RTP ENVIRONMENTAL ASSOCIATES INC.®

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RECEIVED
APR 16 1998
BUREAU OF
AIR REGULATION

April 13, 1998

Mr. Brian Beals
USEPA - Region IV
100 Alabama Street, S.W.
Altanta, Georgia 30303

Dear Mr. Beals:

As discussed, I've enclosed copies of the materials from the recent Orimulsion hearings that relate to the calculation of historical NO_x emissions. These include excerpts from the January hearing testimony, rebuttal, and surrebuttal, as well as recommended changes to the Conditions of Certification.

We still believe that the historical NO_x calculations have been done incorrectly and that the subsequent back-up by the applicant, submitted to the agency on January 22nd and 23rd and provided to us on April 3, 1998 is deficient. We responded to this issue separately in an April 8, 1998 letter, which is also enclosed. Additionally, it is my understanding that Administrator Hankinson was sent a full copy of our overall comments by Thomas W. Reese, Esq. on March 30, 1998.

Should you wish to discuss these attachments or our other comments, please feel free to contact me at the above telephone number.

Sincerely,

RTP ENVIRONMENTAL ASSOCIATES, INC.®

Donald F. Elias

Donald F. Elias
Principal

DFE/mpj

cc: G. Worley/C. Fancy/L. Curtin/W. Corbin/Proj. File: HKOR

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LETTER OF TRANSMITTAL

TO Mr. Clair Fancy
FDEP–Bureau of Air Regulation
111 South Magnolia, Suite 4
Tallahassee, FL 32301

Date: 04-14-98 Proj. ID: HKOR

WE ARE SENDING YOU: ☒ Attached ☐ Under separate cover
VIA: ☐ 1st Class Mail ☒ Federal Express ☐ Hand Delivery ☐ Other
THE FOLLOWING ITEMS: 2nd Day

Copies	Date	No.	Description
1	04-13-98		Copy of letter from Donald F. Elias to Brian Beals of USEPA
			RE: Orimulsion Materials with attachment

THESE ARE TRANSMITTED AS CHECKED BELOW:

☐ For approval ☐ For review and comment ☐ Resubmit ____ copies for approval
☒ For your use ☐ Copies returned after loan ☐ For signature
☐ As requested ☐ Returned for corrections

REMARKS

COPY TO:

SIGNED:

If enclosures are not as noted, kindly notify us at once.

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TABLE OF CONTENTS

Q Would you please briefly summarize the revised and additional conditions in Attachment A to the order of remand that are related to air emissions.

A There were two substantial changes involving air emissions in the remand, the first involved lowering the PM emission rates from that considered at the 1995 hearing.

The second one was lowering the emissions of nitrogen oxides again from that considered in the 1995 hearing.

(FP&L Exhibit No. R-132 marked for identification.)

(FP&L Exhibit No. R-133 marked for identification.)

BY MR. CUNNINGHAM:

Q Mr. Kosky, have you prepared a chart showing particulate matter emissions from the Manatee Plant and comparing historical emissions with those contemplated during the 1995 hearing and the currently proposed emission rates?

A Yes, I have.

Q Is this document that is marked as FP&L R-132 a copy of the chart you prepared?

A Yes, it is. This is an exhibit of particulate matter emission rates that I prepared.

Q If you would, Mr. Kosky, using the enlarged version of this exhibit to your right, please explain the particulate matter emission rates that are depicted.

A This particular exhibit has four columns. The far left column shows emission rates in pounds per million BTU, or mass per input in tons per year.

Three columns that I have supplied information are the historical emissions when firing oil. Historically the pounds per million BTU rate is 0.125 pounds per million BTU. That's a maximum rate for the facility.

Historical 1993-'94 emission rates which are representative of actual historical emissions and, as I have testified previously, were greater than 1,768 tons per year. The actual permitted rate for the facility, the maximum as a cap, is actually close to 9,509.

In the 1995 hearing, proposed maximum emission rate for the facility was 0.03 pounds per million BTU, or about an 80 percent decrease from what was historical operating norm.

The 1995 hearing, the maximum cap of emissions in tons a year was equivalent to my conservative estimate of the historical emissions, that is low estimate of historical emissions of 1,768.

What's considered today is an emission rate a maximum of 0.02 pounds per million BTU for particulate matter and an emissions cap of 858 tons a year, which is about half of that considered in the 1995 hearing.

Q Have you prepared a chart showing nitrogen oxide emissions from the Manatee Plant comparing historical emissions with those contemplated during the 1995 hearing and the currently proposed emission limits?

A Yes, I have.

Q I show you document marked as FP&L R-133 and ask you if that is the chart you prepared?

A Yes, it is. This is a chart of the NOx or nitrogen oxides emission rates that I prepared.

Q Again, if you could step to the enlarged version and perhaps slide it out.

A What I might do is put it here, this chart.

Q Using that version, if you could please explain the nitrogen oxide emissions rates depicted.

A This chart is similar to the chart on particulate matter emission rates in that there are four columns. The only exception, we added another row for tons per day. I will explain the emission rates basis.

The pounds per million BTU on this chart represents a 30-day rolling average. What a 30-day rolling average is if today is a day and you want to calculate that, you take 29 previous days and you average that to get a 30-day rolling average. Now tomorrow, you would drop off maybe one of those days and collect 29 days. So each day you effectively have a new 30-day rolling average that has to be calculated.

When this is used as a compliance mechanism, essentially a plant has to comply each day with this 30-day rolling average.

In the chart I also have tons per day during the ozone season as well as tons per year.

Historically, on oil — and again, the maximum emission rate for the plant on a 30-day rolling average is .3 pounds per million BTU.

The actual average emissions during the ozone season historically for the plant during high ozone days is 34.6 tons a day.

The 1993-'94, representative actual historical emissions is 7,318 tons a year. This is in contrast to the actual permitted rate of 22,700 tons a year.

In the 1995 hearing, the emission rates contemplated were 0.23 pounds per million BTU on a

30-day rolling average, a maximum ton per day of 42.2 and a maximum cap of NOx emissions of 13,410 tons a year.

Today, what's being contemplated is an emission rate of 0.15 pounds per million BTU, about half the rate currently at the plant firing oil, an emissions cap of historical emissions that represent high ozone days of 34.6 tons a day, and the maximum cap per year is kept at the historical rate of 7,318 tons.

MR. CUNNINGHAM: At this time we would offer these two exhibits, FP&L R-132 and FP&L R-133.

MR. CURTIN: No objection.

THE COURT: They are both received.

(FP&L Exhibit R-132 received in evidence.)

(FP&L Exhibit R-133 received in evidence.)

BY MR. CUNNINGHAM:

Q Mr. Kosky, is there any fundamental difference in the NOx control technology now proposed for the Manatee Orimulsion conversion project from that contemplated during the 1995 certification hearing?

A No. There is no difference in the air pollution control technology contemplated at the 1995 hearing when low NOx burners and reburn were considered.

In fact, I testified at the 1995 hearing that emission rates could be lower than 0.23 pounds per million BTU.

The only question at that time was how much lower emission rates could be.

MR. CURTIN: I would object to the monologue. I think Mr. Cunningham asked if there was any difference in the technology between the 1995 hearing and now. He is explaining, I think, his emissions calculations, et cetera.

THE COURT: All right. You may ask your next question.

BY MR. CUNNINGHAM:

Q Mr. Kosky, was there a question during the 1995 hearing regarding whether the technology proposed to achieve emission rate lower than 0.23 pounds per million BTU rate which was proposed as a permit limit?

A Yes, there was.

Q What was that question?

A The question was whether or not lower rates could be achieved.

Q Was there some provision made in the conditions at that time to assess that question?

A Yes, there was. There was a NOx reduction team that was included in the conditions, providing

engineering consensus on how low the emission rate should be.

Q And what is your understanding of whether there has been any progress made, despite the fact that the project was not approved and therefore, the NOx reduction team was not able to do what was uncompleted but what was your -- what is your understanding what progress has been made towards analyzing that question of how low the proposed technology could get at the Manatee Plant?

A In 1995, the design process was only in initial stages. Since that time, over two years ago, there has been additional developmental work that has provided assurance on what the actual emission rates could be. In fact, the vendors have optimized low NOx burner and reburn configuration to provide that assurance.

Q Mr. Kosky, in your opinion, is the annual cap on NOx emissions which is now proposed of 7,318 tons per year scientifically and technically achievable with the NOx control technology proposed for the project, assuming the Manatee Plant operates at an 87 percent annual capacity factor?

A Yes, it is.

Q What is the basis of your opinion?

A My opinion is based on the information supplied by ICL and EER, that I have concluded that an annual average emission rate of 0.125 pounds per million BTU can be achieved. At this emission rate, 87 percent capacity factor for the plant will equate to 7,318 tons a year.

My conclusion was reached based on the Orimulsion test burns, information supplied by the Department of Energy and EPA on reburn technology, the data supplied in performance estimates made by ICL and EER as well as an actual demonstration of Orimulsion reburn at the Hennepin plant.

Q You mentioned that you reviewed information supplied by ICL. Did that include technical guarantees regarding NOx emissions?

A Yes, it did.

Q What is your understanding of the willingness of ICL's successor ABB to provide such guarantees?

A My understanding is that they have reconfirmed their technical guarantee of 0.24 pounds per million BTU.

Q In your opinion, is the NOx emission rate of 0.15 pounds per million BTU on a 30-day rolling average scientifically and technically achievable with the NOx control technology proposed for the project?

A Yes. It is.

Q What is the basis of that opinion?

A The basis is the same information that was supplied by ICL and EER. The 30-day rolling average has a higher emission limit because of the shorter averaging time. This accounts for any operational variabilities that may occur in the operation of the plant.

Q When you refer to a shorter averaging time, what are you comparing the 30-day rolling average to?

A An annual average, for example, you have 30 days compared to an annual period.

Q Mr. Kosky, in your opinion, is the daily cap on NOx emissions in the ozone season of 34.6 tons per day scientifically and technically achievable with the NOx control technology proposed for the project?

A Yes, it is.

Q What is the basis for your opinion?

A Again, the basis is the ICL and EER information that I had cited earlier. The cap is equivalent to 0.168 pounds per million BTU. If the plant were to operate at 24 hours a day at 100 percent load, the technology can clearly meet this emission limit.

Q Turning to particulate matter, is there any fundamental difference in the particulate matter control technology now proposed for the project from that contemplated during the 1995 certification hearing?

A No.

Q And how would you characterize whatever changes had been made with respect to that control technology since the December 1995 hearing?

A The control technology considered at the 1995 hearing, as is today, is what's called electrostatic precipitators or ESP. The only change has been the efficiency of the ESP has been increased to 94 percent from that originally contemplated of 90 percent.

In more practical terms, an ESP, an important parameter of the ESP is the surface area. That has been increased by about 20 percent.

The amount in more common terms originally was contemplated to have about 17 acres per unit of collection area. Now it's close to 21 acres of collection area. This can achieve the emission rate of .02 pounds per million BTU.

Q Mr. Kosky, let me show you what we marked as Exhibit FP&L R-53 and ask you first if you can identify

this document.

A Yes, I can. This shows the emissions on Orimulsion, annual emissions of particulate matter, and I prepared this exhibit.

(FP&L Exhibit No. R-53 marked for identification.)

BY MR. CUNNINGHAM:

Q I believe we have an enlarged version up in the front. If you can unveil that and use that, please explain what is shown.

A This shows the annual emissions of particulate matter from the boiler. I have broken down the particulate matter into two components, total particulate matter and the particulate matter that is shown here as PM 2.5.

PM 2.5 is particulate matter with an aerodynamic diameter of 2.5 microns or less. It's a smaller subset of the total particulate matter.

The emission rate on an annual basis of .3 pounds per million BTU is reduced by the ESP by 94 percent. This results in an emission rate of less than .02 pounds per million BTU.

The gas stream with particulate then goes to the flue-gas desulfurization system. Although the flue-gas desulfurization system's primary purpose is

sulfur dioxide control, it also removes particulate matter.

I have conservatively estimated that 20 percent of the total particulate matter would be removed by the FGD system. That results in emission rate of .0144 actually, and on annual basis, at 87 percent capacity factor, results in emissions of 840 tons per year.

Q Mr. Kosky, in your opinion, are particulate matter emission rates of 0.2 pounds per million BTU and 840 tons per year from the Manatee Plant stacks scientifically and technically achievable with the pollution control technology proposed for the project?

A Yes.

Q And what is the basis of your opinion?

A The basis of my opinion is information supplied by the ESP vendor, Pure Air, and I have concluded that emission rate of .02 pounds per millioJ BTU can be achieved.

This is based on specific design information that has been provided, the configuration of the ESP and the resulting efficiency.

Within that information is information supplied by Mitsubishi Heavy Industries, or MHI, the actual designer of the ESP who has actually experienced

Q Mr. Kosky, what is your opinion regarding whether there would be an increase in the emission of small particulate submitted by the Manatee Plant firing Orimulsion compared with those historically emitted by the plant?

A There would be a decrease of small particulates.

MR. CUNNINGHAM: We would move exhibits FP&L R-53 and FP&L R-54.

THE COURT: They are received.

(FP&L Exhibit R-53 received in evidence.)

(FP&L Exhibit R-54 received in evidence.)

BY MR. CUNNINGHAM:

Q Mr. Kosky, apart from what you just testified about, will there be any other reductions in PM 2.5 levels in the ambient air as a direct result of the Manatee project?

A Yes, there will be.

Q Can you explain your answer.

A The ambient PM 10 (sic) concentrations are made up, to a large degree, by particles formed from gases emitted from air pollution sources. One of those gases is sulfur dioxide. In fact, 40 to 50 percent of the PM 2.5 in the atmosphere is particulate sulfates or particles formed from the emissions of SO2, sulfur

dioxide.

Q Let me interrupt you, just because I believe you may have said that you were referring to PM 10. Is that what you intended?

A PM 2.5, the small particles. These small particles are formed from gases, and as a result of the project, there is going to be a decrease in the amount of sulfur dioxide emissions emitted. In fact, as I testified in the 1995 hearing, there is about 13,000 tons of sulfur dioxide less than historical emissions.

This would result in about 2,000 tons per year less PM 2.5 in the Tampa Bay region as a result of that decrease in sulfur dioxide emissions.

When combined with the decrease of solid particles as well as the decrease of gaseous emissions, the environment will see a substantial reduction in PM 2.5 emissions as a result of the project.

Q Mr. Kosky, have the characteristics of particles emitted from the Manatee Plant firing Orimulsion, other than particle size, been evaluated?

A Yes, they have.

Q And what evaluation are you aware of?

A In the 1995 hearing, I had previously testified that at a higher emission rate of .03 pounds per million BTU, there would be a decrease in metals

which make up a portion of the particulate matter. With more particulate control for the project and less particulate emissions, those metals will decrease.

This important constituent of fly ash will be beneficial as a result of the project.

Q In the 1995 certification hearing you assumed that prevention of significant deterioration review was applicable for two pollutants, NOx and carbon monoxide under FDEP's air rules. Is that still a valid assumption?

A No.

Q Why not?

A The emissions of nitrogen oxides back in 1995, as I have shown on one of my exhibits, increased. With the consideration of going to 7,310 tons a year as a federally enforceable limit of the permit, there will be no net increase in emissions.

The emissions of nitrogen oxides, in fact, would not require PSD review since there is no increase.

It would also not require the consideration of what I had previously testified as Best Available Control Technology, which is part of PSD review.

However, even though BACT does not apply, the emission rates proposed today are consistent with

and, in fact, lower than BACT limits on brand-new sources that have been operating in Florida. In fact, the emission rates are lower than several brand-new plants that have been operating in the 1990s at emission rates of .17 pounds per million BTU.

MR. CUNNINGHAM: We have no further questions at this time and would tender the witness for cross-examination.

MR. BEASON: Your Honor, the Department has some questions. I was wondering as to the protocol. Should we follow Mr. Cunningham?

THE COURT: Yes, I think so.

CROSS-EXAMINATION

BY MR. BEASON:

Q My understanding from your direct examination is that you provided the Department with a professional engineer's statement with regard to the pending permit application.

A Yes, I did.

Q And it's my understanding -- or was that professional engineer's statement, was it signed and sealed by you in your capacity as a registered Florida professional engineer?

A Yes, it was.

Q As a registered Florida professional

engineer, do you have an opinion as to whether the permit application that's presently pending provides the Department with reasonable assurance that the FP&L facility can comply with the proposed emission rate for particulate matter of .02 pounds per million BTU?

A Yes, I do.

Q Could you tell the Judge what your opinion is?

A We have provided information regarding the designs of both the reburn as well as the ESP. We have supplied intents for guarantees to the Department. We had discussions with the Department as well as the PE certification.

Q Again, with particulate matter, do you have an opinion as to whether the proposed Orimulsion conversion project, whether the permit application provides reasonable assurance that the facility can comply with the 858 ton per year limit on particulate matter?

A Yes.

Q What's your opinion?

A My opinion is we have supplied design information, calculations; we supplied the intent to guarantee as well as A professional engineering statement and had discussions with the Department and

their staff.

Q Moving now to the NOx emission rates for ease of reference if you need to, but I am referring to FP&L Exhibit R-133.

Do you have an opinion as to whether the permit application provides the Department with reasonable assurance that the proposed FP&L project, if implemented, would comply with the .15 pounds per million BTU limit for NOx emission?

A Yes, I do.

Q Again, what is your opinion?

A My opinion is we provided that assurance through design information, PE certification, discussions with the department and intents to guarantee that level from vendors.

Q Finally, that opinion of yours is predicated on the 30-day rolling average?

A Yes.

THE COURT: Predicated on what?

MR. BEASON: The 30-day rolling average.

BY MR. BEASON:

Q One final question, Mr. Kosky. Again, to the question of reasonable assurance, do you have an opinion as to whether FP&L has provided the Department with reasonable assurance that the proposed facility,

if implemented, could comply with the 7,318 tons per year limit on emissions?

A Yes, I do.

Q And your opinion?

A My opinion is that we provided that assurance in terms of intents from the vendors, engineering information and PE certification.

MR. BEASON: No further questions, Your Honor.

THE COURT: Mr. Curtin.

CROSS-EXAMINATION

BY MR. CURTIN:

Q Mr. Kosky, is any of the information that you have been discussing today in the site certification application?

A No.

Q It's not?

What is reasonable assurance? Is that an engineering term?

A I would say that's both a regulatory and engineering term.

Q You indicated, I think, in response to several questions that you provided a professional engineering stamp, I guess you would call it, or seal on the changes to the project of air changes; is that

correct?

A I provided a professional engineer's statement, yes, that's correct.

Q When did you do that?

A That was in December, around December 18th of 1997.

Q You indicated that you made an assessment of which pollutants would be subject to PSD review; is that correct?

A Yes.

Q How did you go about making that assessment? Just kind of briefly explain what you did.

A We looked at what's called actual emissions of the facility as defined by FDEP regulations and looked at the emissions of the facility after it would begin operation.

Q So if I am understanding correctly, you compared the past performance of the equipment at the facility with the projected future?

A That's basically how it's done in simple terms, yes.

Q Then what do you do? You see if there is a difference?

A You see if there is a difference between emissions historically versus the future. If there is a, what's called a significant net increase, then there is a certain review required.

Q Are there any regulatory requirements for determining whether there is a significant net increase?

A Yes, there are.

Q Do you know what those are?

A There is a specific definition within the Department's rules of what's called actual emissions, and that's a pretty specific definition.

There is also in the Department's rules a discussion of how you go about looking at what's called contemporaneous increases and decreases, if, in fact, they occurred at the plant, as well as the significant net emission rates. It's a criteria from which you make that calculation.

Q So the regulations, I take it, sort of lay out a little road map on how to do this?

A I wouldn't say you could characterize it as a road map, but it's a lot more complicated than that.

Q A winding road map?

A That's probably a better characterization.

Q Okay. Is it a requirement that when you determine the past actual emissions, that would be done under conditions that are representative of the

operation?

A That's part of the definition; that's correct.

Q Is that what you did in this case?

A Yes.

Q When you determine the future performance of the facility after the change, are you calculating what is known as the potential to emit?

A You are calculating the potential to emit, yes.

Q Is it your understanding that it's acceptable to place limits on the potential to emit to have the facility avoid that PSD review?

A Well, it includes federally enforceable limits on -- for example -- hours of operation could be a capacity factor in this case, yes.

Q Those limits have to be federally enforceable?

A That's correct.

Q What are the federally enforceable limits here for the pollutants that you described that are not going to be subject to PSD review? And I guess primarily I would be interested in particulate matter and nitrogen oxide.

A There are emission limits in tons per year

that are emission caps for the facility. The criteria for determining whether or not prevention of significant deterioration apply is based on tons per year emissions. That will be a federally enforceable emission limit in the PSD permit as well as the site certification.

Q So the ton cap would be the enforceable limit?

A Well, the ton cap is the controlling limit for seeing whether or not you fit the criteria. There is also the other emission limits which also would be federally enforceable that I previously discussed.

Q Those would be -- could you just detail them for me?

A For nitrogen oxides, 0.15 pounds per million BTU on a 30-day rolling average. There is also the emissions cap for NOx. For particulate, it's .02 pounds per million BTU.

Q Turning to the emission caps, I guess it would be the 840 ton particulate stack emission and the 7,318 for nitrogen oxide. How would those be enforced?

A That would be enforced by providing information to the Department on what the actual emissions would be. And in fact, the previous conditions of certification as a result of the 1995

hearing includes such a statement.

Q Are there short-term limits on the amount of, I guess, tons of pollutant that go out of the stack? Are there any short-term limits or is it just an annual number?

A No, there is an annual limit, there is short-term limits. For example, on nitrogen oxides, that's 30-day rolling average. The plant will have to submit what's called a quarterly report to the Department to demonstrate they comply with the nitrogen oxide limit of .15 each quarter.

Q The .15 is the short-term limit?

A Yes.

Q But there are no short-term limits on the total tons per year, are there?

A There is a short-term limit for tons a day, and there is a limit on the tons per year.

Q Okay.

A If I can clarify, it's an annual emissions cap. It's hard to set a short-term limit for an emissions cap. They are two different --

Q That's kind of my point. What I was wondering was: How is the Department going to come in, let's say, after six months of operation and make a determination whether or not you are on the way to complying with the 7,318? Can you do that?

A Very easily. In quarterly reports, for NOx items there will be a continuous emission monitoring. This particular monitor calculates emission rates on a pound per million BTU; it can calculate emission rates on a pounds per hour, it can calculate emission rates on pounds per day or tons per day. It can calculate both tons as well as for pounds per million on a 30-day rolling average as well as any other averaging time you want.

In effect, there is an instrument to provide assurance to the Department that this 7,318 tons a year would not be exceeded.

Q What you are describing, I think, are a number of methods that they could make an assessment. But those are not permit conditions; are they?

A The emission rates are permit conditions. The use of the CEM in compliance will be a permit condition.

Q The use of the CEM, but there is no milestone that the Department can use to compare your performance against. There is nothing in the permit other than .15 and 7,318; is that right?

A Well, it would be no different than really, in my judgment, any other sources that are submitted

quarterly report.

Q Excuse me. That's not the question.

The question is, is there anything in the permit that, other than the .15 or the 7,318 --

A It doesn't provide what the Department would do in reviewing information supplied by an applicant.

Q Right. But there is nothing in there, there is no intermediate milestone, there is nothing they can look at, no short-term hours of operation other than the whole cap for the year and the emission limit to determine compliance; is that right?

A Well, it doesn't specify how the Department may do its job with the information it gets.

Q Yeah. That's right. But there is nothing that they can enforce other than the .15 and the 7,318; is that correct?

A Well, that's not -- well, those are emission limits, yes.

Q Those are --

A Yes, those are enforceable emission rates as well as the tons per day limit as well as during the ozone season.

Q Right. With respect to the nitrogen oxide emissions that you described for us, could you tell us how you arrived at the actual emission figure, the

historical actual emission figure?

A The historical actual emissions, as I testified, is based on the 1993-'94 emission rates based on the actual operation of the plant during those years.

Q Okay. The emission rate that you are speaking of, is that a tested emission rate or is that the permit limit emission rate?

A The calculation is based on the .3 pounds per million BTU.

Q And what is the .3 pounds per million BTU?

A That's the emission rate.

Q Is that a permit limit or is that based on testing?

A That's a permit limit.

Q And would you just explain to me the calculation that you went through to -- what did you do with the .3?

A You calculate the actual heat input for the whole year from the plant and you use the .3 to make the calculation. That ultimately winds up to be the 7,318 tons per year.

Q How does the fuel usage enter into that?

A It's the amount of BTUs that goes into the furnace.

Q So is it accurate to say what you did was take the .3, which is the permit limit, and then essentially calculate that based on all the barrels of fuel that were burned?

A That's correct.

Q Okay. Did the plants operate that way? In other words, did they operate at .3 for each and every barrel of fuel that they burned?

A Back in 1993 and 1994, there is really no way of knowing. They didn't have continuous emission monitors. It's my judgment that on an annual average basis, the .3 would characterize and be representative of their emissions.

Q Okay. Did the plants always operate that way?

A We have no way of knowing. They likely don't.

Q Okay. Is there stack test data available for nitrogen oxide emissions for the years 1993 and 1994 for these plants?

A There is compliance data available, stack test data.

Q Stack test data. Okay. Did you use that information in arriving at the actual emission figure?

A I didn't use that information, no.

Q Why didn't you use that information?
A That information is a single stack test which I do not consider representative of all the operation for a year. In fact, the Department's staff, as well as their regulations, also don't consider a stack test to be representative.
Q Is the stack test the information that you submit to the Department of Environmental Protection to demonstrate compliance with the permit limits?
A It's a benchmark for a specific operating condition that is a test that demonstrates compliance for that particular standard.
Q Okay. Is it fair to say that the nitrogen oxide emission from the facility would be the highest when the loads were the highest?
A In general, that's true.
Q How is the stack test performed? Is it performed at a high load?
A It's generally performed between 90 and 100 percent load.
Q Have there been any changes to the facilities since the 1993-'94 period that might affect the nitrogen oxide emissions?
A There have been changes at the plant that when operated may influence the average nitrogen oxide

emissions, I would say, yes.
Q I guess what I am thinking, there have been some previous testimony about the installation of something called a steam atomization system.
A That's correct.
Q Would that have any impact on nitrogen oxide emissions?
A It would have a potential impact of allowing the combustion process to be better controlled and therefore meet an average NOx emission rate.
Q Is that another way of saying it would result in lower nitrogen oxide emissions?
A Its primary purpose isn't that.
Q I understand that.
A But it can have an effect of reducing by better combustion.
Q Okay. Do these units have continuous emission monitoring equipment on them presently?
A Yes, they do.
Q Do you know when that equipment was installed?
A That equipment was installed in 1995 as required by the Clean Air Act and subsequent regulations.
Q Okay. Have you looked at the nitrogen oxide

emissions rate at these facilities since the continuous emission monitoring systems have been installed?
A I have looked at the emission rates, yes.
Q What do the data show?
A Well, the data show emissions of various types; going from the short-term to long-term, before the installation of CEMs, that there was no way to know what the plant operated because it fluctuates.
The CEM data shows that on the same basis that you would do a stack test, in fact NOx emissions are higher than .3. In fact, some of the emissions are up to .45 pounds per million BTU.
The 30-day rolling average, which is a compliance, varies -- the highest one is near .3, probably more in the range of .27 on some of the units.
And the overall average is probably more like .25 on an annual average. That's my estimate of looking at it. I haven't committed that to memory.
Q Okay. Would those emissions be more representative of actual emissions, those emission limits, than the ones that were selected based on permit condition in 1993 and '94?
A Not in a regulatory sense as defined by DEP regulations. And they are not -- they may not be any

different than what would have occurred if we had CEMs in '93, '94.
Q It sounds a little different to me, and maybe I missed something, but I thought you said that the 30-day rolling average would be .27 as opposed to .3, and the annual average would be in the range of .25. Those both sound lower to me. Did I miss something?
A As annual average, they would be. However, I also mentioned that there are emission rates up to .45 pounds per million BTU on a daily basis.
Q Right. But wouldn't you be using the 30-day rolling average?
A Well, you would be using the 30-day rolling average in terms of compliance, yes.
Q Mr. Kosky, with respect to the particulate matter emissions, the historical actuals that you determined, did you use stack test information for that?
A Yes.
Q How did you account for the soot blowing operation in making that calculation?
A I accounted for the soot blowing using that particular information as a factor in the calculation.
Q Do you recall exactly how you used it? What

did you assume for soot blowing?
A I assumed 21 hours for soot blowing, which was equivalent to the actual operation of the plant, and three hours of steady state as far as the stack tests are concerned.
Q Over what period of time?
A Well, I used that figure to calculate an annual emissions which I have characterized as being low.
Q I think you indicated that you assumed 21 hours of soot blowing and three hours of steady state. Was that over a 24-hour period?
A Yes. I sort of averaged that over 24 hours and used that information to calculate an annual emission.
Q Does the permit allow soot blowing to take place for 21 hours in a 24-hour period?
A It doesn't prohibit it, no.
Q There is no limitation?
A There is no limitations on soot blowing.
Q Would assuming 21 hours of soot blowing and three hours of steady state over a 24-hour period, would that result in representative emissions in your opinion?
A In my opinion, it represents a low estimate

of representative emissions for particulate matter, yes.
Q Why would it be a low estimate. Would you soot blow 24 hours instead of 21?
A Well, it was a calculation that was done using stack test data. As I previously testified, that particular single stack test data may not be representative of the whole plant. In fact, the Department's rules indicate that that kind of approach may not be scientifically valid.
Q Looking for a moment on, I guess, your Exhibit FP&L R-53, you indicate an emission limit there of .014 going into the stack, I guess; is that right?
A It's an emission rate of .0144 on an annual basis.
Q It's .0144 as opposed to .0147
A Yes.
Q Is that an enforceable limit?
A The .0144 as an annual average at 87 percent capacity factor results in a federally enforceable limit of 840 tons per year.
Q Well, is it your judgment that if the Department of Environmental Protection wanted to force you to meet .0144 under the current state of the draft permits, that they could do it?

A Currently, no.
Q The limit is not in the permit?
A No. It's .02 as a maximum limit.
Q I believe you indicated in response to some questions from Mr. Cunningham that you were basing your opinion on the ability to meet the NOx limit on various information that you received from the vendors; is that correct?
A That is correct.
Q Is part of that information things that you reviewed from ICL?
A It is.
Q Is there a contract between ICL and FP&L, to your knowledge?
A To my knowledge, there is not.
Q Is there any guarantee that's currently in effect on the emission limit?
A As I had testified, there is a reconfirmation of a technical guarantee from the original proposal that ICL submitted and ABB has reconfirmed that.
Q And they have done that in writing?
A Yes, they have.
Q In a binding contract?
A Well, it's a letter of commitment. I can't

characterize what a contract is.
Q When did that take place?
A I believe it's this month, there is a letter that was submitted.
Q January of 1998?
A I believe so.
Q But your certification was submitted to the Department in December?
A That's correct.
Q I believe you indicated earlier, Mr. Kosky, that there had not been much of a change in the technology with respect to the NOx emissions since the '85 hearing. Do you recall that?
A Yes, there hasn't been any change in the concepts, low NOx burners and reburn.
Q Has any of the technology been designed, to your knowledge?
A They have had what I would characterize as additional engineering work done and developmental work since the 1995 hearing. And I would characterize that as being a considerable amount.
Q Right. But it hasn't actually been designed yet; has it?
A Well, the final system probably not has been finally designed, no.

A Not 800 megawatts. There is, I know of at least 600 megawatts. There is other several hundred megawatt plants that are using reburn technology.

Q What are the size of the Manatee units?

A They are 800 megawatts on oil, 720 on Orimulsion.

Q So the only units you are familiar with that are using the reburn technology are in the 600 megawatt range, correct?

A As far as the largest size I am aware of, that's correct.

MR. NEILSON: No further questions.

MR. KUMARICH: I have some questions.

CROSS-EXAMINATION

BY MR. KUMARICH:

Q I would like to return to this issue of historical emissions from the Manatee Plant.

Is there some precedent or industry standard for establishing historical emission standards?

A There is a regulatory precedence of what's considered in determining actual emissions from a plant, and that's used to compare with future emissions, yes.

Q And where are those established?

A That is in the Department of Environmental

Regulation rules, 62-210 and 62-212.

Q Does that conform to the way you have established historical standards for this plant?

A Yes, it does.

Q Are you familiar with the number of hours of operation, total number of hours of operation of the Manatee Plant in 1993 and '94?

A I recall seeing a number. I am not that familiar with the exact hours, no.

Q From information we received from the DEP, from Mr. Joe Cox on November 20, 1997, this is MCAP Document Number 30, the information we received stated that the -- if you add the total hours of operation of both units for 1993 and '94, that total would come to just slightly over 22,000 hours, adding both units for both years.

Do you feel that would be -- you want the document here so you can take a look at this? I am sorry, I only have one copy here. I will need to get that back.

A That's what is characterized as the hours of operation, yes.

Q Then the comparable figures for NOx emissions for 1993 and '94, which were the numbers that you used for establishing historical levels; is that

correct?

A That's correct.

Q Actually, if you add these two together, '93 and '94, you'd get a total of 14,396 according to their numbers, and that would average to -- divided by two would average to 7,198 annual NOx emissions in tons, which is just slightly less than the historical levels indicated for use, your use, which was 7,318 tons; is that correct?

A This particular calculation on this exhibit shows that, yes. I can't account where it comes from, though.

Q If we take the total hours of operation for '95 and '96, add those together, that's 19,235 hours total for both units. And you take the comparable annual NOx emissions for those two years and add those together, that comes up to 10,514 tons annual NOx emissions.

You take the total number of hours of operation '93-'94 and divide those into -- divide that into the tons of NOx emissions, you get a rate there of -- 22,000 divided into 14,396 -- you get a rate of .654 tons of NOx per hour emissions. You divide the total hours of operation in '95 and '96 into the total annual emissions of 10,514, you get a rate of .547 tons per

hour.

The difference between the .654 and .547 is .107, which is an improvement of 17 percent.

How do you account for that difference between the hours of operation and NOx emissions between the composite of those two years, that is '93 and '94 versus '95-'96?

A That type of calculation using annual hours and tons quite frankly is a bit meaningless because the plant operates at different loads at different times. For example, it could operate full load at 50 percent, it could operate at 30 percent load. It could operate a couple days at 100 percent load and you get all different types of annual amounts of operation.

Q We are discussing here average hourly rates --

A Correct.

Q -- of NOx emissions.

A Correct. Your calculation --

Q We are talking about total, total annual emissions which is what you are referring to in your historical emissions.

A Your calculation presumes that the plant operates each hour the same way. I can tell you for a fact this is not the case.

Q What difference would that make in terms of the total annual emissions?

A Quite frankly, very little. It would depend on how the plant would be operating during the hours it's operating.

Q Are you stating that the total annual emissions in tons of NOx emissions here is -- that that figure is incorrect?

A Well, I can't authenticate whether or not it's correct. I could state that the annual tons in 1995-'96, is lower than what it was in '93 and '94. Whether there is a difference in rates, you just cannot make that kind of calculation. It's wrong.

Q If we take it on a percentage basis, we are still indicating a percentage reduction of approximately 17 percent, no matter how you calculate that.

You are getting over the number of hours. The number of hours and the nitrous oxide or NOx emissions indicate that there was a substantial difference between the hours of operation and the NOx emissions between the composites of those two years.

A Yes. It is lower. Part of the reason which I have calculated, they used lower fuel and I am aware that at least one unit during 1996 had a forced outage

during the summer when it would be expected to be operating. A forced outage is, I guess in simple terms, the plant broke, and it wasn't operating for about a month and a half during the time it normally would operate.

So 1996 it's lower.

Q Was there any other technology that was instituted, any changes in the plant in that time frame of 1994 to 1995 that might account for that difference in NOx emissions?

A Not from the standpoint of plant operation. There was the installation of, as I testified, steam atomization which was used to better control the combustion process because 1994 to '95 a CEM would now be used to demonstrate compliance.

It had the artifact of potentially reducing the rates, but you can't really tell from this data as I testified. The rate, for example, on the same basis, the rates at higher loads were much higher than .3.

Q Are you stating that the institution of the use of steam atomizers would not account for that reduction in NOx emissions?

A In looking at the information, I would say no. A big part of that difference is just how much the plant operated.

Q How would you compute the period of time for operation of the plant? You are saying that the difference is due to the amount of time that the plant operated?

A Well, the difference, the plant operated less in terms of its fuel used during 1995 and '96 as compared to '93 and '94. That results in lower NOx emissions. What effect steam atomization had, you can't tell from this information.

Q But there is no correlation here between the number of hours of operation and the reduction in NOx emissions?

A That's because the plant, although it might operate several hours, it may operate at different loads. So it uses different fuel now and it has different NOx emissions.

Q Okay. Has the ESP unit that is proposed for use at the Manatee Plant, has that unit been used in any other facility that is burning Orimulsion?

A As I testified, the ESP design is based on designs from Mitsubishi Heavy Industries which has experience in collecting Orimulsion fly ash in Japan. In fact, I believe they are firing it at one of their plants.

Q With that specific unit?

A It's not identical, but the design, the designs that are going to be incorporated into the Manatee project are similar. Size might be different, that kind of thing.

Q Is it safe to say you have no practical or experimental evidence to indicate that the unit as you have it designed will achieve the reduction in particulate emissions that you state that will achieve?

A Well, there is lots of practical evidence of the type of particulate that would be emitted from Orimulsion can be collected by an ESP of this type of design.

Q What is the size distribution of the particulate emissions from burning Orimulsion?

A Burning Orimulsion typically, the majority of the particles would be less than 10 microns in diameter. Approximately 90 percent, conservative estimate that I have previously testified, would be a particle size of 2.5 microns in diameter or less.

Q Is it not true that the emissions from the plant in Dalhousie, the tests that were done originally, that 50 percent of the particulates were 0.3 microns or less?

A I believe that's about correct, yes. Maybe in the range of 40 to 50 percent. I can't remember

Q If I could go back again on that issue, based on your answer to my prior question, when the particulate matter goes through both ESP and the flue-gas -- or the FGD, you all don't have any particulate matter essentially left to escape out of the stack?

A Well, there will be 840 tons a year being emitted. That's the cap.

Q I understand that. In excess of the PM 2.5?

A It will all be -- it will all be PM 2.5 in excess. In practicality, there will be some. You will probably collect some, but virtually --

Q A smaller percentage than currently goes out of the stack?

A Oh, yes.

Q In regard to FP&L Exhibit R-133, the historical oil figures, these are historically permitted or historical actual?

A The pounds per million is the 30-day rolling average permitted rate. The tons per day and tons per year are the historical actual based on 1993-'94.

Q And did I understand that the historical actual was around -- the 30-day rolling average was .27 based on your testimony?

A My testimony was in reviewing data in

1995-'96, that's my recollection of where 30-day rolling averages might be.

Q You testified in regard to a NOx reduction team that was being proposed with the 1995 recommended order. Is that condition being proposed to be eliminated by FP&L?

A Not to my knowledge. I think it's still in the conditions of certification.

Q So to your knowledge, FP&L is still recommending the NOx reduction team review that information as it comes out and make changes as appropriate?

A Yes, if the conditions of certification are approved, FP&L would have to implement that team.

Q Certainly if they are approved.

In regard to a question Mr. Kumarich asked, is it my understanding there was a reduction in NOx emissions from 1993 and '94 to 1995 and '96?

A There are reduction in emissions from 1993 to '94 compared to '95-'96, I mean reduction in the last two years, '95-'96, yes.

Q Did I understand you also to say that the plant was not operating as many hours during that period?

A As I testified, the hours really don't play

as much a function as how the plant burns its fuel. It did have a lot less fuel, one of which was a case of a forced outage during one of those years.

Q Okay. I understand that. I am not sure that answered my question.

Was there a reduction in the number of hours during the first two-year period, '93-'94 to '95-'96?

A I think there may have been a reduction of hours from the exhibit -- I don't recall that -- the MCAP exhibit. From my knowledge, there definitely was reduction in the amount of fuel burned.

Q Do you know for sure if there was a reduction in the NOx emission rate during that period?

A There was -- I really can't say. There were instances where the data was clearly above .3. In fact, I seen data at .45 for a daily. Historically the .3 was a three-hour test. How it operated in the past, it's difficult to know because there wasn't any CEMs that we could compare now with '95-'96.

MR. BARNEBEY: I have no further questions. Thank you.

THE COURT: No other cross? Any redirect?

MR. CUNNINGHAM: No, Your Honor, we have no questions.

MR. REESE: Could I move what I marked as

ManaSota-88 R-18, the three sheets I showed the witness? They had previously been identified as Florida Power & Light R-56 and R-55, item 1 and 2.

THE COURT: All right. Is there any objection? They will be received.

(ManaSota-88 Exhibit R-18 received in evidence.)

MR. BEASON: Your Honor, I am again quite sure of the protocol. I intended to ask the witness questions on redirect.

THE COURT: Go ahead.

RECROSS-EXAMINATION

BY MR. BEASON:

Q Mr. Kosky, I realize you have been up for a while and you have been asked a lot of different questions by a lot of different lawyers. I would like to direct your attention back. I believe you testified there were no final design drawings for the low NOx burners and for the reburn portion of the modifications to the boiler.

A I testified there was no, I guess, final designs. I guess I would characterize that as being final design drawings. You could sort of characterize it that way.

whether or not those CO limits would be met; and if anything we feel they are aggressively set too low which confused us since that was the one pollutant they did claim PSD for, PSD applicability for.

Q Mr. Elias, what analyses have you performed concerning toxic air pollutants from the proposed projects?

A We looked at the proposed toxic emissions that were in the application. We reviewed and attempted to find materials on toxic emissions from Orimulsion burning at other plants worldwide. We then also looked at EPA's database that they were collecting under the Clean Air Act to estimate hazardous air pollutant emissions associated with electrical utilities.

Q Do you have an opinion as to whether the expected air toxic pollutants have been adequately addressed by the applicant?

A Yes, I do.

Q What is that opinion?

A We believe they have not been adequately addressed.

Q What is the basis for that opinion?

A Based on the EPA studies, there is a strong indication that the sources are likely to have

hazardous air pollutant emissions, especially organic emissions.

There were a number of metal emissions identified, toxic metal emissions that were addressed in the application, but we have been able to find no data published by Bitor or searching overseas where measurements were made of organic, trace organic species.

Therefore, we feel due to the lack of data and the probability of their occurrence, the applicant should be required to perform a testing program for organic hazardous air pollutants similar to the study that was performed for EPA. This would involve testing dioxins, purines and 16 polycyclic organic matter emissions. We are proposing on an annual basis alternating units for the first five years, and then having the data collected from that program subjected to the health risk assessment that's already contained in the modified conditions of certification.

Q Mr. Elias, what analyses have you performed concerning nitrogen oxide emissions from the proposed project?

A For nitrogen oxide, we looked at the historical actuals, we looked at the future projected actuals.

Q Do you have an opinion as to the manner in which historical nitrogen oxide emissions have been calculated for the proposed project by the applicant?

MR. CUNNINGHAM: I register essentially the same objection I have, to the extent that the historical emissions of NOx were addressed fully in the 1995 proceeding and established a figure of 7,318 tons per year.

I recognize time has moved on and there could be an issue as to whether some later years' information, which has been the subject of some testimony here, is to be factored in somewhere. But as to what the 1993, '94 NOx emissions are, again, it seems to me if that's reopened in this remand order, so is anything else that anyone wishes to bring up.

MR. CURTIN: Your Honor, I believe we have had testimony in this proceeding about the comparison of the historical actual emissions to the projected future emissions, and I believe we also had testimony about the result of that and the applicability of PSD review. And that is the area that Mr. Elias is prepared to testify about.

THE COURT: I will overrule the objection.

BY MR. CURTIN:

Q What is that opinion?

A Basically regarding the historical actuals, the value has changed several times through the application. The initial values as represented in the draft permit and technical evaluation were based on the four stack tests that were done for oxides and nitrogen in 1993 and '94 at the units times the fuel utilization values.

Originally, in DEP-B3, which is the response prepared by the applicant to DEP, a value --

THE COURT: What were you referring to DEP, 3?

THE WITNESS: DEP-B3, which is a January 15, '95, response in the original proceeding.

THE COURT: Okay.

A The heat content that was used for fuel oil was a lower value than the one that was currently used in the existing exhibit. It was 151,890 BTUs per pound whereas now the applicant is using 152,381 BTU per pound.

To give you a rough idea of the impact of that, that's a difference between the 7,318 currently calculated and the 7,294 that's contained in that exhibit from the prior proceeding.

However, neither of those numbers were the numbers utilized by the Department in the draft permit or technical evaluation. As I started to say, there were four stack tests performed in '93 and '94, one on each unit each year.

These values ranged from .29 pounds per million BTU in '93 for both units, .28 in '94 for Boiler 1, and .26 pounds per million BTU for Boiler 2.

The Department averaged all four of those tests together, averaged the fuel use based on the higher heat content, and came up with 6,827 tons per year as the historical NOx emissions.

In reality, if you keep the stack tests identified with the years they were done and the fuel use for those units and those years, the actual number you would calculate would be 6,813 tons per year.

Additionally, the annual operating reports which were addressed in that same DEP response contained an average of 7,198 tons per year.

In reality, as I stated before, the actual emissions, historical actual emissions, as required by the regulation are supposed to be based on the two most recent years following the particular date of the application that are representative of normal source operations. Normally that means the two years out of the last five and in some cases the applicant's allowed

to go back all the way to 10 years, that represent current normal source operation.

As of the time of the application, normal source operation was represented by the plan as configured at that time. Since the PSD application is still pending and under PSD guidance, it's required that the permit remain open until the end of the comment period. The current year's representative of normal operation would be more representative of the plant as it currently operates. This includes a steam atomization system that was installed in late '94 and '95.

There is continuous emission monitoring data available for the last two quarters of '96 and the first two quarters of '97 that was supplied by the applicant.

In analyzing that data, for 1993, Boiler 1 emitted at a rate .219 pounds per million BTU. Boiler 2 at .229, this would again be based on the calculation of '96, '97, so that stayed the same for '93 or '94 would be the same emission rates.

The fuel use, again we believe the applicant correctly estimated that as representative years as being '93 and '94 for a variety of reasons. So the capacity factor we used was the same.

This then calculates out to 5,478 tons per year. We feel that this meets the requirements of thr regulation in calculating historical actuals for NOx, that this is a representation of how the unit is currently operating.

THE COURT: What was the number again?

THE WITNESS: 5,478 tons.

THE COURT: What was the emission rate you cited for Boiler Number 2, was it .229?

THE WITNESS: That's correct, pounds per million BTU. And we used the higher heat content rate that the applicant had switched to which was an average for the two years of 48,785,409 BTU per year.

BY MR. CURTIN:

Q Just so I understand, with respect to the 5,478 number, did you arrive at that number by utilizing the fuel used for '93 and '94 and the later emission limit, '96-'97?

A Yes, that's correct. We utilized the emission rate of the plant as it's currently operating as representative of normal operations. And we credited the operational capacity rate of the higher capacity that was achieved during '93 and '94 to develop the 5,478 tons.

Q Mr. Elias, using the numbers that you

believe accurately reflects historical nitrogen oxide emissions, would the project be subject to review, of PSD review, rather, for nitrogen oxide?

A Yes, it would. We also believe that the future estimated emissions are incorrectly calculated.

Q Using the number that you cited as a Department of Environmental Protection number for historical nitrogen oxide, would the project be subject to PSD review for nitrogen oxide emissions?

A Yes, it would. In order to be subject to PSD review, there would have to be a 40-ton per year increase from the historical actuals to the future actuals.

Q Have you reviewed information from the applicant concerning the manner in which it proposes to meet its suggested nitrogen oxide limitation?

A Yes, we have.

Q Do you have an opinion as to the capability of the technology that has been proposed to meet the emission limit of .15 pounds per million BTUs for nitrogen oxide?

A Yes, I do.

Q What is that opinion?

A Similar to the case for CO, the emission limit proposed for oxides of nitrogen we feel is a very aggressive number for this type of configuration. Both the low NOx burner as well as the reburn system are attempting to achieve numbers that have not been demonstrated before on any units. We still feel that there is other available technology that would allow the achievement of this number or, in fact, lower numbers with a much simpler and cost effective approach, primarily Selective Catalytic Reduction which has been used with Orimulsion in Japan, which has in the intervening two years since the original demonstration been studied extensively in the United States, including on high sulfur coals, and formed the basis as the demonstrated technology for EPA's proposed new source performance standards for utilities which was published in July of 1997.

Q Do you have an opinion concerning the manner in which future emissions for nitrogen oxide from the facility have been calculated?

A Yes, I do.

Q What is that opinion?

A As I stated, we believe that the emissions for the future actuals were not correctly calculated.

Q What was the basis for that opinion?

A That's based on the actual language in the WEPCO ruling from the judge as well as EPA's subsequent

promulgation of the WEPCO rule. It clearly states that future actuals have to be based on hourly emission rates based on federally enforceable conditions times the capacity factor.

The 7,318 for the future actuals is based on .125 pounds per million BTU times a capacity factor. The short-term limit with the 30-day rolling average .15.

Under the WEPCO requirements, which is the exemption that allows them to use future actuals, the .15 should have been utilized times the capacity factor to represent future actuals.

Q Based upon the analysis that you have performed, are there additional conditions that you believe should be considered for the project if it is to be approved?

A Yes, we do.

Q Could you briefly describe those for us.

A Yes, there is a number of permit conditions, some of them rather lengthy, that are typically included by the Department in these type permits. These relate to the fugitive sources.

An example would be the type conditions that were included in the Florida Crush Stone permit, this is a cement-producing plant which has much more

extensive requirements for the particulate emissions and the minor sources.

In addition, we feel that there should be a condition due to the uncertainty of achieving the NOx standard to avoid future hearings, that if the applicant is unable to achieve the proposed or permitted emission limit of .15 pounds per million BTU on a 30-year rolling average within the first year of operation, that they be required to install an SCR system in order to achieve the limit.

Finally -- well, two others. To address the future actual emissions, the Department included a condition in the technical evaluation but not in the permit that's required under the WEPCO rule that the applicant demonstrate compliance with the future actuals for a period of a minimum of five years.

The rule goes on to say that that can be extended to 10 years. Recent Department policy as evidenced by the draft permit issued for the Hillsborough County retrofit project, this is an existing waste energy plant that's just adding additional pollution control, they are removing an ESP and putting in an acid gas scrubber and bag house.

The Department is requiring them to monitor the future actuals for a period of not less than 10

years. We feel that the applicant should have a specific permit condition that requires them to demonstrate compliance with the future actuals for a period of no less than 10 years, similar to the condition (f)1 of the recent draft Hillsborough permit.

Finally, we believe, because of the uncertainty associated with the numerous particulate emission sources, both in terms of estimating emission rates and impacts, typically what is done when you have a model violation that is believed by the Department or the applicant to be nonrepresentative -- in other words, assuming the model is overly estimating what the impact would be -- this is normally resolved by ambient monitoring programs.

The state has required several sources throughout the state to conduct such programs in order to ensure there are no violations of standard.

We think there should be a condition in the particulate for a minimum of a three-station network for TSP, PM 10 and PM 2.5 along with meteorological parameters that meet the guidelines of the PSD ambient monitoring guidelines.

The current ambient monitoring network that's in place is sited north and south of the plant where the predominant wind direction is east/west.

There is over 60 sources here.

Q That's not in the information you have with you today?

A No, it's not. We provided copies of the modeling runs to you. It's in the modeling input.

Q It would be whatever is stated in whatever you provided; is that fair to say?

A I believe so.

Q I think, Mr. Elias, you also testified as to the carbon monoxide emission limit and some concerns you had with respect to this project's capability of meeting that limit; is that correct?

A That's correct.

Q Is your conclusion regarding CO emissions in that context based on your beliefs that the guaranteed rate for excess 02 emissions is 0.6 percent at the reburn zone?

A I don't know whether that was a guaranteed rate. As it was stated in the EER proposal, that was the expected condition.

Q You were looking at that just spatially in the boiler at the reburn zone?

A I believe that would carry up until you injected the overfired area, yes.

Q With respect to your testimony regarding the

historical NOx emissions from the plant, if I understood your testimony, you applied. I believe it was 1996 and 1997, continuous emission monitoring data to the 1993, 1994 fuel usage; is that correct?

A That's correct. The last two quarters of '96, the first two quarters of '97 was the data we had available.

Q Did you take into account in any way the load or capacity output at which the Manatee Plant was operating?

A During the CEM data?

Q Yes.

A No, we did not. It was not available.

Q Did you ask for it?

A We did look through the files at the southwest district office in an attempt to find it. It wasn't present there. I don't know whether we -- I don't believe we specifically asked FP&L for it.

Q Would you agree that it's generally true that for units like the Manatee units, NOx emission rates would be higher in higher loads?

A In general, I think that's probably an accurate statement.

Q And finally, on that point, has the annual NOx value changed in terms of any documents you have

seen? I believe you testified it changed several times and I just wanted to ask you if in your understanding, that annual NOx value of 7,318 tons per year has changed since December 1995?

A I don't have the exact dates of all the documents. It certainly varied from the annual operating report. The '94 permit application, the draft permit and technical evaluation, all had different numbers in than the 7,318. I couldn't testify as to when the exact time period that the 7,318 became the accepted number or proposed number.

Q I will ask: Are you aware of any document that's been submitted by Florida Power & Light or issued by the Florida DEP that has a different number since December 1995?

A December of '95?

Q Correct.

A I am not aware of any.

Q Thank you.

MR. CUNNINGHAM: Thank you, Mr. Elias. No further questions.

THE COURT: Any redirect?

MR. CURTIN: Just briefly, Your Honor.

REDIRECT EXAMINATION

BY MR. CURTIN:

Q Mr. Elias, does the fact that the proposed NOx historical number of 7,318 may not have changed since December 1995 have any bearing on your opinion as to the accuracy of the calculation of historical NOx emissions?

A None whatsoever. As I testified, I was unable to find any documentation on why the number shifted from the original 6,827 in the technical evaluation to the 7,318 in terms of rationale by the department or the applicant.

MR. CURTIN: Thank you. We have nothing further, Your Honor.

MR. CUNNINGHAM: I guess I have one further -- when my turn comes.

RECROSS-EXAMINATION

BY MR. CUNNINGHAM:

Q Did you, in fact, review the testimony that was given by several witnesses including Mr. Kosky at the December 1995 hearing in this proceeding?

A I did review portions of that testimony, yes.

Q And found no explanation for the figure of 7,318 tons per year of NOx in his testimony?

A I found how it was calculated.

Q I am sorry, I thought you just testified that you had not seen anything to explain that calculation.

A No. I am sorry. You misunderstood. What I testified was that there was no explanation of why that method of calculation was now considered accurate versus the original calculation which gave a 6,827 ton per year number that was presented in the original technical evaluation and draft permit.

Q But you acknowledge that, in fact, Mr. Kosky does explain the basis for the 7,318 tons per year before Judge Johnston in December '95?

A I don't recollect specifically from the testimony. I would have to review it to be sure. But certainly in the recent exhibits, it's been clearly explained in Mr. Kosky's deposition as well as his current testimony.

MR. CUNNINGHAM: Thank you.

MR. CURTIN: Nothing further, Your Honor.

THE COURT: Thank you. That's all. You may be excused.

(Witness excused.)

THE COURT: For the record, FP&L Exhibit R-136 has been moved and it is received. You may call your next witness for the record.

(FP&L Exhibit R-136 received in evidence.)

MR. HOLLIMON: At this time we call Dr. Robert Sansom.

Thereupon,

ROBERT SANSOM, PH.D.

was called as a witness, having been first duly sworn, was examined and testified as follows:

DIRECT EXAMINATION

BY MR. HOLLIMON:

Q Mr. Sansom, will you please state your name and business address.

A Robert L. Sansom, S-a-n-s-o-m. Business address, 1901 North Moore Street, Arlington, Virginia.

Q By whom are you employed?

A The company is called Energy Ventures Analysis, Inc.

Q What is your position?

A I am the president of the company.

(CSX Exhibit No. 8 marked for identification.)

BY MR. HOLLIMON:

Q Dr. Sansom, will you please identify what's been labeled as Exhibit CSX 8.

A Yes, that's my resume.

Q Is that a current resume?

A Reasonably current. I am not sure exactly

when it was prepared.

Q Dr. Sansom, will you outline your educational background following high school.

A Yes. I graduated from the United States Air Force Academy in 1964.

Q Following the Air Force Academy, what did you do?

A I went to Georgetown University. The degree from the Air Force Academy was a bachelor of science degree. I went for a Master's degree in economics from Georgetown University.

Q Was that a Fulbright scholarship?

A No, the Fulbright scholarship, I went to Argentina on a Fulbright scholarship after that.

Q What did you do there?

A I went to Oxford and studied economics.

Q Was that on a road scholarship?

A Yes.

Q Dr. Sansom, what did you do when you left Oxford?

A I was a White House Fellow in 1968, '69 and worked for the Johnson Administration and the Nixon Administration.

Q What did you do next?

A I was on the National Security Council Staff

as a White House Fellow. And when Dr. Kissinger became the assistant to the President for National Security Affairs; he asked me to stay and I worked on the National Security Staff through 1971, April, I think.

Q Where did you go after that?

A I went to the U.S. Environmental Protection Agency.

Q What did you do there?

A My initial job was the deputy assistant administrator for planning and evaluation. The responsibilities of that job were to evaluate all standards and actions of the agencies, primarily their economic and environmental impact for the administrator.

Q What did you do when you left the EPA?

A Well, later on, I changed jobs at the EPA and I became the assistant administrator for air and water programs. And then I left the EPA around April 1974 and started a company called Energy and Environmental Analysis, Inc.

Q Dr. Sansom, will you please describe the work you did while you were with Energy and Environmental Analysis?

A Well, the principal focus of our work was energy issues and environmental issues primarily

McCann works for Mr. Kosky and Mr. Kosky is fully competent to testify about the results of the analysis.

THE COURT: Anything else? I will take that objection under advisement. I don't know that that -- if there is -- if I am to make a finding of fact based on the modeling, I am not sure that those things will overcome the hearsay nature of it. I will receive the exhibits, but as I say, it may be that I would not be able to make a finding of fact based upon the modeling.

(FP&L Exhibit R-125 received in evidence.)

(FP&L Exhibit R-178 received in evidence.)

MR. CUNNINGHAM: Thank you, Your Honor. That being the case, I would advise that I will consider here calling Mr. McCann to the stand. But back to Mr. Kosky.

BY MR. CUNNINGHAM:

Q Mr. Elias testified that DEP originally calculated historical NOx emissions for the Manatee Plant to be 6,827 tons per year based on fuel usage data and stack tests in 1993 and '94. In your opinion, is it valid to use stack testing data for this purpose, that is to calculate the historical NOx emissions from the Manatee Plant for those years?

A In my opinion, it is not.

Q Why not?

A A single stack test is a snapshot in time of the emissions of a source. In fact, FDEP rules regarding actual emissions as they relate to the federal air permitting program referred to as Title V specifically excludes the use of a single stack test in that use.

The other aspect of those tests are that those tests of particularly NOx emissions are done by an indirect method in terms of heat input. Heat input actually is overstated by this particular technique. When all those are taken into account, you actually would use a number that I concluded was appropriate and calculate the actual historical tons of 7,318 tons a year.

Q Mr. Elias also stated that he calculated or recalculated historical NOx emissions to be 5,478 tons per year based on the 1993, '94, fuel usage and extrapolating back from some 1996 and '97, continuous emission monitoring data.

In your opinion, is the manner in which Mr. Elias used the continuous emission monitoring data to calculate '93, '94 NOx emissions correct?

A No, his method was not correct.

Q Why not?
A His method was not correct because he did not factor in the actual load that the plant is operated during the different years between 1993 and '94, and 1995 and '96.
Q Let me show you what has been marked as FP&L 158.
(FP&L Exhibit No. R-158 marked for identification.)
BY MR. CUNNINGHAM:
Q Can you identify this document?
A Yes, this is an exhibit that I prepared showing historical NOx emissions using CEM data.
Q And referring to this exhibit, please explain the basis for your opinion that Mr. Elias's calculation of this figure is not correct.
A Mr. Elias's calculation incorrectly considered what's called net load in his calculation, that is the actual load while the plant is operating. He did conclude that it was appropriate that NOx emissions go up with load, but did not take that into consideration in this calculation. If he did, he would get a totally different conclusion than as shown on this exhibit.
I have listed in the far column what's

called net load. That's the actual load that the plant is when it's operating. It does include days of the plant nonoperating.

I have listed in two columns the 1993, '94, and 1995 net load factors. For '93, '94, it was 56 percent and for '95, '96, it was 41.1 percent. This is a significant difference in how the plant operated during those time frames.

The NOx, the actual NOx CEM data -- I actually looked at the whole year's, two years' worth of data in 1995 and '96 as well as I also looked at a portion of the year 1997.

The NOx CEM over those two years was .23 pounds per million BTU. Now, when you consider the differences in load, you can estimate in 1993, '94, what the CEM could have been in that year using the current CEM data. That is the '95, '96.

My conclusion as a result of my analysis was that the emissions were .3 pounds per million BTU which entirely supports my conclusion in the 1995 hearing as well as this hearing.

Using the .3 pounds per million BTU and the actual heat input, 1993, '94, you would calculate 7,318 tons a year.

Q In his testimony, Mr. Elias also noted that the annual operating report for the Manatee Plant for 1993 and '94 expressed a different value for NOx emissions than the 7,318 tons per year figure that you have calculated.

Can you explain why there is a difference?

A The only difference between the annual operating reports that Mr. Elias cited and our calculation was that we went to the plant and actually got the actual heat content of the fuels used during 1993, '94. That resulted in the calculation of the 7,318 tons a year.

Q How would you compare the accuracy of the figure that you calculated versus what was contained in the annual operating reports?

A The calculation that we made was much more accurate.

MR. CUNNINGHAM: We would offer FP&L R-158.

THE COURT: It's received.

(FP&L Exhibit R-158 received in evidence.)

BY MR. CUNNINGHAM:

Q On a different subject, Mr. Elias testified that NOx emission controls, other than the proposed low NOx burners and reburn technology, specifically mentioning Selective Catalytic Reduction, would be more cost effective for this project. Do you agree with that conclusion?

A No, I do not.

Q Why not?

A As I testified to in the 1995 hearing, for Best Available Control Technology, I concluded that SCR was not cost effective using low NOx burners at an emission rate --

MR. CURTIN: Excuse me. We would just object to this unless he is going to update it or something. All he is doing is regurgitating the testimony that he provided in 1995, which I think is in the transcript.

MR. CUNNINGHAM: In light of Mr. Elias's testimony, we did intend to update it.

MR. CURTIN: Okay. Pardon me.

A I recently updated the costs that I used in the 1995 hearing and determined the cost effectiveness of Selective Catalytic Reduction at an emission rate assuming it could meet 0.1 pounds per million BTU.

My analysis showed that the cost effectiveness of SCR would be $35,000 per ton of NOx removed. This is much higher than the 4,000 to $7000 a ton that FDEP has concluded on many projects as being unreasonable as BACT.

The actual cost effectiveness of the low NOx burners and reburn is $280 per ton. Even if you were to assume that BACT would apply to the project, the actual BACT determination would be made at an emission rate of .01255 pounds per million BTU.

MR. CURTIN: We object and move to strike. Mr. Kosky is not -- our witness did not testify as to a BACT analysis, and Mr. Kosky is now apparently going to be providing us with some sort of a BACT analysis.

That testimony does not rebut anything.

MR. CUNNINGHAM: I believe his testimony rebuts Mr. Elias's statement about the other more cost effective NOx control technologies, and BACT is a commonly used regulatory context in which to make that judgment.

MR. CURTIN: I have no problem with Mr. Kosky updating the cost effectiveness, but when he begins to testify about an emission limitation and what would constitute BACT and what would not, then I think he has gone beyond the testimony that Mr. Elias provided. And I don't know really what the reason is but obviously, they are trying to get it in the record for some reason.

THE COURT: I will sustain the objection.

MR. CUNNINGHAM: Can I inquire as to what was stricken?

THE COURT: Nothing was stricken. The objection was sustained.

MR. CURTIN: I did move to strike the testimony about .1255 constituting BACT.

THE COURT: I will grant that part of it because we are not -- I think it should be limited to the question that's being rebutted, which is what is the cost effectiveness of that SCR. And it does not open up the question of what's BACT.

MR. CUNNINGHAM: Thank you.

BY MR. CUNNINGHAM:

Q Mr. Kosky, were you present for the testimony of Mr. Pedersen on January 28, 1998, in this proceeding?

A Yes, I was.

Q Mr. Pedersen expressed concern that one of the conditions, condition Roman Numeral XIII B13, of the proposed conditions of certification would enable FP&L to change the 20 percent limit on opacity that is contained in a different condition.

Do you agree that that's a basis for concern?

A No. I don't believe it's a concern.

be coming from this project.

Q They are only mutually exclusive in your estimation. They are in the permit. They are separately listed in the permit; are they not?

A They are identified in the permit.

Q And they have been assigned emissions limits, haven't they, opacity limits?

A They have some opacity limits as a result of the performance standards.

Q Mr. Kosky, I am looking at, I guess, Page 23 of the exhibit, DEP R-1. I am going to read you a list of sources here and see if these are ones that you are saying should be eliminated.

Limerock, limestone, prepressure, 12 and 3, those should be eliminated, or should they be retained?

A I don't have that exhibit here.

Q Let me give it to you.

THE COURT What page?

MR. CURTIN: 23.

BY MR. CURTIN:

Q Maybe the easiest way to do it is take the exhibit that shows the sources that are gone, tell us which of the sources are the gone sources.

A Page 23, it would be sources 10 through 18. I am sorry, the conveyers -- yeah, 10 through 18.

Q 10 through 18. Those could be removed from the permit then?

A Yes. Also source number 8 which is a blending silo.

Q Thank you. Exhibit R-158, do you have that?

A Yes.

Q Looking at the column there, NOx CEM adjusted under 1993, 1994, you arrived at a .3 pounds per million BTU; correct?

A That's correct.

Q How exactly did you arrive at that number?

A I looked at the 1995, 1996, CEM data and the corresponding load data, developed a relationship of NOx emissions with load, then used that relationship to estimate 1993, '94, NOx emissions based on the actual load that the plant was operating in those years.

Q How did you develop that relationship? I just don't understand what you did here. So we need to have you explain that.

A It's real simple. I took the net load factors for various data, looked at the CEM data and developed a relationship, essentially an equation that factors in the increase of NOx with load. And in fact, that's the relationship that I determined from that data. I used that relationship to estimate '93, '94 based on the actual loads that the plant was operating during those years.

Q So it's kind of a linear relationship, is that what you are saying?

A It is a linear relationship, yes. Actually a quite good one.

Q NOx would go up as the load goes up, generally speaking?

A Yes. In fact, it's an excellent relationship. The differences I actually looked at with this equation, you can call it equation for '95, '96, I actually predicted for 1995-'96, what the CEM data would predict. That's the NOx CEM adjusted of .23. I actually predicted that.

The difference, the average differences in any unit in the data that I used was less than 2 percent. I call that a very good distribution.

Q You brought all that data with you here today so we could take a look at it?

A I have that data somewhere. I am not sure I have it here today. But I have -- yes, I have it.

Q But you don't know if you have it here today so we could have the benefit of taking a look at it?

A I may have it here, yes.

Q Tell me why you selected the '95, '96 time frame? What was the reason for that?

A Well, that was essentially two full years of CEM data that essentially have been validated. This is a requirement the EPA and I used that data for being full two years. Mr. Elias only used portions of '96 and '97.

In fact, I have looked at '97 and I get the same relationship, same data he used. The data, all data for 1997 is not yet available since it just was taken.

Q Let me ask you this, Mr. Kosky. I think you just testified that the relationship between NOx and loads is linear and that you would expect higher limits at higher -- or higher NOx at higher loads.

Explain to me why that is not reflected in the 1993 and '94 stack tests that were performed, I believe, at 84 percent, then 88 percent load?

A Well, as I characterized previously, that's a snapshot in time. It's a view over a very short time frame of load.

Also, that data is a -- it's taken indirectly in terms of heat input and that reflects, I believe, a slightly lower emission rate than when you use actual heat input by the fuel. Those two things in combination as well as DEP's position on using individual stack test data.

Q So you are saying that the stack test data should not be used to calculate or to give a historic emission figure; is that your testimony?

A That's been my testimony and conclusion.

Q Why did you use stack test data for particulate matter?

A It was an agreement. I concluded in June 1995 that that should not be used. In fact, the original application, I took a similar approach as I did with NOx.

In discussing that with the Department, we used a calculation, because quite frankly, particulate was not necessarily an issue in terms of historical emissions.

My conclusion in 1995 and my conclusion today is that the 1,768 that can be calculated is a low number for historical PM emissions.

Q You used the stack test data for that; did you not?

A Correct. It was an artifact of a calculation.

Q But it's stack test data; isn't it?

A Yes.

Q Do you know what historical emission limit is in the PSD preliminary determination for NOx?

A I believe I testified to that. I think it was 6,827 tons a year, which I --

Q Do you know what that was based on?

A I believe that was based on using stack test data.

Q Are you familiar with the report of the Department of Environmental Protection in the 1995 proceeding, the one that was signed by Secretary Wetherell?

A I am not that familiar. I am more familiar with the draft permit.

Q You don't know what number would be in that for historic NOx emissions?

A I haven't really looked at that.

Q I have got a copy here of what I believe is DEP Exhibit 1 from the original hearing. Maybe you could tell us what the historic NOx is out of that document.

A The actual historical emissions as included on Page 38, Table 1, is 6,827, which I have previously expressed to be low.

Q Right. Yeah. We understand that.

Mr. Kosky, in order for your 7,318 number to be the accurate number, it means that the facility would have had to run at the permit limit for a period of two years, '93, '94, for all barrels of oil that were burned during that period; correct?

A Well, the average would be that. And in fact, that's what your previous question on R-158 concluded.

Q That's what you concluded, but that wasn't what my question concluded.

A Right.

Q So you don't think you should use the continuous emission monitoring data or the stack test data, you think you should just use the permit limit?

A Well, in the time frame of 1993, '94, there was no CEM data.

Q Right.

A And as I indicated previously, I feel that you should use the permit limit that reflects historical emissions based on the factors that I previously testified.

Q But in projecting the future emissions, particularly NOx, you are not using the permit limit, are you, you are using .1255. Why is that?

A Those are conditions for the project.

Q What conditions are those for the project; they are not in the conditions of certification?

A Those are -- the conditions for the project have included a ton a year limit, 30-day rolling average limit, and a 24-hour maximum during ozone season limit. That's what you project.

Q The permit limit is .15; correct?

A As it's currently in the remand.

Q And you don't have any data to show what these particular units will do; do you?

A Well, you don't have data if it hasn't been built.

Q Right. But yet, you are going to use a lower limit than the permit limit to project the future emissions; is that right?

A In my analysis, I am using the 7,318 which is a permit limit.

Q You are assuming an emission limit of less than .15; correct?

A Well, it's an average emission limit of .1255, I don't see any reason why you couldn't meet that on a 30-day rolling average.

Q Is .1255 less than .15?

A Yes.

Q But yet, for historic emissions, when there are data available, you are using the .3 permit limit to calculate those; is that right?

A I am using .3 in the calculation.
Q Is that the permit limit?
A That's the permit limit, yes.
MR. CURTIN: I have no further questions, Your Honor.
THE COURT: Any other cross?

CROSS-EXAMINATION

BY MR. REESE:
Q Mr. Kosky, on your Exhibit R-156, those emissions are for the plant site, correct, they don't include any handling off the plant site?
A That is correct.
Q And your historic particulate emissions, that was based, I think you previously stated it was based on stack tests, but that was also with 21 days of soot blowing or 21 hours of soot blowing per day?
A Yes.
Q And Mr. Curtin asked you about DEP Exhibit 1 from the 1995 hearing. The report that you testified from concerning the historic NOx emissions, that was the report signed by Secretary Wetherell, correct? I think if you turn to the blue tab.
MR. CUNNINGHAM: I object to the form of the question in that it suggests Mr. Kosky testified from a report. Mr. Curtin had him read

Don

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STATE OF FLORIDA
DIVISION OF ADMINISTRATIVE HEARINGS

In Re: Florida Power & Light Company, Manatee Orimulsion Project, Application No. 94-35	DOAH CASE NO: 94-5675-EPP
In Re: Florida Power & Light Company, Manatee Orimulsion Project, PSD Permit No. PSD-FL-29	CASE NO. 95-4829 95-5036 95-5037 95-5598

WRITTEN PROFFER OF SURREBUTTAL TESTIMONY OF DONALD ELIAS

CSX Transportation, Inc. ("CSXT"), by and through undersigned counsel, hereby proffers the Surrebuttal Testimony of Donald Elias (Exhibit 1).

Respectfully submitted, this 16th day of February, 1998.

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Attorneys for
CSX Transportation, Inc.

A. Attachment 1 consists of pages 3-25, 3-26, 3-27, and 3-31 of the ISC3 Users Guide for Modeling. The ISC3 is the model used for impact assessment by both Florida Power & Light Company and CSX. This material states that the area source algorithms are to be used to model storage piles and mechanically generated emission sources such as mobile sources. The modeling performed on behalf of the applicant by Golder and Associates modeled these as volume sources. This underestimates the impacts and is totally inappropriate. Our modeling is identical with Golder's except for the area source correction. We show violations of standards that must be resolved. These violations preclude issuance of a permit.

Q. Mr. Kosky testified that your method of calculating historical nitrogen oxide emissions for the facility is inappropriate. Do you agree with that conclusion?

A. No I do not.

Q. Please explain your answer.

A. First of all, let me say that this is not merely an academic exercise that has no regulatory significance. The determination of whether PSD review is applicable for a particular pollutant, and whether the applicant must go through the rigorous analyses required by that review, depends upon the determination of the differences in emissions before and after physical changes or modifications have been made to the facility. The starting point for this calculation, of course, is the historical actual nitrogen oxide emissions. As I testified earlier, the applicant utilized the permit limit as its estimate of historical actual emissions. This was done even though it is conceded that the facility did not operate at the permit limit. This is totally inappropriate. When actual testing data are available, the testing data must be used. Mr. Kosky stated that the stack test information that was used in our analysis and used by the Department in reaching its conclusions as to actual emissions in the 1995 proceeding is unreliable. This is apparently based on his perception that a single stack test is a snapshot in time. However, neither our calculations nor those made by the Department were based on a single stack test. These calculations were based upon the use of four stack tests during the 1993 and 1994 period. These are the tests that were submitted to the Department by Florida Power & Light Company for purposes of showing compliance with the permit limits. As I noted earlier, these show limits substantially lower than the permit limit for nitrogen oxide. The other information that should be considered in determining historical nitrogen oxide emissions would be the continuous emission monitoring data that has been available from the facility since 1996. It is appropriate to use these data for several reasons. First, the data reflect the operation of the facilities after the steam atomization system was installed. This has the result of lowering the nitrogen oxide emissions substantially. Second, in determining the level of actual emissions that must be utilized, operational data from the most recent two years should be utilized. Florida Power & Light Company's decision to ignore the continuous emission monitoring data and the stack tests for nitrogen oxide emissions is unjustified and unexplained. In fact, it directly contradicts the applicant's decision to utilize stack testing data from 1993 and 1994 for establishing historical particulate matter emissions.

Q. Mr. Kosky testified that the Department's Title V rules specifically excludes the use of a single stack test for that program. Do you agree that this provides a justification for ignoring the stack test data in the calculation of historical emissions?

A. No I do not.

Q. Please explain your answer.

A. The Title V program is a program that is also mandated by the Federal Clean Air Act. The program requires that sources of air emissions generally obtain operation permits. The PSD program, on the other hand, is a construction permit program. One of the significant features of the Title V program is the requirement that the administering agency charge sources fees based upon the amount of emissions from the facility to fund the program. The fees are generally based on allowable emissions unless the applicant can demonstrate that a lower actual emission figure should be used. To ensure that the actual emissions are representative, the Department will not allow the use of a single stack test to establish the emissions upon which the fee is based. This is certainly not inconsistent with the methodology for establishing actual historic emissions under the PSD program. Again, we are not suggesting that a single stack test be used. We reviewed four stack tests, and there are others available. In addition, there is a large body of continuous emission monitoring data that also could be used. We are simply stating that, in light of all this available data, it is unreasonable for the applicant to presume that the historical actual emissions equal the permit limit. To reach that conclusion it is necessary to ignore the available data. That result is just not acceptable under the PSD permit program. Moreover, it would be unusual for the Department to disallow the use of these data even for Title V purposes.

Q. Mr. Kosky testified that it is customary to perform an impact analyses on what would be considered to be the worst case. Was this done in this application, in your opinion?

CONDITIONS OF CERTIFICATION

XIII. AIR

A. Operation and Construction

B. Fossil fuel-fired steam generating Units #1 and #2:

2. The maximum hourly heat input for each unit shall be 8650 MMBtu/hr while firing LSFO or HSFO; and 8100 MMBtu/hr while firing Orimulsion. The maximum rolling 12-month heat input for the facility while firing Orimulsion shall not exceed 116,64,360 MMBtu for all fuels.[a]

3. While firing Orimulsion ~~or HSFO~~, the sulfur dioxide (SO2) emissions from each unit shall not exceed 0.234 lb/MMBtu heat input, based upon a ~~30 day rolling~~ 3-hour[b] average. While firing HSFO, the sulfur dioxide emissions from each unit shall not exceed 0.172 lb/MMBtu, based upon a 3-hour average.[b,c] T~~t~~he annual facility emissions shall not exceed 13,643 tons per year, based upon actual annual MMBtu heat input. While firing LSFO the sulfur dioxide emissions from each unit shall not exceed ~~1.1~~ 0.055[d,e] lb/MMBtu heat input, based upon a ~~1 hour~~ 3-hour[b] average. Continuous emission monitors meeting the requirements of 40 CFR Part 75 shall be used to demonstrate compliance.

4.b. Compliance with these emission limits for Units 1 and 2 shall be demonstrated based upon quarterly compliance testing with Orimulsion or HSFO while burning each fuel that it fired using EPA Method 5B or 17 ~~for~~ conducted during any quarter in which the combined use of Orimulsion or HSFO is fired for more than 100 hours in either unit. Annual compliance testing with LSFO shall be required for any year in which LSFO is fired for more than 400 hours using the same methods. Compliance with the 858 tons per year limit shall be demonstrated by the following method: For each 3-run quarterly stack test, an average of the three test runs shall be calculated to the closest thousandth of lb/MMBtu for each emission unit. ~~The resulting average for each of the four quarterly tests in a calendar year shall then be averaged together to calculate an annual average to the closest average thousandth lb/MMBtu for each emission unit.~~ This ~~annual~~ average lb/MMBtu shall be multiplied by the actual fuel MMBtu input for ~~the~~ each calendar ~~year~~ quarter for each emission unit, based upon actual fuel receipts, inventories, and analyses, and summed to obtain the annual particulate emitted from each boiler.

If no quarterly test data is available, the previous quarter test results shall be used. The annual particulate emissions generated by the materials handling operations shall be calculated by stack test, ~~if performed~~ which shall be performed annually for all minor stack and vent sources,[f] and by emission factors for fugitive sources, and the calculations sealed by a professional engineer. Necessary data and operating records shall be collected and maintained by FPL for all assumptions used in the calculation of total facility emissions as shown in condition 27 below.

7.e. After submittal of the engineering report required pursuant to specific condition 7.d. above, the Department shall make a determination based on the engineering report, regarding establishment of any revised NOx limit for both units when firing Orimulsion. If results of the test program demonstrate that a NOx emission rate lower than ~~0.230~~ 0.15 lb/MMBtu heat input is practically and consistently achievable using low-NOx burners and reburn technology, the NOx emission limit applicable when firing Orimulsion shall be adjusted to reflect the lower emission rate accordingly. If the source does not achieve 0.15 lb/MMBtu heat input on a 30-day rolling average within 12 months, selective catalytic reduction (SCR) must be installed and operating within 12 months. Under no circumstances shall the emission limit be increased beyond the currently permitted value.

7.g. After submittal of the engineering report required pursuant to specific condition 7.f., the Department shall make a determination based upon the engineering report regarding establishment of any revised NOx limit for both units when firing fuel oil. If the results of the test program demonstrate that a NOx emission rate lower than ~~0.270~~ 0.15 lb/MMBtu heat input is practicably and consistently achievable using low-NOx burners and reburn technology, the NOx emission limit applicable when firing oil shall be adjusted accordingly. If the source does not achieve 0.15 lb/MMBtu heat input on a 30-day rolling average within 12 months, selective catalytic reduction (SCR) must be installed and operating within 12 months. Under no circumstances shall the emission limit be increased beyond the currently permitted value.

8. While firing Orimulsion fuel, emissions of carbon monoxide (CO) from each unit shall not exceed 0.325 lbs/MMBtu while firing Orimulsion and 0.634 lb/MMBtu while firing HSFO or LSFO.[g] ~~and the annual~~ Rolling 12-month facility emissions shall not exceed 18,948 tons per year based upon actual annual MMBtu

heat input. Compliance shall be demonstrated annually for each unit by conducting one 3-run test using EPA Method 10 while firing Orimulsion if Orimulsion is fired more than 400 hours. Testing shall be conducted for HSFO and/or LSFO for any year in which HSFO/LSFO firing exceeds 400 hours.

9. While firing Orimulsion, HSFO, or LSFO[g] fuel, total ~~annual~~ rolling 12-month emissions of volatile organic compounds (VOC) from the facility shall not exceed the current actual emissions of 122 tons per year. Compliance shall be demonstrated annually for each unit by conducting one 3-run test using EPA Method 25 while firing Orimulsion if Orimulsion is fired more than 400 hours. Testing shall be conducted for HSFO and/or LSFO for any year in which HSFO/LSFO firing exceeds 400 hours.

10. While firing Orimulsion, HSFO, or LSFO[g] fuel, ~~annual~~ rolling 12-month facility emissions of sulfuric acid mist shall not exceed 1,118 tons/year. Compliance shall be demonstrated annually for each unit by conducting one 3-run test using EPA Method 8 on each unit while firing Orimulsion if Orimulsion is fired more than 400 hours. Testing shall be conducted for HSFO and/or LSFO for any year in which HSFO/LSFO firing exceeds 400 hours. For each stack test, an average of the three test runs shall be calculated to the closest thousandth of lb/MMBtu. FPL shall design and operate each boiler to minimize SO_3 emissions.

11. While firing Orimulsion fuel, ~~annual facility~~ emissions of vanadium shall not exceed ~~170~~ 1.39 lb per hour per unit and 10.59 tons per year for the facility.[h] Compliance shall be demonstrated using a department-approved method by annually conducting one 3-run test while firing Orimulsion.

12. While firing Orimulsion, ~~if any of the following air pollutants exceed the values listed below, FPL shall be required to demonstrate that the applicable Ambient Reference Concentrations would not be exceeded at the actual emission rate or to otherwise demonstrate that the emissions of such pollutant would not pose an unacceptable risk to human health. The annual emissions shall be calculated for the following and included in the Annual Operating Report for inventory purposes only.~~ the following metals emitted from each facility shall not exceed the limits listed as follows:[i]

Pollutant	~~Demonstration Trigger~~ Lb/hr for each unit	Facility ton/yr

Antimony	0.0147	0.112
Arsenic	0.0106	0.0808
Barium	0.0101	0.0770
Beryllium	0.000061	0.0005
Cadmium	0.00515	0.0393
Chromium	0.0180	0.137
Copper	0.0118	0.0899
Fluoride	0.017	0.15
Lead	0.023	0.17
Manganese	0.0175	0.133
Mercury	0.001	0.008
Nickel	3.19	24.3
Phosphorous	0.0275	0.210
Selenium	0.126	0.960
Silver	0.00412	0.0314
Zinc	0.0324	0.247

Emissions testing for all listed metals shall be accomplished by ~~proposed~~ EPA Method 29 while firing Orimulsion during the initial test period and every five years thereafter. Emissions testing for fluoride shall be conducted using Method 13A or 13B while firing Orimulsion, during the initial test period and every five years thereafter.

<u>While firing Orimulsion, emissions testing for the following pollutants shall also be performed during the initial test period and every five years thereafter. Emissions testing shall be accomplished by Method 23 (40 CFR 60 Appendix A) and Method 0010 (SW-846). For these pollutants, which were not considered in the permit application, FPL shall be required to demonstrate that the applicable Ambient Reference Concentrations would not be exceeded at the tested emission rate or otherwise to demonstrate that the emissions of each pollutant would not pose an unacceptable risk to human health and the environment.</u>[j]

Acenaphthene	Acenaphthylene	Anthracene
Benzo(a)anthracene	Benzo(b)fluoroanthene	Benzo(k)fluoroanthene
Benzo(ghi)perylene	Benzo(a)pyrene	Dibenz(a,h)anthracene
Chrysene	Dioxins/Furans	Fluoroanthene
Fluorene	Indeno(1,2,3-cd)pyrene	Naphthalene
Phenanthrene	Pyrene	

<u>Results from the organic pollutant and metals testing will be included in the risk assessment required by Condition XXXI.4.</u>

14. The flue gas desulfurization, electrostatic

precipitation, and NOx pollution reduction equipment including reburn technology equipment for each unit shall be in operation while each unit is firing Orimulsion, low sulfur fuel oil,[d] or high sulfur fuel oil. ~~The electrostatic precipitator and the NOx pollution reduction equipment for each unit must be in operation while each unit is firing low sulfur fuel oil.~~

15. Excess Emissions

Materials Handling and Storage:

16. The maximum lime/limestone received at the facility shall be limited to 650,000 tons per ~~year~~ 12-month period.

17. The sources listed below are subject to the requirements of New Source Performance Standards for Non-Metallic Mineral Processing Plants 40 CFR 60 Subpart OOO.

~~03 Limerock/Limestone Truck Unloading~~[k]
~~04 Limerock Rail Unloading~~[k]
05 Limestone Storage Pile
06 Limerock Storage Pile
~~07 Limerock/Limestone Receiving Hopper~~[k]
~~08 Limestone Blending Silo~~[k]
09 Covered Limerock/Limestone Conveyors
~~10 Limerock/Limestone Day Silo #1~~[k]
~~11 Limerock/Limestone Day Silo #2~~[k]
~~12 Limerock/Limestone Day Silo #3~~[k]
~~13 Limerock Day Silo #1 Covered Recycle Conveyor~~[k]
~~14 Limerock Day Silo #2 Covered Recycle Conveyor~~[k]
~~15 Limerock Day Silo #3 Covered Recycle Conveyor~~[k]
~~16 Limerock/Limestone Precrusher #1~~[k]
~~17 Limerock/Limestone Precrusher #2~~[k]
~~18 Limerock/Limestone Precrusher #3~~[k]
~~19 Limestone Ball Mill #1 Tower Feed~~[k]
~~20 Limestone Ball Mill #2 Tower Feed~~[k]
~~21 Limestone Ball Mill #3 Tower Feed~~[k]

~~a. Emission units 16, 17, 18, 19, 20, and 21, unless enclosed in a building, shall not discharge fugitive emission that exhibit an opacity greater than 15%.~~

~~b.~~a. Emission units ~~04,~~ 05, 06, ~~07, 08,~~ and 09, ~~10, 11, 12, 13, 14, and 15,~~ unless enclosed in a building shall not discharge fugitive emissions that exhibit an opacity greater than 10%.

~~c.~~b. If any emission unit listed in condition 17a, or 17b is enclosed in a building, it must comply with the emission limits of the applicable condition. Alternatively, the building can comply with the following:

18. Particulate matter emissions from the emission units listed below shall not exceed ~~0.02~~ 0.003[f] gr/dscf and an opacity of 5%. Compliance with these standards shall be demonstrated by an initial performance test using EPA Method 5 or 17 and EPA Method 9 for opacity. ~~In accordance with F.A.C. 62-297.620, the particulate emission performance test may be waived if the units can demonstrate compliance with the visible emission standard of 5% opacity using EPA Method 9.~~[f]

25. As required by 40 CFR 52.21(b)(21)(v), FPL shall maintain adequate records and submit information to the Department demonstrating that the modifications did not result in an increase in annual emissions. The information shall be submitted on an annual basis for a period of not less than ten years from the date the unit begins normal operation with Orimulsion fuel.[l]

26. FPL shall provide to the Department all reasonable assurances as may be required prior to firing Orimulsion that public access will be restricted and denied in all areas excluded from the modeling analyses in the January 5, 1998 letter from Robert McCann to Wayne Ondler. Public access shall be restricted by fencelines of such extent to effectively deny public access, or any other methods which comply with USEPA guidance. The public shall mean all individuals other than FPL employees, their subcontractors, or plant visitors (i.e., leasing of FPL property for agricultural operations as currently described in the PPSA application will be prohibited in areas excluded from the modeling analyses).

27. In order to accurately estimate fugitive particulate emissions, FPL shall record and maintain the quantities of all materials (including gypsum and gypsum products, flyash and flyash products, limestone, limerock, and lime) moved, transported, stored, or disposed onsite capable of generating fugitive emissions. FPL shall periodically determine the silt and moisture contents of all material storage piles and predominately traveled onsite unpaved roads according to the procedures in AP-42 or similar EPA guidance documents (such measurements must be taken at least five days after any precipitation event or any surface watering).[m]

Modifications

~~25.~~28. FPL shall give written notification to the Department when there is any modification to this facility. This notice shall be submitted sufficiently in advance of any critical date involved to allow sufficient time for review, discussion, and revision of plans, if necessary. Such notice shall include, but not be limited to, information describing the precise nature of the change; modifications to any emission control system; production capacity of the facility before and after the change; and the anticipated completion date of the change.

XXIX. MANATEE COUNTY

C. TRUCK AND RAIL TRANSPORT

7. Rail transportation of orimulsion flyash from the Manatee Plant shall only be conducted in totally enclosed, pneumatic type, rail cars designed to completely contain the flyash.

ENDNOTES DESCRIBING REASONS FOR PROPOSED REVISIONS

[a]Annual limitation utilized by FPL for PSD applicability and contained in PSD Draft Permit.

[b]Averaging time of emission standard should equal the shortest averaging time of the appropriate ambient air quality standard (3-hours for SO_2).

[c]Condition XIII.B.14 requires the flue gas desulfurization equipment (specified in the PSD Draft Permit as achieving a minimum of 95% control) to be in operation while firing high sulfur fuel oil (HSFO), which gives emissions of:

$$\frac{3\ \text{lb sulfur}}{100\ \text{lb HSFO}} \times \frac{\text{lb HSFO}}{17{,}500\ \text{Btu}} \times \frac{2\ \text{lb } SO_2}{\text{lb sulfur}} \times \frac{10^6\ \text{Btu}}{\text{MMBtu}} \times (100\%-95\%) = \frac{0.172\ \text{lb}}{\text{MMBtu}}$$

[d]The PSD Draft Permit (Specific Condition 14) requires operation of the flue gas desulfurization equipment while firing Orimulsion, HSFO, and LSFO. As currently written, the conditions of certification represent a relaxation from the PSD Draft Permit which was not appropriately publicly noticed.

[e]Flue gas desulfurization equipment (specified in the PSD Draft Permit as achieving a minimum of 95% control) will limit low sulfur fuel oil (LSFO) emissions to:

$$\frac{1\ \text{lb sulfur}}{100\ \text{lb HSFO}} \times \frac{\text{lb HSFO}}{18{,}300\ \text{Btu}} \times \frac{2\ \text{lb } SO_2}{\text{lb sulfur}} \times \frac{10^6\ \text{Btu}}{\text{MMBtu}} \times (100\%-95\%) = \frac{0.055\ \text{lb}}{\text{MMBtu}}$$

[f]Compliance with the extremely aggressive (i.e., low) emission limit of 0.003 gr/dscf should be determined by annual stack tests, which will be federally enforceable.

[g]As a major criteria pollutant (or significant noncriteria pollutant) PSD source, emission limits should be specified for all fuels.

[h]Emission rates as given in the PSD Draft Permit. The revised emissions in the conditions of certification would result in exceedances of the Florida Ambient Reference Concentrations for

vanadium, but no risk analysis was performed for the higher emission rate.

[i]The revised conditions of certification as currently written represent a relaxation from the PSD Draft Permit which were not appropriately publicly noticed.

[j]No data has been gathered or presented by FPL for organic emissions (dioxins/furans and polycyclic organic matter), although there is a potential for emissions of these compounds based on EPA studies of electric utility sources using coal and oil. Since FPL is proposing to utilize a fuel that has never been commercially used in the United States and which has not been studied as part of the Section 112(n) of the Clean Air Act, such testing and health risk assessments should be performed as part of the initial compliance test and periodically thereafter.

[k]Sources deleted by FPL for rail enhancements based on Kosky testimony.

[l]Since FPL has chosen to use future actual emissions under the electric utility steam generator unit rules to avoid PSD and BACT review for some pollutants, it is important that FPL demonstrates compliance as required by the regulations for this exemption. The Department is requiring 10 year recordkeeping and reporting for the retrofit projects at the Hillsborough County and City of Tampa McKay Bay municipal waste combustors.

[m]Since FPL chose to avoid PSD and BACT review for particulate emissions by limiting emissions for all minor PM vents and fugitive emissions to less than 18 tons per year, FPL should be required to maintain adequate records in order to accurately estimate emissions from all such activities so that the permit limit is federally enforceable as a practical matter.

RTP ENVIRONMENTAL ASSOCIATES INC.®

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March 17, 1998

Mr. Brian Beals
U.S. EPA - Region IV
100 Alabama Street, N.W.
Atlanta, GA 30303

Dear Mr. Beals:

I've enclosed additional written information concerning our comments on the Orimulsion project proposed by Florida Power & Light (FP&L) for their Manatee power station. As I indicated to you during our phone conversation, we have considerable concerns related to this application and its processing. The most serious issue relates to the calculation of historical actual, and future predicted emissions for nitrogen oxides (NO_x). We believe there has been a clear miscalculation in the current permitting case, such that PSD review should be required. Additionally, numerous changes have occurred throughout the project that would necessitate reissuing a draft permit for public review.

I've enclosed some back-up calculations related to the NO_x issues to support our contention. Additionally, I understand Manasotta 88 submitted separately a copy of an issues book with references as part of the PSD permit. These contain our additional comments on the application process.

I appreciate your current staff difficulties in terms of availability, but feel that this project is extremely sensitive nationwide as well as within Region IV, and deserves a high priority.

Please feel free to give me a call at (732) 968-9600 if you wish to discuss the enclosed materials or require any further information.

Sincerely,

RTP ENVIRONMENTAL ASSOCIATES, INC.®

Donald F. Elias

Donald F. Elias
Principal

DFE/trp
Enclosures
cc: G. Worley
C. Fancy
L. Curtin
Proj. File - HKOR

ISSUE # 5: Historical Actual Emissions for NO_x Overstated

Historical actual emissions for NO_x are incorrectly calculated and require a further reduction either in emission rate or unit availability to avoid PSD review.

BASIS: Historical actual NO_x emissions as presented in the application and recent applicant exhibits disagree with the annual operating reports filed by the applicant. Since both were filed as true, complete, and accurate, obviously one must be corrected. Assuming the current information filed with the application is correct, it states 7318 tons per year as the historical actuals. This seems to be based on the permit allowables rather than actuals. If you calculate the actuals used by the average of the CEM data, rather than the permit allowables, total average annual actual NO_x emissions based on the '93-'94 data would be 5478 tons/year. Since the facility now operates with steam atomization to reduce NO_x, the "representative" facility rate is the current rate represented by the CEM data times the historical capacity factor. In order to avoid a significant increase for NO_x, future actuals would need to be reduced either by reducing the emission rate or by reducing the operating hours.

BASIS: 1993 and 1994 Annual Operating Reports, Exhibit R-50 from Kosky deposition, CEM data for the Manatee Generating Station, and copy of calculations.

MEMORANDUM

TO: Donald F. Elias
FROM: Brian L. Lubbert & A. Roger Greenway
DATE: 23-Jan-98
SUBJECT: Comparison of Actual Historical Emissions

Comparison of Actual Historical Emissions

Pollutant	Average Emissions Em. Stmt.93 -94	'94 Permit App. Table 3-3 Emissions	FL-DEP Draft Permit Table 1	Kosky Exhibit 6	Additional Stack Test Data	CEM Data
NOx	7198	7581	6827	7318	6813	5478
TSP.	2516	3159	1707	1768-1792	1627	NA

See Attached Calculations, Exhibits, and Emission Statements

DEP - B3 1/15/95

NOx - 7294

caused by switch in heat content from 151,890 Btu/gal to 152,381 Btu/gal

CALCULATIONS
NOx Emissions

Emission Statements

1993	44 lb /kgal	X	313,830.67	kgal	6904 Tons	Average=	7198 T
1994	45.71 lb /kgal	X	327,800.00	kgal	7492 Tons		

**44 lb/kgal is AP-42, 45.71 lbs/kgal is the product of 0.3 lbs/MMBtu by 152,381 Btu/gal

1994 Permit App.

1993	45.564 lb /kgal	X	313,830.68	kgal*	7150 Tons	Average=	7581 T
1994	45.564 lb /kgal	X	351,644.08	kgal*	8011 Tons		

1994 est on fuel usage — *Calculated from Table A-10 (bbls)

**45.594 lbs/kgal is the approx. the product of 0.3 lbs/MMBtu by 151,980 Btu/gal

NOTE: calculation must use 45.564 lbs/kgal to equal what is in permit app.

FL-DEP Permit PA 94-35 PSD-FL-219

0.280 lbs/MMBtu X 48,785,409 MMBtu — 6827 Tons — Average= 6827 T

**Fuel usage/Heat Input based on Kosky Exhibit 10 (average 1993/94).

Emission Factor based on average emissions from stack test reports (see Table 1 footnote a) in Draft Permit PA-35 nPSD-FL-219

Kosky Exhibit 6

0.3 lbs/MMBtu X 48,785,409 MMBtu — 7318 Tons — Average= 7318 T

**Fuel usage/Heat Input based on Kosky Exhibit 10 (average 1993/94)

CEM data

Boiler #1(93)	0.219 lbs/MMBtu	X	20,749,229	MMBtu	2272 Tons		
Boiler #2(93)	0.229 lbs/MMBtu	X	27,072,589	MMBtu	3100 Tons		
		1993:	47,821,818	MMBtu	5372 Tons		
Boiler #1(94)	0.219 lbs/MMBtu	X	22,451,949	MMBtu	2458 Tons		
Boiler #2(94)	0.229 lbs/MMBtu	X	27,297,050	MMBtu	3126 Tons		
		1994:	49,748,999	MMBtu	5584 Tons		
						Average=	5478 T

**Fuel usage/Heat Input based on KoskyExhibit 10

1993/1994 Emissions Compliance Test for Boilers #1 and #2

Boiler #1(93)	0.29 lbs/MMBtu	X	20,749,229	MMBtu	3009 Tons		
Boiler #2(93)	0.29 lbs/MMBtu	X	27,072,589	MMBtu	3926 Tons		
		1993:	47,821,818	MMBtu	6934 Tons		
Boiler #1(94)	0.28 lbs/MMBtu	X	22,451,949	MMBtu	3143 Tons		
Boiler #2(94)	0.26 lbs/MMBtu	X	27,297,050	MMBtu	3549 Tons		
		1994:	49,748,999	MMBtu	6692 Tons		
						Average=	6813 T

Compliance test data is used to estimate the actual historical emissions during the year the stack test was taken.
Compliance test data for Boiler #1 is from 4/1/93 and 5/12/94.
Compliance test data for Boiler #2 is from 4/22/93 and 6/8/94.
**Fuel usage/Heat Input based on KoskyExhibit 10
Annual emissions estimates are based on calculation format used in Kosky Exhibit 10

Emission Compliance Test (1993/94 assuming Worst-case results of 0.29 lbs/MMBtu)

0.29 lbs/MMBtu X 48,785,409 MMBtu — 7074 Tons — Average= 7074 T

Emission Factor based on worst-case results of 1993 and 1994 stack tests.
** Fuel usage/Heat Input based on Kosky Exhibit 10 (average 1993/94)

CALCULATIONS
CEM Test Data: 3Q, 4Q 1996 and 1Q, 2Q, 1997 (Kosky Exhibit 10 12/11/97)

NOx
Boiler #1

1993	136,167	kGal/yr	1994	147,341	kGal/yr
x	152.381	MMBtu/kgal	x	152.381	MMBtu/kgal
	20,749,229	MMBtu		22,451,949	MMBtu
x	0.219	(EF)lbs/MMBtu	x	0.219	(EF)lbs/MMBtu
	2272	T (NOx)/year		2458	T (NOx)/year

Boiler #2

1993	177,664	kGal/yr	1994	179,137	kGal/yr
x	152.381	MMBtu/kgal	x	152.381	MMBtu/kgal
	27,072,589	MMBtu		27,297,050	MMBtu
x	0.229	(EF)lbs/MMBtu	x	0.229	(EF)lbs/MMBtu
	3100	T (NOx)/year		3126	T (NOx)/year

Total Emissions	Boiler #1	Boiler #2	Total	
1993	2272	3100	5372	T (NOx)/year
1994	2458	3126	5584	T (NOx)/year
Average	2365	3113	5478	T (NOx)/year

(Kosky Exhibit 10 12/11/97)
PM
Boiler #1

1993	136,167	kGal/yr	1994	147,341	kGal/yr
x	152.381	MMBtu/kgal	x	152.381	MMBtu/kgal
	20,749,229	MMBtu		22,451,949	MMBtu
x	0.05875	(EF)lbs/MMBtu	x	0.07	(EF)lbs/MMBtu
	610	T (PM)/year		786	T (PM)/year

EF determined as 87.5% of operation: Sootblowing at 0.06 lbs/MMBtu
plus 12.5% of operation: Steady State at 0.05 lbs/MMBtu
EQ: 87.5%x0.06 + 12.5%x0.05 = 0.05875

EF determined as 0.07 =sootblowing=steady state

Boiler #2

1993	177,664	kGal/yr	1994	179,137	kGal/yr
x	152.381	MMBtu/kgal	x	152.381	MMBtu/kgal
	27,072,589	MMBtu		27,297,050	MMBtu
x	0.08	(EF)lbs/MMBtu	x	0.0775	(EF)lbs/MMBtu
	1083	T (PM)/year		1058	T (PM)/year

EF determined as 0.08 =sootblowing=steady state

EF determined by 87.5% of operation: Sootblowing at 0.08 lbs/MMBtu
plus 12.5% of operation: Steady State at 0.06 lbs/MMBtu
EQ: 87.5%x0.08 + 12.5%x0.06 = 0.0775

Total Emissions	Boiler #1	Boiler #2	Total	
1993	610	1083	1693	T (PM)/year
1994	786	1058	1844	T (PM)/year
Average	698	1071	1769	T (PM)/year

NOTE: annual fuel usage is rounded to nearest kgal, MMBtu as shown above calculated (apparently) from actual gallons
Fuel usage numbers/Heat Input based on Exhibit 10)

CALCULATIONS

Annual Emissions Statement(s)

Total Emissions	Boiler #1	Boiler #2	Total	
1993	828	1080	1908	T (PM)/year
1994	1404	1719	3123	T (PM)/year
Average	1116	1400	2516	T (PM)/year

Annual Emissions Statement(s)

Total Emissions	Boiler #1	Boiler #2	Total	
1993	2996	3909	6905	T (NOx)/year
1994	3367	4124	7491	T (NOx)/year
Average	3182	4017	7198	T (NOx)/year

See Attached Emission Statements

DEP-B3

Comment: The application states the current actual emissions to be the highest emissions while firing low sulfur fuel oil (LSFO), although actual emissions are defined in Rule 62-212.200(2) (a), FAC., to be "in general, actual emissions as of a particular date shall equal the average rate, in tons per year, at which the source actually emitted the pollutant during a two year period which precedes the particular date and which is representative of the normal operation of the source". Using the date of application, September 30, 1994, as the "particular date" please provide the actual emissions for the two-year period preceding it. Include your calculations, revise any tables as necessary, and revise or add any modeling as necessary. For example, a review of FPL's annual operating report data, which was submitted for 1992 and 1993, indicates that the increase in particulate matter and PM10 is PSD-significant.

Response: The emission data for the two units at the Manatee Plant presented in the Site Certification Application (SCA) represent actual emission data for the two units for 1993 and 1994. As discussed in the SCA, the 1994 data were based on actual fuel consumption through July 31, 1994, and prorated to the remainder of the year. These data were considered to represent the emissions from the normal operation of the two units for a 2-year period. Although another 2-year period might also be considered, the net changes in actual emissions from the units exceed the PSD significant emission rates for only nitrogen oxides (NO_x) and carbon monoxide (CO), regardless of which 2-year period is considered representative. The net changes in actual emissions are similar even if the last 3 years are considered in the evaluation. As a result, the PSD applicability analyses and review process do not change from those presented in the SCA. The suggestion that the increases in particulate matter and PM10 emissions are PSD-significant is incorrect.

Comparisons of actual annual emissions for the existing units at the Manatee Plant were performed by evaluating fuel usage data over the last 3 years, (1992 through 1994). As requested, an evaluation was performed for September 1992 through September 1994, the 2-year period preceding the application submittal date of September 30, 1994; an evaluation has also been performed for 1993 and 1994 using actual fuel use data for August through December 1994 that was not available at the time of SCA submittal. Summaries of the fuel usage and annual capacity factors for each unit are presented in Table DEP-B3-1 for the period of September 1992 through September 1994; and Table DEP-B3-2 for the years 1993 and 1994. These tables are comparable to Table A-10 presented in the Appendix 10.1.5, Volume II of the SCA.

Comparisons of the maximum estimated annual emissions for existing low sulfur fuel oil (LSFO) and the proposed firing of Orimulsion for the selected periods are presented in Table DEP-B3-3. Emissions are shown for sulfur dioxide, particulate matter, nitrogen oxides, carbon monoxide, volatile organic compounds, and lead. Emissions of other regulated pollutants presented in the SCA (i.e., sulfuric acid mist, fluorides, mercury, beryllium, and arsenic) were added together and summarized. As shown, although there are some differences in the net emission changes for all pollutants among the evaluations, NO_x and CO continue to be the only two pollutants for which there is a PSD-significant net emission increase. For the other regulated pollutants, there is a net decrease in emissions requiring no PSD review. As shown in the footnote, the average annual capacity factors for the plant for the evaluated time periods are within 3 percent, indicating the relatively minor differences in plant operation among the time periods. It should be noted that the emission data for 1992 may not be representative of actual plant operation because of planned outages for equipment upgrades that occur about once every 15 years (the units were not operating for about 25 percent of the year). Therefore, the use of emission data for this year is not necessarily representative of annual plant emissions.

The maximum emissions estimated for the AORs are different than those presented in the Air Permit Application. The information reported in the AORs are based on average emission factors obtained from the EPA document, "Compilation of Air Pollutant Emission Factors," which is referred to as AP-42. These factors do not account for "excess emissions" which are allowed under DEP regulations (Rule 62-210.700, Excess Emissions) and were incorporated in the air permit for each unit. For example, under steady-state operating conditions, each unit has a PM emission limit of 0.1 lb/MMBtu. However, during sootblowing and load changing, each unit can emit up to 0.3 lb/MMBtu for 3 hours in a 24-hour period . As an example, PM emissions for 1992 and 1993 reported in the AORs were estimated to be 1,896 TPY. For this same time period, by accounting for sootblowing, the PM emissions are estimated to be 2,953 TPY. Also, source specific allowable emissions can be assumed equivalent to actual emissions provided that the source specific allowable emissions are federally enforceable (see Rule 62-212.200(2)). These federally enforceable emission limiting standards are codified in Rule 62-296.405 for PM,

SO_2, and NO_x. As a result, the emission limits for these pollutants were used in estimating actual emissions when each unit is firing LSFO.

It should be noted that even using the AORs for 1992 and 1993, PSD applicability for PM/PM10 would not change. As noted above the AORs presented average annual PM/PM10 emissions of 1,896 TPY for 1992/1993. The representative actual PM/PM10 emissions when firing Orimulsion would be 1,749 TPY which is a 147 TPY decrease in PM/PM10 emissions even though sootblowing emissions were not expressly accounted for in the AORs; thus, PSD applicability would not be triggered.

No additional air modeling is required because the impacts due to firing Orimulsion or HSFO assumed the maximum emission rate for each pollutant and did not account for the difference in emissions between firing these fuels and LSFO. For example, the air quality modeling analyses for the Manatee Plant after conversion to Orimulsion that addressed compliance with the NO_2 maximum allowable PSD Class II and I increments did not include the existing Manatee Plant (see Section 7.3 and 7.4, Appendix 10.1.5, Volume II of the SCA). As a result, the increment consumption would be lower than the maximum value reported (increment consumption due to the Manatee Plant is the difference in impacts between the proposed future operations and actual existing operations).

Table DEP-B3-1. Existing Fuel Oil Usage at the FPL Manatee Plant (9/29/92 to 9/28/94)

Parameter	Values for FPL Units	
	Unit 1	Unit 2
Fuel Usage (bbls)		
9/29/92 to 9/28/94	6,639,726	7,951,034
Average	3,319,863	3,975,517
Maximum	11,877,957	11,877,957
Capacity Factor (a)		
9/29/92 to 9/28/94	27.95%	33.47%
Average	27.95%	33.47%
Sulfur Content:		
1992	0.989%	0.986%
1993	0.973%	0.973%
1994	0.973%	0.976%

(a) Based on maximum heat input of 8,650 MMBtu/hr per unit and fuel oil with heat content and density of 18,300 Btu/lb and 8.3 lb/gal, respectively.

Table DEP-B3-2. Existing Fuel Oil Usage at the FPL Manatee Plant (1993/1994) – Actual Fuel Use

Parameter	Values for FPL Units	
	Unit 1	Unit 2
Fuel Usage (bbls)		
1993	3,242,067	4,230,092
1994	3,508,117	4,265,164
Average	3,375,092	4,247,628
Maximum	11,877,957	11,877,957
Capacity Factor (a)		
1993	27.29%	35.61%
1994	29.53%	35.91%
Average	28.41%	35.76%
Sulfur Content:		
1993	0.973%	0.973%
1994	0.973%	0.976%

(a) Based on maximum heat input of 8,650 MMBtu/hr per unit and fuel oil with heat content and density of 18,300 Btu/lb and 8.3 lb/gal, respectively.

Table DEP-B3-3. Comparison of Maximum Estimated Annual Emissions for Existing Low Sulfur Fuel Oil (Actual) and Proposed Orimulsion Representative Actual) Firing at FPL Manatee Units 1 and 2

Pollutant	Emissions (TPY)-Existing Units: Low Sulfur Fuel Oil	Emissions (TPY)- Orimulsion: 2 Units	Emissions (TPY)- Orimulsion: Difference (Orimulsion-LSFO)	PSD Significant Net Emission Rate (TPY)	Significant Net Emission Increase ?
Actual Emissions Based on 1993/1994 – presented in SCA (1)					
Sulfur Dioxide	27,617	13,635	−13,982	40	No
Particulate Matter	3,159	1,749	−1,410	25	No
Particulate Matter (PM10)	2,274	1,749	−525	15	No
Nitrogen Oxides	7,581	17,491	9,910	40	Yes
Carbon Monoxide	16,026	18,948	2,922	100	Yes
Volatile Organic Compounds	126.4	117.6	−8.8	40	No
Lead	0.708	0.163	−0.544	0.6	No
Other Regulated Pollutants (2)	1,162	420	−743	(2)	No
Actual Emissions Based on 1993/1994 Actual Fuel Usage (3)					
Sulfur Dioxide	26,573	13,635	−12,938	40	No
Particulate Matter	3,039	1,749	−1,290	25	No
Particulate Matter (PM10)	2,188	1,749	−439	15	No
Nitrogen Oxides	7,294	17,491	10,196	40	Yes
Carbon Monoxide	15,420	18,948	3,528	100	Yes
Volatile Organic Compounds	121.7	117.6	−4.1	40	No
Lead	0.681	0.163	−0.518	0.6	No
Other Regulated Pollutants (2)	1,119	420	−699	(2)	No
Actual Emissions Based on 9/92 to 9/94 (4)					
Sulfur Dioxide	25,432	13,635	−11,797	40	No
Particulate Matter	2,909	1,749	−1,160	25	No
Particulate Matter (PM10)	2,094	1,749	−345	15	No
Nitrogen Oxides	6,981	17,491	10,510	40	Yes
Carbon Monoxide	14,758	18,948	4,190	100	Yes
Volatile Organic Compounds	116.4	117.6	1.2	40	No
Lead	0.652	0.163	−0.488	0.6	No
Other Regulated Pollutants (2)	1,071	420	−651	(2)	No

(1) See Table 3-3 and Table A-11, Appendix 10.1.5, Volume II, Site Certification Application; fuel usage from 1993 and 1994 (fuel usage through 7/31/94 prorated to entire year).
(2) Other regulated pollutants include sulfuric acid mist (7 TPY), fluorides (3 TPY), mercury (0.1 TPY), beryllium (0.0004 TPY), and arsenic (0 TPY) [Numbers in parentheses in this footnote are the PSD significant emission rates for each specific pollutant).
(3) Based on actual fuel usage from 1993 and 1994.
(4) Based on maximum allowable emission rates/test data from SCA and fuel usage from September 29, 1992 through September 28, 1994.

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Department of Environmental Protection

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

Virginia B. Wetherell
Secretary

PERMITTEE:
Florida Power & Light Company
700 Universe Boulevard
Juno Beach, Florida 33408

Permit Number: PA 94-35
PSD-FL-219
Expiration Date: December 31, 1998
County: Manatee
Location: Hwy 62, 5 miles NE of Parrish, FL
UTM: 17-367.3 km E 3054.1 km N
Project: Manatee Power Plant Modification
Orimulsion Conversion Project

This permit is issued under the provisions of Chapter 403, Florida Statutes, and Florida Administrative Code Chapters 62-200 through 297 & Chapter 62-4. The above named permittee is hereby authorized to perform the work or operate the facility shown an the application and approved drawing(s), plans, and other documents, attached hereto or on file with the department and made a part hereof and specifically described as follows:

For modification of existing emission units

01 Unit #1 - Fossil fuel-fired steam generating unit
02 Unit #2 - Fossil fuel-fired steam generating unit

including adding additional sootblowers and increasing heat surface area of the boilers to accommodate the firing of Orimulsion fuel, and High (maximum 3.0% by weight) Sulfur Fuel Oil (HSFO) when Orimulsion is unavailable, in addition to the Low (1.0% or less) Sulfur Fuel Oil (LSFO) currently fired in the units. Air pollution control equipment, including a Pure Air flue gas desulfurization (FGD) system with a minimum sulfur dioxide removal efficiency of 95%, Pure Air electrostatic precipitators (ESP) with a minimum particulate removal efficiency of 90%, and low-NOx burners, will be installed to reduce emissions of sulfur dioxide, particulate matter, and nitrogen oxides; and

For construction of new emission units for handling and storage of limerock/limestone, flyash, and gypsum as listed below:

03 Limerock/Limestone Truck Unloading - fugitive emissions
04 Limerock Rail Unloading - fugitive emissions
05 Limestone Storage Pile - fugitive emissions
06 Limerock Storage Pile - fugitive emissions
07 Limerock/Limestone Receiving Hoppers - fugitive emissions
08 Limestone Blending Silo with dust collector/bag filter vent

Table 1: Significant and Net Emission Rates (Tons per Year)

Pollutant	Low Sulfur Fuel Oil Actual Emissions$_a$	Projected Maximum Emissions$_b$	Proposed Net Emissions Increase	Significant Emission Rate	Applicable Pollutant (Yes/No)
PM **	1,707	1,707	0	25	No
PM_{10} **	1,707	1,707	0	15	No
SO_2	24,492	13,643	-10,849	40	No
NO_X	6,827	15,742 *	8,915	40	Yes
CO	15,463	18,948	3,485	100	Yes
VOC	122	117 ***	-5	40	No
Lead	0.683	0.163 +	-0.520	0.6	No
Mercury	0.078	0.006 ***	-0.072	0.1	No
Beryllium	0.10240	0.00036 ***	-0.10205	0.0004	No
Fluorides	0.15	0.037 +	-0.117	3	No
Sulfuric Acid Mist	1,122	420 ***	-702	7	No

a–NO_X and particulate emission rates based on 1993 and 1994 fuel data, heat content of 152 mmBtu/kgal and average emissions from stack test reports. SO_2 emissions based on annual operating report (AOR). Emission rates for other pollutants based on emission factors.

b–based on 87 percent capacity factor and a maximum continuous heat input rating of 7,650 mmBtu/hr firing Orimulsion.

* Based on NO_X emission limit of 0.27 lb/mmBtu as provided by FPL. Annual NO_X emissions with a limit of 0.17 lb/mmBtu would be 9,912 TPY.

** Annual PM/PM_{10} emissions capped at previous actual emission level by permit condition.

*** Based on emission rates from tests on Orimulsion submitted by FPL.

+ Based on EPA emission factor and 90% control.

FLORIDA POWER AND LIGHT COMPANY
PLANT SERVICES OPERATIONS SUPPORT
700 UNIVERSE BLVD.
JUNO BEACH, FLORIDA 33408-0240

NOx EMISSION TEST

PLANT: MANATEE
UNIT: 1
TEST: NITROGEN OXIDE EMISSIONS
METHOD: 40 CFR Pt. 60, App. A. 3A & 7E

	RUN 1	RUN 2	RUN 3
DATE OF RUN	04/01/93	04/01/93	04/01/93
GROSS LOAD (AVG MMBTU/HR)	7311	7311	7311
START TIME (24-HR CLOCK)	1129	1403	1538
END TIME (24-HR CLOCK)	1229	1503	1638
CO2 (CORRECTED % DRY)	13.2	13.5	13.4
O2 (CORRECTED % DRY)	4.1	3.9	4.0
Fo TEST	1.273	1.259	1.261
NET TIME OF RUN (MIN)	60	60	60
MEASURED CONCENTRATION (PPM NOx)	213.0	207.4	206.6
AVG ZERO BIAS CHECK (PPM NOx)	0.0	0.0	0.0
UPSCALE CAIBRATION GAS (PPM NOx)	205.0	205.0	205.0
AVG UPSCALE BIAS CHECK (PPM NOx)	202.3	200.3	199.4
CORRECTED CONCENTRATION (PPM NOx)	215.9	212.4	212.4
HEAT INPUT OIL (%)	100.0	100.0	100.0
HEAT INPUT GAS (%)	0.0	0.0	0.0
WEIGHTED AVERAGE F FACTOR (DSCF/MMBTU)	9190.0	9190.0	9190.0
NOx EMISSIONS (LB/MMBTU)	0.294	0.286	0.288
AVERAGE NOx EMISSIONS (LB/MMBTU)		0.29	
NOx EMISSIONS STANDARD (LB/MMBTU)		0.30	

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FLORIDA POWER AND LIGHT COMPANY
PLANT SERVICES OPERATIONS SUPPORT
700 UNIVERSE BLVD.
JUNO BEACH, FLORIDA 33408-0240

NOx EMISSION TEST

PLANT: MANATEE
UNIT: 2
TEST: NITROGEN OXIDE EMISSIONS
METHOD: 40 CFR Pt. 60, App. A, 3A & 7E

	RUN 1	RUN 2	RU
DATE OF RUN	04/22/93	04/22/93	04/22
GROSS LOAD (AVG MMBTU/HR)	7231	7231	7
START TIME (24-HR CLOCK)	1116	1255	1
END TIME (24-HR CLOCK)	1216	1355	1
CO2 (CORRECTED % DRY)	13.7	13.7	1
O2 (CORRECTED % DRY)	3.7	3.7	
Fo TEST	1.255	1.255	1.
NET TIME OF RUN (MIN)	60	60	
MEASURED CONCENTRATION (PPM NOx)	211.7	214.8	21
AVG ZERO BIAS CHECK (PPM NOx)	0.0	0.0	
UPSCALE CAIBRATION GAS (PPM NOx)	128.9	128.9	12
AVG UPSCALE BIAS CHECK (PPM NOx)	125.5	126.5	12
CORRECTED CONCENTRATION (PPM NOx)	217.5	218.9	21
HEAT INPUT OIL (%)	100.0	100.0	10
HEAT INPUT GAS (%)	0.0	0.0	
WEIGHTED AVERAGE F FACTOR (DSCF/MMBTU)	9190.0	9190.0	919
NOx EMISSIONS (LB/MMBTU)	0.289	0.291	0.

AVERAGE NOx EMISSIONS (LB/MMBTU)	0.29
NOx EMISSIONS STANDARD (LB/MMBTU)	0.30

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FLORIDA POWER AND LIGHT COMPANY
PLANT SERVICES OPERATIONS SUPPORT
700 UNIVERSE BLVD.
JUNO BEACH, FLORIDA 33408-0240

NOx EMISSION TEST

PLANT: MANATEE
UNIT: 2
TEST: NITROGEN OXIDE EMISSIONS
METHOD: 40 CFR Pt. 60, App. A, 3A & 7E

	RUN 1	RUN 2	RUN
DATE OF RUN	06/08/94	06/08/94	06/08/
GROSS LOAD (AVG MMBTU/HR)	7602	7602	76
START TIME (24-HR CLOCK)	1100	1232	14
END TIME (24-HR CLOCK)	1200	1332	15
CO2 (CORRECTED % DRY)	13.1	13.2	13
O2 (CORRECTED % DRY)	4.0	4.0	3
Fo TEST	1.293	1.280	1.2
NET TIME OF RUN (MIN)	60	60	[illegible]
MEASURED CONCENTRATION (PPM NOx)	193.5	197.1	193
AVG ZERO BIAS CHECK (PPM NOx)	0.0	0.5	1
UPSCALE CAIBRATION GAS (PPM NOx)	210.0	210.0	210
AVG UPSCALE BIAS CHECK (PPM NOx)	208.5	210.5	211
CORRECTED CONCENTRATION (PPM NOx)	194.8	196.6	192
HEAT INPUT OIL (%)	100.0	100.0	100
HEAT INPUT GAS (%)	0.0	0.0	0
WEIGHTED AVERAGE F FACTOR (DSCF/MMBTU)	9190.0	9190.0	9190
NOx EMISSIONS (LB/MMBTU)	0.264	0.266	0.2
AVERAGE NOx EMISSIONS (LB/MMBTU)		0.26	
NOx EMISSIONS STANDARD (LB/MMBTU)		0.30	

FLORIDA POWER AND LIGHT COMPANY
OPERATIONS SERVICES EMISSION TEST GROUP
700 UNIVERSE BLVD.
JUNO BEACH, FLORIDA 33408-0240

NO EMISSION TEST

PLANT: MANATEE
UNIT: 1
TEST: NITROGEN OXIDE EMISSIONS
METHOD: 40 CFR Pt. 60, App. A, 3A & 7E

	TOTAL RUN 1	TOTAL RUN 2	TOTAL RUN 3
DATE OF RUN	05/12/94	05/12/94	05/12/94
GROSS LOAD (AVG MMBTU/HR)	7514	7514	7514
START TIME (24-HR CLOCK)	949	1127	1314
END TIME (24-HR CLOCK)	1049	1227	1414
CO2 (CORRECTED % DRY)	13.6	13.6	13.5
O2 (CORRECTED % DRY)	3.7	3.8	3.6
Fo TEST	1.265	1.257	1.281
NET TIME OF RUN (MIN)	60	60	60
MEASURED CONCENTRATION (PPM NO)	210.96	212.90	204.89
AVG ZERO BIAS CHECK (PPM NO)	0.0	0.0	0.0
UPSCALE CAIBRATION GAS (PPM NO)	129.7	129.7	129.7
AVG UPSCALE BIAS CHECK (PPM NO)	127.4	127.3	127.0
CORRECTED CONCENTRATION (PPM NO)	214.8	217.0	209.2
HEAT INPUT OIL (%)	100.0	100.0	100.0
HEAT INPUT GAS (%)	0.0	0.0	0.0
WEIGHTED AVERAGE F FACTOR (DSCF/MMBTU)	9190.0	9190.0	9190.0
NO EMISSIONS (LB/MMBTU)	0.286	0.290	0.277
AVERAGE NO EMISSIONS (LB/MMBTU)		0.28	
NO EMISSIONS STANDARD (LB/MMBTU)		0.30	

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ISSUE # 7: Future Projected Actuals Are Incorrectly Calculated

Projected actuals for PM/PM_{10} and NO_x use hourly emission rates that are less than the permitted levels. Additionally, no limits exist for CO and VOC for HSFO and LSFO, and VOC has no hourly limit for Orimulsion. Also, SO_2 has a higher emission limit for HSFO and LSFO. These limits must be revised and permit limits established that demonstrate compliance with the future actual projections.

BASIS: WEPCO Rule 57 FR 32323, "The future actual projection is the product of: (1) the hourly emissions rate, which is based on the unit's physical and operational capabilities following the change and federally enforceable operational restrictions that would effect the hourly emissions rate following this change; and (2) projected capacity utilization, which is based on (a) the unit's historical annual utilization, and (b) all available information regarding the unit's likely post-change capacity utilization."

Also WEPCO ruling.

"WEPCO Rule"

whether a utility unit is "less environmentally beneficial" after controls than it was before controls. Accordingly, the final rule allows consideration of all environmental impacts—beneficial and adverse—in making a determination.

B. Representative Actual Annual Emissions

1. Background

The EPA proposed to clarify its methodology for calculating emissions increases at electric utility steam generating sources that had begun normal operations. The EPA proposed to compare actual emissions before and after changes for all physical or operational changes at an existing electric utility steam generating unit other than the addition of a new unit or the replacement of an existing unit. The EPA proposed to consider a unit to be replaced if it would constitute a reconstructed unit within the meaning of 40 CFR 60.15. Since there is no relevant operating history for wholly new units and replaced units, it is not possible to reasonably project post-change utilization for these units, and hence their future level of "representative annual actual emissions." For other changes, past operating history, and other relevant information, provides a basis for reasonable projections.

As proposed, the "representative actual annual emissions" methodology requires the utility to compare its baseline emissions with its future actual emissions to determine if the proposed change will increase actual emissions. The EPA's existing regulations define baseline emissions as "the average rate, in tpy, at which the unit actually emitted the pollutant during a 2-year period which precedes the particular date and which is representative of normal source operation" (see, e.g., 40 CFR 52.21). The Administrator "shall" allow use of a different time period "upon a determination that it is more representative of normal source operation." *Id.* Although not required by the regulations, EPA has historically used the 2 years immediately preceding the proposed change to establish the baseline [see 45 FR 52676, 52705, 52718 (1980)]. However, in some cases it has allowed the use of earlier periods. For example, in *WEPCO,* EPA found the fourth and fifth years prior to the modification more representative of WEPCO's normal operations since the source's capacity was reduced due to physical problems. The EPA proposed to retain this regulatory language, but to adopt a new presumption regarding its implementation.

Under the proposed action, the Administrator would presume that any 2 consecutive years within the 5 years prior to the proposed change is representative of normal source operations for a utility. This presumption is consistent with the 5-year period for "contemporaneous" emissions increases and decreases in 40 CFR 52.21(b)(3)(i)(b).[17] Source owners or operators desiring to use other than a 2-year period or a baseline period prior to the last 5 years may seek the Administrator's specific determination that such period is more representative of normal operations.[18]

uncertain &?

The future actual projection is the product of: (1) The hourly emissions rate, which is based on the unit's physical and operational capabilities following the change and federally-enforceable operational restrictions that would affect the hourly emissions rate following this change; and (2) projected capacity utilization, which is based on (a) the unit's historical annual utilization, and (b) all available information regarding the unit's likely post-change capacity utilization.[19] The projection of post-change capacity utilization for applicability purposes should be based on a projection of utilization for a period after the physical or operational change. Specifically, EPA proposed to allow sources to base the projection of utilization on the 2 years after the change; or a different consecutive 2-year period within the 10 years after the change, where the Administrator determines that such period is more representative of normal source operations.

2. Comments Generally Favoring the EPA Proposal

a. Several commenters favored the expansion of the time period for establishing the pre-change emissions baseline. Suggestions included:

(1) Allow the use of any 2 consecutive years within the last 5 years of operation to allow for a more representative baseline for units that have been shut down;

(2) Allow utilities to request to use periods of representative high utilization outside the 5 year time period;

(3) Add the "any 2 out of the prior 5 year baseline period" discussed in the preamble to 40 CFR parts 51, 52, and 60;

(4) Allow utilities to use the maximum utilization in any 1 year within at least the last 10 years, since 10 years is a more relevant capacity investment planning horizon than 5 years;

(5) Clarify that the source will be able to select the relevant 2-year period with approval of the reviewing authority required only when the pre-change baseline is outside of the 5-year period proceeding the change;

(6) Expand the baseline calculation period from 5 years to 10 years to be consistent with the after-change calculation period and to address a more representative time period;

(7) Allow the use of any 2 years (rather than consecutive years) due to long reserve shutdowns and because maintenance planning requires that utility boilers be operated in "abnormal" conditions for long durations; and

(8) Require sources to back up the choice of which 2 years to use with a short-term standard using an hourly rate, use the same 2-year period for determining the short-term and annual rates, and codify the 2 years used for the limit.

Several comments that recommended expanding the proposal to include industrial sources in the NSR exemption also noted that a "5-year window" is not satisfactory for industrial sources which do not always have representative periods of emissions immediately before a physical change. One industrial commenter suggested the use of any 2-year period be allowed.

Commenters in favor of the future actual emissions calculation method noted that it will alleviate uncertainty, for nonroutine repair, replacement, and maintenance projects while still protecting local air quality; the future-actual method reduces speculation and allows more reliance on factual data; and the actual-to-future-actual emissions comparison is more appropriate to look at the operating history and projected capacity of an existing unit to determine whether a change will increase emissions. One commenter stated that the actual-to-potential method discouraged environmentally beneficial modifications, but suggested that the

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[17] This presumption does not apply to past modifications at an emissions unit for the purpose of determining contemporaneous emission changes at a source and cannot be used to extend the 5 year period specified in that provision [see 40 CFR 52.21(b)(3)(i)(b)].

[18] The level of baseline emissions selected must be consistent with current assumptions regarding the source's emissions that are used under the SIP for planning or permitting purposes. Thus, the source may not select a level of baseline emissions higher than that used by the permitting authority in issuing a PSD or other construction permit to a source in the area, if such higher level would result in a NAAQS or increment violation, or violate a visibility limitation.

[19] In projecting future utilization and emissions factors, the permitting authority may consider the company's historical operational data, its own representations, filings with Federal, State or local regulatory authorities, and compliance plans developed under title IV of the 1990 Amendments;

Wepco Court Case #4,48

compare representative actual emissions for the baseline period to estimated future actual emissions based on all the available facts in the record. Specifically, in calculating post-renovation actual emissions, this approach takes into account 1) physical changes and operational restrictions that would affect the hourly emissions rate following the renovation, 2) WEPCO's pre-renovation capacity utilization, and 3) factors affecting WEPCO's likely post-renovation capacity utilization.

To quantify WEPCO's estimated future actual emissions after the proposed changes EPA relied heavily on projected and historical operational data (e.g., fuel consumption, MMBTU consumed) representative of the source. Specifically, the Agency considered available information regarding (1) projected post-change capacity utilization filed with public utility commissions; (2) Federal and State regulatory filings; (3) the source's own representations; and (4) the source's historical operating data. As described below, EPA determined an appropriate utilization factor for future operations and combined this with post-change emissions factors (to the extent they are or will be made federally enforceable) to estimate a future level of annual emissions for the purpose of determining whether the proposed physical and operational changes would be considered a major modification for PSD purposes. Where a significant emissions increase is projected to occur, WEPCO could voluntarily agree to federally-enforceable limits on any aspect of its future operation (including physical capacity and hours of operation) to ensure that no significant emissions increase will occur.

IV. THE AGENCY'S REVISED PSD APPLICABILITY DETERMINATION

A. Estimated Future Actual Emissions.

The Agency has revised its October 14, 1989 PSD applicability determination for WEPCO's proposed Port Washington renovation based on a "representative actual" to "estimated future actual emissions" comparison (as outlined above). As previously discussed, estimated future actual emissions projections take into account the likelihood that the plant will operate in the future as it has in the past.

The stated purpose of WEPCO's renovations is to refurbish the power plant units to an "as-new" condition in terms of their capacity, efficiency, and availability. Consequently, EPA has used actual, historical, operational data representative of the plant's past operations, approximating an "as-new" configuration, to calculate "estimated future actual emissions." The Agency has verified these data by comparison to WEPCO's own projections of post-renovation capacity utilization and industry averages.

As to the emissions factors used to calculate future emissions, EPA has used WEPCO's own emissions factors for future hourly emissions rates. These emissions factors are based on WEPCO's own assumptions regarding future sulfur in fuel and control technology performance levels. However, since these assumptions go beyond current State implementation plan (SIP) requirements, they must be made federally enforceable for EPA to continue to consider them for PSD applicability purposes.

Operational data (i.e., heat input) from the years 1978-1979 show a capacity utilization factor of 42 percent. These data points represent the closest projection of WEPCO's operational characteristics, approximating an "as-new" state, as currently available to EPA. The data currently available to us regarding WEPCO's past operational levels are limited to a 10-year period. The Agency believes that these historical levels of operation are representative of the plant's past operations in an "as-new" condition. In addition, the 1978-79 data points appear consistent with WEPCO's own projection of future operations for the year 2010 (as submitted to the Wisconsin Department of Natural Resources on March 29, 1990) and common capacity levels for the utility industry, in general, for new units. However, by this letter, EPA is requesting that WEPCO submit operational data from previous years (i.e., pre-1978), if such data show heat input levels notably higher than the 1978-1979 levels.

As previously mentioned, to calculate future emissions levels for each pollutant, EPA assumed that the amount of future coal consumed in terms of heat input to the plant would be comparable to WEPCO's annual average 1978-1979 coal-consumption figure. On March 29, 1990, WEPCO submitted to the Wisconsin Department of Natural Resources information which contained estimates of future emissions for different levels of coal and heat input to the plant. The Agency used these estimates to establish future emissions based on 1978-1979 heat-input values. Again, it is important to note that EPA's calculation of "estimated future actual emissions" is based on WEPCO's projection of control technology performance levels and/or fuel sulfur content for post-renovation operations. Consequently, EPA's PSD applicability determination is valid only to the extent that the emissions factors (based on control technology performance levels and sulfur in fuel) used to calculate future emissions are made federally enforceable. Otherwise, the calculation of estimated future actual emissions for each pollutant will need to be revised by EPA based on existing federally-enforceable limits (i.e., applicable SIP, NSPS). The use of current, federally-enforceable emissions in the current SIP would result in higher projected future emissions than assumed in EPA's calculations and, consequently, could affect the indicated PSD applicability finding.

HKC

Department of Environmental Protection

Lawton Chiles
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Virginia B. Wetherell
Secretary

FAX TRANSMITTAL SHEET

TO: Don Elias

DATE: 4-3-98

FAX PHONE: 732/968-9603

TOTAL NUMBER OF PAGES, INCLUDING COVER PAGE: 7

FROM: Clair Fancy

DIVISION OF AIR RESOURCES MANAGEMENT

COMMENTS:

PHONE: 850/488-1344

FAX NUMBER: 850 /922-6979

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

Memorandum

January 22, 1998

To: Clair Fancy, P.E., FDEP

From: Ken Kosky, P.E., Golder Associates

RE: Historical NOx Emissions from Manatee Plant

Dear Clair:

Please find attached my analysis of the CEM, Net Load Factor (NLF) and Capacity Factor (CF) data from the Manatee Plant during 1995 and 1996. The NLF is the load that the unit is operating when it is running. As shown from those data 1993 and 1994 are quite different. An analysis of the CEM data clearly indicate a relationship of NLF and NOx emissions. This is as expected since higher loads produce higher NOx emissions. Using a direct linear relationship between NLF and NOx emissions (top table), NOx emissions for each unit during 1993 and 1994 were calculated. As shown the calculated NOx emission rate is 0.30 lb/mmBtu. The other method used was the actual regression equation that was developed form the CEM and NLF data. The resulting average NOx emission is also 0.3 lb/mmBtu. Given that the steam atomization provides better combustion control and therefore NOx, the relationships are likely to produce lower NOx emissions than what actually happened. I concluded back in 1994, and confirmed by an analysis of the CEM data, that using a single stack test for pollutants produced through combustion processes (i.e., NOx and PM) is not appropriate. Therefore the 7,318 tons/year is an appropriate emission.

I have also included a chart of the daily, 30-day rolling and annual NOx emissions from one of the Manatee units. Note that daily emissions frequently exceed the 0.3 and include considerable variability. Such variability alone make the use of a single test questionable. I totally agreed with your assessment in the development of the Title V process that fees which were to be based on actual emissions cannot be based on a single test.

Calculation of NOx Emission Rate Using CEM and Net Load Factor

Net Load Factor (NLF)	Unit 1	Unit 2	Average	
1993	55.03%	59.54%	57.49%	
1994	51.01%	58.51%	54.89%	56.19%
1995	42.30%	47.64%	45.16%	
1996	41.54%	45.09%	43.18%	44.17%
1995&96	41.92%	46.37%	44.17%	

NOx Emission Rates (NER) in lb/mmBtu

	Unit 1	Unit 2	Average	1993/94
1993(a)	**0.282**	**0.317**	**0.302**	
1994(a)	**0.262**	**0.312**	**0.289**	**0.30**
1995	0.207	0.242	0.227	
1996	0.223	0.252	0.237	0.23
1995&96	0.215	0.247		

Capacity Factor (CF)	Unit 1	Unit 2	Total	
1993	29.99%	39.11%	69.10%	0.3455
1994	31.97%	39.35%	71.32%	0.3566
1995	21.81%	28.35%	50.16%	0.2508
1996	22.74%	21.28%	44.02%	0.2201

Notes: (a) Unit NER calculated based on net load factor (NLF) for each unit relative to NOx emission rate from CEM:
Unit 1993 NLF x 1/1995&96 NLF x 1995&96 NER
Average NER calculated based on relative capacity factor
[Unit 1(NER x CF) + Unit 2 (NER x CF)] / [Unit 1 CF + Unit 2

Calculation of 1993 & 1994 NOx CEM Using Regression Analysis

Regression Equation $Y = mx + b$

NOx = 0.53 (NLF) - 0.00282

	NLF	NOx (lb/mmBtu)	
1993 Unit 1	55.03%	0.294	.289
1994 Unit 1	51.01%	0.273	.267
1993 Unit 2	59.54%	0.318	.313
1994 Unit 2	58.51%	0.313	.307
	Average:	**0.300**	.294

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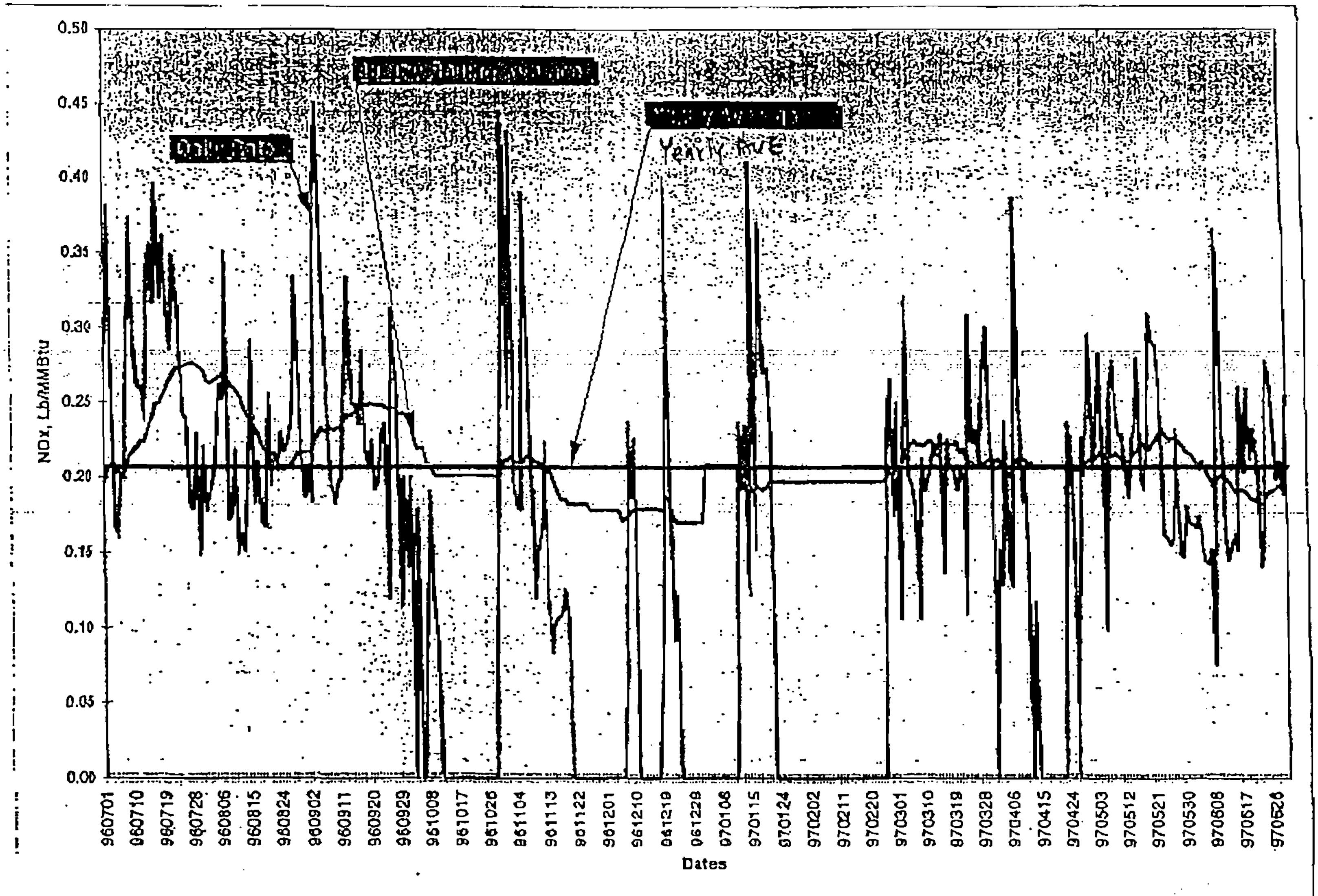
Manatee Plant Unit 1 NOx Data
July 1996 to July 1997



Memorandum

January 23, 1998

To: Clair Fancy, P.E., FDEP

From: Ken Kosky, P.E., Golder Associates

RE: Historical NOx Emissions from Manatee Plant

Dear Clair:

Attached is an updated prediction of NOx emission levels for 1993 and 1994 that includes the weighted average of NOx emissions based on the capacity factor (i.e., fuel usage). As shown, the predicted NOx level using the regression equation for 1993 and 1994 is 0.296 lb/mmBtu. This prediction is conservatively low, given the installation of steam atomization in 1995 to control the combustion process. This had the effect of being able to lower NOx levels in 1995 and 1996 relative to high pressure atomization used prior to 1995. Also included, is a comparison between the difference in predicted and actual concentrations. As shown the lb/mmBtu difference (last column) is quite small and the average difference is less than 5% (see 4.71%: 0.011 divided by 0.231). This is quite good given the limited data points used in the predictions.

I have also included a graphic of the historical NOx emission for the Manatee Plant over 19 years (1978 through 1996). The 19 year average is 6,970 tons/year. As shown in the figure, there have been years that the NOx was above and below the 1993 and 1994 levels.

Please call if you have any questions.

Ken

Calculation of NOx Emission Rate Using CEM and Net Load Factor

Net Load Factor (NLF)	Unit 1	Unit 2	Average	
1993	55.03%	59.54%	57.49%	
1994	51.01%	58.51%	54.89%	56.19%
1995	42.30%	47.64%	45.16%	
1996	41.54%	45.09%	43.18%	44.17%
1995&96	41.92%	46.37%	44.17%	

NOx Emission Rates (NER) in lb/mmBtu	Unit 1	Unit 2	Average	1993/94
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Notes: (a) Unit NER calculated based on net load factor (NLF) for
each unit relative to NOx emission rate from CEM:
Unit 1993 NLF x 1/1995&96 NLF x 1995&96 NER
Average NER calculated based on relative capacity factor:
[Unit 1(NER x CF) + Unit 2 (NER x CF)] / [Unit 1 CF + Unit 2 CF]

Calculation of 1993 & 1994 NOx CEM Using Regression Analysis

Regression Equation
Y = mx + b
NOx = 0.53 (NLF) - 0.00282

	NLF	Unweighted NOx (lb/mmBtu	Capacity Factor
1993 Unit 1	55.03%	0.289	29.99%
1994 Unit 1	51.01%	0.267	31.97%
1993 Unit 2	59.54%	0.313	39.11%
1994 Unit 2	58.51%	0.307	39.35%

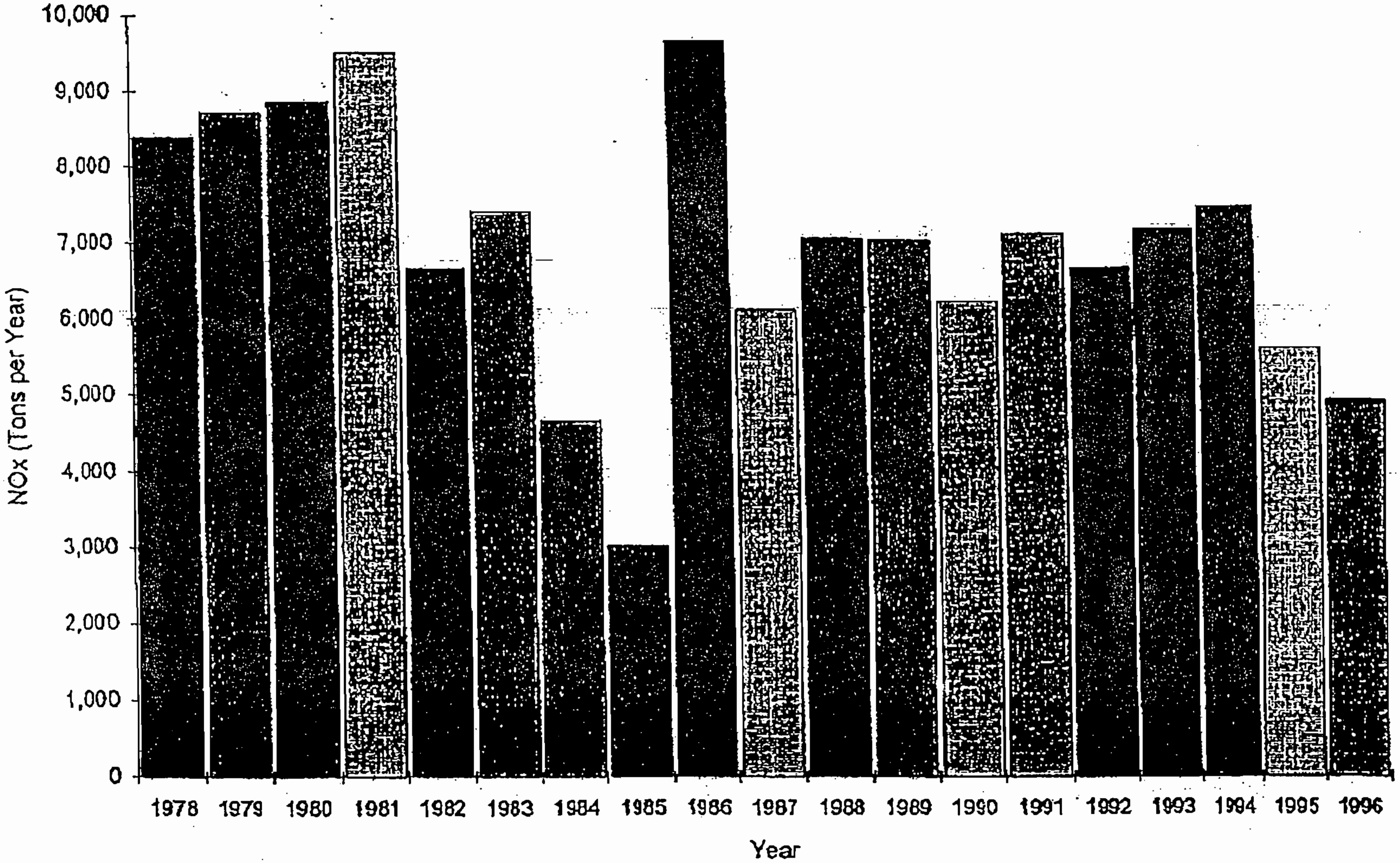
Average NOx: 0.294
Weighted NOx: 0.296

Note: weighted NOx based on capacity factor (i.e., total fuel usage)

Calculation of the Difference Between Regression and Actual Data

	NLF	Regression (a)	Actual (a)	Difference (a)
1995 Unit 1	42.30%	0.221	0.207	0.0142
1996 Unit 1	41.54%	0.217	0.223	-0.0058
1995 Unit 2	47.64%	0.250	0.242	0.0075
1996 Unit 2	45.09%	0.236	0.252	-0.0160
Average:		0.231	0.231	0.011
Std. Dev.		0.013	0.017	
Average Diff.		4.71%		

Historical NOx Emissions
FPL Manatee Plant (Units 1 and 2)



RTP ENVIRONMENTAL ASSOCIATES INC.®

AIR · WATER · SOLID WASTE CONSULTANTS

239 U.S. Highway 22 East
Green Brook, New Jersey 08812-1909
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April 8, 1998

Mr. Clair Fancy
Florida Department of Environmental Protection
Bureau of Air Regulation
111 South Magnolia, Suite 4
Tallahassee, Florida 32301

Dear Mr. Fancy:

This letter is in response to the materials you faxed us on April 3, 1998, namely the January 22nd and January 23rd memos (copies attached) from Ken Kosky concerning the historical NO_x emissions from the Manatee County FP&L plant. As discussed previously with the agency and in our testimony, we still believe that the representative period that should be used to determine the historical actual emissions for the proposed Orimulsion® project would be the two-year period which precedes the particular date and which is representative of normal source operation. Due to the delay in the application process, this period should be 1996 and 1997. This requirement is defined in Rule 62-212.200(2)a F.A.C., as well as 40 CFR 52.21(b)21(ii). As noted in the regulation, "*The Administrator shall allow the use of a different time period upon a determination that it is more representative of normal source operation.*" No demonstration has been made which defines a different time period as more representative of normal source operations. In fact, in the original Site Certification/PSD application (SCA/PSD), the applicant chose to utilize fuel use data up through the end of 1994, using pro-rated fuel consumption data for the second half of 1994, as actual data was not yet available. This resulted in a more favorable determination (i.e., higher historical actual emissions) due to the increased fuel usage in the 1993-1994 period versus prior years. This approach confirms the use of the most recent two-year period.

As noted in the January 23, 1998 memo from Mr. Kosky, the NO_x emission rate for the 1995-1996 period, and as indicated in our testimony for the 1996-1997 period, was approximately 0.23 lbs/MMBTU, which when using the 1993-1994 average fuel usage/heat input would result in a calculation of 5621 tons of NO_x emitted per year. As noted in our testimony, the CEM data from 1996 and 1997 would yield a number less than 5500 tons per year. As stated above, due to the lack of any representations made that the pre-steam atomization operations represent current normal operations, we believe the Florida and federal rules require that the representative period be determined based on emissions associated with current normal operations which includes the steam atomization system.

Further, in our review of the January 23, 1998 memo (which corrects the January 22, 1998 data), there are several important points to note, namely:

1. The data, as presented, indicates a PSD significant emissions increase for NO_x.

2. The analysis contains emissions for two years for Unit 2 in excess of the permit limits. This cannot be used in calculating historical actuals, as values up to but not over the permit limit are allowed to be used in this calculation.

3. The analysis is based on the assumption that there exists a linear relationship between the NO_x emission rate and the net load factor on a long-term basis. We concur that a relationship does exist between these two parameters, however there is no data to indicate that it is linear for large oil-fired units. Literature review indicates that the emission rate may be anywhere from 0.5 to 1% for a percentage of net load factor (see attached AP-40 and AP-42 sections). Additionally, the linear relationship that was established based on the 1995-1996 data was established with the steam atomization system in place. There is no data available to support that this relationship would be identical to that during the period when the Units were operating with the high-pressure atomization as opposed to steam atomization systems.

4. The calculations presented still contain mathematical errors. It is unclear how the average net load factors were calculated. They do not appear to match the data presented.

5. The statistics used (linear regression) are inappropriate for this data set and exhibit poor correlation.

Issue 1:
Regarding issue number 1, if you calculate the average NO_x emission rate for 1993 and 1994 using the data presented, results are as follows:

1993 Average	0.302	
1994 Average	0.289	Average = 0.296
	0.591	

$$0.296 \; lbs/MMBTU \; x \; 48{,}785{,}409 \; MMBTU \; x \; \frac{1 \; ton}{2000 \; lbs} = 7220 \; tons \; per \; year$$

This would be a 98 ton per year increase, which is greater than the 40 ton per year PSD significance level.

Issue 2:
Regarding the second issue, if the data for Unit 2 for 1993 and 1994 are reduced to the allowable levels of 0.30. The averages change as follows:

1993 Average	0.292	
1994 Average	0.283	Average = 0.288
	0.575	

$$0.288\ lbs/MMBTU\ x\ 48{,}785{,}409\ MMBTU\ x\ \frac{1\ ton}{2000} = 7025\ tons$$

This yields a 293 ton per year increase, which again exceeds the 40 ton per year PSD significance level.

Issue 3:
In addition to the references cited above concerning the linear relationship of NO_x emission rates and net load factors, the attached stack test data (ten separate three hours tests) clearly indicates that this relationship cannot be linear throughout the normal range of operations. In fact, the relationship developed in the January 23, 1998 memo indicates that the NO_x emissions should be greater than the permit limit of 0.30 lbs/MMBTU whenever the units operate at loads higher than 56%. Additionally, the NO_x CEM data graph attached to the January 22, 1998 memo shows significant variability in NO_x emissions. It is unlikely that load followed these significant swings in NO_x emissions in a direct linear relationship.

In the rebuttal testimony provided by Mr. Kosky, he indicated that the stack test data was not representative of source operation. This statement is remarkable, in that annual compliance tests form the linchpin of the state program for determining that a source is in compliance at conditions representative of its maximum operations. Both the applicant and FDEP utilized individual stack test data for particulate matter (PM) in the recent application, and also used the 1993-1994 stack test data for NO_x and PM for calculating historical actuals in the original SCA/PSD application. To respond to the criticism that the stack tests represent a "snap-shot" in time and may not be representative of normal operations of the source, we have obtained an additional eight stack tests that were available from the District Office files. Attached is a table of the results of these twelve three-hour tests, all of which indicate that the representative source operation, even prior to the steam atomization system, would yield a NO_x level below 0.30 lbs/MMBTU.

Issue 4:
All of the averages presented for the net load factor contain minor errors. The calculation for Unit 2 1993 and 1994 NO_x emission rates using the data in the table and the formula in

footnote (a) are in error in favor of the applicant (0.310 vs. **0.317** and 0.305 vs. **0.312**, underlined values are the calculated numbers using the data in the table and the bold numbers are the values presented in the table). The capacity factor numbers presented in the January 23, 1998 memo vary from those provided by FP&L in the response to FDEP comments on the original SCA/PSD application (Table DEP-B3-2 attached).

Capacity Factors

	Table DEP-B3-2		Kosky 1/23/98 Memo	
	Unit 1	Unit 2	Unit 1	Unit 2
1993	27.29%	35.61%	29.99%	39.11%
1994	29.53%	35.91%	31.97%	39.35%

Issue 5:
I have attached a graph which shows the four data points used in the linear regression in the Kosky memo, and a line for the analyses presented in the January 23, 1998 memo, and a second line based off the four data points plus the twelve stack test points. The difference clearly demonstrates that a significantly lower value would be obtained for the NO_x emission rate/net load factor even assuming a linear relationship exists for these units. The correlation coefficient for the Kosky data is 0.544 and for the full data 0.698. Correlation coefficients typically exceed 0.9 for data that exhibit a consistent relationship. The standard error in the first coefficient for the Kosky data is 0.343. If the absolute value of the correlation coefficient is an order of magnitude larger than the standard error in the first coefficient, then you can be sure that the linear regression is significant (Principals and Procedures of Statistics, Steel & Torrie). The data passes a "t" test only at the 75% confidence level. Thus, the regression analysis proves that there is a poor fit for the data and little confidence in applying the predicted linear regression to predict 1993-1994 emissions based on net loads which were outside the range of data analyzed.

Including the 1989-1994 stack tests in the linear regression analysis gives the second line shown on the attached figure. The correlation coefficient for the stack test and CEM data is 0.70, primarily due to the larger number of data points, and the standard error in the first coefficient of 0.02 means that the correlation is significant at greater than the 99.9% confidence level. This line predicts average NO_x emissions of 0.244 lbs/MMBTU for 1993-1994, or 5952 tons per year, yielding a future increase of 1366 tons per year.

Therefore, it is obvious from the applicant's own data that the project is PSD significant for NO_x and should undergo full PSD review for this pollutant including BACT analyses. It is important, especially for a controversial project, that the process be followed correctly. This allows full public input and review of the application, as well as the agency's decision process. Possible changes that might occur through a full BACT review are differences in the emission rate as well as possible changes in the control technology. It is not possible at this time to accurately predict the conclusion of the process without performing the required analyses.

I hope the above proves useful in your review of the project. Should you have any questions concerning our analyses, please feel free to contact me at (732) 968-9600.

Sincerely,

RTP ENVIRONMENTAL ASSOCIATES, INC.®

Donald F. Elias

Donald F. Elias
Principal

DFE/mpj

cc: L. Curtin, Esq.
B. Beals
G. Worley
W. Corbin
M. Hober
G. McCutchen
Proj. File: HKOR

DEPARTMENT OF ENVIRONMENTAL PROTECTION FLORIDA

Department of Environmental Protection

Lawton Chiles
Governor

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

Virginia B. Wetherell
Secretary

FAX TRANSMITTAL SHEET

TO: Don Elias

DATE: 4-3-98

FAX PHONE: 732/968-9603

TOTAL NUMBER OF PAGES, INCLUDING COVER PAGE: 7

FROM: Clair Fancy

DIVISION OF AIR RESOURCES MANAGEMENT

COMMENTS:

PHONE: 850/488-1344

FAX NUMBER: 850 /922-6979

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

Memorandum

January 22, 1998

To: Clair Fancy, P.E., FDEP

From: Ken Kosky, P.E., Golder Associates

RE: Historical NOx Emissions from Manatee Plant

Dear Clair:

Please find attached my analysis of the CEM, Net Load Factor (NLF) and Capacity Factor (CF) data from the Manatee Plant during 1995 and 1996. The NLF is the load that the unit is operating when it is running. As shown from these data 1993 and 1994 are quite different. An analysis of the CEM data clearly indicate a relationship of NLF and NOx emissions. This is as expected since higher loads produce higher NOx emissions. Using a direct linear relationship between NLF and NOx emissions (top table), NOx emissions for each unit during 1993 and 1994 were calculated. As shown the calculated NOx emission rate is 0.30 lb/mmBtu. The other method used was the actual regression equation that was developed form the CEM and NLF data. The resulting average NOx emission is also 0.3 lb/mmBtu. Given that the steam atomization provides better combustion control and therefore NOx, the relationships are likely to produce lower NOx emissions than what actually happened. I concluded back in 1994, and confirmed by an analysis of the CEM data, that using a single stack test for pollutants produced through combustion processes (i.e., NOx and PM) is not appropriate. Therefore the 7,318 tons/year is an appropriate emission.

I have also included a chart of the daily, 30-day rolling and annual NOx emissions from one of the Manatee units. Note that daily emissions frequently exceed the 0.3 and include considerable variability. Such variability alone make the use of a single test questionable. I totally agreed with your assessment in the development of the Title V process that fees which were to be based on actual emissions cannot be based on a single test.

Calculation of NOx Emission Rate Using CEM and Net Load Factor

Net Load Factor (NLF)	Unit 1	Unit 2	Average	
1993	55.03%	59.54%	57.49%	
1994	51.01%	58.51%	54.89%	56.19%
1995	42.30%	47.64%	45.16%	
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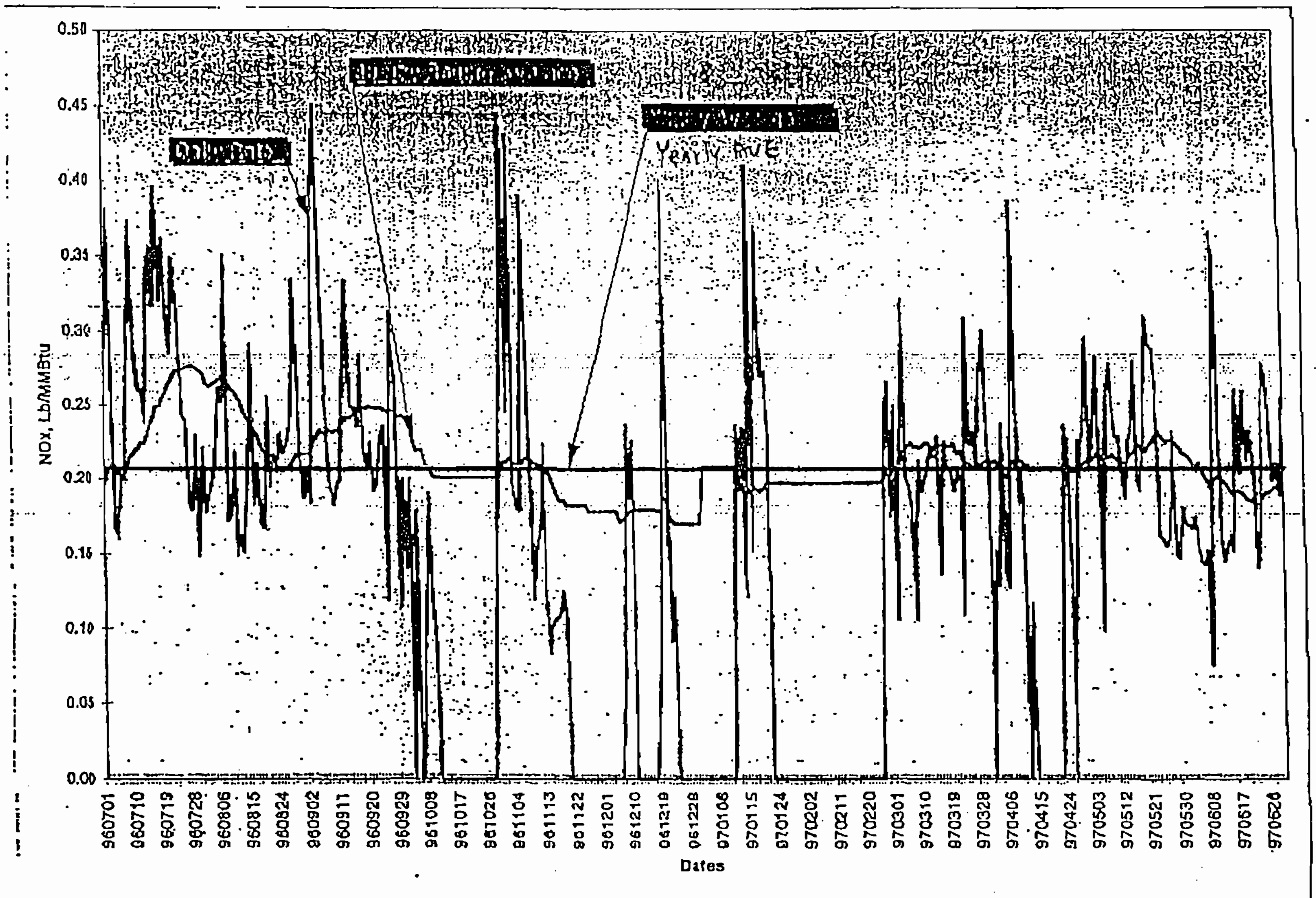

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Calculation of 1993 & 1994 NOx CEM Using Regression Analysis

Regression Equation: Y = mx + b
NOx = 0.53 (NLF) - 0.00282

	NLF	Unweighted NOx (lb/mmBtu	Capacity Factor
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1994 Unit 2	58.51%	0.307	39.35%
Average NOx:		0.294	
Weighted NOx:		0.296	

Note: weighted NOx based on capacity factor (i.e., total fuel usage)

Calculation of the Difference Between Regression and Actual Data

	NLF	Regression (a)	Actual (a)	Difference (a)
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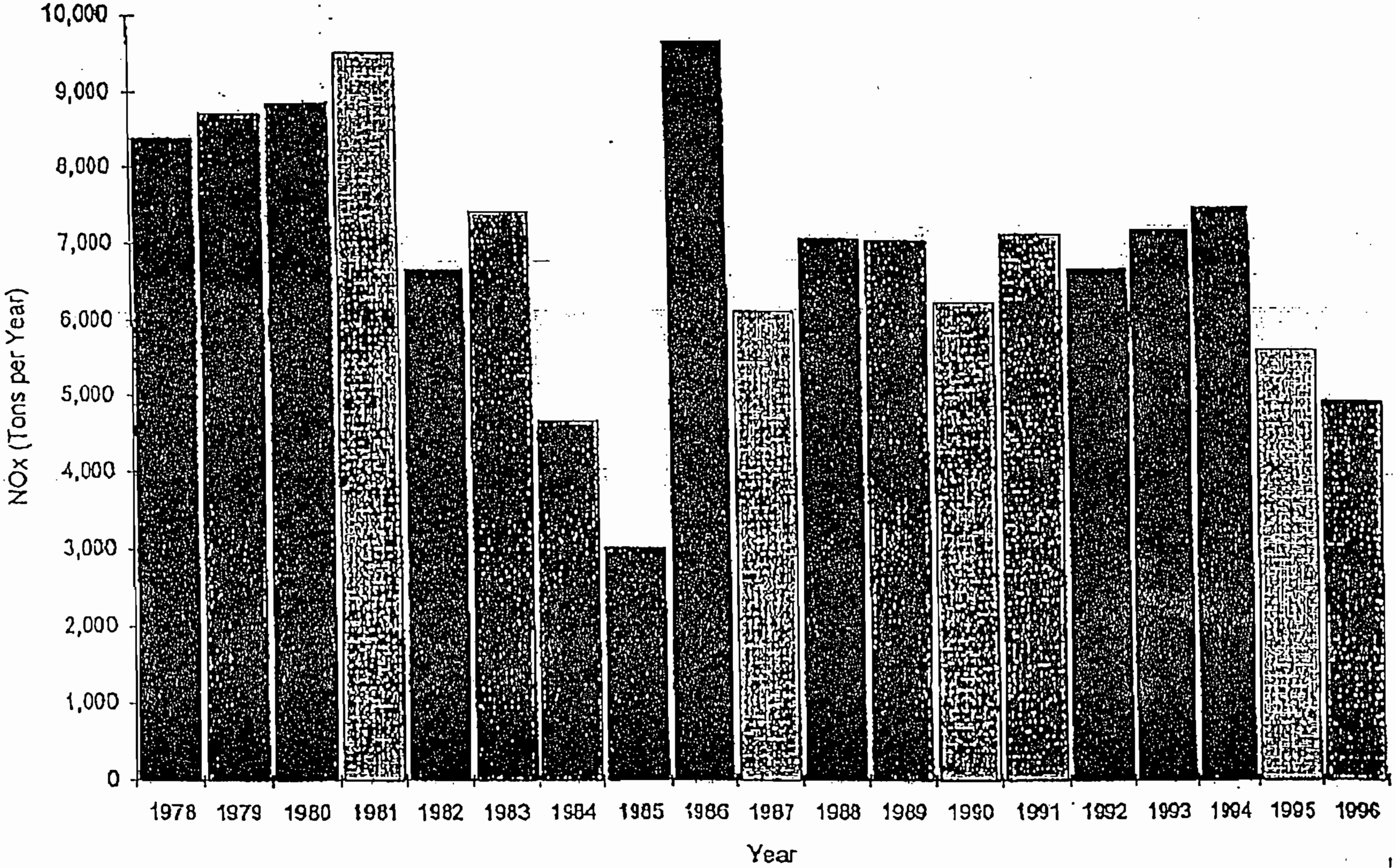
Historical NOx Emissions
FPL Manalee Plant (Units 1 and 2)



Air Pollution Engineering Manual

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recirculation, staged combustion, or some combination thereof, may result in NO_x reductions of 5–60%. In Japan, however, selective catalytic reduction technology is more common for oil-fired-boiler NO_x control.[30]

Load reduction can likewise decrease NO_x production. Nitrogen oxide emissions may be reduced from 0.5% to 1% for each percentage reduction in load from full-load operation. It should be noted that most of these variables, with the exception of excess air, influence the NO_x emissions only of large oil-fired boilers. Limited excess air firing is possible in many small boilers, but the resulting NO_x reductions are not nearly as significant.

One U.S. utility noted, in a study, that the particulate emissions tended to increase with NO_x controls. Further studies have been planned and emphasis is being placed on improving atomizer design and on staging of air to reduce NO_x without increasing the particulate emissions.

Retrofit capital costs for installing LNB and OFA systems in oil-fired boilers are estimated to be \$20 to \$40 per kilowatt, based on 1989 estimates.[30]

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COMPILATION OF AIR POLLUTANT EMISSION FACTORS

VOLUME I: STATIONARY POINT AND AREA SOURCES

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combustion (SC), reduced air preheat (RAP), low NO_x burners (LNBs), or some combination thereof may result in NO_x reductions of 5 to 60 percent. Load reduction (LR) can likewise decrease NO_x production. Nitrogen oxides emissions may be reduced from 0.5 to 1 percent for each percentage reduction in load from full load operation. It should be noted that most of these variables, with the exception of excess air, influence the NO_x emissions only of large oil fired boilers. Low excess air-firing is possible in many small boilers, but the resulting NO_x reductions are less significant.

Recent N_2O emissions data indicate that direct N_2O emissions from oil combustion units are considerably below the measurements made prior to 1988. Nevertheless, the N_2O formation and reaction mechanisms are still not well understood or well characterized. Additional sampling and research is needed to fully characterize N_2O emissions and to understand the N_2O formation mechanism. Emissions can vary widely from unit to unit, or even from the same unit at different operating conditions. It has been shown in some cases that N_2O increases with decreasing boiler temperature. For this update, average emission factors based on reported test data have been developed for conventional oil combustion systems. These factors are presented in Table 1.3-9.

Table 1.3-9 (Metric And English Units). EMISSION FACTORS FOR NITROUS OXIDE (N_2O), POLYCYCLIC ORGANIC MATTER (POM), AND FORMALDEHYDE (HCOH) FROM FUEL OIL COMBUSTION

EMISSION FACTOR RATING: E

Firing Configuration (SCC)[a]	Emission Factor, $kg/10^3$ L ($lb/10^{12}$ Btu)		
	N_2O[b]	POM[c]	HCOH[c]
Utility/industrial/commercial boilers			
No. 6 oil fired (1-01-004-01, 1-02-004-01, 1-03-004-01)	0.013 (0.11)	3.2-3.6 (7.4-8.4)[d]	69-174 (161-405)
Distillate oil fired (1-01-005-01, 1-02-005-01, 1-03-005-01)	0.013 (0.11)	9.7 (22)[e]	100-174 (233-405)
Residential furnaces (No SCC)	0.006 (0.05)	ND	ND

[a] SCC = Source Classification Code. ND = no data.
[b] References 28-29.
[c] References 16-19.
[d] Particulate and gaseous POM.
[e] Particulate POM only.

The new source performance standards (NSPS) for PM, SO_2, and NO_x emissions from residual oil combustion in fossil fuel-fired boilers are shown in Table 1.3-10.

1.3.2.4 Carbon Monoxide Emissions[16-19] -

The rate of CO emissions from combustion sources depends on the oxidation efficiency of the fuel. By controlling the combustion process carefully, CO emissions can be minimized. Thus if a unit is operated improperly or not well maintained, the resulting concentrations of CO (as well as organic compounds) may increase by several orders of magnitude. Smaller boilers, heaters, and furnaces tend to emit more of these pollutants than larger combustors. This is because smaller units

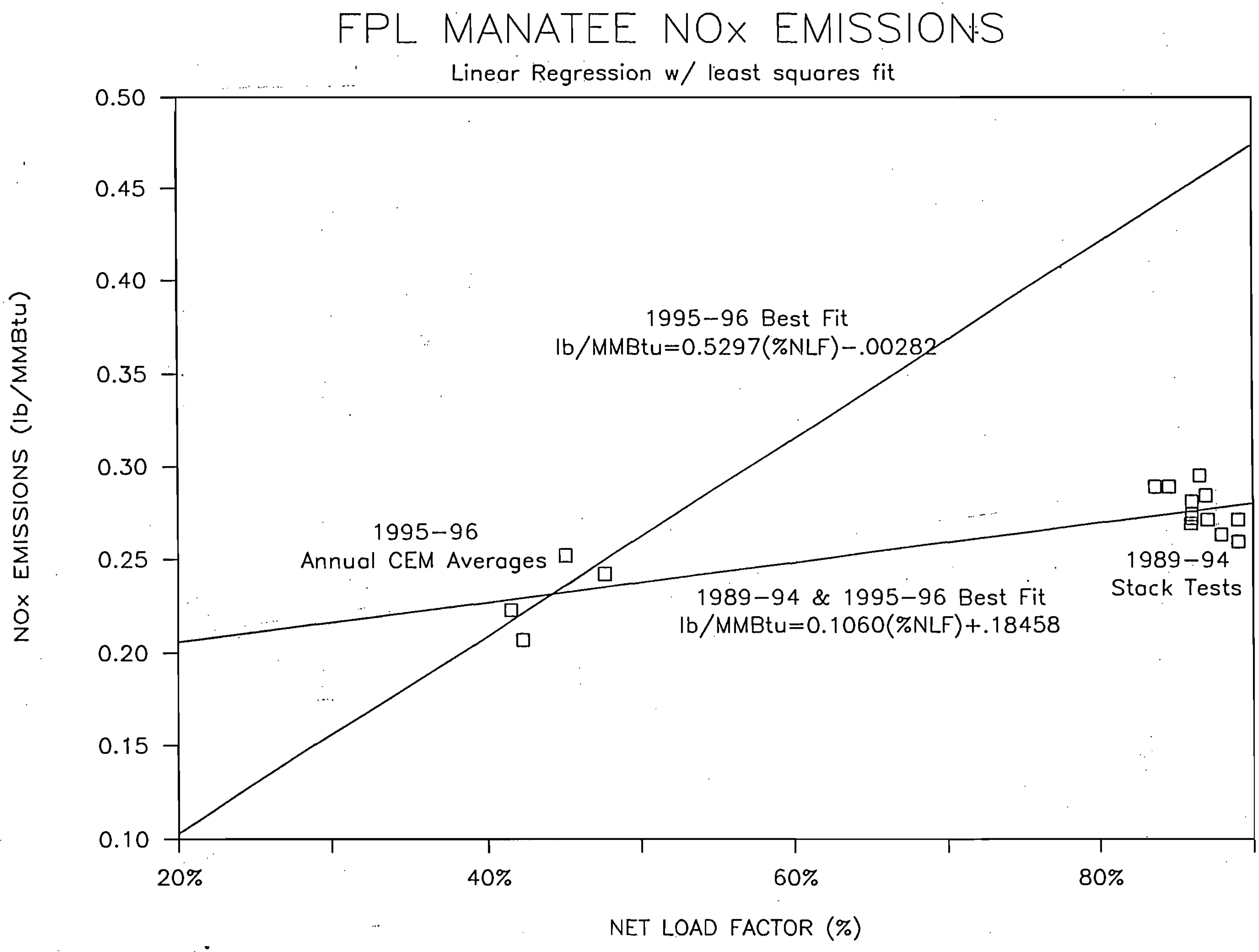
SUMMARY OF NO_x STACK TEST DATA
(1989-1994)

Test	Unit 1			Unit 2		
Year	Test Date	lb/MMBtu	% Load	Test Date	lb/MMBtu	% Load
1989	9/27/89	0.272	86%	1/11/89	0.274	86%
1990	6/27/90	0.259	89%	3/21/90	0.271	87%
1991	4/17/91	0.281	86%	7/17/91	0.271	89%
1992	7/15/92	0.295	86.5%	12/19/91	0.269	85.9%
1993	4/01/93	0.289	84.5%	4/22/93	0.289	83.6%
1994	5/12/94	0.284	86.9%	6/08/94	0.263	87.9%

Table DEP–B3–2. Existing Fuel Oil Usage at the FPL Manatee Plant (1993/1994) – Actual Fuel Use

Parameter	Values for FPL Units Unit 1	Unit 2
Fuel Usage (bbls)		
1993	3,242,067	4,230,092
1994	3,508,117	4,265,164
Average	3,375,092	4,247,628
Maximum	11,877,957	11,877,957
Capacity Factor (a)		
1993	27.29%	35.61%
1994	29.53%	35.91%
Average	28.41%	35.76%
Sulfur Content:		
1993	0.973%	0.973%
1994	0.973%	0.976%

(a) Based on maximum heat input of 8,650 MMBtu/hr per unit and fuel oil with heat content and density of 18,300 Btu/lb and 8.3 lb/gal, respectively.


FPL MANATEE NOx EMISSIONS
Linear Regression w/ least squares fit
NOx EMISSIONS (lb/MMBtu)
0.50
0.45
0.40
0.35
0.30
0.25
0.20
0.15
0.10
1995-96 Best Fit
lb/MMBtu=0.5297(%NLF)-.00282
1995-96
Annual CEM Averages
1989-94 & 1995-96 Best Fit
lb/MMBtu=0.1060(%NLF)+.18458
1989-94
Stack Tests
20%
40%
60%
80%
NET LOAD FACTOR (%)