland** State: **Florida** Zip Code: **33801-5099**

3. **Owner/Authorized Representative or Responsible Official Telephone Numbers:**

   Telephone: (813) 499-6300 Fax: **(813) 499-6344**

4. Owner/Authorized Representative or Responsible Official Statement:

   I, the undersigned, am the owner or authorized representative of the facility (non-Title V source) addressed in this Application for Air Permit or the responsible official, as defined in Chapter 62-213, F.A.C., of the Title V source addressed in this application, whichever is applicable. I hereby certify, based on information and belief formed after reasonable inquiry, that the statements made in this application are true, accurate and complete and that, to the best of my knowledge, any estimates of emissions reported in this application are based upon reasonable techniques for calculating emissions. Further, I agree to operate and maintain the air pollutant emissions units and air pollution control equipment described in this application so as to comply with all applicable standards for control of air pollutant emissions found in the statutes of the State of Florida and rules of the Department of Environmental Protection and revisions thereof. If the purpose of this application is to obtain an air operation permit or operation permit revision for one or more emissions units which have undergone construction or modification, I certify that, with the exception of any changes detailed as part of this application, each such emissions unit has been constructed or modified in substantial accordance with the information given in the corresponding application for air construction permit and with all provisions contained in such permit. I understand that a permit, if granted by the Department, cannot be transferred without authorization from the Department, and I will promptly notify the Department upon sale or legal transfer of any permitted emissions unit.*

   Ronald W. Tomlin
   Signature

   December 27, 1994
   Date

* Attach letter of authorization if not currently on file.

Scope of Application

This Application for Air Permit addresses the following emissions unit(s) at the facility (or Title V source). An Emissions Unit Information Section (a Section III of the form) must be included for each emissions unit listed.

Emissions Unit Id	Description of Emissions Unit
Unit 3	Unit 3 Boiler at C.D. McIntosh Power Plant

Purpose of Application and Category

Check one (except as otherwise indicated):

Category I: All Air Operation Permit Applications Subject to Processing Under Chapter 62-213, F.A.C.

This Application for Air Permit is submitted to obtain:

[ ] Initial air operation permit under Chapter 62-213, F.A.C., for an existing facility which is classified as a Title V source.

[ ] Initial air operation permit under Chapter 62-213, F.A.C., for a facility which, upon start up of one or more newly constructed or modified emissions units addressed in this application, would become classified as a Title V source.

Current construction permit number: ____________________

[ ] Air operation permit renewal under Chapter 62-213, F.A.C., for a Title V source.

Operation permit to be renewed: ____________________

[ ] Air operation permit revision for a Title V source to address one or more newly constructed or modified emissions units addressed in this application.

Current construction permit number: ____________________

Operation permit to be revised: ____________________

[ ] Air operation permit revision or administrative correction for a Title V source to address one or more proposed new or modified emissions units and to be processed concurrently with the air construction permit application. Also check Category III.

Operation permit to be revised/corrected: ____________________

____

[ ] Air operation permit revision for a Title V source for reasons other than construction or modification of an emissions unit. Give reason for the revision; e.g., to comply with a new applicable requirement or to request approval of an "Early Reductions" proposal.

Operation permit to be revised: ____________________

Reason for revision: ____________________

____

Category II: All Air Operation Permit Applications Subject to Processing Under Rule 62-210.300(2)(b), F.A.C.

This Application for Air Permit is submitted to obtain:

[ ] Initial air operation permit under Rule 62-210.300(2)(b), F.A.C., for an existing facility seeking classification as a synthetic non-Title V source.

Current operation/construction permit number(s): ______________________________

____

[ ] Renewal air operation permit under Rule 62-210.300(2)(b), F.A.C., for a synthetic non-Title V source.

Operation permit to be renewed: ______________________________

[ ] Air operation permit revision for a synthetic non-Title V source. Give reason for revision; e.g., to address one or more newly constructed or modified emissions units.

Operation permit to be revised: ______________________________

Reason for revision: ______________________________

____

Category III: All Air Construction Permit Applications for All Facilities and Emissions Units

This Application for Air Permit is submitted to obtain:

[X] Air construction permit to construct or modify one or more emissions units within a facility (including any facility classified as a Title V source).

Current operation permit number(s), if any: PA 74-06-SR (PPSA); PSD-FL-0008

[ ] Air construction permit to make federally enforceable an assumed restriction on the potential emissions of one or more existing, permitted emissions units.

Current operation permit number(s): ______________________________

[ ] Air construction permit for one or more existing, but unpermitted, emissions units.

Application Processing Fee

Check one:

[X] Attached - Amount: $ 10,000* [ ] Not Applicable.

Construction/Modification Information

1.	Description of Proposed Project or Alterations: Use of up to 20 percent (weight basis) of petroleum coke with coal. Minor amendments to PSD permit.
2.	Projected or Actual Date of Commencement of Construction (DD-MON-YYYY): No construction of new facilities required
3.	Projected Date of Completion of Construction (DD-MON-YYYY): Not Applicable

*Submitted on December 7, 1994 under a modification request of the Site Certification for the unit (PA 74-06-SR).

Professional Engineer Certification

1. Professional Engineer Name: Kennard F. Kosky Registration Number: 14996	
2. Professional Engineer Mailing Address: Organization/Firm: KBN Engineering and Applied Sciences, Inc. Street Address: 6241 NW 23rd Street, Suite 500 City: Gainesville State: FL Zip Code: 32653-1500	
3. Professional Engineer Telephone Numbers: Telephone: (904) 336-5600 Fax: (904) 336-6603	

4. Professional Engineer Statement:

I, the undersigned, hereby certify, except as particularly noted herein, that:*

(1) To the best of my knowledge, there is reasonable assurance (a) that the air pollutant emissions unit(s) and the air pollution control equipment described in this Application for Air Permit, when properly operated and maintained, will comply with all applicable standards for control of air pollutant emissions found in the Florida Statutes and rules of the Department of Environmental Protection; or (b) for any application for a Title V source air operation permit, that each emissions unit described in this Application for Air Permit, when properly operated and maintained, will comply with the applicable requirements identified in this application to which the unit is subject, except those emissions units for which a compliance schedule is submitted with this application;

(2) To the best of my knowledge, any emission estimates reported or relied on in this application are true, accurate, and complete and are either based upon reasonable techniques available for calculating emissions or, for emission estimates of hazardous air pollutants not regulated for an emissions unit addressed in this application, based solely upon the materials, information and calculations submitted with this application; and

(3) For any application for an air construction permit for one or more proposed new or modified emissions units, the engineering features of each such emissions unit described in this application have been designed or examined by me or individuals under my direct supervision and found to be in conformity with sound engineering principles applicable to the control of emissions of the air pollutants characterized in this application.

Kennard F. Kosky — December 27, 1994

Signature — Date

(seal) KFK

* Attach any exception to certification statement.

Application Contact

1. Name and Title of Application Contact: Ms. Farzie Shelton, Environmental Coordinator	
2. Application Contact Mailing Address: Organization/Firm: Lakeland Department of Electric and Water Utilities Street Address: 501 East Lemon Street City: Lakeland State: FL Zip Code: 33801-5099	
3. Application Contact Telephone Numbers: Telephone: (813) 499-6603	Fax: (813) 499-6688

Application Comment

This application is being submitted to obtain FDEP recognition that petroleum coke can be burned in McIntosh Unit 3. There will be no new construction of facilities or changes in the current procedures when petroleum coke is being fired in Unit 3. The application also addresses minor amendments to the PSD approval and previous application.

II. FACILITY INFORMATION

A. GENERAL FACILITY INFORMATION

Facility Name, Location, and Type

1. Facility Owner or Operator: City of Lakeland, Department of Electric and Water Utilities			
2. Facility Name: C.D. McIntosh Power Plant			
3. Facility Identification Number: 40TPA530004 [ ] Unknown			
4. Facility Location Information: Facility Street Address: 3030 East Lake Parker Drive City: Lakeland County: Polk Zip Code: 33805			
5. Facility UTM Coordinates: Zone: 17 East (km): 408.5 North (km): 3,105.8			
6. Facility Latitude/Longitude: Latitude (DD/MM/SS): Longitude (DD/MM/SS):			
7. Governmental Facility Code: 4	8. Facility Status Code: A	9. Relocatable Facility? [ ] Yes [X] No	10. Facility Major Group SIC Code: 49
11. Facility Comment: The C.D. McIntosh Power Plant includes two oil- and gas-fired steam electric generating units (Units 1 and 2), one coal-, refuse-, and oil-fired steam electric generating unit (Unit 3), and three combustion turbines (Units 1-3). This application addresses only the steam electric generating Unit 3.			

Facility Contact

1. Name and Title of Facility Contact: Ms. Farzie Shelton, Environmental Coordinator
2. Facility Contact Mailing Address: Organization/Firm: City of Lakeland, Department of Electric and Water Utilities Street Address: 501 East Lemon Street City: Lakeland State: FL Zip Code: 33801-5099
3. Facility Contact Telephone Numbers: Telephone: (813) 499 - 6303 Fax: (813) 499 - 6688

Facility Regulatory Classifications

1. Small Business Stationary Source? [ ] Yes	[X] No	[ ] Unknown
2. Title V Source? [X] Yes	[ ] No	
3. Synthetic Non-Title V Source? [ ] Yes	[X] No	
4. Major Source of Pollutants Other than Hazardous Air Pollutants (HAPs)? [X] Yes	[ ] No	
5. Synthetic Minor Source of Pollutants Other than HAPs? [ ] Yes	[X] No	
6. Major Source of HAPs? [ ] Yes	[ ] No	[X] Possible*
7. Synthetic Minor Source of HAPs? [ ] Yes	[X] No	
8. One or More Emissions Units Subject to NSPS? [X] Yes	[ ] No	
9. One or More Emissions Units Subject to NESHAP? [ ] Yes	[X] No	
10. Title V Source by EPA Designation? [ ] Yes	[X] No	
11. Facility Regulatory Classifications Comment: This application addresses only Unit 3; therefore, facility information is not applicable. *The HAPS emissions are not expected to change as a result of this modification request. A detailed HAPS emission inventory for the facility will be submitted with the Title V application.		

B. FACILITY REGULATIONS

Depending on the application category, this subsection of the Application for Air Permit form provides either a brief analysis or detailed listing of federal, state, and local regulations applicable to the facility as a whole. (Regulations applicable to individual emissions units within the facility are addressed in Subsection III-B of the form.)

Rule Applicability Analysis (Required for Category II applications and Category III applications involving non Title-V sources. See Instructions.)

Not Applicable

<u>List of Applicable Regulations</u> (Required for Category I applications and Category III applications involving Title-V sources. See Instructions.) **Not Applicable. Refer to Page 22 for regulations applicable to Unit 3.**

C. FACILITY POLLUTANT INFORMATION

This subsection of the Application for Air Permit form allows for the reporting of potential and estimated emissions of selected pollutants on a facility-wide basis. It must be completed for each pollutant for which the applicant proposes to establish a facility-wide emissions cap and for each pollutant for which emissions are not reported at the emissions-unit level.

Facility Pollutant Information: Pollutant ____ of ____ Not Applicable

1. Pollutant Emitted:		
2. Estimated Emissions:		(tons/yr)
3. Requested Emissions Cap:	(lb/hr)	(tons/yr)
4. Basis for Emissions Cap Code:		
5. Facility Pollutant Comment:		

Facility Pollutant Information Pollutant ____ of ____

1. Pollutant Emitted:		
2. Estimated Emissions:		(tons/yr)
3. Requested Emissions Cap:	(lb/hr)	(tons/yr)
4. Basis for Emissions Cap Code:		
5. Facility Pollutant Comment:		

Facility Pollutant Information Pollutant ____ of ____

1. Pollutant Emitted:		
2. Estimated Emissions:		(tons/yr)
3. Requested Emissions Cap:	(lb/hr)	(tons/yr)
4. Basis for Emissions Cap Code:		
5. Facility Pollutant Comment:		

Facility Pollutant Information Pollutant ____ of ____

1. Pollutant Emitted:		
2. Estimated Emissions:		(tons/yr)
3. Requested Emissions Cap:	(lb/hr)	(tons/yr)
4. Basis for Emissions Cap Code:		
5. Facility Pollutant Comment:		

D. FACILITY SUPPLEMENTAL INFORMATION

This subsection of the Application for Air Permit form provides supplemental information related to the facility as a whole. (Supplemental information related to individual emissions units within the facility is provided in Subsection III-I of the form.) Supplemental information must be submitted as an attachment to each copy of the form, in hard-copy or computer-readable form.

Supplemental Requirements for All Applications

1. Area Map Showing Facility Location: [ ] Attached, Document ID: ____________ [X] Not Applicable [ ] Waiver Requested
2. Facility Plot Plan: [ ] Attached, Document ID: ____________ [X] Not Applicable [ ] Waiver Requested
3. Process Flow Diagram(s): [ ] Attached, Document ID(s): ____________ [X] Not Applicable [ ] Waiver Requested
4. Precautions to Prevent Emissions of Unconfined Particulate Matter: [ ] Attached, Document ID: ____________ [X] Not Applicable
5. Fugitive Emissions Identification: [ ] Attached, Document ID: ____________ [X] Not Applicable
6. Supplemental Information for Construction Permit Application: [ ] Attached, Document ID: ____________ [X] Not Applicable

Additional Supplemental Requirements for Category I Applications Only

7. List of Insignificant Activities: [ ] Attached, Document ID: ____________ [X] Not Applicable
8. List of Equipment/Activities Regulated under Title VI: [ ] Attached, Document ID: ____________ [ ] Equipment/Activities Onsite but Not Required to be Individually Listed [X] Not Applicable

9. Alternative Methods of Operation: [ ] Attached, Document ID: _____ [X] Not Applicable
10. Alternative Modes of Operation (Emissions Trading): [ ] Attached, Document ID: ___________ [X] Not Applicable
11. Enhanced Monitoring Plan: [ ] Attached, Document ID: ___________ [X] Not Applicable
12. Risk Management Plan Verification: [ ] Plan Submitted to Implementing Agency - Verification Attached Attached, Document ID: ___________ [ ] Plan to be Submitted to Implementing Agency by Required Date [X] Not Applicable
13. Compliance Report and Plan [ ] Attached, Document ID: ___________ [X] Not Applicable
14. Compliance Statement (Hard-copy Required) [ ] Attached, Document ID: ___________ [X] Not Applicable

III. EMISSIONS UNIT INFORMATION

A separate Emissions Unit Information Section (including subsections A through I as required) must be completed for each emissions unit addressed in this Application for Air Permit. If submitting the application form in hard copy, indicate, in the space provided at the top of each page, the number of this Emissions Unit Information Section and the total number of Emissions Unit Information Sections submitted as part of this application.

A. GENERAL EMISSIONS UNIT INFORMATION

This subsection of the Application for Air Permit form provides general information on the emissions unit addressed in this Emissions Unit Information Section, including information on the type, control equipment, operating capacity, and operating schedule of the emissions unit.

Type of Emissions Unit Addressed in This Section

Check one:

[X] This Emissions Unit Information Section addresses, as a single emissions unit, a single process or production unit, or activity, which produces one or more air pollutants and which has at least one definable emission point (stack or vent).

[ ] This Emissions Unit Information Section addresses, as a single emissions unit, an individually-regulated emission point (stack or vent) serving a single process or production unit, or activity, which also has other individually-regulated emission points.

[ ] This Emissions Unit Information Section addresses, as a single emissions unit, a collectively-regulated group of process or production units and activities which has at least one definable emission point (stack or vent) but may also produce fugitive emissions.

[ ] This Emissions Unit Information Section addresses, as a single emissions unit, one or more process or production units and activities which produce fugitive emissions only.

Emissions Unit Information Section 1 of 1

Emissions Unit Description and Status

1. Description of Emissions Unit Addressed in This Section: McIntosh Unit 3		
2. ARMS Identification Number: [ ] No Corresponding ID [ ] Unknown 40TPA530004-06		
3. Emissions Unit Status Code: A	4. Acid Rain Unit? [X] Yes [ ] No	5. Emissions Unit Major Group SIC Code: 49
6. Initial Startup Date (DD-MON-YYYY): 01-SEP-1982		
7. Long-term Reserve Shutdown Date (DD-MON-YYYY): Not applicable		
8. Package Unit: Not Applicable Manufacturer: Model Number:		
9. Generator Nameplate Rating: 364 MW		
10. Incinerator Information: Not Applicable Dwell Temperature: °F Dwell Time: seconds Incinerator Afterburner Temperature: °F		
11. Emissions Unit Comment: Initial start-up date is the unit's commercial operation date.		

Emissions Unit Control Equipment

A.

1.	Description: Electrostatic Precipitator (ESP)
2.	Control Device or Method Code: 010

B.

1.	Description: Flue Gas Desulfurization (FGD) System
2.	Control Device or Method Code: 067

C.

1.	Description: Low-NO_x Burner
2.	Control Device or Method Code: 024

Emissions Unit Information Section 1 of 1

Emissions Unit Operating Capacity

1. Maximum Heat Input Rate:	3,640	mmBtu/hr	
2. Maximum Incineration Rate:	Not applicable	lbs/hr	tons/day
3. Maximum Process or Throughput Rate: Not Applicable			
4. Maximum Production Rate: Not Applicable			
5. Operating Capacity Comment: The maximum heat input rate applies to all fuels and fuel combinations.			

Emissions Unit Operating Schedule

Requested Maximum Operating Schedule:

24	hours/day	7	days/week
52.143	weeks/yr	8,760	hours/yr

Emissions Unit Operating Capacity

1. Maximum Heat Input Rate:	3,640 mmBtu/hr
2. Maximum Incineration Rate:	Not applicable lbs/hr tons/day
3. Maximum Process or Throughput Rate: Not Applicable	
4. Maximum Production Rate: Not Applicable	
5. Operating Capacity Comment: Emissions unit burns coal and refuse-derived fuel (RDF); The emissions unit is authorized to burn residual oil.	

Emissions Unit Operating Schedule

Requested Maximum Operating Schedule:

24	hours/day	7	days/week
52.143	weeks/yr	8,760	hours/yr

B. EMISSIONS UNIT REGULATIONS

Depending on the application category, this subsection of the Application for Air Permit form provides either a brief analysis or detailed listing of all federal, state, and local regulations applicable to the emissions unit addressed in this Emissions Unit Information Section.

<u>Rule Applicability Analysis</u> (Required for Category II applications and Category III applications involving non Title-V sources. See Instructions.)

Not Applicable.

Emissions Unit Information Section __1__ of __1__

List of Applicable Regulations (Required for Category I applications and Category III applications involving Title-V sources. See Instructions.)

62-296.405(2)(a)	62-297.401(9)
62-296.405(2)(b)	62-297.401(17)
62-296.405(2)(c)	62-297.401(19)
62-296.405(2)(d)	40 CFR 60 Subpart D (as applicable)
62-296.800(2)(a)(1)	40 CFR Part 72 (as applicable)
62-296.800(3)	40 CFR Part 73 (as applicable)
62-296.800(4)(a)	40 CFR Part 75 (as applicable)
62-296.800(4)(b)	62-296.405 (1)(f)
62-296.800(4)(e)	62-296.405 (1)(e)
62-297.310	62-296.405(1)(g)
62-297.330	
62-297.340	
62-297.345(1)	
62-297.345(3)	
62-297.350	
62-297.400	
62-297.401(1)	
62-297.401(2)	
62-297.401(3)	
62-297.401(4)	
62-297.401(5)	
62-297.401(6)	
62-297.401(7)	

Emissions Unit Information Section 1 of 1

C. EMISSION POINT (STACK/VENT) INFORMATION

This subsection of the Application for Air Permit form provides information about the emission point associated with the emissions unit addressed in this Emissions Unit Information Section. An emission point is typically a stack or vent but can be any identifiable location at which air pollutants, including fugitive emissions, are discharged into the atmosphere.

Emission Point Description and Type

1. Identification of Point on Plot Plan or Flow Diagram: S003 in attached flow diagram				
2. Emission Point Type Code:	[X] 1	[ ] 2	[ ] 3	[ ] 4
3. Descriptions of Emissions Points Comprising this Emissions Unit: Unit 3 stack, S003 in attached flow diagram; PFD-1				
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common: Not applicable				
5. Discharge Type Code:	[ ] D	[ ] F	[ ] H	[ ] P
	[ ] R	[X] V	[ ] W	
6. Stack Height:			250 ft	

7. Exit Diameter:	18	ft
8. Exit Temperature:	167	°F
9. Actual Volumetric Flow Rate:	1,260,536	acfm
10. Percent Water Vapor:	11.5	%
11. Maximum Dry Standard Flow Rate:	925,198	dscfm
12. Nonstack Emission Point Height:	Not applicable	ft

13. Emission Point UTM Coordinates:

Zone: 17 East (km): 408.5 North (km): 3,105.8

14. Emission Point Comment: Stack parameters reflect design conditions. Exit temperature is operated greater than 167°F during normal operation. For oil firing with no SO_2 scrubbing, the estimated exit gas temperature and flow are 250°F and 1,093,685 ACFM, respectively.

D. SEGMENT (PROCESS/FUEL) INFORMATION

For the emissions unit addressed in this Emissions Unit Information Section, a separate set of segment data (Fields 1-10) must be completed for each segment required to be reported and for each alternative operating method or mode (emissions trading scenario) under Chapter 62-213, F.A.C., for which the maximum hourly or annual segment-related rate would vary. A segment is a material handling, process, fuel burning, volatile organic liquid storage, production, or other such operation to which emissions of the unit are directly related. See instructions for further details on this subsection of the Application for Air Permit.

Segment Description and Rate Information: Segment 1 of 7

1. Segment Description (Process/Fuel Type and Associated Operating Method/Mode): Coal	
2. Source Classification Code (SCC): 10100101	
3. SCC Units: Tons	
4. Maximum Hourly Rate: 159.6	5. Maximum Annual Rate: 1,398,096
6. Estimated Annual Activity Factor: Not applicable	
7. Maximum Percent Sulfur: 3.3	8. Maximum Percent Ash: < 15
9. Million Btu per SCC Unit: 22.81	
10. Segment Comment: Maximum hourly rates and percent sulfur will vary depending upon coal source but will not exceed 3.3 percent. Heat content-based on maximum hourly rate (TPH) and maximum heat input rating for unit of 3,640 MMBtu/hr. $159.6\ \frac{\text{Tons}}{\text{hr}} \times \frac{22.81\ \text{MMBTU}}{\text{Ton}} = 3640$ MMBTU/hr	

Emissions Unit Information Section 1 of 1

Segment Description and Rate Information: Segment 2 of 7

1. Segment Description (Process/Fuel Type and Associated Operating Method/Mode): Coal and RDF (90/10 heat input basis)	
2. Source Classification Code: 10100101 and 10101202	
3. SCC Units: Tons	
4. Maximum Hourly Rate: 184.1	5. Maximum Annual Rate: 1,612,716
6. Estimated Annual Activity Factor: Not applicable	
7. Maximum Percent Sulfur: 2.6 (3.3/0.1)	8. Maximum Percent Ash: < 15
9. Million Btu per SCC Unit: 21.56	
10. Segment Comment: Maximum hourly rates and percent sulfur will vary depending upon mixture. Coal and RDF are blended to a sulfur content of 2.6 percent with coal at 3.3 percent sulfur and RDF at 0.1 percent sulfur. Maximum hourly rate based on 143.7 TPH coal and 40.4 TPH RDF. Heat content of mixture based on maximum hourly rate (TPH) and maximum heat input rating for unit of 3,640 MMBtu/hr. Typical heat contents for coal and RDF are 24.6 and 9 MMBtu/ton, respectively.	

Emissions Unit Information Section 1 of 1

Segment Description and Rate Information: Segment 3 of 7

1. Segment Description (Process/Fuel Type and Associated Operating Method/Mode): Oil	
2. Source Classification Code: 10100401	
3. SCC Units: 1000 gallons	
4. Maximum Hourly Rate: 24.268	5. Maximum Annual Rate: 212,584.2
6. Estimated Annual Activity Factor: Not applicable	
7. Maximum Percent Sulfur: 2.5	8. Maximum Percent Ash: < 1
9. Million Btu per SCC Unit: 150	
10. Segment Comment: Heat content based on maximum hourly rate (TPH) and maximum heat input rating for unit of 3,640 MMBtu/hr. Distillate oil is used for unit startup and load stabilization. The PSD permit also provides that oil or a combination of oil and RFD may be used as an emergency fuel without the use of the SO_2 scrubber only when the scrubber malfunctions and the SO_2 cannot exceed 0.8 lb/mmBtu, resulting in a maximum sulfur content limit of 0.77% when the scrubber is not used.	

Emissions Unit Information Section 1 of 1

Segment Description and Rate Information: Segment 4 of 7

1. Segment Description (Process/Fuel Type and Associated Operating Method/Mode): Oil and RDF (90/10 heat input basis)	
2. Source Classification Code: 10100401 and 10101202	
3. SCC Units: 1000 gallons and tons	
4. Maximum Hourly Rate: 21.84/40.4	5. Maximum Annual Rate: 192,318.4 and 353,904
6. Estimated Annual Activity Factor: Not applicable	
7. Maximum Percent Sulfur: 2.5	8. Maximum Percent Ash: < 2
9. Million Btu per SCC Unit: 150 and 9.0	
10. Segment Comment: Maximum hourly rates and percent sulfur will vary depending upon mixture. Oil and RDF will be blended to a maximum sulfur content of 2.5 percent. Maximum hourly rate based on 90/10 percent heat input basis, respectively, for oil/RDF. Heat content of mixture based on maximum hourly rate (TPH) and maximum heat input rating for unit of 3,640 MMBtu/hr.	

Emissions Unit Information Section 1 of 1

Segment Description and Rate Information: Segment 5 of 7

1. Segment Description (Process/Fuel Type and Associated Operating Method/Mode): Coal and petroleum coke (80/20 weight basis)	
2. Source Classification Code: 10100101	
3. SCC Units: Tons	
4. Maximum Hourly Rate: 152.6	5. Maximum Annual Rate: 1,336,776
6. Estimated Annual Activity Factor: Not applicable	
7. Maximum Percent Sulfur: 2.75	8. Maximum Percent Ash: < 15
9. Million Btu per SCC Unit: 23.85	
10. Segment Comment: Maximum hourly rates and percent sulfur will vary depending upon mixture. Coal and petroleum coke will be blended to a maximum sulfur content of 2.75 percent. Typical sulfur content of petroleum coke is 5 percent. Maximum hourly rate based on 122.1 TPH coal and 30.5 TPH petroleum coke. Heat content of mixture based on maximum hourly rate (TPH) and maximum heat input rating for unit of 3,640 MMBtu/hr. Heat contents of coal and petroleum coke are 22.81 and 28.0 MMBtu/ton (see also FA-1).	

Emissions Unit Information Section 1 of 1

Segment Description and Rate Information: Segment 6 of 7

1. Segment Description (Process/Fuel Type and Associated Operating Method/Mode): Coal, petroleum coke, and RDF; coal/coke. (80/20 weight basis at 90% of heat input; RDF at 10% heat input)	
2. Source Classification Code: 10100101	
3. SCC Units: Tons	
4. Maximum Hourly Rate: 168.8	5. Maximum Annual Rate: 1,478,688
6. Estimated Annual Activity Factor: Not applicable	
7. Maximum Percent Sulfur: 2.75	8. Maximum Percent Ash: < 15
9. Million Btu per SCC Unit: 21.56	
10. Segment Comment: Maximum hourly rates and percent sulfur will vary depending upon mixture. Coal, RDF, and petroleum coke will be blended to a maximum sulfur content of 2.75 percent. Maximum hourly rate based on 100.9 TPH coal, 40.4 TPH RDF, and 27.5 TPH petroleum coke. Heat content of mixture based on maximum hourly rate (TPH) and maximum heat input rating for unit of 3,640 MMBtu/hr.	

Emissions Unit Information Section 1 of 1

Segment Description and Rate Information: Segment 7 of 7

1. Segment Description (Process/Fuel Type and Associated Operating Method/Mode): Natural gas	
2. Source Classification Code: 10100601	
3. SCC Units: Million cubic feet	
4. Maximum Hourly Rate: 3.529	5. Maximum Annual Rate: 30,576
6. Estimated Annual Activity Factor: Not applicable	
7. Maximum Percent Sulfur: 0.1	8. Maximum Percent Ash: Negligible
9. Million Btu per SCC Unit: 1,031.4	
10. Segment Comment: Natural gas is proposed as a supplementary fuel, to be burned alone or with any other fuel or fuel combination. Heat content of mixture based on maximum hourly rate (TPH) and maximum heat input rating for unit of 3,640 MMBtu/hr.	

Emissions Unit Information Section 1 of 1

Segment Description and Rate Information: Segment 7 of 7

1. Segment Description (Process/Fuel Type and Associated Operating Method/Mode): Natural gas	
2. Source Classification Code: 10100601	
3. SCC Units: Million cubic feet	
4. Maximum Hourly Rate: 3.529	5. Maximum Annual Rate: 30,576
6. Estimated Annual Activity Factor: Not applicable	
7. Maximum Percent Sulfur: 0.003	8. Maximum Percent Ash: Negligible
9. Million Btu per SCC Unit: 1,031.4	
10. Segment Comment: Natural gas is proposed as a supplementary fuel. Heat content of mixture based on maximum hourly rate (TPH) and maximum heat input rating for unit of 3,640 MMBtu/hr.	

Emissions Unit Information Section 1 of 1

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 5**

1. Pollutant Emitted: PM
2. Total Percent Efficiency of Control: 99.1 %
3. Primary Control Device Code: 010
4. Secondary Control Device Code: Not applicable
5. Potential Emissions: 364 lbs/hr 1,594 tons/yr
6. Synthetically Limited? [ ] Yes [X] No
7. Range of Estimated Fugitive/Other Emissions: Not applicable [ ] 1 [ ] 2 [ ] 3 _____ to _____ tons/yr
8. Emission Factor: 0.1 lb/MMBtu Reference: Regulatory requirement
9. Emissions Method Code: [ ] 1 [X] 2 [ ] 3 [ ] 4 [ ] 5
10. Calculation of Emissions: 3,640 MMBtu/hr x 0.1 lb/MMBtu
11. Pollutant Potential/Estimated Emissions Comment: Specific conditions of site certification (PA 74-06-SR) have a limitation of 0.1 lb/MMBtu; the PSD permit (PSD-FL-008) has emission limitations of 0.044 lb/MMBtu for coal; 0.05 lb/MMBtu for coal/refuse (RDF); 0.07 lb/MMBtu for oil and 0.075 lb/MMBtu for oil/refuse (RDF). This application includes a request to make the PSD emission rate consistent with the site certification. See Section A.

Emissions Unit Information Section 1 of 1

Allowable Emissions (Pollutant identified on front page)

A.

1. Basis for Allowable Emissions Code: Rule	
2. Future Effective Date of Allowable Emissions: Not applicable	
3. Requested Allowable Emissions and Units: 0.1 lb/MMBtu	
4. Equivalent Allowable Emissions: 364 lbs/hr	1,594 tons/yr
5. Method of Compliance: Annual Stack Test	
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode): The allowable emission limit is based on FDEP Rule 62-296.800; 40 CFR Part 60, Subpart D (see also Attachment 1).	

B. Not Applicable

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):	

Emissions Unit Information Section 1 of 1

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 2 of 5

1. Pollutant Emitted: SO_2
2. Total Percent Efficiency of Control: 85 %
3. Primary Control Device Code: 067
4. Secondary Control Device Code: Not applicable
5. Potential Emissions: 4,368 lbs/hr 19,131 tons/yr
6. Synthetically Limited? [ ] Yes [X] No
7. Range of Estimated Fugitive/Other Emissions: Not applicable [ ] 1 [ ] 2 [ ] 3 _____ to _____ tons/yr
8. Emission Factor: 1.2 lb/MMBtu Reference: Regulatory requirement
9. Emissions Method Code: [ ] 1 [X] 2 [ ] 3 [ ] 4 [ ] 5
10. Calculation of Emissions: 3,640 MMBtu/hr x 1.2 lb/MMBtu
11. Pollutant Potential/Estimated Emissions Comment: The total percent efficiency of control (i.e, 85 percent) applies to using 3.3 percent sulfur coal only. The PSD approval has a control efficiency of 85 percent. See also Section A.

Allowable Emissions (Pollutant identified on front page)

A. Coal firing

1. Basis for Allowable Emissions Code: Rule	
2. Future Effective Date of Allowable Emissions: Not applicable	
3. Requested Allowable Emissions and Units: 1.2 lb/MMBtu	
4. Equivalent Allowable Emissions: 4,368 lbs/hr	19,131 tons/yr
5. Method of Compliance: Annual stack test if > 400 hours of operation	
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode): The allowable emission limit is based on FDEP Rule 62-296.800; 40 CFR Part 60, Subpart D. Section 60.43(a)(2) (see also Attachment 1).	

B. Oil firing

1. Basis for Allowable Emissions Code: Rule	
2. Future Effective Date of Allowable Emissions: Not Applicable	
3. Requested Allowable Emissions and Units: 0.8 lb/MMBtu	
4. Equivalent Allowable Emissions: 2,912 lbs/hr	12,754.6 tons/yr
5. Method of Compliance: N/A (testing done on worst-case fuel (coal))	
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode): The allowable emission limit is based on FDEP Rule 62-296.800; 40 CFR Part 60, Subpart D. Section 60.43(a)(1).	

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 3 of 5**

1. Pollutant Emitted: NO_x				
2. Total Percent Efficiency of Control: Not Applicable %				
3. Primary Control Device Code: 024				
4. Secondary Control Device Code: Not applicable				
5. Potential Emissions: 2,548 lbs/hr 11,160 tons/yr				
6. Synthetically Limited? [ ] Yes [X] No				
7. Range of Estimated Fugitive/Other Emissions: Not applicable [ ] 1 [ ] 2 [ ] 3 ____ to ____ tons/yr				
8. Emission Factor: 0.7 lb/MMBtu Reference: Regulatory requirement				
9. Emissions Method Code: [ ] 1 [X] 2 [ ] 3 [ ] 4 [ ] 5				
10. Calculation of Emissions: 3,640 MMBtu/hr x 0.7 lb/MMBtu				
11. Pollutant Potential/Estimated Emissions Comment: NO_x control is integral to the boiler. See Section A				

Allowable Emissions (Pollutant identified on front page)

A. Coal firing

1. Basis for Allowable Emissions Code: Rule	
2. Future Effective Date of Allowable Emissions: Not applicable	
3. Requested Allowable Emissions and Units: 0.7 lb/MMBtu	
4. Equivalent Allowable Emissions: 2,548 lbs/hr	11,160 tons/yr
5. Method of Compliance: Annual stack test; if > 400 hours operation	
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode): The allowable emission limit is based on FDEP Rule 62-296.800; 40 CFR Part 60, Subpart D, Section 60.44(a)(3) (see also Attachment 1).	

B. Oil firing

1. Basis for Allowable Emissions Code: Rule	
2. Future Effective Date of Allowable Emissions: Not Applicable	
3. Requested Allowable Emissions and Units: 0.3 lb/MMBtu	
4. Equivalent Allowable Emissions: 1,092 lbs/hr	4,783.0 tons/yr
5. Method of Compliance: Annual stack test; if > 400 hours operation	
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode): The allowable emission limit is based on FDEP Rule 62-296.800; 40 CFR Part 60, Subpart D, Section 60.44(a)(2).	

Allowable Emissions (Pollutant identified on front page)

C. Natural gas firing

1. Basis for Allowable Emissions Code: Rule		
2. Future Effective Date of Allowable Emissions: Not applicable		
3. Requested Allowable Emissions and Units: 0.2 lb/MMBtu		
4. Equivalent Allowable Emissions:	728 lbs/hr	3,188.6 tons/yr
5. Method of Compliance: Annual stack test if > 400 hours operation		
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode): The allowable emission limit is based on FDEP Rule 62-296.800; 40 CFR Part 60, Subpart D, Section 60.44(a)(1) (see also Attachment 1).		

D.

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):		

Emissions Unit Information Section 1 of 1

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 4 of 5

1. Pollutant Emitted: CO				
2. Total Percent Efficiency of Control: Not applicable %				
3. Primary Control Device Code: Not applicable				
4. Secondary Control Device Code: Not applicable				
5. Potential Emissions:		323.96 lbs/hr	1,418.9 tons/yr	
6. Synthetically Limited?	[ ] Yes	[X] No		
7. Range of Estimated Fugitive/Other Emissions: Not applicable				
[ ] 1	[ ] 2	[ ] 3 ____ to ____ tons/yr		
8. Emission Factor: 0.089 lb/MMBtu Reference: Trial Test Burn				
9. Emissions Method Code:				
[X] 1	[ ] 2	[ ] 3	[ ] 4	[ ] 5
10. Calculation of Emissions: 3,640 MMBtu/hr x 0.0893 lb/MMBtu				
11. Pollutant Potential/Estimated Emissions Comment: CO emissions dependent upon combustion conditions. CO emissions estimate based on trial test burn (see Attachment 1).				

Emissions Unit Information Section 1 of 1

Allowable Emissions (Pollutant identified on front page) Not applicable.

A.

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):	

B. Not Applicable

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):	

Emissions Unit Information Section __1__ of __1__

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 __5__ of __5__**

1. Pollutant Emitted: SAM				
2. Total Percent Efficiency of Control:		~50 %		
3. Primary Control Device Code: 067				
4. Secondary Control Device Code: Not applicable				
5. Potential Emissions:		92.86 lbs/hr	406.6 tons/yr	
6. Synthetically Limited? [ ] Yes		[X] No		
7. Range of Estimated Fugitive/Other Emissions: Not applicable [ ] 1	[ ] 2	[ ] 3 ____ to ____ tons/yr		
8. Emission Factor: 0.0255 lb/MMBtu Reference: Trial test burn				
9. Emissions Method Code: [X] 1	[ ] 2	[ ] 3	[ ] 4	[ ] 5
10. Calculation of Emissions: 3,640 MMBtu/hr x 0.0255 lb/MMBtu				
11. Pollutant Potential/Estimated Emissions Comment: Sulfuric acid mist (SAM) emissions based on trial test burn (see Attachment 1).				

Emissions Unit Information Section 1 of 1

Allowable Emissions (Pollutant identified on front page) Not applicable.

A.

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):		

B. Not Applicable

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):		

F. VISIBLE EMISSIONS INFORMATION

This subsection of the Application for Air Permit form must be completed for only those emissions units which are subject to a visible emissions limitation. The intent of this subsection of the form is to identify each activity associated with the emissions unit addressed in this section for which a separate opacity limitation would be applicable. Visible emission subtype codes for each such activity are listed in the instructions for Field 1. Most emissions units will be subject to a "subtype VE" limit only.

Visible Emissions Limitations: Visible Emissions Limitation 1 of 2

1. Visible Emissions Subtype: VE
2. Basis for Allowable Opacity: [X] Rule [ ] Other
3. Requested Allowable Opacity: Normal Conditions: 20 % Exceptional Conditions: 27 % Maximum Period of Excess Opacity Allowed: 6 min/hr
4. Method of Compliance: Annual VE testing
5. Visible Emissions Comment: FDEP Rule 62-296.800; 40 CFR Part 60, Subpart D, Section 60.42(a) (2)

Emissions Unit Information Section 1 of 1

Visible Emissions Limitations: Visible Emissions Limitation 2 of 2

1. Visible Emissions Subtype: VEX	
2. Basis for Allowable Opacity: [X] Rule	[ ] Other
3. Requested Allowable Opacity: Normal Conditions: %	Exceptional Conditions: 100 %
Maximum Period of Excess Opacity Allowed:	2 hr/24 hrs* min/hr
4. Method of Compliance: None	
5. Visible Emissions Comment: Excess VE emissions allowed under FDEP Rule 62-210.700(a) for startup, shut down, or malfunction conditions. * > 2 hours allowed if prior FDEP approval received.	

Visible Emissions Limitations: Visible Emissions Limitation ____ of ____

1. Visible Emissions Subtype:	
2. Basis for Allowable Opacity: [ ] Rule	[ ] Other
3. Requested Allowable Opacity: Normal Conditions: %	Exceptional Conditions: %
Maximum Period of Excess Opacity Allowed:	min/hr
4. Method of Compliance:	
5. Visible Emissions Comment:	

Emissions Unit Information Section 1 of 1

G. CONTINUOUS MONITOR INFORMATION

This subsection of the Application for Air Permit form must be completed for only those emissions units which are required by rule or permit to install and operate one or more continuous emission, opacity, flow, or other type monitors. A separate set of continuous monitor information (fields 1-6) must be completed for each monitoring system required.

<u>Continuous Monitoring System</u> Continuous Monitor 1 of 3

1. Parameter Code: SO_2	
2. CMS Requirement:	[X] Rule [ ] Other
3. Monitor Information: Manufacturer: Lear Siegler Model Number: SM 810	Serial Number: 29259-M
4. Installation Date (DD-MON-YYYY): 1982	
5. Performance Specification Test Date (DD-MON-YYYY): 1982	
6. Continuous Monitor Comment: CEMS required under 40 CFR Part 75 will be addressed in forthcoming Title V application	

Emissions Unit Information Section 1 of 1

<u>Continuous Monitoring System</u> Continuous Monitor 2 of 3

1. Parameter Code: NO_x	
2. CMS Requirement:	[ ] Rule [ ] Other
3. Monitor Information: Manufacturer: Model Number:	Serial Number:
4. Installation Date (DD-MON-YYYY):	
5. Performance Specification Test Date (DD-MON-YYYY):	
6. Continuous Monitor Comment: No CEM required as during certification Unit No. 3 demonstrated NO_x emission less than 70 percent of its allowable emission rate. CEMS required under 40 CFR Part 75 will be addressed in forthcoming Title V application.	

<u>Continuous Monitoring System</u> Continuous Monitor 3 of 3

1. Parameter Code: VE	
2. CMS Requirement:	[X] Rule [ ] Other
3. Monitor Information: Manufacturer: Lear Siegler Model Number: RM-41	Serial Number: 291-230
4. Installation Date (DD-MON-YYYY): 1982	
5. Performance Specification Test Date (DD-MON-YYYY): 1982	
6. Continuous Monitor Comment: CEMS required under 40 CFR Part 75 will be addressed in forthcoming Title V application	

H. PREVENTION OF SIGNIFICANT DETERIORATION (PSD) INCREMENT TRACKING INFORMATION

This subsection of the Application for Air Permit form must be completed for all applications, not just those undergoing prevention-of-significant-deterioration (PSD) review pursuant to Rule 62-212.400, F.A.C. The intent of this subsection is to make a preliminary determination as to whether the emissions unit addressed in this Emissions Unit Information Section consumes PSD increment. PSD increment is consumed (or expanded) as a result of emission increases (decreases) occurring after pollutant-specific baseline dates. Pollutants for which baseline dates have been established are sulfur dioxide, particulate matter, and nitrogen dioxide.

PSD Increment Consumption Determination

1. Increment Consuming for Particulate Matter or Sulfur Dioxide?

   If the emissions unit addressed in this section emits particulate matter or sulfur dioxide, answer the following series of questions to make a preliminary determination as to whether or not the emissions unit consumes PSD increment for particulate matter or sulfur dioxide. Check the first statement, if any, that applies and skip remaining statements.

   [X] The emissions unit is undergoing PSD review as part of this application, or has undergone PSD review previously, for particulate matter or sulfur dioxide. If so, emissions unit consumes increment.

   [ ] The facility addressed in this application is classified as an EPA major source pursuant to paragraph (c) of the definition of "major source of air pollution" in Chapter 62-213, F.A.C., and the emissions unit addressed in this section commenced (or will commence) construction after January 6, 1975. If so, baseline emissions are zero, and emissions unit consumes increment.

   [ ] The facility addressed in this application is classified as an EPA major source, and the emissions unit began initial operation after January 6, 1975, but before December 27, 1977. If so, baseline emissions are zero, and emissions unit consumes increment.

   [ ] For any facility, the emissions unit began (or will begin) initial operation after December 27, 1977. If so, baseline emissions are zero, and emissions unit consumes increment.

   [ ] None of the above apply. If so, the baseline emissions of the emissions unit are nonzero. In such case, additional analysis, beyond the scope of this application, is needed to determine whether changes in emissions have occurred (or will occur) after the baseline date that may consume or expand increment.

2. Increment Consuming for Nitrogen Dioxide?

If the emissions unit addressed in this section emits nitrogen oxides, answer the following series of questions to make a preliminary determination as to whether or not the emissions unit consumes PSD increment for nitrogen dioxide. Check first statement, if any, that applies and skip remaining statements.

[ ] The emissions unit addressed in this section is undergoing PSD review as part of this application, or has undergone PSD review previously, for nitrogen dioxide. If so, emissions unit consumes increment.

[ ] The facility addressed in this application is classified as an EPA major source pursuant to paragraph (c) of the definition of "major source of air pollution" in Chapter 62-213, F.A.C., and the emissions unit addressed in this section commenced (or will commence) construction after February 8, 1988. If so, baseline emissions are zero, and emissions unit consumes increment.

[ ] The facility addressed in this application is classified as an EPA major source, and the emissions unit began initial operation after February 8, 1988, but before March 28, 1988. If so, baseline emissions are zero, and emissions unit consumes increment.

[ ] For any facility, the emissions unit began (or will begin) initial operation after March 28, 1988. If so, baseline emissions are zero, and emissions unit consumes increment.

[X] None of the above apply. If so, the baseline emissions of the emissions unit are nonzero. In such case, additional analysis, beyond the scope of this application, is needed to determine whether changes in emissions have occurred (or will occur) after the baseline date that may consume or expand increment.

3. Increment Consuming/Expanding Code:

PM	[X] C	[ ] E	[ ] Unknown
SO2	[X] C	[ ] E	[ ] Unknown
NO2	[ ] C	[ ] E	[ ] Unknown

4. Baseline Emissions:

PM		lbs/hr		tons/yr
SO2		lbs/hr		tons/yr
NO2			11,160	tons/yr

5. PSD Comment: Potential emissions assumed for NO_x baseline. Attachment 2 presents modeling analysis for CO and H_2SO_4 emissions from co-firing coal and petroleum coke.

Emissions Unit Information Section __1__ of __1__

I. EMISSIONS UNIT SUPPLEMENTAL INFORMATION

This subsection of the Application for Air Permit form provides supplemental information related to the emissions unit addressed in this Emissions Unit Information Section. Supplemental information must be submitted as an attachment to each copy of the form, in hard-copy or computer-readable form.

<u>Supplemental Requirements for All Applications</u>

1. Process Flow Diagram [X] Attached, Document ID: PFD-1 [ ] Not Applicable	 [ ] Waiver Requested
2. Fuel Analysis [X] Attached, Document ID: FA-1 [ ] Not Applicable	 [ ] Waiver Requested
3. Detailed Description of Control Equipment [ ] Attached, Document ID: ________ [X] Not Applicable	 [ ] Waiver Requested
4. Description of Stack Sampling Facilities [ ] Attached, Document ID: ________ [X] Not Applicable	 [ ] Waiver Requested
5. Compliance Test Report [ ] Attached, Document ID: ________ [ ] Previously Submitted, Date: ________	 [X] Not Applicable
6. Procedures for Startup and Shutdown [ ] Attached, Document ID: ________	 [X] Not Applicable
7. Operation and Maintenance Plan [ ] Attached, Document ID: ________	 [X] Not Applicable
8. Supplemental Information for Construction Permit Application [X] Attached, Document ID: SI-1	 [ ] Not Applicable
9. Other Information Required by Rule or Statute [ ] Attached, Document ID: ________	 [X] Not Applicable

Emissions Unit Information Section __1__ of __1__

Additional Supplemental Requirements for Category I Applications Only

10. Alternative Methods of Operation [X] Attached, Document ID: AMO-1	[ ] Not Applicable
11. Alternative Modes of Operation (Emissions Trading) [ ] Attached, Document ID: __________	[X] Not Applicable
12. Enhanced Monitoring Plan [ ] Attached, Document ID: __________	[X] Not Applicable
13. Identification of Additional Applicable Requirements [ ] Attached, Document ID: __________	[X] Not Applicable
14. Acid Rain Permit Application [ ] Acid Rain Part - Phase II (Form No. 62-210.900(1)(a)) Attached, Document ID: __________ [ ] Repowering Extension Plan (Form No. 62-210.900(1)(a)1.) Attached, Document ID: __________ [ ] New Unit Exemption (Form No. 62-210.900(1)(a)2.) Attached, Document ID: __________ [ ] Retired Unit Exemption (Form No. 62-210.900(1)(a)3.) Attached, Document ID: __________ [X] Not Applicable	

ATTACHMENT 1 - POLLUTION INFORMATION

The City of Lakeland requested in August 1993 authorization from the Florida Department of Environmental Protection (FDEP) to conduct a trial test burn of co-firing petroleum and coal (see August 16, 1993 letter from Ms. Farzie Shelton, Environmental Coordinator for Lakeland Department Electric and Water Utilities to Mr. Buck Oven of FDEP). FDEP authorized the trial burn in January 1994 (see letter from Mr. Oven to Ms. Shelton dated January 31, 1994). The trial test burn was conducted in February 1994 with a report of the results furnished to FDEP (see Emission Test Report by Environmental Science & Engineering, Inc. dated February 1994). Three operating conditions were evaluated during the trial test burn:

Condition 1. High-sulfur coal only,

Condition 2. A 90/10 percent blend of high-sulfur coal and petroleum coke, and

Condition 3. A 80/20 percent blend of low-sulfur coal and petroleum coke.

Note: High-sulfur in this context refers to coal with a sulfur content of 2.5 percent. Low-sulfur refers to 1 percent sulfur coal.

Measurements were conducted using U.S. Environmental Protection Agency (EPA) and FDEP sampling procedures for particulate matter, sulfur dioxide, nitrogen oxides, carbon monoxide, and sulfuric acid mist.

The potential applicability of the Prevention of Significant Deterioration (PSD) rules [Rules 62-212.400(2)(d)4, Florida Administrative Code (F.A.C.)] as they may apply to modifications are related to whether a source has a significant increase in actual emissions. The results of the trial test can be used to determine if an emissions increase has occurred. In order to determine any differences in emissions rate for the pollutants that were sampled during the trial test burn, confidence intervals using the student "t" test were performed and are presented in Table 1. Calculations are attached. The results of the evaluation indicated that, except for CO, there was either no statistical difference between emissions from the three test conditions or that emissions when co-firing petroleum were lower than when firing high-sulfur coal. Unit 3 is currently authorized to burn coal with 3.3 percent sulfur content. While the emission rate for sulfuric acid mist under Condition 3 was higher than the emission rate for high-sulfur coal only test condition (Condition 1), the differences were not statistically significant. This was confirmed using the approach outlined in Appendix C of 40 Code of Federal Regulations (CFR) Part 60 for determination of emission rate change (see calculations).

The emission rate of carbon monoxide for Condition 3 was statistically higher than Condition 1. The increase in CO emission was not due to petroleum coke in the coal/petroleum coke mixture. The primary and most important factor causing this increase was due to the hardness measured by the Hardgrove Grindability Index (HGI) of the coal that was being used for the trial test mixture in test condition 3. The petroleum coke used in the test burn had a high HGI. The higher the number, the softer the fuel. The 2.5 percent S coal used in test conditions 1 and 2 (alone and in combination with the coke) had a hardness of 43 HGI. The efficiency of fuel combustion is directly related to the particle size of pulverized coal; the softer (higher HGI) the coal, the greater amount of small particles which will produce overall better combustion and less CO concentrations.

Attached is a graph (Insert A) to show the effect of hardness on the performance of the pulverizers on coal particle size referred to as "fineness." As an example, both mixtures have been plotted based on a feed rate of 70,000 lb/hr. At this feed rate, the lower hardgrove mixture would be expected to give a fineness of ≈ 67 percent passing 200 mesh while the higher hardgrove mixture would be expected to give a fineness of ≈ 85 percent passing 200 mesh. This results in better fuel distribution and combustion and concomitantly lower CO generation. Insert B shows the hardness for the two mixtures used during the tests and an analysis of the petroleum coke used in the mixtures. If the fineness is reduced (i.e., a lower amount of small particles) it reduces the combustion efficiency and degrades the fuel distribution in the combustion zone, thus forming more CO. Therefore, the change in the CO noted during testing is primarily due to the difference between the high sulfur and low sulfur coal hardness and thus grindability.

The higher CO can also be affected by the oxygen (O_2) concentrations observed during the each test condition. The O_2 concentrations during Condition 3 (80/20 coal petroleum coke blend) averaged 6.9 percent. In contrast, the O_2 concentrations during Condition 1 (high-sulfur coal only) averaged 7.7 percent. CO and O_2 concentrations are inversely proportional, suggesting that the higher CO concentrations were a result of combustion conditions and not the fuel. This observation is confirmed by the results for Condition 2 in which O_2 concentrations were the highest (7.8 percent) and CO emission rate was the lowest [0.05 pound per million British thermal units (lb/MMBtu)].

This application has been completed based on:

- Emissions of particulate matter (PM), sulfur dioxide (SO_2), and nitrogen oxides (NO_x) when co-firing coal and petroleum coke were based on allowable emission rates.
- For emissions of CO and sulfuric acid mist, the highest emission rate from the trial test burn was used to estimate emissions.

Table 1. Statistical Evaluation of Trial Test Burn for Co–Firing Petroleum Coke at City of Lakeland McIntosh Plant – Unit 3

Pollutant	Test Condition (a)	Average	"t" – distribution Lower 90% C.I.	"t" – distribution Upper 90% C.I.	Conclusions (b)
Particulate	1. HSC Only	0.0481	0.0381	0.0582	1=2>3
	2. HSC w/10% PC	0.0459	0.0329	0.0589	2=1>3
	3. LSC w/20% PC	0.0141	0.0096	0.0187	3<1&2
Sulfur Dioxide	1. HSC Only	1.0866	1.0639	1.1094	1=2>3
	2. HSC w/10% PC	1.1087	1.0618	1.0618	2=1>3
	3. LSC w/20% PC	0.8935	0.8585	0.9284	3<1&2
Nitrogen Oxides	1. HSC Only	0.5391	0.5353	0.5428	1=2>3
	2. HSC w/10% PC	0.5466	0.5329	0.5602	2=1>3
	3. LSC w/20% PC	0.4126	0.4052	0.4199	3<1&2
Carbon Monoxide	1. HSC Only	0.0054	0.0044	0.0064	1=2<3
	2. HSC w/10% PC	0.0050	0.0047	0.0053	2=1<3
	3. LSC w/20% PC	0.0890	0.0231	0.1549	3>1&2
Sulfuric Acid Mist	1. HSC Only	0.0240	0.0166	0.0315	1=2=3
	2. HSC w/10% PC	0.0213	0.0167	0.0258	2=1=3
	3. LSC w/20% PC	0.0255	0.0174	0.0336	3=1=2

(a) HSC = High Sulfur Coal; LSC = Low Sulfur Coal; PC = Petroleum Coke
(b) "1, 2, and 3" refer to test conditions; "=" means no significant difference between test conditions; "< and >" refers to a significant difference betwen test conditions.

Calculations for Table 1

Calculations:

PM HSC Only

Run 2	0.054
Run 3	0.0483
Run 4	0.0421
Mean	0.04813333
STD. DEV.	0.00485958
V	2
ta/2	2.92
C.I.	0.01003383

PM–HSCw/10%PC

Run 5	0.0399
Run 6	0.0432
Run 7	0.0546
Mean	0.0459
STD. DEV.	0.00629762
V	2
ta/2	2.92
C.I.	0.01300302

PM–LSCw/20%PC

Run 8	0.0151
Run 9	0.0162
Run 10	0.0111
Mean	0.01413333
STD. DEV.	0.0021914
V	2
ta/2	2.92
C.I.	0.00452469

SO2 HSC Only

Run 1	1.0744
Run 2	1.1011
Run 3	1.0844
Mean	1.08663333
STD. DEV.	0.01101403
V	2
ta/2	2.92
C.I.	0.02274124

SO2–HSCw/10%PC

Run 4	1.1399
Run 5	1.0865
Run 6	1.0997
Mean	1.1087
STD. DEV.	0.02271035
V	2
ta/2	2.92
C.I.	0.04689124

SO2–LSCw/20%PC

Run 7	0.9113
Run 8	0.8707
Run 9	0.8984
Mean	0.89346667
STD. DEV.	0.01693799
V	2
ta/2	2.92
C.I.	0.03497275

NOx HSC Only

Run 1	0.5385
Run 2	0.5372
Run 3	0.5415
Mean	0.53906667
STD. DEV.	0.00180062
V	2
ta/2	2.92
C.I.	0.00371783

NOx–HSCw/10%PC

Run 4	0.5544
Run 5	0.5382
Run 6	0.5471
Mean	0.54656667
STD. DEV.	0.00662437
V	2
ta/2	2.92
C.I.	0.01367767

NOx–LSCw/20%PC

Run 7	0.4104
Run 8	0.4097
Run 9	0.4176
Mean	0.41256667
STD. DEV.	0.00357056
V	2
ta/2	2.92
C.I.	0.00737232

CO HSC Only

Run 1	0.0061
Run 2	0.005
Run 3	0.0051
Mean	0.0054
STD. DEV.	0.00049666
V	2
ta/2	2.92
C.I.	0.00102547

CO–HSCw/10%PC

Run 4	0.0051
Run 5	0.0048
Run 6	0.0051
Mean	0.005
STD. DEV.	0.00014142
V	2
ta/2	2.92
C.I.	0.000292

NOx–LSCw/20%PC

Run 7	0.0845
Run 8	0.1301
Run 9	0.0523
Mean	0.08896667
STD. DEV.	0.03191837
V	2
ta/2	2.92
C.I.	0.06590351

Calculations for Table 1

H2SO4 HSC Only		H2SO4-HSCw/10%PC		H2SO4-LSCw/20%PC	
Run 1	0.0248	Run 4	0.0204	Run 7	0.0208
Run 2	0.028	Run 5	0.0243	Run 8	0.0304
Run 3	0.0193	Run 6	0.0191	Run 9	0.0254
Mean	0.02403333	Mean	0.02126667	Mean	0.02553333
STD. DEV.	0.00359289	STD. DEV.	0.00220958	STD. DEV.	0.00392032
V	2	V	2	V	2
ta/2	2.92	ta/2	2.92	ta/2	2.92
C.I.	0.00741843	C.I.	0.00456222	C.I.	0.00809448

40 CFR Part 60, Appendix C Calculation

H2SO4 HSC Only		H2SO4-LSCw/20%PC	
Run 1	0.0248	Run 7	0.0208
Run 2	0.028	Run 8	0.0304
Run 3	0.0193	Run 9	0.0254
Mean	0.02403333	Mean	0.02553333
Sa^2	0.00001936	Sa^2	0.00002305
Sp^2	0.00460525		
t	0.39891799		
t'	2.132		

no significant difference

40 CFR Part 60, Appendix C Calculation – Test

Run A		Run B	
Run 1	100	Run 7	115
Run 2	95	Run 8	120
Run 3	110	Run 9	125
Mean	101.666667	Mean	120
Sa^2	58.3333333	Sb^2	25
Sp^2	6.45497224		
t	3.47850543		
t'	2.132		

significant difference–same as CFR Example
Note: CFR example has round–off which produces slightly different values.

INSERT A

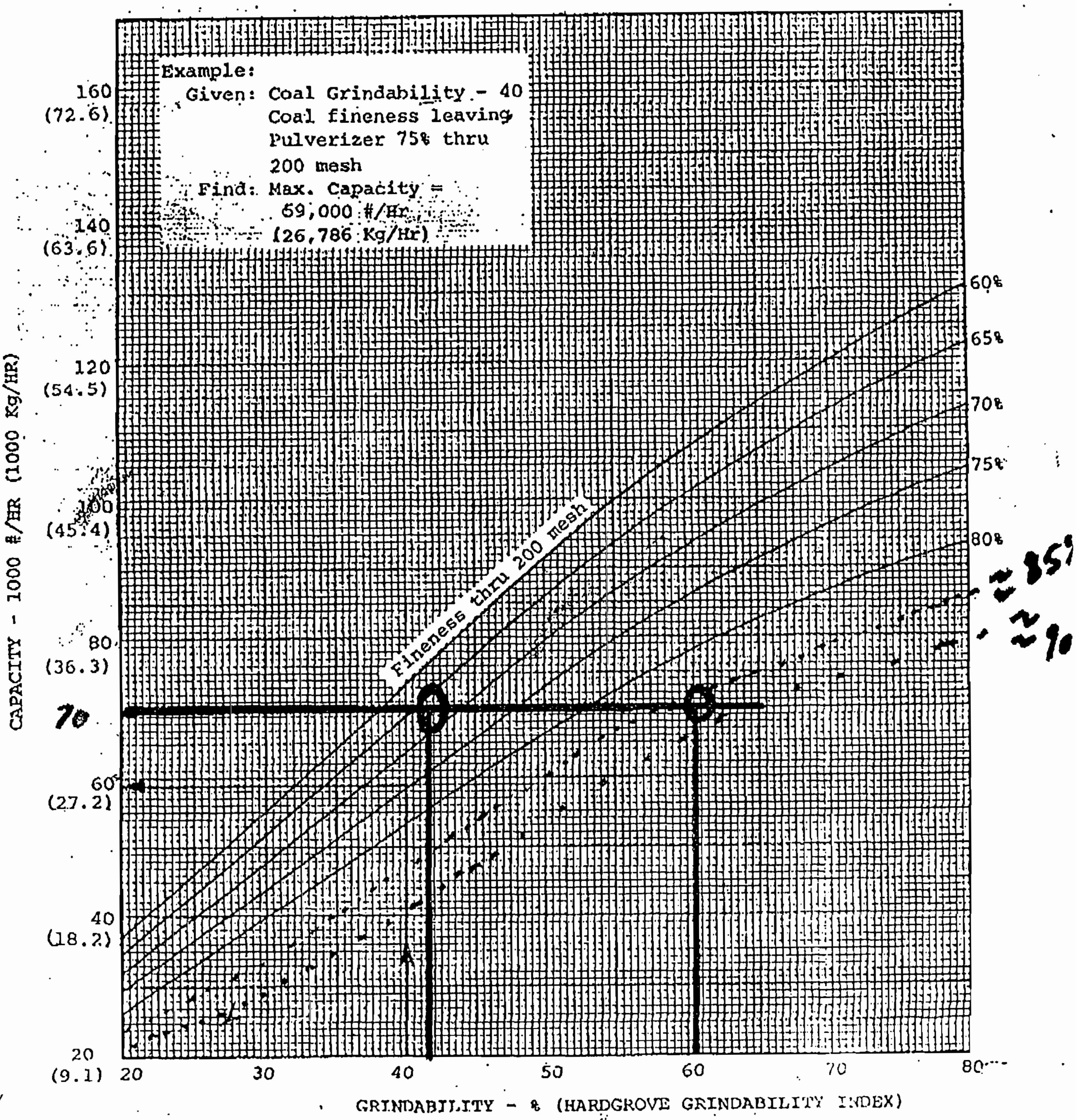
(09?)-190
9P1 (FPG)
6R211 - (75)
7A3
57/10-5-77

THE BABCOCK & WILCOX COMPANY
FOSSIL POWER GENERATION DIVISION

ATTACHMENT A

PULVERIZED FUEL SYSTEMS
TYPE MPS 75 PULVERIZER
OPERATING INSTRUCTIONS

FIG. 8 MPS-75 PULVERIZER EXPECTED PERFORMANCE (NOT CORRECTED FOR MOISTURE)



INSERT B

ATTACHMENT B
PAGE 1

COAL ANALYSIS

McINTOSH POWER PLANT

DATE ANALYZED 2/17/94

SAMPLE POINT C-3 Auto Sampler

SAMPLE ID # 112-94

ANALYZED BY Landry / Parish

DATE SAMPLED 2/15/94

DATE RECEIVED 2/16/94

SAMPLED BY Grandy

RELEASED BY SEP

PROXIMATE ANALYSIS

	AS RECEIVED	DRY BASIS	A-M FREE
% MOISTURE (TOTAL)	7.18		
% ASH	7.34	7.90	
% VOLATILE MATTER	32.25	34.74	37.72
% FIXED CARBON	53.24	57.36	62.28
BTU/LB	12,962	13,965	15,163
% SULFUR	1.54	1.66	1.81

HARDGROVE GRINDABILITY INDEX 43

ATTACHMENT B
PAGE 2

COAL ANALYSIS

McINTOSH POWER PLANT

DATE ANALYZED	2/14/94	DATE SAMPLED	2/9/94
SAMPLE POINT	C-3 Auto Sampler	DATE RECEIVED	2/10/94
SAMPLE ID #	107-94	SAMPLED BY	unknown
ANALYZED BY	Steven Parrish	RELEASED BY	SEP

PROXIMATE ANALYSIS

	AS RECEIVED	DRY BASIS	A-M FREE
% MOISTURE (TOTAL)	10.64		
% ASH	11.32	12.66	
% VOLATILE MATTER	23.38	26.17	29.96
% FIXED CARBON	54.66	61.17	70.04
BTU/LB	11,698	13,091	14,989
% SULFUR	2.83	3.17	3.63

HARDGROVE GRINDABILITY INDEX 61

ATTACHMENT B
PAGE 3

SGS Commercial Testing & Engineering Co.

January 18, 1994

1212 N. 39th Street
Suite 323
Tampa, Florida 33605
Tel: (813) 248-6566
Fax: (813) 247-2582

KOCH CARBON, INC.
P. O. Box 2219
Wichita, KS 67201

CERTIFICATE OF ANALYSIS

KIND OF SAMPLE:	PETROLEUM COKE
SAMPLE TAKEN AT:	TECO, BIG BEND TERMINAL, TAMPA, FLORIDA
SAMPLE TAKEN BY:	CT&E, TAMPA FROM BARGE "WANDA WHEELOCK"
DATED SAMPLED:	JANUARY 16, 1994
DATE RECEIVED:	JANUARY 17, 1994.

ANALYSIS REPORT NO. 08-1680

	AS RECEIVED	DRY BASIS
Moisture	10.35 %	xxxx
Ash	0.28 %	0.31 %
Volatile Matter	9.11 %	10.16 %
Fixed Carbon (by difference)	80.26 %	89.53 %
Sulfur	4.46 %	4.97 %
Gross Calorific Value	13751 Btu/lb	15339 Btu/lb
Moisture Ash Free Btu		15387

Hardgrove Grindability Index = 69

TRACE ELEMENTS P.P.M.

Silicon, Si	330
Calcium, Ca	155
Iron, Fe	130
Nickle, Ni	218
Vanadium, V	1090

SIZE ANALYSIS (Square Hole)

Over 3	Inch	3.79%
3 x 2	Inch	5.69%
2 x 1	Inch	16.63%
1 x 1/2"	Inch	15.53%
Under 1/2"	Inch	58.36%

COMMERCIAL TESTING & ENGINEERING CO.

Edward B. Linde
Branch Manager

EBL/vl

ATTACHMENT 2 - MODELING ANALYSIS

Since emissions of carbon monoxide were statistically higher during one of the co-firing test conditions (i.e., Condition 3) than the coal only test (Condition 1), screening modeling was performed to determine if the impacts were above the modeling significant impact levels. The modeling was performed using EPA's Screen2 model. The results of the model run are attached. The maximum impacts compared to the significant impact levels are presented below:

Averaging Time	Impact ($\mu g/m^3$)	Significant Impact Level ($\mu g/m^3$)
1-hour	39.9	500
8-hour	27.9	2,000

The results clearly indicate that the impacts are less than the EPA/FDEP significant impact levels and the facility would not cause or contribute to a violation of the ambient air quality standards (CO) for CO.

For sulfuric acid mist, there are no applicable AAQS. Maximum impacts for the 8-hour averaging time were calculated as 8.01 $\mu g/m^3$ which is less than the FDEP draft air reference concentrations for this averaging time (i.e., 10 $\mu g/m^3$).

BEST AVAILABLE COPY

12/29/94
15:03:27

*** SCREEN2 MODEL RUN ***
*** VERSION DATED 92245 ***

City of Lakeland Co Impacts

SIMPLE TERRAIN INPUTS:

SOURCE TYPE	=	POINT
EMISSION RATE (G/S)	=	40.8200
STACK HEIGHT (M)	=	76.2000
STK INSIDE DIAM (M)	=	5.4900
STK EXIT VELOCITY (M/S)	=	25.1313
STK GAS EXIT TEMP (K)	=	348.1500
AMBIENT AIR TEMP (K)	=	293.0000
RECEPTOR HEIGHT (M)	=	0.0000
URBAN/RURAL OPTION	=	RURAL
BUILDING HEIGHT (M)	=	0.0000
MIN HORIZ BLDG DIM (M)	=	0.0000
MAX HORIZ BLDG DIM (M)	=	0.0000

STACK EXIT VELOCITY WAS CALCULATED FROM
VOLUME FLOW RATE = 1260536.0 (ACFM)

BUOY. FLUX = 294.156 M**4/S**3; MOM. FLUX = 4005.111 M**4/S**2.

** FULL METEOROLOGY ***

****
*** SCREEN AUTOMATED DISTANCES ***
****

*** TERRAIN HEIGHT OF 0. M ABOVE STACK BASE USED FOR FOLLOWING DISTANCES ***

DIST (M)	CONC (UG/M**3)	STAB	U10M (M/S)	USTK (M/S)	MIX HT (M)	PLUME HT (M)	SIGMA Y (M)	SIGMA Z (M)	DWASH
100.	0.4070E-07	5	1.0	2.0	10000.0	232.17	32.76	32.37	NO
200.	0.5103E-02	5	1.0	2.0	10000.0	232.17	46.06	45.00	NO
300.	0.6195E-02	5	1.0	2.0	10000.0	232.17	47.66	45.40	NO
400.	0.7601E-02	5	1.0	2.0	10000.0	232.17	49.70	45.86	NO
500.	0.5398	1	3.0	3.5	960.0	415.13	125.88	118.40	NO
600.	6.792	1	3.0	3.5	960.0	415.13	146.86	166.16	NO
700.	18.06	1	3.0	3.5	960.0	415.13	167.34	224.30	NO
800.	25.08	1	3.0	3.5	960.0	415.13	187.39	292.97	NO
900.	32.83	1	2.0	2.3	640.0	584.60	226.45	383.37	NO
1000.	38.87	1	2.0	2.3	640.0	584.60	246.88	472.62	NO
1100.	39.81	1	2.0	2.3	640.0	584.60	266.97	572.80	NO
1200.	38.71	1	1.5	1.7	755.1	754.06	312.35	695.11	NO
1300.	37.95	1	1.5	1.7	755.1	754.06	326.57	814.20	NO
1400.	36.55	1	1.5	1.7	755.1	754.06	340.97	945.19	NO
1500.	35.08	1	1.5	1.7	755.1	754.06	355.53	1087.98	NO
1600.	33.69	1	1.5	1.7	755.1	754.06	370.22	1242.49	NO
1700.	32.40	1	1.5	1.7	755.1	754.06	385.00	1408.72	NO
1800.	31.19	1	1.5	1.7	755.1	754.06	399.86	1586.65	NO
1900.	30.07	1	1.5	1.7	755.1	754.06	414.78	1776.31	NO
2000.	29.02	1	1.5	1.7	755.1	754.06	429.73	1977.72	NO
2100.	28.05	1	1.5	1.7	755.1	754.06	444.72	2190.91	NO
2200.	27.13	1	1.5	1.7	755.1	754.06	459.73	2415.93	NO
2300.	26.27	1	1.5	1.7	755.1	754.06	474.75	2652.81	NO
2400.	25.47	1	1.5	1.7	755.1	754.06	489.77	2901.60	NO
2500.	24.71	1	1.5	1.7	755.1	754.06	504.78	3162.34	NO
2600.	24.00	1	1.5	1.7	755.1	754.06	519.79	3435.08	NO
2700.	23.32	1	1.5	1.7	755.1	754.06	534.79	3719.86	NO
2800.	22.69	1	1.5	1.7	755.1	754.06	549.77	4016.73	NO

2900.	22.09	1	1.5	1.7	755.1	754.06	564.74	4325.73	NO
3000.	21.52	1	1.5	1.7	755.1	754.06	579.68	4646.92	NO
3500.	19.07	1	1.5	1.7	755.1	754.06	654.00	5000.00	NO
4000.	18.70	2	2.0	2.3	640.0	584.60	546.95	520.86	NO
4500.	18.47	2	1.5	1.7	755.1	754.06	616.06	601.24	NO
5000.	17.83	2	1.5	1.7	755.1	754.06	670.07	667.65	NO
5500.	16.91	2	1.5	1.7	755.1	754.06	723.73	735.33	NO
6000.	15.93	2	1.5	1.7	755.1	754.06	777.02	804.10	NO
6500.	14.99	2	1.5	1.7	755.1	754.06	829.93	873.79	NO
7000.	14.12	2	1.5	1.7	755.1	754.06	882.45	944.30	NO
7500.	13.34	2	1.5	1.7	755.1	754.06	934.59	1015.54	NO
8000.	12.69	3	1.5	1.8	715.0	714.00	696.60	448.29	NO
8500.	12.90	3	1.5	1.8	715.0	714.00	732.70	469.73	NO
9000.	12.99	3	1.5	1.8	715.0	714.00	768.65	491.22	NO
9500.	12.97	3	1.5	1.8	715.0	714.00	804.47	512.77	NO
10000.	12.88	3	1.5	1.8	715.0	714.00	840.13	534.35	NO

MAXIMUM 1-HR CONCENTRATION AT OR BEYOND 100. M:

1074.	39.91	1	2.0	2.3	640.0	584.60	261.57	544.67	NO

DWASH= MEANS NO CALC MADE (CONC = 0.0)
DWASH=NO MEANS NO BUILDING DOWNWASH USED
DWASH=HS MEANS HUBER-SNYDER DOWNWASH USED
DWASH=SS MEANS SCHULMAN-SCIRE DOWNWASH USED
DWASH=NA MEANS DOWNWASH NOT APPLICABLE, X<3*LB

****
*** SUMMARY OF SCREEN MODEL RESULTS ***
****

CALCULATION PROCEDURE	MAX CONC (UG/M**3)	DIST TO MAX (M)	TERRAIN HT (M)
SIMPLE TERRAIN	39.91	1074.	0.

****
** REMEMBER TO INCLUDE BACKGROUND CONCENTRATIONS **
****

12/29/94
15:04:59

*** SCREEN2 MODEL RUN ***
*** VERSION DATED 92245 ***

City of Lakeland H2SO4 Mist Impacts

SIMPLE TERRAIN INPUTS:

SOURCE TYPE	=	POINT
EMISSION RATE (G/S)	=	11.7000
STACK HEIGHT (M)	=	76.2000
STK INSIDE DIAM (M)	=	5.4900
STK EXIT VELOCITY (M/S)	=	25.1313
STK GAS EXIT TEMP (K)	=	348.1500
AMBIENT AIR TEMP (K)	=	293.0000
RECEPTOR HEIGHT (M)	=	0.0000
URBAN/RURAL OPTION	=	RURAL
BUILDING HEIGHT (M)	=	0.0000
MIN HORIZ BLDG DIM (M)	=	0.0000
MAX HORIZ BLDG DIM (M)	=	0.0000

STACK EXIT VELOCITY WAS CALCULATED FROM
VOLUME FLOW RATE = 1260536.0 (ACFM)

BUOY. FLUX = 294.156 M**4/S**3; MOM. FLUX = 4005.111 M**4/S**2.

*** FULL METEOROLOGY ***

****
*** SCREEN AUTOMATED DISTANCES ***
****

*** TERRAIN HEIGHT OF 0. M ABOVE STACK BASE USED FOR FOLLOWING DISTANCES ***

DIST (M)	CONC (UG/M**3)	STAB	U10M (M/S)	USTK (M/S)	MIX HT (M)	PLUME HT (M)	SIGMA Y (M)	SIGMA Z (M)	DWASH
100.	0.1167E-07	5	1.0	2.0	10000.0	232.17	32.76	32.37	NO
200.	0.1463E-02	5	1.0	2.0	10000.0	232.17	46.06	45.00	NO
300.	0.1776E-02	5	1.0	2.0	10000.0	232.17	47.66	45.40	NO
400.	0.2179E-02	5	1.0	2.0	10000.0	232.17	49.70	45.86	NO
500.	0.1547	1	3.0	3.5	960.0	415.13	125.88	118.40	NO
600.	1.947	1	3.0	3.5	960.0	415.13	146.86	166.16	NO
700.	5.176	1	3.0	3.5	960.0	415.13	167.34	224.30	NO
800.	7.188	1	3.0	3.5	960.0	415.13	187.39	292.97	NO
900.	9.409	1	2.0	2.3	640.0	584.60	226.45	383.37	NO
1000.	11.14	1	2.0	2.3	640.0	584.60	246.88	472.62	NO
1100.	11.41	1	2.0	2.3	640.0	584.60	266.97	572.80	NO
1200.	11.10	1	1.5	1.7	755.1	754.06	312.35	695.11	NO
1300.	10.88	1	1.5	1.7	755.1	754.06	326.57	814.20	NO
1400.	10.48	1	1.5	1.7	755.1	754.06	340.97	945.19	NO
1500.	10.05	1	1.5	1.7	755.1	754.06	355.53	1087.98	NO
1600.	9.657	1	1.5	1.7	755.1	754.06	370.22	1242.49	NO
1700.	9.286	1	1.5	1.7	755.1	754.06	385.00	1408.72	NO
1800.	8.941	1	1.5	1.7	755.1	754.06	399.86	1586.65	NO
1900.	8.619	1	1.5	1.7	755.1	754.06	414.78	1776.31	NO
2000.	8.319	1	1.5	1.7	755.1	754.06	429.73	1977.72	NO
2100.	8.039	1	1.5	1.7	755.1	754.06	444.72	2190.91	NO
2200.	7.776	1	1.5	1.7	755.1	754.06	459.73	2415.93	NO
2300.	7.531	1	1.5	1.7	755.1	754.06	474.75	2652.81	NO
2400.	7.300	1	1.5	1.7	755.1	754.06	489.77	2901.60	NO
2500.	7.082	1	1.5	1.7	755.1	754.06	504.78	3162.34	NO
2600.	6.878	1	1.5	1.7	755.1	754.06	519.79	3435.08	NO
2700.	6.685	1	1.5	1.7	755.1	754.06	534.79	3719.86	NO
2800.	6.503	1	1.5	1.7	755.1	754.06	549.77	4016.73	NO

2900.	6.331	1	1.5	1.7	755.1	754.06	564.74	4325.73	NO
3000.	6.167	1	1.5	1.7	755.1	754.06	579.68	4646.92	NO
3500.	5.466	1	1.5	1.7	755.1	754.06	654.00	5000.00	NO
4000.	5.360	2	2.0	2.3	640.0	584.60	546.95	520.86	NO
4500.	5.295	2	1.5	1.7	755.1	754.06	616.06	601.24	NO
5000.	5.110	2	1.5	1.7	755.1	754.06	670.07	667.65	NO
5500.	4.848	2	1.5	1.7	755.1	754.06	723.73	735.33	NO
6000.	4.567	2	1.5	1.7	755.1	754.06	777.02	804.10	NO
6500.	4.296	2	1.5	1.7	755.1	754.06	829.93	873.79	NO
7000.	4.048	2	1.5	1.7	755.1	754.06	882.45	944.30	NO
7500.	3.824	2	1.5	1.7	755.1	754.06	934.59	1015.54	NO
8000.	3.638	3	1.5	1.8	715.0	714.00	696.60	448.29	NO
8500.	3.698	3	1.5	1.8	715.0	714.00	732.70	469.73	NO
9000.	3.722	3	1.5	1.8	715.0	714.00	768.65	491.22	NO
9500.	3.718	3	1.5	1.8	715.0	714.00	804.47	512.77	NO
10000.	3.691	3	1.5	1.8	715.0	714.00	840.13	534.35	NO

MAXIMUM 1-HR CONCENTRATION AT OR BEYOND 100. M:

1074.	11.44	1	2.0	2.3	640.0	584.60	261.57	544.67	NO

DWASH= MEANS NO CALC MADE (CONC = 0.0)
DWASH=NO MEANS NO BUILDING DOWNWASH USED
DWASH=HS MEANS HUBER-SNYDER DOWNWASH USED
DWASH=SS MEANS SCHULMAN-SCIRE DOWNWASH USED
DWASH=NA MEANS DOWNWASH NOT APPLICABLE, X<3*LB

****
*** SUMMARY OF SCREEN MODEL RESULTS ***
****

CALCULATION PROCEDURE	MAX CONC (UG/M**3)	DIST TO MAX (M)	TERRAIN HT (M)
SIMPLE TERRAIN	11.44	1074.	0.

****
** REMEMBER TO INCLUDE BACKGROUND CONCENTRATIONS **
****

Attachment: FA-1

Table 3.2.3

TYPICAL PETROLEUM COKE ANALYSIS

UNIT #3

Petroleum Coke Quality: As Rec'd Basis

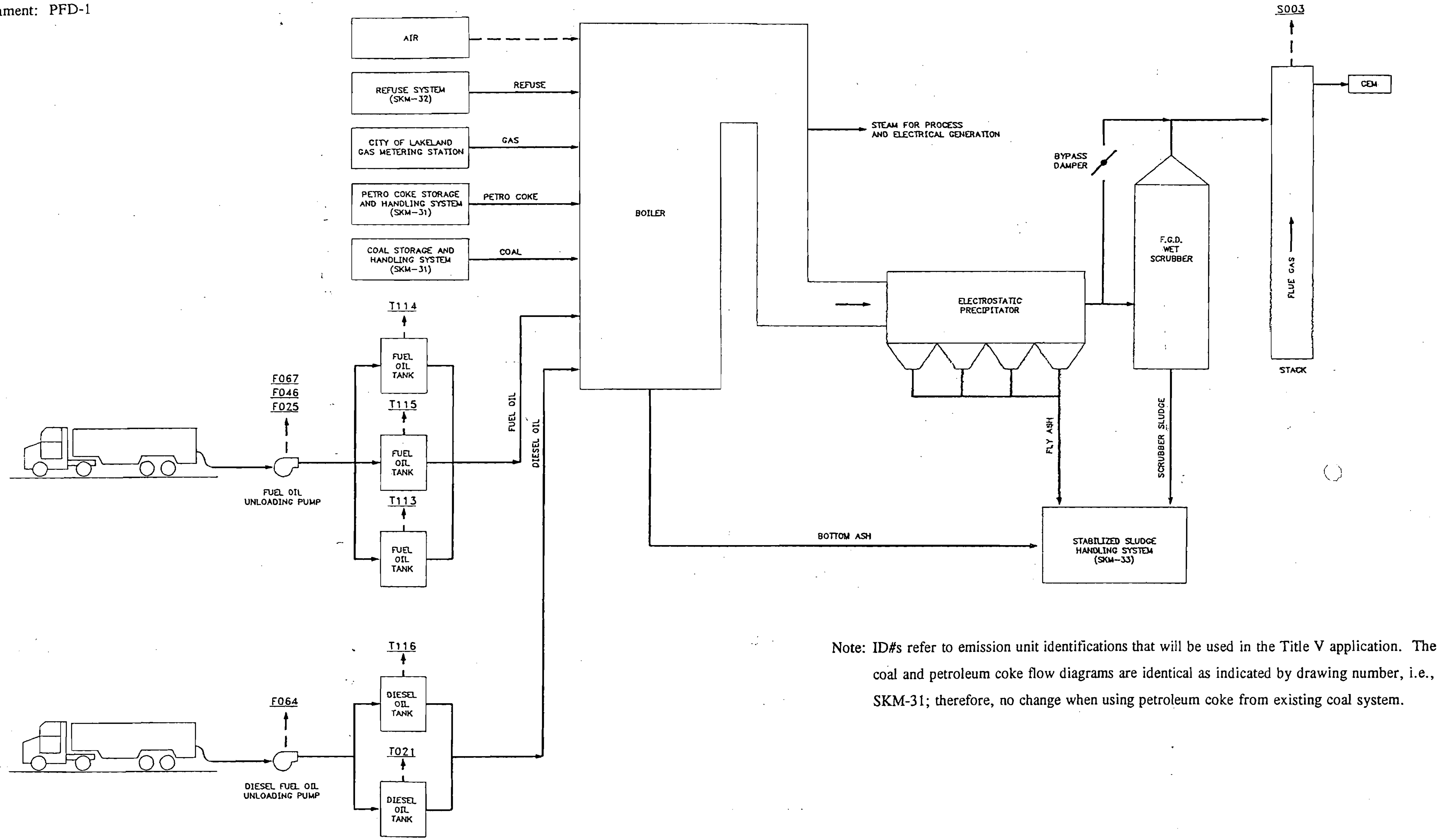
Moisture	8.00%	12.00% Max
Ash	0.25%	1.00% Max
Volatile	10.00%	14.00% Max
Sulfur	4.75%	5.50% Max
Btu/lb	14,200	14,200 Penalty
Hardgrove Grindability Index	65	50 Min
	Typical	Maximum
Vanadium	950 ppm	1500 ppm
Iron	100 ppm	500 ppm
Silicon	50 ppm	250 ppm
Calcium	100 ppm	250 ppm
Nickel	250 ppm	500 ppm

Sizing	+3"	5%
	2x3"	5%
	1x2"	25%
	½x1"	20%
	-½"	45%

Revised 12-06-94

BEST AVAILABLE COPY

Attachment: PFD-1



Note: ID#s refer to emission unit identifications that will be used in the Title V application. The coal and petroleum coke flow diagrams are identical as indicated by drawing number, i.e., SKM-31; therefore, no change when using petroleum coke from existing coal system.

REV. NO.	BY	DATE	APPR.	REVISION
[redacted]	MG	11-2-94		ISSUED FOR TITLE V PERMIT APPLICATION
	MG	9-21-94		FOR APPROVAL
[redacted]	MG	X		FOR APPROVAL

LAKELAND ELECTRIC & WATER

DESCRIPTION	McINTOSH POWER PLANT UNIT NO. 3 SIMPLIFIED FLOW DIAGRAM
DIVISION	PRODUCTION ENGINEERING
ENGINEER	PATTERSON
DRN. BY:	MGIEGER
DATE	9-19-94
APPR. BY:	
CAD	
SCALE	NONE
PROJ. NO.	EWR-94-199
DWG. NO.	SKM-27
REV.	Ø
SIZE	B

LAKELAND ELECTRIC & WATER

Excellence Is Our Goal, Service Is Our Job

(813) 499-6603

Farzie Shelton
ENVIRONMENTAL COORDINATOR, Ch E.

December 7, 1994

Hamilton S. Oven, Jr., P.E.
Administrator, Power Plant Siting Section
Department of Environmental Protection
3900 Commonwealth Boulevard, MS #48
Tallahassee, FL 32399-3000

RE: City of Lakeland--C.D. McIntosh Power Plant, Unit No. 3
Proposed Agreement to Modify Site Certification--PA-74-06

Dear Mr. Oven:

The City of Lakeland ("Lakeland") hereby requests that its Site Certification for the above-referenced C.D. McIntosh Power Plant, Unit No. 3 be revised. As you may recall, the Certification Order for Unit No. 3 was issued in 1978 and subsequently revised in 1980, 1988, and 1993. Consistent with that Certification and the Conditions of Certification, Lakeland constructed a coal-, municipal refuse-, and oil-fired steam electric generation unit, which began operating in 1982. Based on a successful test burn of petroleum coke earlier this year, Lakeland is proposing revisions to its application to describe this alternative fuel and its characteristics. In addition, as a result of the final design of Unit No. 3, Lakeland has identified several needed clarifications and minor revisions to the Site Certification application. To update citations and to clearly authorize the burning of petroleum coke, Lakeland is also proposing amendments to the Conditions of Certification. A more detailed description of the proposed changes to the application and Conditions of Certification is included in Attachment 1.

In support of its request, Lakeland has prepared a "Proposed Agreement for Modification of Site Certification" (Attachment 2), which includes revised portions of the Site Certification application and suggested minor changes to the Conditions of Certification (which are attached to the Agreement as Exhibits 1 and 2, respectively). The Conditions of Certification, as proposed to be revised, are also included on the enclosed computer disk in WordPerfect 5.1 format. Another version of the revised application pages (showing additions with double underlining and deletions with strike throughs) is included as Attachment 3 to this request.

The Proposed Agreement for Modificaton of Site Certification is submitted to the Department of Environmental Protection pursuant to Rule 62-17.211, Florida Administrative Code, and Section 403.516(1)(b), Florida Statutes, which authorizes the Department to modify the Site Certification when no objection is raised by a party or substantially affected person. We have enclosed eleven copies of this request for the Department's use, and we are sending copies to all of the other parties to the original certification proceeding. Lakeland will inform the Department as to responses received from any of the parties as a result of this notice, and we would appreciate hearing from you if any of the parties notify the Department.

Attachment SI-1

In addition to the Proposed Agreement for Modification of Site Certification, Lakeland is seeking a separate amendment to the Prevention of Significant Deterioration (PSD) permit for Unit No. 3, which was issued by the U.S. Environmental Protection Agency in December of 1978 (PSD-FL-08). A copy of the formal request for PSD permit revision will be sent to you once it has been prepared for submission to the Department's Bureau of Air Regulation.

Thank you for your consideration of the Proposed Agreement for Modification. A check in the amount of $10,000 is enclosed as the fee for review of the requested modification. After you and other Department staff have had an opportunity to review the proposed revisions, please let me know within the next thirty days if you have any questions, need any additional information, or do not agree with the approach taken in this letter to revise the application through a formal modification.

Sincerely,

Farzie Shelton

am/ Farzie Shelton
Environmental Coordinator
Department of Electric & Water Utilities

cc: Clair Fancy, DEP
Bill Thomas, DEP SW District
Mike Hickey, DEP SW District
Ken Kosky, KBN
Angela Morrison, HBGS

45467

CITY OF LAKELAND
McIntosh Unit No. 3

Description of Amendments to Site Certification Application

Section 3.2.1 Fuel Types

Earlier this year, the City of Lakeland conducted a successful test burn of petroleum coke blended with coal. In an effort to use the most cost-effective fuels while not increasing emissions above allowable limits, the City of Lakeland requests that the Department approve its revised application to allow petroleum coke to be burned when blended with coal. Because continuous emissions monitors are installed for sulfur dioxide, nitrogen oxides, and opacity, as required by the PSD permit (Condition No. 6) and NSPS (40 CFR § 60.45), Lakeland can ensure that the emission limits for these pollutants are not exceeded when coke is blended with coal (or coal and refuse) and burned in Unit No. 3. A 0 to 10 percent blended petroleum coke product will be used with medium to high sulfur coal and a 0 to 20 percent blended petroleum coke product will be used with low sulfur coal. Lakeland has clarified in the revised application what fuels and fuel blends may be burned and the conditions under which such fuels and blends may be burned. Specifically, Lakeland is requesting authorization to burn petroleum coke and has clarified that natural gas and/or low sulfur oil will be used for ignition and fuel stabilization of the unit. Because natural gas and low sulfur oil are "clean fuels," such fuels may be burned at any time.

Section 3.2.2 Fuel Quantities

Heat Input Rate--The heat input rate provided in the site certification application was 2.162×10^{13} mmBtu per year for coal, based on manufacturer's data. The heat input rate was not included in the conditions of certification. Recently, Lakeland has carefully reviewed the heat input capacity for McIntosh Unit No. 3 and has identified that the rate in the original site certification application is not reflective of the unit's actual operating capability. The appropriate maximum heat input rate is 2.8697×10^{13} Btu per year. The heat input rate now requested is *not* the result of a physical change in, or change in the method of operation of, McIntosh Unit No. 3. The new heat input rate represents a *corrected* rate that more accurately reflects the maximum heat input capacity of the unit. Further, the correction of the heat input rate to reflect maximum unit capacity will not result in an increase in "actual" (annual) emissions. The Department should therefore allow the correction to the maximum heat input rate in the application, without the need for a revision to the conditions of certification and without triggering a "modification" under the Department's new source review rules (Chapter 62-212, F.A.C.).

Fuel Flow Rates--Similar to the heat input rate issue, the fuel flow rates for McIntosh Unit No. 3 that were provided in the application need to be adjusted to reflect the actual maximum fuel flow rates experienced at Unit No. 3. These slightly higher fuel rates are needed to produce the same megawatt output of 364. As with the adjustment to the heat input rate, the maximum fuel flow rates (hourly and annual) were not included in the conditions of certification, rather only in the application.

Section 3.2.3 Transportation

Lakeland has clarified several fuel transportation issues in the site certification application. Specifically, Lakeland has updated the application to indicate that the fuel trains include 90 rather than 70 one-hundred-ton bottom dump hopper cars per unit. The train unloading operations are more fully described in the application revisions.

Lakeland has also clarified that its coal supply is primarily from the area east of the Mississippi River, with a majority of the coal coming from Eastern Kentucky. Other sources of suitable quality may also be used. Petroleum coke will be obtained from a suitable source based on lowest evaluated delivered cost. It will be delivered by truck from a nearby port or by rail, directly from a supply source. If the petroleum coke is blended off-site, it will be delivered either by rail or truck from a blending facility. The blend will be carefully monitored and controlled to assure compliance with all regulated air pollutant emissions through continuous emission monitors (i.e., sulfur dioxide, nitrogen oxides, and opacity).

Natural gas will be supplied to the site by a high-pressure main tied in with Florida Gas Transmission several miles north of the McIntosh Plant.

Section 3.2.4 Storage

Lakeland is also clarifying its fuel storage operations. Coal is stored on a sealed surface with a complete run-off control system to collect rain water or dust control water. Coal is delivered from this storage area to the unit silos by a series of conveyors through several transfer points, which are more fully described in the revisions than in the original application. Petroleum coke will be stored in the coal storage area either as an unblended or blended product.

Oil is stored in on-site tanks within containment areas. These tanks are more fully described in this application than in the original application.

Refuse is not stored on site. All material received is processed and burned as quickly as possible. Lakeland has included clarification language regarding the storage of refuse in the application.

Section 3.2.5 Fuel Analysis

As a supplement to the application, Lakeland has provided a fuel analysis for petroleum coke.

Section 3.2.7 Coal Pile Run-Off

The application revisions clarify that coal pile runoff will be collected and transported to a surge pond before being pumped to the current settling pond for reuse. (See also Section 3.5.)

Section 3.4 Heat Dissipation System

The application is being revised to clarify that Lakeland has abandoned the Marsh Treatment System because the water now goes directly to Lakeland's public works system. In addition, the application revisions clarify that the mechanical draft cooling tower includes thirteen cells and is supplemented by a two-cell draft auxiliary tower.

Section 3.5 Changes in Chemical and Biocide Wastes

Lakeland also clarifies that the settling pond will be lined with bitumastic to prevent leaking and that collected runoff will be pumped from the north landfill surge pond to the final wastewater ponds for reuse on site.

Section 3.6.3 Flue Gas Desulfurization Scrubber Sludge

Sulfur Dioxide Removal Efficiency--Lakeland originally proposed a removal efficiency of 80 percent of the sulfur dioxide from the stack gases through installation of a limestone scrubber based on the expectation of utilizing "high sulfur" coal (sulfur content of greater than 3.0 percent). Any fuel (or combination of fuels) with a sulfur content of less than 3.1 percent sulfur should not require 80 percent removal efficiency since the 1.2 lb/mmBtu heat input limit could be achieved without the desulfurization unit being operated. The actual sulfur dioxide emissions will be much less than 1.2 lb/mmBtu even when the 80 percent removal rate is not achieved because the desulfurization unit will continue to operate even when lower sulfur coal (or coal/refuse/coke combinations) is burned. In other words, the resultant sulfur dioxide emissions when burning a non-high, lower sulfur fuel and operating the desulfurization unit will be less than the sulfur dioxide emissions would be if high sulfur (greater than 3.0 percent sulfur) were burned, even with the desulfurization unit operating at an 85 percent removal efficiency. Accordingly, Lakeland has revised its application to clarify that the 80 percent removal efficiency applies only when high sulfur coal (or blends) is burned. This same change is being made to Section 3.7.4, Sulfur Dioxide Compliance Method. In addition, Lakeland has clarified this section of the application to show that the sulfur dioxide limit of 1.2, rather than 0.8 applies when coal is burned in the unit, consistent with Section 3.7.

Section 3.7 Air Emissions

Compliance Standards--Lakeland has clarified in the application that the same limits that apply to coal and coal/refuse blends will apply to coke blends as well. As stated above, Lakeland has also clarified that the 80 percent removal efficiency for sulfur dioxide applies only when high sulfur coal is burned.

Section 5.6

Lakeland has revised the application to describe an expansion to the present refuse processing plant tipping floor, with the addition of a relatively small building (approximately 100' by 70').

Section 5.6.2 Scrubber Sludge Disposal

Lakeland is clarifying in the application revisions that the stabilized sludge operation and various silos are equipped with dust control systems.

Description of Proposed Changes to Conditions of Certification

Citations

Citations throughout the Conditions of Certification have been updated with current chapter and rule numbers. Similarly, the state agencies' names have been corrected, where necessary, such as changing the Department of Environmental *Regulation* to the Department of Environmental *Protection*.

General Condition No. 1

Because the only certified unit is Unit No. 3., Lakeland suggests a revision to this condition to clarify that only *proposed* changes in discharges from Unit No. 3 and expansions of Unit No. 3's generating capacity would require a new or supplemental application. In addition, to clarify that only regulated air pollutant emissions must be identified, the word "regulated" is being added.

General Condition No. 2

Lakeland proposes to clarify that it must notify the Department in writing of a noncompliance situation within 72 working day hours. Because certain holiday weekends extend beyond 3 days, it would be appropriate for the notice requirements to correspond to working day hours.

General Condition No. 3

Because only Unit No. 3 is certified under the Site Certification, Lakeland proposes to clarify this condition to refer to Unit No. 3 rather than the entire "facility."

Special Condition No. I.B.5.

The unit number is being corrected to Unit No. 3 (rather than Unit No. 2).

Special Condition No. I.D.

Lakeland is requesting that this condition be changed to allow it to submit fuel usage and analysis data annually rather than quarterly.

Special Condition No. I.H.

The various fuels and fuel combinations that are specifically authorized to be burned have been listed in a proposed subsection H., including petroleum coke, which is being proposed in this request.

Special Condition Nos. II.A.1. and IV.A., B.

Because the artificial marsh is being phased out and is no longer used, Lakeland is requesting that references to it be deleted from the Conditions of Certification.

45467
12/6/94

BEFORE THE STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION AND
THE GOVERNOR AND CABINET OF THE STATE OF FLORIDA

IN RE:	)	
	)	
McIntosh Unit No. 3, Modification	)	**Certification PA-74-06**
of Site Certification proposed by	)	
the City of Lakeland.	)	
	)	

PROPOSED AGREEMENT FOR MODIFICATION OF SITE CERTIFICATION

I.

The City of Lakeland ("Lakeland") hereby requests a modification of the Site Certification for C.D. McIntosh Power Plant Unit Number 3 ("McIntosh Unit No. 3") (PA-74-06) pursuant to Section 403.516(1)(b), Florida Statutes; Rule 62-17-211, Florida Administrative Code; and General Condition of Certification Number 12. Those provisions authorize the Department of Environmental Protection (Department) to modify the certification after public notice and opportunity for review by the public and by the parties to the original certification proceeding and upon no objection to the proposed modifications being raised.

This agreement for modification addresses several changes to the Site Certification application and to the Conditions of Certification. In support of the proposed modification, Lakeland states:

II.

On December 7, 1978, the Siting Board issued a final Certification to Lakeland pursuant to Chapter 403, Part II, Florida Statutes, authorizing the construction and operation of McIntosh Unit No. 3. The Site Certification was subsequently modified in 1980, 1988, and 1993. Subject to the provisions of the Certification Order and the associated Conditions of Certification, Lakeland constructed a coal-, refuse-, and oil-fired steam electric generating unit, along with various associated support facilities, and began operating the unit in 1982. Based on a successful test burn of petroleum coke earlier this year, Lakeland has proposed several revisions to its Site Certification application to allow petroleum coke to be blended with other fuels and burned in McIntosh Unit No. 3. In addition, as a result of the final design of Unit No. 3 and its associated facilities, Lakeland has identified several needed clarifications and minor revisions to the Site Certification application and Conditions of Certification. The revised pages of the Site Certification application are attached hereto as Exhibit A and the Conditions of Certification as proposed to be revised are attached as Exhibit B.

Petroleum Coke

Specifically, Lakeland is proposing to burn petroleum coke when blended with other fuels in amounts up to 20 percent based on weight. At this rate of 20 percent or less, the permitted emission limits will not be exceeded, which will be confirmed through the use of continuous emission monitors for sulfur dioxide. A fuel analysis of petroleum coke is provided with the proposed application revisions. The application clarifies that the same air emission limits that apply to coal and coal/refuse blends will apply to petroleum coke blends as well. The Conditions of Certification have also been revised to authorize the use of petroleum coke, as shown in Exhibit B.

Application

The 80 percent sulfur dioxide removal efficiency achievable through the use of the desulfurization unit is based on high-sulfur coal, and this point is clarified in the revised application.

Lakeland has updated the application to indicate that the refuse processing plant tipping floor is being expanded to include a relatively small building. Lakeland has also clarified that the stabilized sludge operation and various silos are equipped with dust control systems.

Lakeland has also clarified that natural gas and/or low sulfur oil will be used for ignition and fuel stabilization of the unit, and that these fuels may be used at any time.

The application has been revised to reflect the actual maximum heat input achievable by the unit, as well as the actual fuel flow rates experienced. These higher rates are needed to produce the same megawatt output of 364.

Lakeland has also revised the application to clarify several fuel transportation and storage issues. Petroleum coke will be obtained from a suitable source, delivered by truck or rail, and stored in the coal storage area. Natural gas will be supplied to the site by pipeline.

The application clarifies that the coal pile runoff will be pumped from the north landfill surge pond to the final wastewater ponds for reuse on site. Lakeland also clarifies that the Marsh Treatment System is being abandoned because the water now goes directly to the public works system.

Conditions of Certification

The citations and agency names are being updated, and the certified site is being more clearly identified in certain conditions as Unit No. 3

The conditions are also being revised to clarify that Lakeland has 72 working day hours within which to provide written notice of noncompliance situations.

The conditions also reflect that fuel analysis and fuel quality data must be submitted annually. Further, as in the application, references to the artificial marsh are being deleted since this system is being phased out and is no longer used.

REQUEST FOR RELIEF

Accordingly, Lakeland requests that:

1. All parties to the original Certification agree to, or otherwise do not object to, this proposed Modification and the attached revised Site Certification application pages and revised Conditions of Certification attached hereto within forty-five (45) days of submittal of this proposed Agreement, as provided for in Section 403.516(1)(b), Florida Statutes.

2. Upon no objection being raised by the parties as provided above or by a substantially affected person within thirty (30) days of public notice of this proposed modification, the Department of Environmental Protection issue an order modifying the Site Certification, pursuant to Section 403.516(1)(b), Florida Statutes.

3. The Department of Environmental Protection grant such other relief as may be appropriate, including necessary additional conditions of certification proposed by agency parties and accepted by Lakeland.

Respectfully submitted this 7th day of December, 1994.

HOPPING BOYD GREEN & SAMS

Angela R. Morrison

Angela R. Morrison
Fla. Bar No. 0855766
123 South Calhoun Street
P.O. Box 6526
Tallahassee, FL 32314
(904) 425-2258
Attorneys for the City of Lakeland

CERTIFICATE OF SERVICE

I hereby certify that a copy of the foregoing and attachment have been furnished to the following by U.S. mail, certified and return receipt requested, on this 7th day of December, 1994:

Hamilton S. Oven, Jr., P.E.
Administrator, Power Plant Siting Section
Department of Environmental Protection
3900 Commonwealth Boulevard, MS #48
Tallahassee, FL 32399

Richard T. Donelan, Jr., Esquire
Assistant General Counsel
Florida Department of Environmental Protection
2600 Blair Stone Road
Tallahassee, FL 32399

Michael Palecki
Division of Legal Services
Florida Public Service Commission
101 East Gaines Street
Tallahassee, FL 32301

Andrew R. Reilly
East Lake Parker Residents
P.O. Box 2039
Haines City, FL 33844

Greg DeMuth
Orlando Utilities Commission
500 South Orange Street
Orlando, FL 32801

Daniel Fernandez
Southwest Florida Water Management District
2379 Broad Street
Brooksville, FL 33512

David Jordan, Senior Attorney
Department of Community Affairs
2740 Centerview Drive
Tallahassee, FL 32399

County Administrator
Polk County, Florida
P.O. Box 60
Bartow, FL 33830

City of Lakeland, Florida
P.O. Box 38
Lakeland, FL 33802

ATTORNEY

45467
12/6/94

LAKELAND ELECTRIC & WATER

Excellence Is Our Goal, Service Is Our Job

(813) 499-6603

Farzie Shelton
ENVIRONMENTAL COORDINATOR, Ch E.

December 7, 1994

Hamilton S. Oven, Jr., P.E.
Administrator, Power Plant Siting Section
Department of Environmental Protection
3900 Commonwealth Boulevard, MS #48
Tallahassee, FL 32399-3000

RE: City of Lakeland--C.D. McIntosh Power Plant, Unit No. 3
Proposed Agreement to Modify Site Certification--PA-74-06

Dear Mr. Oven:

The City of Lakeland ("Lakeland") hereby requests that its Site Certification for the above-referenced C.D. McIntosh Power Plant, Unit No. 3 be revised. As you may recall, the Certification Order for Unit No. 3 was issued in 1978 and subsequently revised in 1980, 1988, and 1993. Consistent with that Certification and the Conditions of Certification, Lakeland constructed a coal-, municipal refuse-, and oil-fired steam electric generation unit, which began operating in 1982. Based on a successful test burn of petroleum coke earlier this year, Lakeland is proposing revisions to its application to describe this alternative fuel and its characteristics. In addition, as a result of the final design of Unit No. 3, Lakeland has identified several needed clarifications and minor revisions to the Site Certification application. To update citations and to clearly authorize the burning of petroleum coke, Lakeland is also proposing amendments to the Conditions of Certification. A more detailed description of the proposed changes to the application and Conditions of Certification is included in Attachment 1.

In support of its request, Lakeland has prepared a "Proposed Agreement for Modification of Site Certification" (Attachment 2), which includes revised portions of the Site Certification application and suggested minor changes to the Conditions of Certification (which are attached to the Agreement as Exhibits 1 and 2, respectively). The Conditions of Certification, as proposed to be revised, are also included on the enclosed computer disk in WordPerfect 5.1 format. Another version of the revised application pages (showing additions with double underlining and deletions with strike throughs) is included as Attachment 3 to this request.

The Proposed Agreement for Modificaton of Site Certification is submitted to the Department of Environmental Protection pursuant to Rule 62-17.211, Florida Administrative Code, and Section 403.516(1)(b), Florida Statutes, which authorizes the Department to modify the Site Certification when no objection is raised by a party or substantially affected person. We have enclosed eleven copies of this request for the Department's use, and we are sending copies to all of the other parties to the original certification proceeding. Lakeland will inform the Department as to responses received from any of the parties as a result of this notice, and we would appreciate hearing from you if any of the parties notify the Department.

Attachment SI-1

In addition to the Proposed Agreement for Modification of Site Certification, Lakeland is seeking a separate amendment to the Prevention of Significant Deterioration (PSD) permit for Unit No. 3, which was issued by the U.S. Environmental Protection Agency in December of 1978 (PSD-FL-08). A copy of the formal request for PSD permit revision will be sent to you once it has been prepared for submission to the Department's Bureau of Air Regulation.

Thank you for your consideration of the Proposed Agreement for Modification. A check in the amount of $10,000 is enclosed as the fee for review of the requested modification. After you and other Department staff have had an opportunity to review the proposed revisions, please let me know within the next thirty days if you have any questions, need any additional information, or do not agree with the approach taken in this letter to revise the application through a formal modification.

Sincerely,

Farzie Shelton

am/ Farzie Shelton
Environmental Coordinator
Department of Electric & Water Utilities

cc: Clair Fancy, DEP
Bill Thomas, DEP SW District
Mike Hickey, DEP SW District
Ken Kosky, KBN
Angela Morrison, HBGS

45467

CITY OF LAKELAND
McIntosh Unit No. 3

Description of Amendments to Site Certification Application

Section 3.2.1 Fuel Types

Earlier this year, the City of Lakeland conducted a successful test burn of petroleum coke blended with coal. In an effort to use the most cost-effective fuels while not increasing emissions above allowable limits, the City of Lakeland requests that the Department approve its revised application to allow petroleum coke to be burned when blended with coal. Because continuous emissions monitors are installed for sulfur dioxide, nitrogen oxides, and opacity, as required by the PSD permit (Condition No. 6) and NSPS (40 CFR § 60.45), Lakeland can ensure that the emission limits for these pollutants are not exceeded when coke is blended with coal (or coal and refuse) and burned in Unit No. 3. A 0 to 10 percent blended petroleum coke product will be used with medium to high sulfur coal and a 0 to 20 percent blended petroleum coke product will be used with low sulfur coal. Lakeland has clarified in the revised application what fuels and fuel blends may be burned and the conditions under which such fuels and blends may be burned. Specifically, Lakeland is requesting authorization to burn petroleum coke and has clarified that natural gas and/or low sulfur oil will be used for ignition and fuel stabilization of the unit. Because natural gas and low sulfur oil are "clean fuels," such fuels may be burned at any time.

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BEFORE THE STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION AND
THE GOVERNOR AND CABINET OF THE STATE OF FLORIDA

IN RE:	)	
	)	
McIntosh Unit No. 3, Modification	)	**Certification PA-74-06**
of Site Certification proposed by	)	
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The application clarifies that the coal pile runoff will be pumped from the north landfill surge pond to the final wastewater ponds for reuse on site. Lakeland also clarifies that the Marsh Treatment System is being abandoned because the water now goes directly to the public works system.

Conditions of Certification

The citations and agency names are being updated, and the certified site is being more clearly identified in certain conditions as Unit No. 3

The conditions are also being revised to clarify that Lakeland has 72 working day hours within which to provide written notice of noncompliance situations.

The conditions also reflect that fuel analysis and fuel quality data must be submitted annually. Further, as in the application, references to the artificial marsh are being deleted since this system is being phased out and is no longer used.

REQUEST FOR RELIEF

Accordingly, Lakeland requests that:

1. All parties to the original Certification agree to, or otherwise do not object to, this proposed Modification and the attached revised Site Certification application pages and revised Conditions of Certification attached hereto within forty-five (45) days of submittal of this proposed Agreement, as provided for in Section 403.516(1)(b), Florida Statutes.

2. Upon no objection being raised by the parties as provided above or by a substantially affected person within thirty (30) days of public notice of this proposed modification, the Department of Environmental Protection issue an order modifying the Site Certification, pursuant to Section 403.516(1)(b), Florida Statutes.

3. The Department of Environmental Protection grant such other relief as may be appropriate, including necessary additional conditions of certification proposed by agency parties and accepted by Lakeland.

Respectfully submitted this 7th day of December, 1994.

HOPPING BOYD GREEN & SAMS

Angela R. Morrison
Fla. Bar No. 0855766
123 South Calhoun Street
P.O. Box 6526
Tallahassee, FL 32314
(904) 425-2258
Attorneys for the City of Lakeland

CERTIFICATE OF SERVICE

I hereby certify that a copy of the foregoing and attachment have been furnished to the following by U.S. mail, certified and return receipt requested, on this 7th day of December, 1994:

Hamilton S. Oven, Jr., P.E.
Administrator, Power Plant Siting Section
Department of Environmental Protection
3900 Commonwealth Boulevard, MS #48
Tallahassee, FL 32399

Richard T. Donelan, Jr., Esquire
Assistant General Counsel
Florida Department of Environmental Protection
2600 Blair Stone Road
Tallahassee, FL 32399

Michael Palecki
Division of Legal Services
Florida Public Service Commission
101 East Gaines Street
Tallahassee, FL 32301

Andrew R. Reilly
East Lake Parker Residents
P.O. Box 2039
Haines City, FL 33844

Greg DeMuth
Orlando Utilities Commission
500 South Orange Street
Orlando, FL 32801

Daniel Fernandez
Southwest Florida Water Management District
2379 Broad Street
Brooksville, FL 33512

David Jordan, Senior Attorney
Department of Community Affairs
2740 Centerview Drive
Tallahassee, FL 32399

County Administrator
Polk County, Florida
P.O. Box 60
Bartow, FL 33830

City of Lakeland, Florida
P.O. Box 38
Lakeland, FL 33802

ATTORNEY

45467
12/6/94

PROPOSED REVISIONS TO THE C.D. McINTOSH POWER PLANT - UNIT NO. 3
Recertification Application - June 1978, as Amended in 1987
(December 1994)

Section	Subject	Discard Old Pages	Insert New Pages
3.2	Fuels	3.2-1 - 3.2-6	3.2-1 - 3.2-7
3.4	Heat Dissipation System	3.4-1	3.4-1
3.5	Changes in Chemical & Biocide Wastes	3.5-1 - 3.5-2	3.5-1 - 3.5-2
3.6	Changes in Sanitary & Other Wastes	3.6-2	3.6-2 - 3.6-2a
3.7	Air Emissions	3.7-1 - 3.7-2	3.7-1 - 3.7-2
5.6	Other Effects of Plant Operation	5.6-1 -5.6-3	5.6-1 - 5.6-3

45619.1

3.2 FUELS

3.2.1 FUEL TYPES

Unit #3 will have the capability of burning the types of fuels and fuel combinations described herein.

The primary fuel will be pulverized coal. The Unit has been designed to burn processed municipal solid waste, known as Refuse Derived Fuel or RDF, to supplement the pulverized coal.

The furnace design is such that RDF can supply up to 10% of the expected full load heat input to the Unit.

As an alternative fuel source, petroleum coke will be added as a supplement to the pulverized coal. The blend rate can range from 0% to 20% by weight, depending on the quality of the coal. A 0% to 10% blended product will be used with medium sulfur coal (2.5% sulfur) and a 0% to 20% blended product with low sulfur coal (1% sulfur).

As a backup to pulverized coal, Unit #3 has the capability to burn low sulfur oil (.77% sulfur) as a primary fuel. In which case, RDF can also be burned with the low sulfur oil at a rate of up to 10% of expected full load heat input to the Unit.

Ignition or fuel stabilization of this Unit will be provided primarily by natural gas and/or low sulfur oil. Neither fuel can provide full load capability and only nominal loads can be achieved. They are primarily used for start-up and low load operation.

In summary, Unit #3 will have the capability of firing modes including (primary plus alternate fuels):

1. Pulverized coal only
2. Pulverized coal and RDF
3. Pulverized coal and petroleum coke
4. Pulverized coal, RDF, and petroleum coke
5. Low sulfur oil only
6. Low sulfur oil and RDF

It is possible for Unit #3 to operate under any of the above firing modes on a given day, but the primary operating modes will be 1 thru 4. Natural gas may be burned during startup or at any other time.

3.2.2 FUEL QUANTITIES

Unit #3 has a maximum annual heat input requirement of 2.8697×10^{13} BTU's based on 100% availability (365 days) at a 90% capacity factor. The predicted annual <u>average</u> heat input requirement is

2.72629×10^{13} BTU's based on a 95% availability (347 days) at a 90% capacity factor.

It is anticipated that the Unit will be operated in one of the four primary firing modes at all times (coal only, coal and RDF, coal and petroleum coke, or coal, RDF, and petroleum coke). Based on these modes, the approximate <u>average</u> annual fuel usage will be:

<u>FUEL</u>	<u>QUANTITY</u>
Coal	864,550 tons (Typical Coal)
RDF	75,000 tons
Petroleum Coke	190,000 tons

The maximum and average heat inputs and fuel flows for the primary firing modes as described in Section 3.2.1 are shown in Table 3.2.1.

<u>3.2.3 TRANSPORTATION</u>

<u>COAL</u>

Coal normally will be delivered to the Plant site in two continuously operating unit trains in ninety (90) cars of one hundred ton (nominal) bottom dump hopper cars per unit train.

The coal supply will be primarily from the area east of the Mississippi River. The majority of the coal will come from Eastern Kentucky, but may also be obtained from other sources of suitable quality.

The coal will normally be delivered to the Plant via single line rail haul, using CSX Transportation (CSXT). The unit train will reach the Plant site on a railroad spur line connecting the coal trestle with the CSXT track located one and one half miles east of the Plant. The coal will be unloaded using an elevated trestle approximately 1000 feet long. The bottom dump hopper cars will unload when they are given a signal through a third rail system as determined by an Operator.

PETROLEUM COKE

Petroleum coke will be obtained from a suitable source based on lowest evaluated delivered cost. Options to be evaluated include: purchasing a material blended with coal off site and delivered as a blended fuel ready for burning or purchasing a supply of petroleum coke to be delivered to the site and blended with the normal supply of coal.

The petroleum coke will be delivered to the Plant by truck from a nearby port or by rail, directly from a supply source. A blended fuel would be delivered either by rail or truck from a blending facility.

The blend will be carefully monitored and controlled to assure compliance with all regulated parameters at the stack exit with continuous emissions monitoring systems (i.e., sulfur dioxide, nitrogen oxide, and opacity). A blend of 90/10 (by weight) medium sulfur (2.5%) coal with petroleum coke and a blend of 80/20 (by weight) low sulfur (1.0%) coal with petroleum coke has been tested and all environmental and operational parameters checked. The entire range of blends provide good operation and no adverse environmental impacts.

The fuel blend supplied to Unit #3 and the flexibility built into the flue gas desulfurization system (Scrubber) will be fully controlled, to ensure complete environmental compliance at all times.

REFUSE

Refuse collected from Lakeland and the surrounding area will be delivered to the refuse processing facility by the collection trucks.

OIL

Oil will be delivered to the Plant site by fuel oil trucks from the Port of Tampa.

NATURAL GAS

Natural gas is supplied to the site by a high pressure main tied in with Florida Gas Transmission several miles north of the Plant.

3.2.4 STORAGE

COAL

Coal will be stored on site in open piles for immediate use (active pile) and an emergency reserve storage of approximately sixty days will be maintained in sealed piles.

Coal will be stored on a sealed surface and will be provided with a complete run-off control system to collect rain water or dust control water. Fugitive emissions from coal piles will be minimized by a dust water separation system.

Coal will be delivered to Unit #3 silos by a series of conveyors thru several transfer points. These transfer points and the silos will be equipped for dust control.

OIL

Oil will be stored in on-site tanks within containment areas. Diesel oil tanks piping, and receiving areas all conform to regulations and rules of the Department governing petroleum products.

PETROLEUM COKE

Petroleum coke will be stored in the coal storage area either as a unblended or blended product.

REFUSE

Refuse will not be stored on site. All material received will be processed and burned as quickly as possible.

3.2.5 FUEL ANALYSIS

Typical fuel analysis for coal, petroleum coke, refuse, and oil are located in Tables 3.2.2, 3.2.3, 3.2.4, and 3.2.5 respectively.

3.2.6 PLANS FOR EMERGENCY SPILLS

As described in Section 3.2.4, no new oil tanks will be required, so existing fuel oil unloading areas will be utilized. Since these areas already comply with the U.S. Environmental Protection Agency's rule on the prevention of oil spills, no additional spill protection will be required.

3.2.7 COAL PILE RUN-OFF

The entire coal receiving and storage area is constructed on an impermeable base and is surrounded by a series of asphalt lined ditches to collect all rainfall run-off and dust control water. The collected water will be directed to a series of sumps and will be pumped to the north landfill sedimentation pond or to the ash settling ponds. The collected water will be recycled for reuse in Plant systems in an effort to minimize the consumptive use of water. The design of the storm water run-off system for the coal yard has been designed for a ten year, twenty-four hour storm event. More detailed information is given in Section 3.3.

TYPICAL PETROLEUM COKE ANALYSIS

UNIT #3

Petroleum Coke Quality: As Rec'd Basis

Moisture	8.00%	12.00% Max
Ash	0.25%	1.00% Max
Volatile	10.00%	14.00% Max
Sulfur	4.75%	5.50% Max
Btu/lb	14,200	14,200 Penalty
Hardgrove Grindability Index	65	50 Min
	Typical	Maximum
Vanadium	950 ppm	1500 ppm
Iron	100 ppm	500 ppm
Silicon	50 ppm	250 ppm
Calcium	100 ppm	250 ppm
Nickel	250 ppm	500 ppm

Sizing	+3"	5%
	2x3"	5%
	1x2"	25%
	½x1"	20%
	-½"	45%

Table 3.2.1

FIRING MODES

FUEL FLOW RATES

MODE/LOAD	HOURLY FLOW RATES 364 Mw
NO. 1 COAL ONLY (TONS/HR)	159.6
NO. 2 COAL/RDF: (10% RDF)	
COAL (TONS/HR)	143.7
RDF (TONS/HR)	40.4
NO. 3 OIL ONLY (BBLS/HR)	577.8
NO. 4 OIL/RDF: (10% RDF)	
OIL (BBLS/HR)	520.0
RDF (TONS/HR)	40.4
NO. 5 COAL/COKE (80/20)	122.1 COAL 30.5 COKE
NO. 6 COAL/COKE/RDF (80/20 - 90%) (RDF - 10%)	100.9 COAL 40.4 RDF 27.5 COKE

Revised 12-06-94

Table 3.2.4

MCINTOSH PLANT SITE - PETROLEUM STORAGE

EMISSION POINT	TYPE	LOCATION	SIZE (GALLON)	EMISSION
DIESEL TANK	VENT	E OF WATER TANK	2,000	VOC
GASOLINE TANK	VENT	S OF WELD BARN	1,000	VOC
DIESEL STORAGE TANK	VENT	TANK FARM	101,346	VOC
DIESEL TANK	VENT	S OF WELD BARN	1,000	VOC
DIESEL FUEL TANK (REFUSE AREA)	VENT	SE OF LARGE THICKENER	1,000	VOC
DIESEL FUEL (10,000 GAL) TANK	VENT	N OF PEO BLDG	9,000	VOC
HEAVY OIL TANK	VENT	TANK FARM	4,057,200	VOC
HEAVY OIL TANK	VENT	TANK FARM	4,057,200	VOC
HEAVY OIL TANK	VENT	TANK FARM	4,057,200	VOC
DIESEL STORAGE TANK	VENT	TANK FARM	22,500	VOC

Revised 12-06-94

Table 5.6.2

MCINTOSH PLANT SITE - DUST COLLECTORS

EMISSION POINT	TYPE	LOCATION	EMISSION
LIMESTONE SILO DUST COLLECTOR	EXHAUST	N OF SCRUBBER #32	DUST
QUICKLIME SILO DUST COLLECTOR	EXHAUST	N OF CSI BLDG	DUST
SODA ASH SILO DUST COLLECTOR	EXHAUST	WWTP/ABOVE BLDG RO	DUST
QUICKLIME SILO DUST COLLECTOR	EXHAUST	WWTP/ABOVE BLDG RO	DUST
FLY ASH SILO DUST COLLECTOR	EXHAUST	E OF CSI BLDG	DUST
SHREDDER EXPLOSION VENT	VENT	REFUSE	DUST
KLEISLER FILTER	VENT	REFUSE	DUST
SILO 31 DUST COLL. EXHAUST/C4	EXHAUST	TRIPPER HOUSE	DUST
SILO 32 DUST COLL. EXHAUST	EXHAUST	TRIPPER HOUSE	DUST
SILO 33 DUST COLL. EXHAUST/C5	EXHAUST	TRIPPER HOUSE	DUST
SILO 34 DUST COLL. EXHAUST	EXHAUST	TRIPPER HOUSE	DUST
CRUSHER HOUSE DUST COLLECTOR	EXHAUST	COAL CRUSHER HOUSE	DUST
C2 COAL CONVEYOR DUST COLLECTOR	EXHAUST	C2 CONV. (BEGIN)	DUST
C3 REFUSE CONVEYOR DUST COLLECTOR	EXHAUST	REFUSE	DUST
C5 REFUSE CONVEYOR DUST COLLECTOR	EXHAUST	REFUSE	DUST
PUGMILL #31 DUST COLLECTOR	EXHAUST	CSI	DUST
PUGMILL #32 DUST COLLECTOR	EXHAUST	CSI	DUST

Revised 12-06-94

3.4 HEAT DISSIPATION SYSTEM

The Unit will use a thirteen-cell wet mechanical draft cooling tower supplemented by a two cell mechanical draft auxiliary tower, for dissipation of waste heat from the condenser and accessory equipment cooling water.

The tower will have a total circulating water flow of 144300 GPM with a design inlet water temperature of 114.7°F. The tower will be designed to dissipate 1636 MMBTUH with a 79°F inlet wet bulb air temperature.

Condenser cooling water will comprise 138300 GPM of the circulating water flow and 6000 GPM will be utilized to cool a secondary fluid for accessory equipment cooling.

Process wastewater and blowdown from the tower will be utilized as makeup for the SO_2 removal system (scrubber) on the boiler. Any excess blowdown will be transported to the new City of Lakeland's Public Works Sewage Plant Wetlands Treatment System located seven and one-half miles south of McIntosh Power Plant. The present on-site Marsh Treatment System will be phased out, because the new wetlands system has proven to be very effective. A new pipeline has been constructed to transport the blowdown from the tower to the Sewage Plant to be combined with its effluent going to the new Wetlands Treatment System.

3.5 CHANGES IN CHEMICAL AND BIOCIDE WASTES

The flow diagram shown in Figure 3.3.1 shows the major wastewater flow paths. The Figure shows that Unit No. 3 will not discharge waste streams to any water body. Waste streams will be reused to the extent practicable and that the remaining process wastewaters will be treated on site and pumped to the Sewage Plant Wetlands Treatment Systems (Wetlands system). Excess cooling tower blowdown will be transported also to the Sewage Plant Wetlands Treatment System.

Figure 3.3.1 shows that after the scrubber makeup water is taken from the cooling tower blowdown stream, approximately 500 GPM or 720,000 gallons per day, will be pumped to the Sewage Plant Wetlands Treatment System. The wastewater treatment scheme shown in Figure 3.3.1 is similar to that which was originally presented in the 250 MW application. One notable change in the system is the addition of bottom ash dewatering bins for separating bottom ash and sluice water in lieu of a 5-acre sluice pond. This change was made to facilitate the handling of bottom ash for the sludge stabilization process. The flow diagram shows a settling pond will be used as a backup system to the ash dewatering bin system, a storage area for sluice water makeup, and a holding area for the collection of runoff from the coal pile and coal handling area and water used in the dust suppression system.

The north landfill surge pond will help collect and contain the coal pile runoff from the 12-acre coal storage area that is expected from the 10-year, 24-hour storm event. The 10-year, 24-hour storm event in the Lakeland area is 6.60 inches. The settling pong is lined with bitumastic to prevent leaking of the water to shallow groundwater. Collected runoff will be pumped from the north landfill surge pond to the final wastewater ponds for reuse on site.

Disposal of the cooling tower blowdown and process wastewaters will be to the back end of the sewage treatment plant of the City of Lakeland. Disposal of the solids from the process wastewater treatment plant will be to the plant stabilized sludge landfill.

5.6 OTHER EFFECTS OF PLANT OPERATION

5.6.1 ENERGY RECOVERY FROM SOLID WASTE

As discussed in the 250 MW Unit #3 application, processed municipal refuse will be used as a supplemental fuel supply to the Unit. The processing system will still consist of shredding, magnetic separation of ferrous materials and air classification prior to combustion in the boiler. However, with the 364 MW Unit #3, refuse will be burned with both coal and oil rather than just with coal as in the 250 MW Unit #3.

For calculation purposes, the amount of refuse that will be burned has been limited to what is collected within the city limits of Lakeland and from contiguous outlying areas. This will produce approximately 300 tons per day of raw refuse and 210 tons per day of combustible material to be used as a refuse derived fuel (RDF).

In addition to the use of the RDF, the Unit #3 architect engineers are currently studying the possibility of burning the sewage sludge from the Lakeland Sewage Treatment Plant. Sewage sludge has a heating value of 4000 to 7000 BTU/per pound and its use would eliminate another City of Lakeland disposal problem.

Another important aspect of the refuse burning capability of Unit #3 is that Polk County has been designated by the Florida Department of Environmental Protection to develop a county wide plan for resource recovery, and while the plan is in its beginning stages, preliminary discussions with Polk County representatives have indicated that the processing facility at the McIntosh site and the Unit #3 RDF capability could be an integral part of the Polk County resource recovery plan.

Tests from the pilot RDF project in St. Louis at Union Electric's Merrimac Station have concluded that up to 20% of boiler heat requirements can be from RDF without noticeable boiler damage. Based on this assumption, Unit #3 could burn over 1000 tons per day of the County's refuse. In order to produce the 1000 tons per day of RDF, over 1450 tons per day, essentially all the raw refuse projected to go to landfills in 1983 would have to be processed.

The present refuse processing Plant tipping floor will be expanded to the north with an addition of a building approximately 100' x 70'.

5.6.2 SCRUBBER SLUDGE DISPOSAL

The 250 MW Unit #3 application indicated that at the time of submittal, four (4) methods of disposing of sulfur sludge were being considered. The methods under consideration were:

1. Stabilized landfill with load bearing capacity.
2. Returning the sludge to the limestone mine where the limestone for the SO_2 scrubber was taken.
3. Using the sludge as a reclamation fill for phosphate strip mines.
4. Permanent ponding of the sludge on site in clay lined ponds.

The "Conditions of Certification" for the 250 MW Unit #3 stipulated that "Flue as desulfurization sludge shall be stabilized prior to disposal in other than a lined pond or basin". In keeping with this stipulation, the 364 MW Unit #3 will combine all the sludges and ash generated by the Unit to form a stabilized fill material.

The stabilized sludge (pozzolanic) will be primarily used as a landfill material in the immediate area of the Plant site. However, once the Plant is in operation and actual samples of stabilized material are available, a study will be undertaken to determine the suitability and marketability of this material for use as a road and parking lot base coarse material, earthen embankments, impermeable liners for holding ponds and synthetic aggregate for concrete block and asphalt formulations.

The stabilized sludge operation will be located at the McIntosh Plant site. The operations will consist of blending the scrubber sludge, as well as other sludges generated in the operation of Unit #3 with fly ash, bottom ash and lime to form the stabilized pozzolanic material, prior to its use or disposal in the dedicated Plant site landfill. The stabilized pozzolanic sludge process provided by Conversion Systems, Inc. is located in a building next to the scrubber sludge thickener. This building, as well as the silos (fly ash, lime, etc.), is equipped with the proper dust control systems, as listed in Table 5.6.2.

All quantities of collected ash from the operation of Unit #3 will be used as an integral ingredient in the sludge stabilization process described in Sections 3.6.3 and 5.6.2.

3.6.3 FLUE GAS DESULFURIZATION SCRUBBER SLUDGE

Sulfur dioxide emissions in the flue gas from the coal, coal and petroleum coke, coal, RFD and petroleum coke, and coal and RFD firing modes will comply with the State and Federal new source performance standard of 1.2 lbs/mmBTU by using a limestone slurry flue gas scrubber with an 80% removal efficiency for high sulfur fuel (higher than 3.0% sulfur).

The end product of the SO_2 scrubber system will be a 50% solids sludge consisting of the following materials:

Constituent	% By Weight
$CaCO_3$	33
$CaSO_3 \bullet 2H_2O$	58
$CaSO_4 \bullet 2H_2O$	9

The quality of sludge expected to be produced from Unit #3 is shown in Table 3.6.1.

In order to dispose of the annual amounts of sludge shown in Table 3.6.1 and the amounts of fly ash and bottom ash described in Section 3.6.2 in an acceptable manner, all sludge and ash quantities will be brought to an on-site stabilization process. In this process, ash and scrubber sludge will be combined with lime and other aggregates to form a cementitious material suitable for use as landfill material, road base material, embankments and impermeable liners.

3.7 AIR EMISSIONS

3.7.1 AIR EMISSIONS COMPLIANCE STANDARDS

Unit #3 will be required to meet the State and Federal emission limits for Nitrous Oxide (NO_x), Sulfur Dioxide (SO_2), Particulate Matter (PM) and Opacity as listed in Rule 62-296.405, F.A.C. As discussed in Section 3.2, Unit #3 will be capable of burning four different fuels in six firing modes, which will require meeting various emission limits depending on the firing mode. The following are the emission limits for each firing mode:

FIRING MODE	SO_2 LB/MMBTU	NO_X LB/MMBTU	PM LB/MMBTU	OPACITY %
Coal Only	1.2	0.7	0.1	20
Coal/RDF	1.2	0.7	0.1	20
Coal/Petroleum Coke	1.2	0.7	0.1	20
Coal/Petroleum Coke /RDF	1.2	0.7	0.1	20
Oil Only	0.8	0.3	0.1	20
Oil/RDF	0.8	0.3	0.1	20

Natural gas and/or low sulfur fuel oil may be burned during startup or at any other time.

3.7.2 NITROUS OXIDES (NO_X) COMPLIANCE METHOD

NO_X will be maintained within the established limits through either boiler, burner or a combination of boiler and burner design. Each of the boiler companies that are currently bidding on this project uses a different method, however each company guarantees that applicable NO_x emission limits will be met.

3.7.3 PARTICULATE (PM) COMPLIANCE METHOD

Particulate emissions will be maintained within the limit of 0.1 lb/mmBTU with a cold side precipitator with a minimum removal efficiency of 99.5%.

Particulate compliance during the oil only firing mode will not require the use of the precipitator since the ash content of 0.77% sulfur oil results in PM emission levels of less than the emission standard.

A certain amount of particulate removal will also take place in the SO_2 limestone scrubbing system during the (1) coal, (2) coal and RDF, (3) coal and petroleum coke, and (4) coal, RDF and petroleum coke firing mode when use of the scrubber will be required. However, for the purpose of determining the PM emission rates for these modes, it was assumed that no removal would take place in the scrubber.

3.7.4 SULFUR DIOXIDE (SO_2) COMPLIANCE METHOD

As discussed above, compliance with SO_2 emission limits for the (1) coal, (2) coal and RDF, (3) coal and petroleum coke, and (4) coal, RDF and petroleum coke firing modes will be achieved with limestone slurry scrubbing system. The system used in the 364 MW size will have removal efficiency of 80% for high sulfur fuel and is the same as described in the 250 MW Unit #3 certification application. SO_2 emission limits due to the low amounts of sulfur in both the fuels.

3.7.5 EMISSIONS DISPERSION METHOD

As reported in the 250 MW application, flue gas exiting the boiler and pollution control equipment will be discharged from a 250 foot stack. Flue gas from the (1) coal, (2) coal and RDF, (3) coal and petroleum coke and (4) coal, RDF, and petrolum coke firing modes which require SO_2 scrubbing will be reheated to approximately 200°F and exit the stack at 170°F. Flue gas from the oil only

State of Florida Department of Environmental Regulation
City of Lakeland
C.D. McIntosh, Jr. Power Plant - Unit No. 3
Case No. PA 74-06-SR
CONDITIONS OF CERTIFICATION

GENERAL

Table of Contents

State of Florida Department of Environmental Regulation
City of Lakeland
C.D. McIntosh, Jr. Power Plant - Unit No. 3
Case No. PA 74-06-SR
CONDITIONS OF CERTIFICATION

GENERAL

1. Change in Discharge

All discharges or emissions authorized herein shall be consistent with the terms and conditions of this certification. The discharge of any regulated pollutant not identified in the application, or any discharge more frequent than, or at a level in excess of that authorized herein, shall constitute a violation of the certification. Any ~~anticipated~~ proposed ~~facility~~ expansions, production increases, or process modifications which will result in new, different or increased discharges or expansion in steam generating capacity of Unit No. 3 will require a submission of a new or supplemental application pursuant to Chapter 403, Florida Statutes.

2. Noncompliance Notification

If, for any reason, the permittee does not comply with or will be unable to comply with any limitation specified in this certification, the permittee shall notify the Southwest District Manager of the Department by telephone during the working day during which said noncompliance occurs and shall confirm this situation in writing within seventy-two (72) working-day hours of first becoming aware of such conditions, supplying the following information:

a. A description and cause of noncompliance; and

b. The period of noncompliance, including exact dates and times; or, if not corrected, the anticipated time the noncompliance is expected to continue, and steps being taken to reduce, eliminate and prevent recurrence of the noncomplying event.

3. ~~Facilities~~ Unit No. 3 Operation

The permittee shall at all times maintain in good working order and operate as efficiently as possible all treatment or control facilities or systems installed or used by the permittee to achieve compliance with the terms and conditions of this certification. Such systems are not to be bypassed without prior department approval.

4. Adverse Impact

The permittee shall take all reasonable steps to minimize any adverse impact resulting from noncompliance with any limitation specified in this certification, including but not limited to such accelerated or additional monitoring as necessary to determine the nature and impact of the noncomplying event.

5. Right of Entry

The permittee shall allow the Secretary of the Florida Department of Environmental Protection ~~Regulation~~ and/or authorized representatives, upon the presentation of credentials:

a. To enter upon the permittee's premises where an effluent source is located or in which records are required to be kept under the terms and conditions of this permit; and

b. To have access to and copy all records required to be kept under the conditions of this certification; and

c. To inspect and test any monitoring equipment or monitoring method required in this certification and to sample any discharge or pollutants, and

d. To assess any damage to the environment or violation of ambient standards.

6. Revocation or Suspension

This certification may be suspended or revoked pursuant to Section 403.512, Florida Statutes, or for violations of any General or Special Condition.

7. Civil and Criminal Liability

This certification does not relieve the permittee from civil or criminal responsibility or liability for noncompliance with any conditions of this certification, applicable rules or regulations of the Department, or Chapter 403, Florida Statutes, or regulations thereunder.

Subject to Section 403.511, Florida Statutes, this certification shall not preclude the institution of any legal action or relieve the permittee from any responsibilities or penalties established pursuant to any other applicable State Statutes or regulations.

8. Property Rights

The issuance of this certification does not convey any property rights in either real or personal property tangible or intangible, nor any exclusive privileges, nor does it authorize any injury to public or private property or any invasion of personal rights, nor any infringement of Federal, State or local laws or regulations. The applicant will obtain title, lease or right of use from the State of Florida, to any sovereign submerged lands occupied by plant, transmission line structures, or appurtenant facilities.

9. Severability

The provisions of this certification are severable, and if any provision of this certification, or the application of any provision of this certification to any circumstances, is held invalid, the application of such provision to other circumstances and the remainder of the certification shall not be affected thereby.

10. Definitions

The meaning of terms used herein shall be governed by the definitions contained in Chapter 403, Florida Statutes, and any regulation adopted pursuant thereto. In the event of any dispute over the meaning of a term used in these general or special conditions which is not defined in such statutes or regulations, such dispute shall be resolved by reference to the most relevant definitions contained in any other state or federal statute or regulation or, in the alternative by the use of the commonly accepted meaning as determined by the Department.

11. Review of Site Certification

The certification shall be final unless revised, revoked or suspended pursuant to law. At least every five years from the date of issuance of this certification or any National Pollutant Discharge Elimination System Permit issued pursuant to the Federal Water Pollution Control Act Amendments of 1972, for the plant units, the Department shall review all monitoring data that has been submitted to it during the preceding five-year period, for the purposes of determining the extent of the permittee's compliance with the conditions of this certification and the environmental impact of this ~~facility~~ unit. The Department shall submit the results of its review and recommendations to the permittee. Such review will be repeated at least every five years thereafter.

12. Modification of Conditions

The conditions of this certification may be modified in the following manner:

a. The Board hereby delegates to the Secretary the authority to modify, after notice and opportunity for hearing, any conditions pertaining to monitoring or sampling.

b. All other modifications shall be made in accordance with Section 403.516, F.S.

State of Florida Department of Environmental Protection ~~Regulation~~
City of Lakeland
C.D. McIntosh, Jr. Power Plant Unit No. 3
Case No. PA 74-06-SR
CONDITIONS OF CERTIFICATION

SPECIAL

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State of Florida Department of Environmental Protection ~~Regulation~~
City of Lakeland
Power Plant No. 3 - Unit No. 3
Case No. PA 74-06
CONDITIONS OF CERTIFICATION

SPECIAL

I. Air

The construction and operation of the Unit No. 3 at the McIntosh Plant shall be in accordance with all applicable provisions of the Chapters ~~-17-2, 17-5, and 17-7~~ 62-210 - 62-297, Florida Administrative Code. The permittee shall comply with the following conditions of certification:

A. Emission Limitations

1. Stack emissions shall not exceed those specified in Chapter ~~17-2.04(6)(e)-1.~~ 62-296.405, FAC.

2. The permittee shall not burn a fuel oil containing more than an average of 0.7% sulfur unless it can be demonstrated that either, a) heat efficiency is such as to insure compliance with all applicable emission limitations, or b) that a flue gas desulfurization unit is installed that will insure compliance with applicable emission limitations.

3. The height of the boiler exhaust stack for Unit 3 shall be not less than 250 feet above grade. The height of stacks for future units shall be determined after review of supplemental applications.

4. Particulate emissions from the coal handling facilities:

   a. The applicant shall not cause to be discharged into the atmosphere from any coal processing or conveying equipment, coal storage system, or coal transfer and loading system ~~processing coal~~, visible emissions which exceed 20 percent opacity.

   b. The applicant must submit to the Department within five (5) working days after it becomes available, copies of technical data pertaining to the selected particulate emissions control for the coal handling facility. These data should include, but not be limited to, a copy of the formal bid from the successful bidder, guaranteed efficiency and emission rates, and major design parameters such as air/cloth ratio and flow rate. The Department may, upon review of these data, disapprove the use of such device if the Department determines the selected control device to be inadequate to meet the visible emission limit specified in 5 (a) above.

B. <u>Air Monitoring Program</u>

1. The permittee shall install and operate continuousl~~y~~ monitoring devices for the Unit No. 3 boiler exhaust for sulfur dioxide, nitrogen dioxide and opacity. The monitoring devices shall meet the applicable requirements of ~~17-2.08~~ <u>62-297.500</u>, FAC.

2. The permittee shall operate the ambient monitoring device for sulfur dioxide in accordance with EPA reference methods in 40 CFR Part 53 and two ambient monitoring device for suspended particulates. New and existing monitoring devices shall be located as designated by the Department. The frequency of operation shall be every six days or as specified by the Department.

3. The permittee shall maintain a daily log of fuels used and copies of fuel analyses containing information on sulfur content, ash content and heating values to facilitate calculations of emissions.

4. The permittee shall provide sampling ports into the stack and shall provide access to the sampling ports, in accordance with <u>Standard Sampling Techniques and Methods of Analysis for The Determination of Air Pollutants from Point Sources</u>, July 1975.

5. The ambient monitoring program may be reviewed annually beginning two years after start-up of Unit No. ~~2~~<u>3</u> by the Department and the permittee.

6. <u>Emission Control Systems:</u>

   Prior to operation of the source, the owner or operator shall submit to the Department a standardized plan or procedure that will allow the company to monitor emission control equipment efficiency and enable the company to return malfunctioning equipment to proper operation as expeditiously as possible.

C. <u>Stack Testing:</u>

1. Within 60 days after achieving the maximum capacity at which the facility will be operated, but no later than 180 days after initial startup, the owner or operator shall conduct performance tests for particulates and SO_2 and promptly furnish the Department a written report of the results of such performance tests.

2. Performance tests shall be conducted and data reduced in accordance with methods and procedures in accordance with Standard Sampling Techniques and Methods of the Determination on Air Pollutants from Point Sources, July 1975.

3. Performance tests shall be conducted under such conditions as the Department shall specify based on representative performance of the facility. The owner or operator shall make available to the Department such records as may be necessary to determine the conditions of the performance tests.

4. The owner or operator shall provide the Department with 30 days prior notice of the performance tests and afford the Department the opportunity to have an observer present.

5. Stack tests for particulates NO_x and SO_2 shall be performed annually in accordance with conditions 2, 3 and 4 above.

D. Reporting

1. Stack monitoring~~, fuel usage and fuel analysis~~ data shall be reported to the Department on a quarterly basis in accordance with 40 CFR, Part 60, Section 60.7 and in accordance with ~~17-2.08~~ 62-297.500(2), FAC. Fuel usage and fuel analysis data shall be reported to the Department on an annual basis.

2. Ambient air monitoring data shall be reported to the Department quarterly by the last day of the month following the quarterly reporting period utilizing the SAROAD or other format approved by the Department in writing.

E. Coal Characteristics and Contracts

Before approval can be granted by the Department for use of control devices, characteristics of the coal to be fired must be known. Therefore, before these approvals are granted, the applicant must submit to the Department copies of coal contracts which should include the expected sulfur content, ash content, and heat content of the coal to be fired. These data will be used by the Department in its evaluation of the adequacy of the control devices.

F. Coal Information

As an alternative to the submittal of contracts for purchase of coal under condition E above, the applicant may submit the following information:

1. The name of the coal supplier;

2. The sulfur content, ash content, and heat content of the coal as specified in the purchase contracts;

3. The location of the coal deposits covered by the contract (including mine name and seam);

4. The date by which the first delivery of coal will be made;

5. The duration of the contract; and

6. An opinion of counsel for the applicant that the contract(s) are legally binding and enforceable.

G. Reporting:

Beginning one month after certification the applicant shall submit to the Department a quarterly status report briefly outlining progress made on engineering design and purchase of major pieces of equipment (including control equipment). All reports and information required to be submitted under this condition shall be submitted to Mr. Hamilton S. Oven, Jr., Administrator of Power Plant Siting, Department of Environmental Protection ~~Regulation~~, 2600 Blair Stone Road, Tallahassee, Florida 32301.

H. Fuels:

The following fuels may be burned:

Coal only
Oil only
Coal and up to 10% RFD (by heat input)
Oil and up to 10% RFD (by heat input)
Coal and up to 20% petroleum coke (by weight)
Coal and up to 20% petrolum coke (by weight) and 10% RFD (by heat input)

In addition, natural gas may be used during startup or at any other time.

II. Water Discharges

Discharges during construction and operation of the Unit No. 3 shall be in accordance with all applicable provisions of Chapter 62-302 ~~17-3~~, Florida Administrative Code and 40 CFR 423, Effluent Guidelines and Standards for Steam Electric Power Generating Point Source Category. In addition, the permittee shall comply with the following conditions of certification:

A. Pretreatment Standards

Wastewater discharges from Unit No. 3 to the Lakeland wetlands treatment system shall comply with the effluent limitation guidelines contained in 40 CFR~~, Part~~ § 423.12 and amendments. The specific standards applicable to the facilities as planned are:

1. Cooling Tower Blowdown

   There shall be no detectable amounts of materials added for corrosion inhibition containing zinc and chromium in cooling tower blowdown discharged to the City of Lakeland wetland treatment system. ~~On an emergency basis the on site Marsh Treatment System may be used to treat cooling tower blowdown.~~

2. pH

   The pH of all discharges shall be within the range of 6.0 to 9.0.

3. Polychlorinated Biphenyl Compounds

   There shall be no release to the environment of polychlorinated biphenyl compounds.

4. Chemical Wastes and Boiler Blowdown

   All low volume wastes (demineralizer regeneration, cooling tower basin cleaning wastes, floor drainage, sample drains and similar wastes), metal cleaning wastes (including preheater and fireside wash) and boiler blowdown shall be treated as required for pH adjustment and removal of chemical constituents. These wastewaters will be treated in an process wastewater treatment system capable of complying with 40 CFR~~, Part~~ § 423.12 and discharged with the cooling tower blowdown via a return pipeline to the Lakeland wetlands treatment system. The remaining sludge shall be disposed of in the on site FGD stabilized sludge landfill.

5. Sluice Pond Overflow

   Sluice pond overflow (coal pile runoff from less than 10-year, 24-hour rainfall and bottom and fly ash transport water) shall be treated if required to meet the requirements of 40 CFR § ~~Part~~ 423.12 and discharged with the cooling tower blowdown to the Lakeland wetlands treatment system.

6. Flue Gas Desulfurization Sludge Pond Overflow

   The flue gas desulfurization sludge pond overflow shall be treated if required to meet the requirements of 40 CFR § ~~Part~~ 423.12 in a process waste system and discharged with the cooling tower blowdown to the Lakeland wetlands treatment system.

B. In-Plant Water Monitoring Program

A monitoring program shall be undertaken by the City of Lakeland on each effluent stream within the facility to determine compliance by Unit 3 with the applicable effluent guidelines of 40 CFR, Part 423.12 for those wastewaters discharged to the Lakeland wetlands treatment system. This monitoring program may be reviewed annually to determine the necessity for its continuance.

III. Groundwater

A. General

The use of groundwater shall be minimized to the greatest extent practicable.

B. Well Criteria

The well locations shall be approved by the Southwest Florida Water Management District. Design and construction of new wells shall be in accordance with the applicable rules of the Department of Environmental Protection ~~Regulation~~ and Southwest Florida Water Management District.

C. Groundwater Use Limitations

1. Groundwater used for makeup for the cooling tower for Unit No. 3 shall be limited to emergency use only, not to exceed 0.2166 million gallons per day on an average annual basis or 5.271 mgd on a maximum daily basis from 3 new wells.

2. Daily water use from the new wells shall be reported quarterly to the Southwest Florida Water Management District.

IV. Leachate

A. Compliance

Leachate from coal storage piles, settling and treatment ponds, ~~artificial marsh, rapid infiltration beds,~~ secure land fills and flue gas desulfurization sludge ponds (FGD) shall not contaminate waters of the State (including both surface and groundwaters) in excess of the limitations of Chapters 62-302 and 62-520 ~~17-3~~, FAC.

B. Monitoring

A monitoring well system shall be used to determine whether or not leachate from the treatment ponds, ~~artificial marsh,~~ secure landfill, ash sluice ponds, and the flue gas desulfurization sludge ponds is reaching the groundwater.

1. Permittee shall collect background samples monthly commencing at least two months prior to construction of the waterwater treatment system sampling the following parameters: specific conductance, chlorides, sulfates, pH, zinc and iron.

2. The permittee shall annually monitor Arsenic, Barium, Cadmium, Lead, Mercury, Nitrates, Gross Alpha, Selenium and Silver beginning with commencement of construction of the wastewater treatment system.

3. The permittee shall monthly monitor specific conductance, chlorides, sulfates, pH, zinc and iron beginning with commencement of operation of the wastewater treatment system.

4. If any the monitoring parameters listed in paragraph 3 above exceed the average background levels by 35%, the permittee shall commence monthly monitoring on the parameters listed in paragraph 2 above.

5. A quarterly summary of the results of the monitoring shall be provided by the permittee to the Southwest District of the Department of Environmental Protection ~~Regulation~~ and to the Southwest Florida Water Management District.

6. The permittee shall keep a monthly record of the monitoring results and shall notify the Department's Southwest District Manager and the Southwest Florida Water Management District when said measurements reach 90% of the levels permitted in the water quality standards of Rule 62-520.420 ~~17-3.101~~, F.A.C.

C. Corrective Action

When the leachate monitoring system indicates significant leakage to the groundwater in the shallow aquifer, the appropriate ponds (settling spray or sludge) shall be sealed, relocated or closed, or the operation of the affected pond shall be altered in such a manner as to assure the Department that no significant contamination of the groundwater will occur.

V. Control Measures During Construction

A. Stormwater Runoff

During construction and plant operation, necessary measures shall be used to settle, filter, treat or absorb silt containing or pollutant laden stormwater runoff to limit the suspended solids to 50 mg/1 or less during rainfall periods not exceeding the 10-year, 24-hour rainfall, and to prevent an increase in turbidity to more than 50 Jackson Turbidity Units above background in waters of the State.

Control measures shall consist at the minimum, of filters, sediment traps, barriers, berms or vegetative planting. Exposed or disturbed soil shall be protected as soon as possible to minimize silt and sediment laden runoff. The pH shall be kept within the range of 6.0 to 8.5.

B. Sanitary Wastes

Disposal of sanitary wastes from construction toilet facilities shall be in accordance with applicable regulations of the Department and appropriate local health agency.

C. Environmental Control Program

An environmental control program shall be established under the supervision of a qualified person to assure that all construction activities conform to good environmental practices and the applicable conditions of certification.

The permittee shall notify the Department if unexpected harmful effects or evidence of irreversible environmental damage are detected during construction, shall immediately cease work and shall provide an analysis of the problem and a plan to eliminate or significantly reduce the harmful effects or damage, and to prevent reoccurrence.

VI. Solid Wastes

Solid Wastes resulting from construction or operation shall be disposed of in accordance with the applicable regulations of Chapter ~~17-7~~ 62-701, FAC.

Open burning in connection with land clearing shall be in accordance with Chapter ~~71-5~~ 62-256, FAC, no additional permits shall be required, but the Division of Forestry shall be notified. Open burning shall not occur if the Division of forestry has issued a ban on burning due to fire hazard conditions.

VII. Operation Safeguards

The overall design and layout of the facilities shall be such as to minimize hazards to humans and the environment. Security control measures shall be utilized to prevent exposure of the public to hazardous conditions.

VIII. Solid Waste Utilization System

The solid waste utilization facility shall be designed and operated in compliance with all applicable regulations of the Department, including but not limited to Chapter ~~71-7~~ 62-701, FAC.

IX. Screening

The permittee shall provide screening of the site through the use of aesthetically acceptable structures, vegetated earthen walls and/or existing or planted vegetation.

X. Potable Water Supply System

The potable water supply system shall be designed and operated in conformance with Chapter ~~17-22~~ 62-550, 62-551, 62-555, and 62-560, FAC. ~~Information as required in 17-22.05 shall be submitted to the Department prior to construction and operation. The operator of the potable water supply system shall be certified in accordance with Chapter 17-16, FAC.~~

XI. Transformer and Electric Switching Gear

The foundations for transformers, capacitors, and switching gear necessary for McIntosh Unit 3 to the existing distribution system shall be constructed of an impervious material and shall be constructed in such a manner to allow complete collection and recovery of any spills or leakage of oily, toxic, or hazardous substances.

XII. Toxic, Deleterious, or Hazardous Materials

The spill of any toxic, deleterious, or hazardous materials shall be reported in the manner specified by General Condition 2.

XIII. Transmission Line

Directly associated transmission lines shall be constructed and maintained in a manner to minimize environmental impacts in accordance with Chapter 403, F.S., and Chapter ~~22~~27F-6, FAC.

A. Construction

1. Filling and construction in waters of the State shall be minimized to the extend practicable. No such activities shall take place without obtaining lease or title from the Board of Trustees of the Internal Improvement Trust Fund ~~Department of Natural Resources.~~

2. Placement of fill in wetland areas shall be minimized by spanning such areas with the maximum transmission lines span practicable. Such areas should be bridged by maintenance or access roads.

3. Construction and access roads should avoid wetlands and be located in surrounding uplands. Any fill required in wetlands for construction but not required for maintenance purposes shall be removed and the ground restored to its original contours after transmission line placement.

4. Keyhole fills from upland areas are preferable to a single road and should be oriented as nearly parallel to surface water flow lines as possible.

5. Sufficient culverts shall be placed through fill causeways to maintain sheet flow. The number and locations of such culverts will be determined in the field by consultation with DE~~R~~P field inspectors.

6. Maintenance roads shall be planted with native species to prevent erosion and subsequent water quality degradation.

7. Construction activities should proceed as much as possible during the dry season.

8. Turbidity control measures, where needed, shall be employed to prevent violation of water quality standards.

9. Good environmental practices as described in Environmental Criteria for Electric Transmission Systems or published by the U.S. Department of Interior and the U.S. Department of Agriculture should be followed.

10. Any archaeological sites discovered during construction of the transmission line shall be disturbed as little as possible and such discovery shall be communicated to the Department of State, Division of Archive History and Records Management.

B. Maintenance

1. Vegetative removal for maintenance should be carried out in the following manner:

   Vegetation within the right-of-way may be cut or removed no lower than the soil surface under the conductor, and for a distance up to 20 feet to either side of the outermost conductor, while maintaining the remainder of the project right-of-way by selectively clearing vegetation which has an expected mature height above 14 feet. Brazilian pepper, Australian pine and Melaleuca shall be eradicated throughout the wetland portion of the right-of-way.

2. Herbicides registered with the U.S. Environmental Protection Agency may be used for vegetation control within the transmission line easement without prior approval of the Department.

XIV. Construction in Waters of the State

No construction in waters of the State shall commence without obtaining lease or title from the Board of Trustees of the Internal Improvement Trust Fund ~~Department of Natural Resources~~.

XV. Cooling Water Treatment

A study to determine the presence of pathogenic organisms in the sewage treatment plant effluent shall be performed to determine the degree of treatment required prior to use in cooling towers. A plan or study will be developed by the Department and the Department of Health & Rehabilitative Services. Based on the number of pathogenic organisms detected, the final degree of treatment and amount of chlorination to be required will be determined by the Department.

XVI. Sanitary Waste Disposal

Sanitary waste from operating plant facilities shall be disposed of in a septic tank system, as approved by the ~~Health~~ Department of Health & Rehabilitative Services, as long as the average daily flow does not exceed 2,000 gallons per day. If the sanitary waste exceeds 2000 gpd, a properly designed treatment system shall be constructed upon receipt of approval by the Department.

42381.03

CITY OF LAKELAND
McINTOSH UNIT No. 3

Revised Site Certification Application

3.2 FUELS

3.2.1 FUEL TYPES

Unit #3 will have the capability of burning the types of fuels and fuel combinations described herein ~~in the 250 MW application~~.

The primary fuel will be pulverized coal. ~~and additionally~~ Tthe Uunit has been designed to burn processed municipal solid waste, known as Rrefuse Derived Fuel or RDF, to supplement the pulverized coal. ~~The unit has been designed so that refuse can supply up to 10% of the necessary heat input for loads over the 50% of the design maximum capability (approximately 182 MW). However for the purposes of calculating the emission rates, flue gas volumes and flow rates, and for annual fuel consumption for this report, it was assumed that the unit would burn refuse at a constant rate of 26.25 tons per hour for 8 hours per day.~~

The furnace design is such that RDF can supply up to 10% of the expected full load heat input to the Unit.

As an alternative fuel source, petroleum coke will be added as a supplement to the pulverized coal. The blend rate can range from 0% to 20% by weight, depending on the quality of the coal. A 0% to 10% blended product will be used with medium sulfur coal (2.5% sulfur) and a 0% to 20% blended product with low sulfur coal (1%

sulfur).

As a backup to pulverized coal, Unit #3 ~~will also have~~ has the capability to burn low sulfur oil (.77% sulfur) as a ~~principal~~ primary fuel. ~~The unit will also have the capability to burn processed refuse with the oil.~~ In which case, RDF can also be burned with the low sulfur oil at a rate of up to 10% of expected full load heat input to the Unit. ~~Oil and the oil/refuse will be used during those periods when the use of coal is impossible due to precipitator or scrubber malfunction or disruption of the coal supply. Possible disruptions could result from coal handling equipment failures, coal mine strikes, railroad strikes, etc.~~

Ignition or fuel stabilization of this Unit will be provided primarily by natural gas and/or low sulfur oil. Neither fuel can provide full load capability and only nominal loads can be achieved. They are primarily used for start-up and low load operation.

In summary, Unit #3 will have the capability of firing modes including (primary plus alternate fuels):

1. Pulverized coal only
2. Pulverized coal and ~~processed-refuse~~ RDF
3. Pulverized coal and petroleum coke
4. Pulverized coal, RDF, and petroleum coke

35. Low sulfur oil only

46. Low sulfur oil and ~~processed-refuse~~ RDF

It is ~~entirely~~ possible ~~that any or all~~ for Unit #3 to operate under any of the above firing modes ~~could be utilized~~ on a given day, ~~however, during normal operation, firing modes 1 and 2 will be considered the primary~~ but the primary operating modes~~:~~ will be 1 thru 4. Natural gas may be burned during startup or at any other time.

3.2.2 FUEL QUANTITIES

Unit #3 ~~will have an~~ has a maximum annual heat input requirement of 2.~~162~~ 8697 x 10^{13} BTU's based on ~~a 75% load factor and annual~~ 100% availability ~~of 95% or 345 days.~~ (365 days) at a 90% capacity factor. The predicted annual average heat input requirement is

2.72629 x 10^{13} BTU's based on a 95% availability (347 days) at a 90% capacity factor.

It is anticipated that the ~~coal-only-and-coal/refuse~~ Unit will be operated in one of the four primary firing modes at all times (coal only, coal and RDF, coal and petroleum coke, or coal, RDF, and petroleum coke). ~~will-be-available-for-311-days-annually-with-the oil-and-oil-refuse-modes-accounting-for-the-remaining-availability.~~ Based on ~~above-data,-typical~~ these modes, the approximate average annual fuel ~~uses-are:~~ usage will be:

FUEL	QUANTITY
Coal	~~818,000~~ 864,550 tons (Typical Coal)
~~Refuse~~RDF	~~72,450~~ 75,000 tons
~~Oil~~Petroleum Coke	~~337,600-Bbls.~~ 190,000 tons

~~The-expected-hourly-fuel-flow-requirements-at-both-maximum-load (364MW)-and-at-average-load-(272MW)-for-each-of t~~The maximum and average heat inputs and fuel flows for the primary firing modes as described in Section 3.2.1 are shown in Table 3.2.1.

3.2.3 TRANSPORTATION

COAL

Coal normally will be delivered to the ~~p~~Plant site in two continuously operating unit trains in ~~70 one hundred ton~~ ninety (90) cars of one hundred ton (nominal) bottom dump hopper cars per unit train. ~~At this time a particular coal supplier has not been determined, but an investigation is currently in progress to determine the most economical sources of coal the transportation costs involved with each source. Presently, four potential areas have been identified. They are:~~

~~1. District 13 Alabama~~

~~2. District 9 West Kentucky~~

~~3. District 8 East Kentucky and parts of West Virginia, Tennessee and Virginia~~

~~4. District 3 North West Virginia~~

~~Coals from Alabama, East Kentucky and West Kentucky can be transported to Lakeland by single line rail haul (L&N/SCL RR) and can be expected to have the lowest unit train freight rates. Northern West Virginia (the "Fairmont" coal field) represents a source of high quality, medium to high sulfur coal, suitable for use in the proposed Lakeland unit; and, despite a two line rail haul to Lakeland (Chessie System/SCL RR), is considered potentially competitive with coals from other areas. Although West Virginia District 8 coals originating on the N&W RWY. and the C&O would likewise involve two line rail hauls, they cannot at this stage of the Coal Supply Study be ruled out as non competitive.~~

~~Unit trains from any of the above mentioned sources will reach the plant site on a railroad spur line which will be constructed.~~

~~from the coal unloading area to an existing Seaboard Coast Line tract located 1.5 miles due east of the plant site. The spur will cross Combee Road in a northwesterly direction to pass north of Fish Lake. The coal storage area, as shown on map 2.1.2, has been moved from the location shown in the 250 MW application to a site located northeast of the boiler. The spur line, as shown on map 2.1.1 will loop around Fish Lake with the coal unloading area being located due west of the lake.~~

~~The coal pile as shown on map 2.1.2, will be entirely located within the existing plant property and will not require the purchase of additional adjacent land.~~

~~Oil will be delivered into the plant site by fuel oil trucks from Port Tampa as is presently done for existing units.~~

~~Refuse collected in the Lakeland area will be delivered to the refuse processing area located on the plant site by collection and/or transfer trucks.~~

The coal supply will be primarily from the area east of the Mississippi River. The majority of the coal will come from Eastern Kentucky, but may also be obtained from other sources of suitable quality.

The coal will normally be delivered to the Plant via single line rail haul, using CSX Transportation (CSXT). The unit train will reach the Plant site on a railroad spur line connecting the coal trestle with the CSXT track located one and one half miles east of the Plant. The coal will be unloaded using an elevated trestle approximately 1000 feet long. The bottom dump hopper cars will unload when they are given a signal through a third rail system as determined by an Operator.

PETROLEUM COKE

Petroleum coke will be obtained from a suitable source based on lowest evaluated delivered cost. Options to be evaluated include: purchasing a material blended with coal off site and delivered as a blended fuel ready for burning or purchasing a supply of petroleum coke to be delivered to the site and blended with the normal supply of coal.

The petroleum coke will be delivered to the Plant by truck from a nearby port or by rail, directly from a supply source. A blended fuel would be delivered either by rail or truck from a blending facility.

The blend will be carefully monitored and controlled to assure compliance with all regulated parameters at the stack exit with continuous emissions monitoring systems (i.e., sulfur dioxide, nitrogen oxide, and opacity). A blend of 90/10 (by weight) medium sulfur (2.5%) coal with petroleum coke and a blend of 80/20 (by weight) low sulfur (1.0%) coal with petroleum coke has been tested and all environmental and operational parameters checked. The entire range of blends provide good operation and no adverse environmental impacts.

The fuel blend supplied to Unit #3 and the flexibility built into the flue gas desulfurization system (Scrubber) will be fully controlled, to ensure complete environmental compliance at all times.

REFUSE

Refuse collected from Lakeland and the surrounding area will be delivered to the refuse processing facility by the collection trucks.

OIL

Oil will be delivered to the Plant site by fuel oil trucks from the Port of Tampa.

NATURAL GAS

Natural gas is supplied to the site by a high pressure main tied in with Florida Gas Transmission several miles north of the Plant.

3.2.4 STORAGE

COAL

Coal will be stored on site in open piles for immediate use ~~and an approximate 60 day emergency reserve supply~~ (active pile) and an emergency reserve storage of approximately sixty days will be maintained in a sealed piles. ~~The emergency reserve pile will require approximately 20 acres of land when the coal is compacted and layered to a height of 20 feet. The reserve pile will store approximately 185,000 tons of coal and the active pile will store approximately 10,000 tons.~~

Coal will be stored on a sealed surface and will be provided with a complete run-off control system to collect rain water or dust control water. Fugitive emissions from coal piles will be minimized by a dust water separation system.

Coal will be delivered to Unit #3 silos by a series of conveyors thru several transfer points. These transfer points and the silos will be equipped for dust control.

OIL

Oil will be stored in ~~the two (2) existing 96,000 barrel low sulfur oil tanks. Unlike the original 250 MW application, no additional fuel oil storage tanks will be constructed for the 364 MW unit.~~ on-site tanks within containment areas. Diesel oil tanks, piping, and receiving areas all conform to regulations and rules of the Department governing petroleum products.

PETROLEUM COKE

Petroleum coke will be stored in the coal storage area either as a unblended or blended product.

REFUSE

Refuse will ~~be received and~~ not be stored ~~in the same manner as described in the original 250 MW application~~ on site. All material received will be processed and burned as quickly as possible.

3.2.5 FUEL ANALYSIS

Typical fuel analysis for coal, ~~oil, and~~ petroleum coke, refuse, and oil ~~that will be burned in Unit #3~~ are located in Tables 3.2.2, 3.2.3, 3.2.4, and 3.2.5 respectively.

3.2.6 PLANS FOR EMERGENCY SPILLS

As described ~~the entire~~ in Section 3.2.4, no new oil tanks will be required, so existing fuel oil unloading areas will be utilized. Since these areas already comply with the U.S. Environmental

Protection Agency's rule on the prevention of oil spills, no additional spill protection will be required.

3.2.7 COAL PILE RUN-OFF

~~As described in the original 250 MW application, t~~The entire coal ~~handling facility will be encircled by a trench system which will collect and direct coal pile run-off (up to and including the amount of run-off expected from the ten year, 24 hour storm event.)~~ receiving and storage area is constructed on an impermeable base and is surrounded by a series of asphalt lined ditches to collect all rainfall run-off and dust control water. The collected water will be directed to a series of sumps and will be pumped to the north landfill sedimentation pond or to the ash settling ponds. The collected water will be recycled for reuse in Plant systems in an effort to minimize the consumptive use of water. The design of the storm water run-off system for the coal yard has been designed for a ten year, twenty-four hour storm event. ~~Run-off quantities and diagrams are shown in more detail~~ More detailed information is given in Section 3.3.

Table 3.2.3

TYPICAL PETROLEUM COKE ANALYSIS

UNIT #3

Petroleum Coke Quality: As Rec'd Basis

Moisture	8.00%	12.00% Max
Ash	0.25%	1.00% Max
Volatile	10.00%	14.00% Max
Sulfur	4.75%	5.50% Max
Btu/lb	14,200	14,200 Penalty
Hardgrove Grindability Index	65	50 Min
	Typical	Maximum
Vanadium	950 ppm	1500 ppm
Iron	100 ppm	500 ppm
Silicon	50 ppm	250 ppm
Calcium	100 ppm	250 ppm
Nickel	250 ppm	500 ppm

Sizing	+3"	5%
	2x3"	5%
	1x2"	25%
	½x1"	20%
	-½"	45%

Revised 12-06-94

Table 3.2.1

FIRING MODES

FUEL FLOW RATES

MODE/LOAD	**HOURLY FLOW RATES**
	364 Mw
NO. 1 COAL ONLY (TONS/HR)	~~140.9~~ 159.6
NO. 2 COAL/~~REFUSE~~RDF: (10% ~~REFUSE~~RDF) COAL (TONS/HR) ~~REFUSE~~RDF (TONS/HR)	 ~~129.4~~ 143.7 ~~26.25~~ 40.4
NO. 3 OIL ONLY (BBLS/HR)	~~531.1~~ 577.8
NO. 4 OIL/~~REFUSE~~RDF: (10% ~~REFUSE~~RDF) OIL (BBLS/HR) ~~REFUSE~~RDF (TONS/HR)	 ~~488.1~~ 520.0 ~~26.25~~ 40.4
NO. 5 COAL/COKE (80/20)	122.1 COAL 30.5 COKE
NO. 6 COAL/COKE/RDF (80/20 - 90%) (RDF - 10%)	100.9 COAL 40.4 RDF 27.5 COKE

Table 3.2.4

MCINTOSH PLANT SITE - PETROLEUM STORAGE

EMISSION POINT	TYPE	TITLE V LOCATOR	LOCATION	SIZE (GALLON)	EMISSION
DIESEL TANK	VENT	T009	E OF WATER TANK	2,000	VOC
GASOLINE TANK	VENT	T020	S OF WELD BARN	1,000	VOC
DIESEL STORAGE TANK	VENT	T021	TANK FARM	101,346	VOC
DIESEL TANK	VENT	T022	S OF WELD BARN	1,000	VOC
DIESEL FUEL TANK (REFUSE AREA)	VENT	T068	SE OF LARGE THICKENER	1,000	VOC
DIESEL FUEL (10,000 GAL) TANK	VENT	T109	N OF PEO BLDG	9,000	VOC
HEAVY OIL TANK	VENT	T113	TANK FARM	4,057,200	VOC
HEAVY OIL TANK	VENT	T114	TANK FARM	4,057,200	VOC
HEAVY OIL TANK	VENT	T115	TANK FARM	4,057,200	VOC
DIESEL STORAGE TANK	VENT	T116	TANK FARM	22,500	VOC

Table 5.6.2

3.4 HEAT DISSIPATION SYSTEM

The unit will use a thirteen-cell ~~utilize a~~ wet mechanical draft cooling tower supplemented by a two cell mechanical draft auxiliary tower, for dissipation of waste heat from condenser and accessory equipment cooling water. ~~The proposed tower location is shown on Map 2.1.2.~~

The tower will have a total circulating water flow of 144300 GPM with a design inlet water temperature of 114.7°F. ~~and a design outlet water temperature of 91°F.~~ The tower will be designed to dissipate 1636 MMBTUH with a 79°F inlet wet bulb air temperature.

Condenser cooling water will comprise 138300 GPM of the circulating water flow and 6000 GPM will be utilized to cool a secondary fluid for accessory equipment cooling.

Process wastewater and bBlowdown from the tower will be utilized as makeup for the SO_2 removal system (scrubber) on the boiler. Any excess blowdown will be transported to the new City of Lakeland's Public Works Sewage Plant Wetlands Treatment System located seven and one-half miles south of McIntosh Power Plant. The present on-site Marsh Treatment System will be ~~kept functional as a backup.~~ phased out, because the new wetlands system has proven to be very effective. A new pipeline ~~will be~~ has been constructed to transport the blowdown from the tower to the Sewage Plant to be combined with its effluent going to the Wetlands Treatment System.

Figure 3.4.1 (P. 3.4-2) shows all flows and temperatures in the circulating water system. Table 3.4.1 (P. 3.4-2) tabulates all quantities for maximum plant conditions.

3.5 CHANGES IN CHEMICAL AND BIOCIDE WASTES

The flow diagram shown in Figure 3.3.1 shows the major wastewater flow paths. The Figure shows that Unit No. 3 will not discharge waste streams to any water body. Waste streams will be reused to the extent practicable and that the remaining process wastewaters will be treated on site and pumped to ~~disposal facilities~~ the Sewage Plant Wetlands Treatment System (Wetlands system). Excess cooling tower blowdown will be transported also to the Sewage Plant Wetlands Treatment System.

Figure 3.3.1 shows that after the scrubber makeup water is taken from the cooling tower blowdown stream, approximately 500 GPM or 720,000 gallons per day, will be pumped to the Sewage Plant Wetlands Treatment System. ~~The on-site Marsh Treatment System will be used as a backup. The City of Lakeland has instructed its consultant to investigate the possibility of reusing more of the process wastewater and cooling tower blowdown in other plant systems to further reduce the volume of wastewater that must be treated by the on-site facilities.~~ The wastewater treatment scheme shown in Figure 3.3.1 is similar to that which was originally presented in the 250 MW application. One notable change in the system is the addition of bottom ash dewatering bins for separating bottom ash and sluice water in lieu of a 5-acre sluice pond. This change was made to facilitate the handling of bottom ash for the sludge stabilization process. The flow diagram shows a settling pond will be used as a backup system to the ash dewatering bin system, a storage area for sluice water makeup, and a holding area for the collection of runoff from the coal pile and coal handling area and water used in the dust suppression system.

The north landfill surge pond will help ~~The settling pond will be sized to~~ collect and contain ~~all~~ the coal pile runoff from the 12-acre coal storage area that is expected from the 10-year, 24-hour storm event. The 10-year, 24-hour storm event in the Lakeland area is 6.60 inches. ~~so the pond will be sized to contain 2.151 million gallons of water, or 6.60 acre feet, which would be expected from this event.~~ The settling pond is lined with bitumastic to prevent leaking of the water to shallow groundwater. Collected runoff will be pumped from the north landfill surge pond to the final wastewater ponds for reuse on site. ~~will be clay lined to prevent leaking of the water to shallow groundwater supplies. As described in the original 250 MW application, all storage or holding ares shown in Figure 3.3.1 will be clay lined.~~

Disposal of the cooling tower blowdown and process wastewaters will be to the back end of the sewage treatment plant of the City of Lakeland. Disposal of the solids from the process wastewater treatment plant will be to the plant stabilized sludge landfill.

All quantities of collected ash from the operation of Unit #3 will be used as an integral ingredient in the sludge stabilization process described in Sections 3.6.3 and 5.6.2.

3.6.3 FLUE GAS DESULFURIZATION SCRUBBER SLUDGE

~~As reported in Section 3.7, s~~Sulfur dioxide emissions in the flue gas from the coal, coal and petroleum coke, coal, RFD and petroleum coke, and coal/~~refuse~~ and RFD firing modes will comply with the State and Federal new source performance standard of ~~0.80~~ 1.2 lbs/mmBTU by using a limestone slurry flue gas scrubber with an 80% removal efficiency for high sulfur fuel (higher than 3.0% sulfur).

The end product of the SO_2 scrubber system will be a 50% solids sludge consisting of the following materials:

Constituent	% By Weight
$CaCO_3$	33
$CaSO_3 \bullet 2H_2O$	58
$CaSO_4 \bullet 2H_2O$	9

The quality of sludge expected to be produced from Unit #3 is shown in Table 3.6.1.

In order to dispose of the annual amounts of sludge shown in Table 3.6.1 and the amounts of fly ash and bottom ash described in Section 3.6.2 in an acceptable manner, all sludge and ash quantities will be brought to an on-site stabilization process. In this process, ash and scrubber sludge will be combined with lime and other aggregates to form a cementitious material suitable for use as landfill material, road base material, embankments and impermeable liners.

3.7 AIR EMISSIONS

3.7.1 AIR EMISSIONS COMPLIANCE STANDARDS

Unit #3 will be required to meet the State and Federal ~~new source~~ emission limits for Nitrous Oxide (NO_x), Sulfur Dioxide (SO_2), ~~Total Suspended~~ Particulate matter (~~TSP~~PM) and Opacity as listed in ~~chapter 17-3 (FAC) and 40 CFR 60~~ Rule 62-296.405, F.A.C. As discussed in Section 3.2, Unit #3 will be capable of burning ~~three~~ four different fuels in ~~four~~ six firing modes, which will require meeting various emission limits depending on the firing mode. The following are the emission limits for each firing mode:

FIRING MODE	SO_2 LB/MMBTU	NO_X LB/MMBTU	TSP LB/MMBTU	OPACITY %
Coal Only	1.2	0.7	0.1	20
Coal/~~Refuse~~RDF	1.2	0.7	0.1	20
Coal/Petroleum Coke	1.2	0.7	0.1	20
Coal/Petroleum Coke /RDF	1.2	0.7	0.1	20
Oil Only	0.8	0.3	0.1	20
Oil/~~Refuse~~RDF	0.8	0.3	0.1	20

Natural gas and/or low sulfur fuel oil may be burned during startup or at any other time.

3.7.2 NITROUS OXIDES (NO_X) COMPLIANCE METHOD

NO_X will be maintained within ~~new source performance standards (NSPS)~~ the established limits through either boiler, burner or a combination of boiler and burner design. Each of the boiler companies that are currently bidding on this project uses a different method, however each company guarantees that applicable NO_x emission limits will be met.

3.7.3 PARTICULATE (~~TSP~~ PM) COMPLIANCE METHOD

Particulate emissions ~~resulting from the coal-only, coal/refuse and oil/refuse firing modes~~ will be maintained within the ~~new source performance standard~~ limit of 0.1 lb/mmBTU with a cold side stack. Flue gas from the (1) coal, ~~only-and-coal/refuse~~ (2) coal and RFD, (3) coal and petroleum coke and (4) coal, RFD, and petroleum coke firing modes which require SO_2 scrubbing will be reheated to approximately 200°F and exit the stack at 170°F. Flue gas from the oil only

5.6 OTHER EFFECTS OF PLANT OPERATION

5.6.1 ENERGY RECOVERY FROM SOLID WASTE

As discussed in the 250 MW Unit #3 application, processed municipal refuse will be used as a supplemental fuel supply to the Unit. The processing system will still consist of shredding, magnetic separation of ferrous materials and air classification prior to combustion in the boiler. However, with the 364 MW Unit #3, refuse will be burned with both coal and oil rather than just with coal as in the 250 MW Unit #3.

For calculation purposes, the amount of refuse that will be burned has been limited to what is collected within the city limits of Lakeland and from contiguous outlying areas. This will produce approximately 300 tons per day of raw refuse and 210 tons per day of combustible material to be used as a refuse derived fuel (RDF).

In addition to the use of the RDF, the Unit #3 architect engineers are currently studying the possibility of burning the sewage sludge from the Lakeland Sewage Treatment Plant. Sewage sludge has a heating value of 4000 to 7000 BTU/per pound and its use would eliminate another City of Lakeland disposal problem.

Another important aspect of the refuse burning capability of Unit #3 is that Polk County has been designated by the Florida Department of Environmental ~~Regulation~~ Protection to develop a county wide plan for resource recovery, and while the plan is in its beginning stages, preliminary discussions with Polk County representatives have indicated that the processing facility at the McIntosh site and the Unit #3 RDF capability could be an integral part of the Polk County resource recovery plan.

Tests from the pilot RDF project in St. Louis at Union Electric's Merrimac Station have concluded that up to 20% of a boiler heat requirements can be from RDF without noticeable boiler damage. Based on this assumption, Unit #3 could burn over 1000 tons per day of the County's refuse. In order to produce the 1000 tons per day of RDF, over 1450 tons per day, essentially all the raw refuse projected to go to landfills in 1983 would have to be processed.

The present refuse processing Plant tipping floor will be expanded to the north with an addition of a building approximately 100' x 70'.

5.6.2 SCRUBBER SLUDGE DISPOSAL

The 250 MW Unit #3 application indicated that at the time of submittal, four (4) methods of disposing of sulfur sludge were being considered. The methods under consideration were:

1. Stabilized landfill with load bearing capacity.
2. Returning the sludge to the limestone mine where the limestone for the SO_2 scrubber was taken.
3. Using the sludge as a reclamation fill for phosphate strip mines.
4. Permanent ponding of the sludge on site in clay lined ponds.

The "Conditions of Certification" for the 250 MW Unit #3 stipulated that "Flue as desulfurization sludge shall be stabilized prior to disposal in other than a lined pond or basin". In keeping with this stipulation, the 364 MW Unit #3 will combine all the sludges and ash generated by the ~~u~~Unit to form a stabilized fill material.

The stabilized sludge (pozzolanic) will be primarily used as a landfill material in the immediate area of the pPlant site. However, once the pPlant is in operation and actual samples of stabilized material are available, a study will be undertaken to determine the suitability and marketability of this material for use as a road and parking lot base coarse material, earthen embankments, impermeable liners for holding ponds and synthetic aggregate for concrete block and asphalt formulations.

The stabilized sludge operation will be located at the McIntosh Plant site. The operations will consist of blending the scrubber sludge, as well as other sludges generated in the operation of Unit #3 with fly ash, bottom ash and lime to form the stabilized pozzolanic material, prior to its use or disposal in the dedicated Plant site landfill. The stabilized pozzolanic sludge process provided by Conversion Systems, Inc. is located in a building next to the scrubber sludge thickener. This building, as well as the silos (fly ash, lime, etc.), is equipped with the proper dust control systems, as listed in Table 5.6.2.

Table 5.6.2

MCINTOSH PLANT SITE - DUST COLLECTORS

EMISSION POINT	TYPE	LOCATION	EMISSION
LIMESTONE SILO DUST COLLECTOR	EXHAUST	N OF SCRUBBER #32	DUST
QUICKLIME SILO DUST COLLECTOR	EXHAUST	N OF CSI BLDG	DUST
SODA ASH SILO DUST COLLECTOR	EXHAUST	WWTP/ABOVE BLDG RO	DUST
QUICKLIME SILO DUST COLLECTOR	EXHAUST	WWTP/ABOVE BLDG RO	DUST
FLY ASH SILO DUST COLLECTOR	EXHAUST	E OF CSI BLDG	DUST
SHREDDER EXPLOSION VENT	VENT	REFUSE	DUST
KLEISLER FILTER	VENT	REFUSE	DUST
SILO 31 DUST COLL. EXHAUST/C4	EXHAUST	TRIPPER HOUSE	DUST
SILO 32 DUST COLL. EXHAUST	EXHAUST	TRIPPER HOUSE	DUST
SILO 33 DUST COLL. EXHAUST/C5	EXHAUST	TRIPPER HOUSE	DUST
SILO 34 DUST COLL. EXHAUST	EXHAUST	TRIPPER HOUSE	DUST
CRUSHER HOUSE DUST COLLECTOR	EXHAUST	COAL CRUSHER HOUSE	DUST
C2 COAL CONVEYOR DUST COLLECTOR	EXHAUST	C2 CONV. (BEGIN)	DUST
C3 REFUSE CONVEYOR DUST COLLECTOR	EXHAUST	REFUSE	DUST
C5 REFUSE CONVEYOR DUST COLLECTOR	EXHAUST	REFUSE	DUST
PUGMILL #31 DUST COLLECTOR	EXHAUST	CSI	DUST
PUGMILL #32 DUST COLLECTOR	EXHAUST	CSI	DUST

Attachment AMO-1

Alternative Methods of Operation

Operation at various heat input rates
C.D. McIntosh Unit 3 may be operated up to 8760 hours per year at heat input rates from zero to 3640 MMBtu per hour.

Operation on various types of fuels
Unit No. 3 may use the following fuels:

- Coal only
- Oil only
- Coal and up to 10% refuse (based on heat input)
- Oil and up to 10% refuse (based on heat input)
- Coal and up to 20% petroleum coke (based on weight)
- Coal and up to 20% petroleum coke (based on weight) and 10% refuse (based on heat input)
- Natural gas may be fired during startup or at any other time, alone or with any other fuels or fuel combinations.