BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

In the Matter of	DOCKET NO. 980693-EI
Petition by Tampa Electric Company for Approval of Cost Recovery for a New Environmental Program, the Big Bend Units 1 & 2 Flue Gas Desulfurization System.	

VOLUME 1

Pages 1 through 111

PROCEEDINGS:	**HEARING**
BEFORE:	CHAIRMAN JULIA L. JOHNSON COMMISSIONER J. TERRY DEASON COMMISSIONER SUSAN F. CLARK COMMISSIONER JOE GARCIA COMMISSIONER E. LEON JACOBS, JR.
DATE:	**Wednesday, September 2, 1998**
TIME:	Commenced at 9:40 a.m.
PLACE:	Betty Easley Conference Center Room 148 4075 Esplanade Way Tallahassee, Florida
REPORTED BY:	JOY KELLY, CSR, RPR Chief, Bureau of Reporting

APPEARANCES:

HARRY W. LONG, JR., TECO Energy, Inc., Post Office Box 111, Tampa, Florida, 33601-0111; and **LEE L. WILLIS and JAMES D. BEASLEY**, Ausley & McMullen, Post Office Box 391, Tallahassee, Florida 32302, appearing on behalf of **Tampa Electric Company (TECO).**

JOHN McWHIRTER, JR., McWhirter, Reeves, McGlothlin, Davidson, Decker, Kaufman, Arnold & Steen, P.A., 100 North Tampa Street, Suite 2800, Tampa, Florida 33601-3350 and **VICKI GORDON KAUFMAN**, McWhirter, Reeves, McGlothlin, Davidson, Decker, Kaufman, Arnold & Steen, P.A., 117 South Gadsden Street, Tallahassee, Florida 32301, appearing on behalf of **Florida Industrial Power Users Group (FIPUG).**

GAIL KAMARAS, 1114 Thomasville Road, Suite E, Tallahassee, Florida 32303-6290, appearing on behalf of **Legal Environmental Assistance Foundation (LEAF).**

JOHN ROGER HOWE, Deputy Public Counsel, Office of Public Counsel, 111 West Madison Street, Room 812, Tallahassee, Florida 32399-1400, appearing on behalf of the **Citizens of the State of Florida.**

WITNESSES - VOLUME 1

EXHIBITS - VOLUME 1

P R O C E E D I N G S

(Hearing convened at 9:40 a.m.)

CHAIRMAN JOHNSON: We're going to go on the record and begin the proceeding.

Counsel, could you read the notice.

MS. JAYE: Pursuant to notice issued July 16, 1998, this time and place has been set aside for a hearing in Docket No. 980693-EI, a petition by Tampa Electric Company for approval of cost recovery for a new environmental program, Big Bend Units 1 and 2 flue gas desulfurization system.

COMMISSIONER CLARK: We'll take appearances.

MR. McWHIRTER: John McWhirter and Vicki Kaufman appearing on behalf of the Florida Industrial Power Users Group. Our address is accurately stated in the record.

MR. HOWE: I'm Roger Howe with Public Counsel's office, appearing on behalf of the citizens of the state of Florida.

MS. KAMARAS: Gail Kamaras with the Legal Environmental Assistance Foundation.

MR. BEASLEY: James D. Beasley and Lee L. Willis with the law firm of Ausley & McMullen, and Harry W. Long, Jr. Senior Corporate Administrative Counsel for TECO Energy, Incorporated, representing

Tampa Electric Company.

MS. JAYE: Grace A. Jaye on behalf of Commission Staff.

COMMISSIONER CLARK: Are there any preliminary matters?

MS. JAYE: I believe there are some of the parties that have some preliminary matters.

MS. KAUFMAN: Madam Chairman, FIPUG has two preliminary matters. First of all, at the prehearing conference we had distributed a list of items that we wanted the Commission to take official recognition of.

We do not plan to use all those items, but what we have done is we have put together an exhibit that contains information that Tampa Electric Company has filed with the Commission, and we would like the Commission to take official recognition of the documents that are in here and we will distribute those at this time.

CHAIRMAN JOHNSON: Okay. Seeing no objection we will take official recognition. Do you want that marked?

MS. KAUFMAN: That will be fine.

COMMISSIONER CLARK: Ms. Kaufman, does that have Order 94-0044-FOF-EI in it?

MS. KAUFMAN: No, it does not have any

orders in it. However, I do have an order -- not the one mentioned -- that I want the Commission to take official recognition of. And it's not included in the bound material but I do have copies available if anybody needs one. It's PSC Order 98-0802-FOF-EI.

CHAIRMAN JOHNSON: I wasn't listening. What did you just say?

MS. KAUFMAN: Commissioner Clark was asking me if I had a particular Order in here, and I do not. But I have a different order that I want the Commission to take official recognition of.

CHAIRMAN JOHNSON: Okay.

MS. KAUFMAN: And I have copies, and it's Order No. PSC-98-0802-FOF-EI.

CHAIRMAN JOHNSON: Thank you. We'll take official recognition of that order. Sir?

MR. LONG: Chairman Johnson, in looking through the proposed exhibit, I'm a little concerned that there's no index and nothing indicating the source of many of these documents; whether they are from a particular docket or --.

CHAIRMAN JOHNSON: So, I've identified this -- if you could explain that because we may have an issue with getting it --

MS. KAUFMAN: First, I want to apologize --

CHAIRMAN JOHNSON: I'm sorry. These are documents that you're going to request that we take official recognition of.

MS. KAUFMAN: Yes, ma'am. The first thing I want to say is first that the first two pages are repeated twice and that's my mistake, so you can probably rip out the first two pages.

What this exhibit contains is Tampa Electric's surveillance reports that have been filed with this Commission year end from 1993 through 1997, and then the one they filed for June 1998.

And I apologize, it probably would have been better to have an index, but these are all documents that Tampa Electric has filed with this Commission. First few pages is simply information extracted from those documents.

MR. LONG: Chairman, I think it's appropriate to ask the witness if he's familiar with any of these documents and base whatever cross examination counsel wishes to make on that answer.

CHAIRMAN JOHNSON: She is asking that we take official recognition of these documents. What -- are these the kind of documents we generally take official recognition of?

MS. KAUFMAN: I believe so, ma'am. These

are all documents that have been filed by Tampa Electric Company and we don't think they are the kind of documents that require proof by a particular wit ess. They're reports they are required to file with this Commission.

CHAIRMAN JOHNSON: Sir, to the extent that there will be an objection, if you could couch it in terms of why we should or should not take official recognition of the documents that would be helpful.

MR. LONG: Generally, official recognition is taken with regard to Commission decisions and Orders of courts.

CHAIRMAN JOHNSON: Could you speak up a bit.

MR. LONG: Here we have factual information that arguably is taken out of context, and to me there's a real danger of misinterpreting the significance of the data. So in that sense I'm not sure this is a good candidate for official recognition. And counsel is free to adduce whatever facts she can from this material through cross examination.

MS. KAUFMAN: Chairman Johnson, there are no facts taken out of context. That's why we have -- in anticipation of such an objection, we have included the entire Surveillance Report for each of those

years. We haven't picked out selected pages. We've included the entire thing. These are documents that you require the company to file with you. And we think it's appropriate for you to take official recognition of them.

CHAIRMAN JOHNSON: Staff.

COMMISSIONER CLARK: While they are conferring, I think it would be useful to have Ms. Kaufman look up in Chapter 90 and tell us which one it falls under.

MR. McWHIRTER: 90.20(2).

COMMISSIONER CLARK: Okay. Because it didn't seem to me -- you know, we normally take official recognition of orders and official actions. And I don't know that we've taken official recognition of this kind of thing before. But what was the number?

MR. McWHIRTER: Commissioner Clark, the section of the Evidence Code is Section 90.20(2) Florida Statutes, and it permits you to take official notice of information the truth of which is beyond dispute because the facts are readily ascertainable. And our presumption is that when Tampa Electric Company filed its Surveillance Reports giving this information to you, that those were truthful reports

and that if we looked into them in great detail, we would find that they were actual facts.

MR. LONG: Commissioner, I think the point here is none of the other parties have submitted witnesses, and this material, therefore, is without a sponsor. Now, the witnesses that we're presenting may or may not be familiar with the specifics of this data that counsel wants to ask about. But I think the way to manage the record is to let counsel ask whatever questions she has with regard to this data of the witnesses who are here. That way the record will consist of information that is supported by a witness by testimony.

MS. KAUFMAN: Chairman, the entire purpose of taking official recognition is that you don't have to have a witness to sponsor the exhibit, as Mr. McWhirter has said. Tampa Electric has filed these reports. We assume they are truthful reports. It's not necessary to have a witness sponsor them, and we would suggest they are the kind of documents that are appropriate, unless Tampa Electric is telling us that there's something in those documents we cannot rely upon.

COMMISSIONER CLARK: What was that number again?

MR. McWHIRTER: 90.20(2) and I think it's subsection 12, but I may be in error on that.

COMMISSIONER CLARK: I thought those things -- it says "Facts that are not subject to dispute because they are capable of accurate and ready determination by a resort to sources whose accuracy cannot be questioned."

You know, I thought those things were like, you know, Gainesville is east of Tallahassee and you can go to a map and -- nobody disputes that and take official recognition of that.

MR. McWHIRTER: Well, you might look also at 90.80(5) which is admissions of a party. Subsection 18 there, this is an exception to the hearsay rule. You can bring in statements that have been made by a party in the proceeding that relate to the issues before the official body taking recognition. So I think under either of these proposals, the facts, we don't dispute them. I'm sure they are accurate. Tampa Electric wouldn't file inaccurate reports with you.

And with respect to the secondary rule, its an admission by Tampa Electric --

CHAIRMAN JOHNSON: Staff has had an opportunity to look at the provisions?

MS. JAYE: Yes, Commissioner. Staff believes that the Commission doesn't have to make a ruling on this right now. Staff would appreciate the opportunity to do some investigation and come up with a --

CHAIRMAN JOHNSON: That will be fine. But let me retract, because on the record when you first started handing these out, generally with the documents that we're asking for official recognition, the parties have seen the documents and it's always okay. So I think I said earlier we will take official recognition of these documents. Make sure the record is clear that there is an objection, and that we will wait until we come back with Staff's analysis. And I'll have a opportunity to look at the provisions that you cited as the authority for us taking the recognition. And you'll have another opportunity to rebut whatever might be said before we make a ruling on those.

I have identified this as Exhibit 1, but that may or may not be admitted. It's just identified.

(Exhibit 1 marked for identification.)

MS. KAUFMAN: We do have another preliminary matter, and that is that we discussed at the

prehearing conference the possibility of stipulating into the record the testimony of FIPUG's witness, Mr. Selecky, and the testimony of Mr. Hernandez on rebuttal.

I believe we have reached agreement on that and we have not brought Mr. Selecky here today. And also at the prehearing conference we discussed the fact that certain parts of Mr. Selecky's testimony was going to be withdrawn due to the narrowing of the issues, and that the lines and pages are reflected in the Prehearing Order. So whenever it's your pleasure we would ask that his testimony as revised, and that of Mr. Hernandez on rebuttal, would be inserted without their appearance.

CHAIRMAN JOHNSON: Okay. Would it be preferable for purposes of clarification of the record just to go through the people and when we get to that particular witness at that time --

MS. KAUFMAN: That would be fine. I just wanted to let you know.

CHAIRMAN JOHNSON: Thank you.

MS. KAUFMAN: Thank you.

CHAIRMAN JOHNSON: Anything else? No other preliminary matters?

MS. JAYE: Yes, Commissioner. There's an

outstanding oral motion made by TECO at the prehearing to allow for reply briefs. Staff is opposed to that and we need to get a ruling on it.

CHAIRMAN JOHNSON: Okay. I'm sorry, whose --

MR. BEASLEY: Commissioner, we had requested the opportunity for one additional week, from October 2nd to October the 9th, to submit a reply brief if the parties deem it appropriate and necessary, not to say that that would be necessary but certainly if something came up in the initial briefs that needed to be clarified for the benefit of the Commission, we would have a opportunity to do that. It would only be a one-week opportunity. It would not cramp the Staff's time frame within which to submit a Staff recommendation. I think it would still leave them approximately a month to do a Staff recommendation.

CHAIRMAN JOHNSON: You said on October 2nd.

MR. BEASLEY: October 2nd is when the initial briefs were due, and we were simply asking that we be afforded an additional week until the following Friday, October 9th, within which to submit a short reply brief, if necessary. And the Commission has done that on numerous occasions in the telecommunications field. I have a number of examples

where the parties were not only allowed to, but were directed to file reply briefs for the benefit of the Commission to give you the ability to be fully ap rised on all factual matters and argument. That's all we're asking for and we would urge the Commission grant that, have the record complete.

MR. LONG: I'd like to add that there are some practical reasons for having a reply brief in this proceeding. None of the other parties have submitted witnesses so whatever case the parties intend to make will be made by cross examination.

In past proceedings parties have raised issues for the first time in their brief, and that's caused a great deal of delay and inefficiency in affording Tampa Electric the opportunity for a fair response.

I think that allowing reply briefs would ensure that the Commission would have a full record and that all of the issues that are raised would be fully joined.

CHAIRMAN JOHNSON: Thank you. Any other comments from the parties? I understand Staff objects and I'll let them explain that.

MS. KAUFMAN: FIPUG objects to the filing of reply briefs. We discussed this at the prehearing

conference. The prehearing order defines what the issues are. Those are the issues you will hear about today I'm sure, and those are the issues that the parties will brief. I think that the filing of reply briefs is the exception rather than the rule, and we would be opposed to. We think the practice of the parties simultaneously filing the briefs based on the record today will fully develop the record for your consideration and so we would agree with Staff.

CHAIRMAN JOHNSON: But right now all of the parties would simultaneously file on October 2nd. And under his proposal, under TECO's proposal they would have the opportunities to look at everyone else's brief, and if they determine necessary, all of the parties could file something else on the 9th.

MS. KAUFMAN: I understand the proposal to be as you've stated, but we think that it is unnecessary; creates additional work and additional filings. And as I said, the issues are clearly defined for your consideration and the parties will brief them. And we are opposed to going to this practice or setting any precedent of filing a reply brief.

CHAIRMAN JOHNSON: Let me let everybody else -- you may have more to say.

MR. HOWE: Thank you, Chairman Johnson. We believe that reply briefs are inappropriate. In the first instance, we're all lawyers here. If you give us a chance to file reply briefs, we're going to do it.

But more than that, if there's anything improper in anybody's brief when filed, the proper response is to file a Motion to Strike. It's not appropriate to address something that's improper in another brief in a reply brief. I think the procedure is streamlined enough now if something comes up during the case in which Tampa Electric, after receiving the briefs and so forth, thinks it can make a good showing, that reply briefs are appropriate, it can file an appropriate motion at that time. Thank you.

CHAIRMAN JOHNSON: Mr. Kamaras, do you want to add anything to that?

MS. KAMARAS: No.

MS. JAYE: Staff is opposed to allowing reply briefs for three reasons, Commissioners. Number one, allowing for reply briefs would just add another step into a process, and this process has been expedited. And it would lead into the second problem that Staff has, which is it would cramp Staff's time to prepare our own response because it would have to

wait for another round of paper from the parties before we could write a recommendation.

And the third problem that Staff has with this is that there is still a motion for reconsideration available should any party think that Staff has blown it and has not done its job. We believe that the need has not been demonstrated here for allowing reply briefs.

CHAIRMAN JOHNSON: Okay. Thank you. Mr. Long.

MR. LONG: I wanted to reemphasize one thing. There have been proceedings in the past where the parties spent a great deal of time going through and defining the issues for hearing. And new issues were raised in the opening brief after the hearing was over, and the Commission felt compelled, at least in one instance, to more fully consider that issue. Had we had an opportunity for reply briefs there, I think we could have taken up a lot less of the Commission's time.

The other consideration here is that we have the burden of proof. Given that, I think it's only fair that we have an opportunity to reply. We're not asking for an exclusive opportunity to reply, but I think we should at least have that option open to us.

CHAIRMAN JOHNSON: Staff, you went through the points why you were objecting, but you do agree that we have the discretion to do so. You're just advising that we not in this case.

MS. JAYE: Yes, you do have the discretion t , do so.

CHAIRMAN JOHNSON: I'd like to hear input from the other Commissioners, but I think it's actually a good idea, but I'm always inclined to -- I'm probably one of the people that all of those times that we said let them file something else I let them file something else.

And I agree with the points made by Mr. Long given the complexity of this, and the fact that all of the parties will have an opportunity to look at everyone's brief and provide in my mind to Staff useful information that might be clarifying. It is always for me, whenever I read the briefs, that I get a lot out of that process. And given the nature that they do have -- TECO has the burden of proof, that would be my inclination, but it's before the whole Commission.

COMMISSIONER DEASON: My only suggestion, I'm not opposed to it, my only suggestion is I would put a strict page limitation on a response to brief.

COMMISSIONER CLARK: Mr. Beasley, I'd like to know what other cases we've allowed it in and, in fact, required it in.

Commissioners, this issue came up in the prehearing. And I think -- the arguments being made by Tampa Electric are essentially an argument that we change our procedure; not just for this case but for other cases. I have to say I disagree with the notion that this case is particularly complicated. I don't really think it is complicated. And I like the suggestion Mr. Howe said, you know, when a brief comes in, if you see something you need to reply to, put it in a motion then and we'll rule on it.

You know, the issue is not just this case. It's do we want to change our procedures to allow a reply brief? And I think there is merit in some cases to do that. And if we do it here, then I would suggest we look at the whole notion of incorporating that into a procedure and seeing what impact that might have.

COMMISSIONER DEASON: I don't necessarily disagree with that, but I do think there are times when there is a response appropriate other than just to say that something is inappropriate in someone else's brief. Just a counter-argument that something

was in the record. We recall this being in the record and this is a response to the point that was made in the other party's brief.

And I do agree with you, though, it does seem we're getting on the verge of changing established Commission procedure.

COMMISSIONER CLARK: We could try it in this case and see how we like it.

CHAIRMAN JOHNSON: See, I think the reason why I was saying I'm familiar with that is because I was Prehearing Officer before, we've allowed this --

COMMISSIONER CLARK: Are you on all those cases he has?

CHAIRMAN JOHNSON: He's going to cite my name. (Laughter) I'm pretty sure that we have, but you may want to go ahead and cite.

MR. BEASLEY: Commissioners, I just pulled a few examples, but in Harris Corporation against BellSouth, a 1997 decision, the parties were directed to file briefs of not more than 60 pages and reply briefs of not more than 30 pages, which is a page limitation that you mentioned, Commissioner Deason.

Another, Harris Corporation versus BellSouth, a 1996 decision. Parties shall file briefs of not more than 60 and reply briefs of not more than

30.

Interconnection of Mobile Service Providers with facilities of local exchange companies, a 1995 decision, GTE Mobilenet, McCaw, et cetera, filed reply briefs on August 24, 1995, in accord with the schedule established by Order No. 950916, re: Southern Bell Telephone & Telegraph Company. It was a 1975 case. The record in this proceeding consists of trillions of pages, plus initial and reply briefs.

CHAIRMAN JOHNSON: Thank you. I can say though, as I recall, generally when -- at least when I have been involved as the Prehearing Officer it's been because all of the parties have suggested it, and we haven't had objections. I do need to clarify that; where the parties kind of agreed they needed that additional time. So this one is probably a little unique this that regard.

COMMISSIONER DEASON: Let me say one other thing. I think my primary concern would be putting an undue burden on our Staff. If it were a situation we felt that would result, I would not be in favor. I know Staff is concerned about that. But it seems like there's sufficient time between that. But if it is not -- I guess I'm asking a question of Staff to review the time schedule.

MR. ELIAS: I was just going to add one point to the mix. And that is that in past proceedings, when we've seen the briefs that were filed and believed that there were issues raised that weren't adequately addressed in the hearing, we've come to the Commission with recommendations that the parties file additional briefs. We've done that posthearing when we've seen the briefs and felt that there wasn't sufficient evidence to -- or sufficient information to make an informed recommendation to the Commission. So that option is also available to us if it appears to us once the briefs are filed that additional input is needed.

COMMISSIONER DEASON: Which agenda conference? Which agenda conference is this matter scheduled to appear on?

MS. JAYE: The 17th of November.

COMMISSIONER DEASON: Which means you would be filing a recommendation on the 5th of November.

MS. JAYE: Yes. About a month after the briefs are due.

CHAIRMAN JOHNSON: You mean a month after if we go with the extended or a month after under the original?

MS. JAYE: Under the original.

MR. ELIAS: And we do have a number of other E&G hearings that are coming up during the November-December time frame, including one involving Tampa Electric Company; the need determination for Duke New Smyrna; the conservation hearing the week before Thanksgiving where we'll set annual factors for most of the utilities. So we will do what we need to do to serve the Commission's information needs, but --

COMMISSIONER DEASON: With the current schedule, you have got slightly over a month. If there are to be responsive briefs, you'd have slightly under a month. And it seems that when you receive the initial briefs, which is going to have the bulk of the information in it, you could start your initial review at that point. You wouldn't have to wait until you received the responsive briefs.

MR. ELIAS: Let me be clear that we can get the recommendation completed and filed in three weeks. In a little bit more than three weeks. It's just a little bit tighter than we like, and I'm very much concerned about lengthening the process, especially with the number -- with the increasing number of decisions that we have to make within shorter and shorter statutory time frames.

COMMISSIONER JACOBS: Do you think that our

existing pleading process is inadequate to handle all of the information that we need to gather for this case?

MR. ELIAS: No. Absolutely not.

COMMISSIONER CLARK: What is the page limit on briefs? Is it 50 pages for initial briefs?

MR. McWHIRTER: You put 60 in your Prehearing Order in this case.

COMMISSIONER CLARK: I get concerned about, you know, the length of the argument. I know Federal Court says you get 20 pages for memorandum and ten page for reply, and, really, if you can't say it in that amount of time you probably lose your reader.

I would suggest if we're going to do it, the total page limit should be 60 pages, you know, between the two briefs. You don't have any more to read.

MR. LONG: Commissioner Clark, from our perspective that would be a good solution.

CHAIRMAN JOHNSON: What was your --

MR. LONG: I'm sorry. I just indicated that from Tampa Electric's perspective, Commissioner Clark's solution would be a good one.

CHAIRMAN JOHNSON: To stay within the 60 pages.

COMMISSIONER CLARK: Maybe that will have

the effect of keeping that first one short and maybe you won't find anything that you need to respond.

CHAIRMAN JOHNSON: Is there a motion then? Are we going to rule on this?

COMMISSIONER DEASON: I move we allow a responsive brief, with page limitation on the initial brief of 40 pages and 20 pages on the response brief.

COMMISSIONER GARCIA: Are you moving that?

COMMISSIONER DEASON: I guess in essence I'm -- I guess it's the Chairman's ruling.

COMMISSIONER CLARK: I said 60 total. They could break it up how they wanted to.

CHAIRMAN JOHNSON: 60 total and let them break it up?

COMMISSIONER CLARK: Right.

CHAIRMAN JOHNSON: I'll allow the reply brief period, and using that week I think it was October 9th is when they would be due. Was that the date? October 9th, with an inclusive 60-page limitation, and you can allocate that how you think best.

MR. BEASLEY: Thank you, Chairman Johnson.

MS. JAYE: None.

CHAIRMAN JOHNSON: At this time, the witnesses who are going to testify, if you could stand

and raise your right hand.

(Witnesses collectively sworn.)

MR. LONG: Madam Chairman, I'd like to call Charles R. Black to the stand.

COMMISSIONER GARCIA: I might suggest you might want to move over here (indicating chair). I don't think the parties can see you and it's helpful for them. Just one over so they can see you.

(Witness moves to another chair.)

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CHARLES R. BLACK

was called as a witness on behalf of Tampa Electric Company and, having been duly sworn, testified as follows:

DIRECT EXAMINATION

BY MR. LANGER:

Q Would you state your name and business address for the record?

A My name is Charles R. Black. My address is 702 North Franklin Street, Tampa, Florida 33602.

Q Are you the Charles R. Black who prefiled testimony in this proceeding?

A Yes, I am.

Q As part of that prefiled testimony, did you also file an exhibit in this proceeding?

A Yes, I did.

MR. LONG: Madam Chairman, I'd like to have a document marked for purposes of identification. It is at the end of Mr. Black's prefiled testimony. It's headed "Tampa Electric Company, Witness Black, Exhibit No. CRB-1" and it consists of six documents.

CHAIRMAN JOHNSON: I will identify that as Exhibit 2; short title "CRB-1".

MR. LONG: Thank you.

(Exhibit 2 marked for identification.)

Q **(By Mr. Long)** Was your prefiled testimony prepared by you or under your direction and supervision?

A Yes, it was.

Q Was Exhibit No. 2 also prepared by you or under your supervision?

A Yes, it was.

Q Do you have any changes or corrections to make to your prefiled testimony or Exhibit 2?

A No.

Q If I were to ask you the questions which appear in your prefiled testimony today, would your responses be the same?

A Yes, they would.

Q And do you adopt that prefiled testimony as

your sworn testimony in this proceeding?

A I do.

MR. LONG: Madam Chairman, I ask that Mr. Black's prefiled testimony be inserted into the record as though read.

CHAIRMAN JOHNSON: It will be so inserted.

MR. LONG: And I'd like to move the admission of Exhibit up 2 at this time.

MR. HOWE: I would object to it being moved into evidence at this time. We've not had an opportunity to cross examine Mr. Black.

MR. LONG: That's fine, Madam Chairman.

TAMPA ELECTRIC COMPANY
DOCKET NO. 980693-EI
SUBMITTED FOR FILING 6/30/98

BEFORE THE PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

CHARLES R. BLACK

Q. Please state your name, address and occupation.

A. My name is Charles R. Black. My business address is 702 North Franklin Street, Tampa, Florida 33602. I am Vice President-Energy Supply for Tampa Electric Company.

Q. Mr. Black, please furnish a brief outline of your educational background and business experience.

A. I graduated from the University of South Florida in August 1973 with a bachelor of science degree in Engineering, majoring in Chemical Engineering. I am a Registered Professional Engineer in the State of Florida. I began my career with Tampa Electric Company in September 1973 as a staff engineer in the Production Department. Between 1973 and 1989, I held various engineering and management positions in the Production Department, Power Plant Engineering Department, and the Budget Department. In

March of 1989, I joined our affiliated company, TECO Power Services as Director Engineering and Construction. In December of 1990, I was elected Vice President of Engineering and Construction. In December of 1991, I returned to Tampa Electric as Vice President of Project Management. In December 1996 I assumed my present role as Vice President-Energy Supply.

Q. Have you previously testified before this Commission?

A. Yes. I testified in support of the prudence of Polk Unit One in Docket No. 960409-EI.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to demonstrate that the cost estimates associated with the proposed flue gas desulfurization ("FGD") system, and the other project alternatives considered in the economic analysis described by Mr. Hernandez are reasonable. As discussed below, the proposed FGD system will enable Tampa Electric to comply with the SO_2 emission limitations set forth in Phase II of the Clean Air Act Amendments of 1990 ("CAAA").

Q. Have you prepared an exhibit in support of your testimony?

A. Yes I have. My Exhibit No. 1 (CRB-1) consisting of 6 documents, was prepared under my direction and supervision.

Q. Please explain the Phase I and Phase II environmental compliance requirements related to SO_2 emissions created by the CAAA.

A. The Acid Rain Program of the 1990 CAAA set as its primary goal the reduction of annual SO_2 emissions by 10 million tons below 1980 levels. To achieve these reductions, the law requires a two-phase program which establishes annual SO_2 tonnage emission limits for fossil fuel-fired power plants. Compliance with Phase I was required by January 1, 1995. Phase I placed initial emission limitations on certain units named in the CAAA.

Tampa Electric has complied with Phase I and this Commission has approved the company's cost of compliance for cost recovery as part of its environmental cost recovery ("ECRC") in docket No. 960688-EI. The purpose of this proceeding is to review the company's plan for compliance with Phase II.

Compliance with Phase II is required by January 1, 2000 and further reduces annual emissions from Phase I plants. Phase II also sets SO_2 emission limits for additional fossil fuel fired plants encompassing more than 2,000 units in all. As such, the program imposes SO_2 emissions limits on existing steam electric units serving generators with an output capacity of greater than 25 MW and all new utility units.

Q. For background purposes, please summarize how Phase I of the CAAA imposed limits on Tampa Electric.

A. Units of Tampa Electric's system affected by Phase I are Big Bend Units 1, 2 and 3. These units were granted a combined total of 80,085 SO_2 allowances. This number defines the maximum SO_2 emissions allowed under this program, without further mitigation measures, for these three units. Each allowance held allows for the discharge of one ton of SO_2 emissions. In addition, Tampa Electric Company voluntarily substituted Big Bend Unit 4 into the Phase I requirements of the CAAA program. As a designated Phase I Substitution Unit, Big Bend 4 was granted a total of 6,400 additional annual allowances during Phase I. This measure provided Tampa Electric with a total of 86,485

Phase I allowances.

Q. How do the Phase II compliance requirements impact Tampa Electric?

A. All current and future Tampa Electric units, except Phillips and existing combustion turbines, are affected by Phase II compliance requirements. In Phase II, Tampa Electric will be allocated 83,882 allowances, thereby reducing the amount of allowances available to the company while increasing the number of units affected. This effectively reduces the amount of SO_2 emissions allowed without further mitigation measures.

Q. How do the limitations in Phase II compare to those in Phase I?

A. As shown in my Document 1, approximately twice the amount of Tampa Electric's generating capacity is covered by Phase II than by Phase I, yet we will receive approximately 2,600 fewer allowances.

Q. Can you briefly describe Tampa Electric's Phase I compliance strategy?

A. Tampa Electric began its CAAA compliance plan in 1990 and sought relevant input from across many areas of the company. In 1994 the SO_2 compliance plan evaluation of Phase I was completed. That plan was to blend fuel with low sulfur coal and purchase SO_2 allowances to meet the CAAA limits. Following the implementation of that plan Tampa Electric engineers, working with EPRI, DOE and others, determined that it would be possible to treat all of the flue gas from Big Bend Unit 3 in the existing FGD system that was currently treating the flue gas from Big Bend Unit 4. This was accomplished in 1995 at a very low cost. This modification, in conjunction with fuel blending and allowance purchases, provided a much lower compliance cost for Phase I than fuel blending and allowance purchases alone.

Q. Has Tampa Electric's Phase I compliance effort been successful to date?

A. Implementation of our plan has been very successful. We have been able to achieve compliance with the CAAA Phase I with high unit availability, efficiency, and reliability. Treating the flue gas from a second unit has allowed us to be flexible in our fuel utilization as well.

Q. How did Tampa Electric determine the options for complying with Phase II of the CAAA?

A. We began this process by compiling a list of viable compliance options for initial screening studies. Options that were not viable were eliminated. These remaining options went through both quantitative and qualitative analysis to screen the options. This process is described in Mr. Hernandez's testimony. These options were compared to the best "non-build" option of fuel blending and allowance purchases at all of Tampa Electric's coal units.

Q. How were the capital and operating costs developed for use in the economic studies for the screening analysis as described in Mr. Hernandez's testimony?

A. The screening process began with an evaluation of adding an FGD system to Gannon Station Units 4,5, and 6. Tampa Electric Company retained an architect engineering firm with considerable expertise with FGD systems to develop a cost estimate for installing one of two different technology FGD systems at that location. Tampa Electric engineers, with experience in design and operation of FGD systems, reviewed these costs and found them to be reasonable. As the screening process continued we looked

at FGD options at Big Bend Station, including a new stand alone FGD system for Big Bend 1&2 or treating the flue gas from Big Bend 2 in the existing FGD system for Big Bend Units 3&4. The costs for these options were determined by Tampa Electric's engineers using the Gannon FGD study cost as the basis for the Big Bend 1&2 stand alone option. The Big Bend 3 FGD integration was used as the basis for the Big Bend 2 integration feasibility assessment. These capital and operating costs estimates were utilized in the economic evaluations.

Q. How did Tampa Electric forecast the fuel and SO_2 allowance prices utilized in the economic studies?

A. Tampa Electric monitors the prices of all fuels and SO_2 allowances on a regular basis. The prices are tracked through numerous periodicals, actual buying experience, and through market information obtained through supply representatives. A forecast of expected fuel prices is developed annually to support the company's planning process. The forecast used in this analysis is the same forecast utilized in the Tampa Electric 1998 Ten Year Site Plan. The development of the forecast includes a review of historical fuel prices compared with new projections obtained from various consultants and agencies including

Energy Information Administration, American Gas Association, Cambridge Energy Research Associates, Resource Data International, and Energy Ventures Analysis. Fuel Pricing publications include: Coal Outlook, Coal Daily, Natural Gas Week, Platt's Oilgram, Oil and Gas Journal, and Pace Petroleum Coke Quarterly.

Q. How did these forecasts impact the base case and FGD case analysis?

A. The base case achieves compliance by switching from high sulfur and medium sulfur coals to low sulfur coals in conjunction with allowance purchases. As we reviewed the forecasts from consultants for high sulfur and low sulfur coal, we determined that our forecast for low sulfur coal was less expensive than the consultant's estimates, and that our forecast for high sulfur coal was more expensive than the consultant's. These comparisons are shown in my Documents 2, Pages 1 and 2. Consequently, the consultants forecasts would favor the FGD option more than the forecasts we used in our cost recovery studies.

Q. The screening process described in Mr. Hernandez's testimony indicated that the Big Bend 1&2 FGD addition was our best Phase II compliance choice.' How did Tampa

Electric proceed to ensure their estimates were reasonable?

A. To ensure Tampa Electric's estimated cost of the Big Bend 1&2 FGD system was reasonable, we hired a second experienced architect engineering firm to provide us with a more refined cost estimate of this system. This firm developed a design basis for the FGD system with Tampa Electric's engineers. It then developed a conceptual design with site layouts, arrangement drawings, equipment lists, electric load lists, piping lists and materials of construction. This firm also received vendor quotes for the major equipment and utilized published data or its internal cost databases to come up with an accurate estimate of the cost. This more refined estimate supported the previous costs utilized in the screening analysis. Based upon these two cost studies, which were reviewed by Tampa Electric's engineering personnel experienced in FGD technology, we found the FGD cost estimates to be reasonable. These revised costs were then utilized in the cost effectiveness analyses described in Mr. Hernandez's testimony.

Q. Please describe the proposed FGD system and explain how it operates.

A. An overview of the FGD system is shown in my Document 3. An FGD System, or "scrubber", consists of equipment capable of removing sulfur dioxide from the flue gas generated by the combustion of coal. The flue gas is directed to an absorber tower where it is treated with a slurry spray of limestone and water. The SO_2 in the flue gas is absorbed by the slurry to form an acid which is then neutralized by the dissolved limestone. The reaction of the SO_2 and limestone produces calcium sulfite which is then oxidized by the introduction of air into the reaction tank. The product of this forced oxidation is gypsum which then precipitates out of solution. The resulting gypsum slurry is then dewatered to produce a near dry gypsum cake which is sold as a raw material, predominately to wallboard producers.

Q. What are the estimated capital costs of the new FGD sytem?

A. It is estimated to cost approximately $90 million (including AFUDC). This estimate is based on the conceptual design and the detailed cost estimate performed by an outside consulting firm described previously in my testimony. Tampa Electric added costs that were not included in the detailed estimate and adjusted some of the costs based upon our past large project experience. The

adjusted costs include owner's costs and contingency. My Document 4 sets forth a detailed breakdown of the components of the total capital cost.

Q. What are the estimated annual O & M expenses of the Big Bend 1 and 2 FGD system?

A. Tampa Electric has thirteen years of experience operating the FGD system on Big Bend Units 3 and 4 which is very similar to the technology proposed for the new FGD system. The operations and maintenance requirements for the new FGD system were developed by comparing new equipment requirements to the existing equipment requirements. Cost information gathered from actual operations was obtained for each system area and used to estimate the O&M cost for the new equipment. These present day costs were then escalated to year 2000 dollars.

The annual O & M expense for the FGD system is estimated to be approximately $3.5 million. My Document 5 sets forth a detailed breakdown of the estimated O & M expense for this project. The $3.5 million estimate is stated in year 2000 dollars. Reagent costs were based on limestone costs of $2.1 million and dibasic acid costs of $0.27 million. The remainder amounts to about $1.17 million and consists

of plant O & M. We have assumed that all O&M costs will escalate at a rate of 3% per year.

Q. What assumptions did you make regarding the efficiency and availability of the FGD for Big Bend Units 1 and 2?

A. The FGD case assumes that Big Bend Units 1 and 2 would burn high sulfur coal with treatment at 95% efficiency with a 98% FGD availability. This option results in all coal units at Big Bend Station being fitted with an FGD system. Because Tampa Electric is restricted to a system SO_2 cap, the flue gas treatment of Big Bend Station allows Gannon units to burn a lower cost fuel and still meet the system SO_2 cap. Consequently, fuel savings are realized at both Gannon and Big Bend Stations. In addition, by blending higher sulfur coal at Gannon, those units are able to regain some of the operational derations associated with burning low sulfur coal.

Q. What is Tampa Electric's compliance plan implementation schedule for this project?

A. Tampa Electric will proceed on a very aggressive schedule to place the FGD system in service in June of the year 2000. We are, however, attempting to achieve an even

earlier in service date by continuing to expedite all facets of environmental permitting, engineering and construction. During the short time between the compliance date and the in service date of the new FGD system we will comply with the more stringent CAAA requirements through fuel blending and allowance purchases.

With respect to the permitting schedule, Tampa Electric plans to submit required environmental permit applications in mid-1998. Based on communications with the Department of Environmental Protection, Tampa Electric anticipates the release to initiate construction to be received in September 1998. As shown in my document 6, all project environmental permits should be obtained by December 1999.

Q. Please summarize your testimony.

A. Tampa Electric has a legal obligation to comply with the CAAA. Phase II of the CAAA requires that Tampa Electric reduce its emissions of SO_2 by approximately 50% by January 1, 2000. Tampa Electric has determined the capital and O&M costs of the viable options. These costs were developed with the assistance of professional engineering firms with specific expertise in the design and construction of FGD

systems. Tampa Electric staff have reviewed the cost estimates developed and have determined that these cost estimates are reasonable. The selection of an FGD system for Big Bend Units 1 and 2 will allow Tampa Electric to meet the requirement of the CAAA while maintaining its system capability and availability.

Q. Does this conclude your testimony?

A. Yes

Q (By Mr. Long) Mr. Black, would you please summarize your testimony.

A Yes. Good morning, Commissioners.

Tampa Electric is required to comply with the SO2 emission limitations set forth in Phase II of the Clean Air Act Amendments of 1990. The statute establishes a two-phase program which progressively tightens the annual SO2 emission limits for fossil-fired power plants. As discussed in my direct testimony, Tampa Electric achieved compliance with Phase I of the Act by January 1, 1995, as required under the Act. This Commission approved recovery of the company's Phase I compliance cost in Docket No. 960688-EI. It is our intention in these proceedings to demonstrate the prudence of Tampa Electric's proposed construction of a flue gas desulfurization system for Big Bend Units 1 and 2 as a means of complying with the Phase II requirements of the Act.

The detailed chemical processes that the FGD system will use are described in my exhibit. For the purposes of my summary, I will simply say that sulfur dioxide will be removed by the flue gas desulfurization system from the flue gas of Big Bend 1 and 2 with one by-product in this process being

commercial grade gypsum.

We began the Phase II compliance process by identifying options which were feasible from an operational perspective and not obviously unsuitable from a cost-effectiveness perspective. As part of this process, we considered various options for achieving SO2 emission reductions required under the Act, as well as compliance alternatives which will allow us to address both NOX and SO2 emissions as part of a single solution. While Tampa Electric has developed an approach for meeting NOX reduction requirements, it became clear that there were no commercially proven or potentially cost-effective means of addressing both NOX and SO2 requirements as part of a single solution. The viable solutions all included the use of a FGD system, or fuel blending combined with the purchases of additional SO2 allowances. These potential approaches to compliance were subjected to further cost-effectiveness evaluations as described in Mr. Hernandez's direct testimony.

The projected costs associated with the proposed FGD system evaluated by the company were established by an outside consultant, were then validated by the company, and then reverified through

a second outside consultant. On the basis of this analysis, the costs associated with the proposed FGD system are projected to be $90 million, including AFUDC. This amount represents roughly one-half of the industry average cost for a project of a similar nature. The annual O&M expense is projected to be $3.5 million in year 2000 dollars.

The fuel in SO2 allowance price forecasts used in the company's cost-effectiveness studies was based on various external forecasts, actual prices reported in various periodicals, actual buying experiences, and information obtained through supply representatives. The same fuel forecast used by Tampa Electric in its 1998 Ten Year Site Plan was used in evaluating the FGD compliance options.

We have been diligent in identifying potential compliance options and reasonable in our projection of the costs associated with those options. Thank you.

MR. LONG: Madam Chairman, the witness is available for cross examination.

CHAIRMAN JOHNSON: Okay.

CROSS EXAMINATION

BY MR. McWHIRTER:

Q Mr. Black, my name is John McWhirter, and I

represent the Florida Industrial Power Users Group who have intervened in this case.

How many total generators does Tampa Electric have?

A Total generators.

Q Yes, sir.

A We have five at our Hookers Point station. We have six at Gannon station, plus a combustion turbine at Gannon so that would be seven total. At Big Bend station we have four generators, four coal-fired units plus three combustion turbines. We have one generating unit at our Polk station and we have two generating units at our Phillips station.

Q How many of these generators are affected by the sulfur dioxide emission reduction requirements?

A Gannon Units 3, 4, 5 and 6; Big Bend Units Nos. 1, 2 and 3.

Q With respect to Gannon 1 and 2, why are they not affected?

A The Act called for effected units to be larger than 155 megawatts. Gannon 1 and 2 are smaller than that. With respect to total SO2 allowances for Phase II, Big Bend 4 is also included in that limitation as well as our Polk unit.

Q What is your present SO2 emission from these

effected generating stations in tons per year?

A On a total system basis?

Q Yes, sir.

A Let me check that for you. (Pause)

COMMISSIONER GARCIA: Mr. McWhirter, I missed the question. What was the question?

MR. McWHIRTER: I asked what the total emissions and SO2 stated in tons per year is at the present time from the effected generating stations.

WITNESS BLACK: Let me make a correction to a previous answer, Mr. McWhirter. Units 1 and 2 at Gannon are affected for purposes of SO2 under Phase II. They are not affected with respect to NOX requirements. In addition, the Hookers Point units are also affected by that Phase II requirements.

To address the question of total SO2 emissions on a per-station basis, I have it on a per-station basis as opposed to a total, but for the year 1997, at Hookers Point the total emissions were 1,157 tons of SO2. At Gannon station the total is 66,853 tons. At Big Bend station the total is 102,527 tons. At Polk station, 935 tons. And at the Phillips station, 613 tons.

Q As I understand, your total suggested solution for the SO2 Phase II compliance will be to

put a scrubber on a new chimney at Big Bend 1 and 2?

A That's correct. We would construct one FGD system that would serve both Big Bend Units 1 and 2, and as part of that project a new chimney would be constructed.

Q And what will be your reduction in SO2 emissions as a result of this new chimney and scrubber?

A In tons per year or --.

Q In tons per year.

A Just a second. (Pause)

Our total allowed emissions, once Phase II to the Act becomes operative, as shown in my exhibit Document No. 1, would be 83,882 allowances. So our emissions would be reduced to that number, plus any allowances that we may purchase over and above that.

Q Can you do a quick calculation and give me the emissions reduction to be achieved by this proposal?

A Yes, sir. Just a minute. (Pause)

The reduction between the 1997 actual SO2 numbers that I quoted earlier and the number of allowances that we would be granted under Phase II of the Act is approximately 89,000 tons of SO2 reduction.

Q Is it your testimony that by the

installation of a scrubber and chimney to serve Big Bend 1 and 2 you would reduce your SO2 emissions by 89,000 tons?

A As compared to the 1997 actual numbers, plus any allowances that we may purchase as allowed by the Act that would be correct. The actual numbers that we would see going forward from 1997 may vary from the numbers that I quoted.

Q I see. But the question is what is the reduction that you propose to achieve through this FGD process on Big Bend 1 and Big Bend 2? How many tons will that reduce your total emissions?

A When looking at the 1997 numbers it would reduce it approximately 89,000 except for any allowances that we would purchase.

Q Well, how many allowances do you plan to purchase?

A In our compliance plan, the number was slated at about 25,000.

Q Can I fairly conclude from that then that you expect the reduction in emissions to be achieved by the process which you propose will be 64,000 tons from Big Bend 1 and 2?

A Relative to the 1997 numbers, and if you assume that the number for allowance purchases that

we've used in our planning work turns out to be the actual number then that would be correct.

Q Is 1997 a relevant number that's used by the Department of Environmental Protection or does it use another number?

A I'm sorry, I didn't understand.

Q Well, you point out that your comparison is made on 1997 emissions. And is 1997 the relevant year that is studied by DEP to determine whether your emissions reduction is satisfactory or is some other year study?

A 1997 is the last full year of data that we have to compare to. With respect to the DEP, we make reports to the DEP. The limits that are set under Phase II were done based on a historical average that preceded 1997.

Q Has the DEP approved your plan for SO2 reduction at this time?

A We have submitted the required permits application to the DEP. We have had preliminary meetings with the DEP. We have not yet received final permit approval. We have received from the Department of Environmental Protection authorization to commence construction at the site at Big Bend.

Q In your professional opinion, is there any

likelihood that the DEP will disapprove your SO2 program?

A I'm confident that we'll get the required permits.

Q The reduction that you are looking for, the 64,000 tons, would bring your 1997 emissions into line with the Clean Air Act requirements if you go out and buy 25,000 tons, but would it be fair to say that Tampa Electric anticipates that its sales will grow from time to time and that it will sell more electricity in the year 2002, for example, than it does in 1997?

A That would be our expectation.

Q Okay. How do you -- do you know, or has your study indicated what the anticipated additional SO2 emissions will be as a result of the growth in sales between 1997 and 2002?

A Let me check. (Pause)

The addition of a scrubber on Big Bend 1 and 2 we believe will provide an ability for us to continue to comply with the Phase II requirements of the Act well into the future. The 25,000 allowances that we have in our planning work is a maximum amount. We would not anticipate to utilize that amount every year. Mr. Hernandez could better describe the actual

application of those allowances to the planning work.

Q What would -- what is your anticipated growth in emissions between 1997 and 2002 excluding the installation of the scrubbers? It's somewhere what, around 175,000 tons now. If nothing were done, it would grow to what number?

A I don't know.

Q Has any study been given to what that number would be in 2002?

A I believe that information is contained in the cost-effectiveness studies that were done under Mr. Hernandez's direction.

Q Now, as I understand it Big Bend 1 is what, 29 years old and Big Bend 2 is 25 years old?

A That's roughly correct, yes, sir.

Q And you project that each of these units will have an additional life of some 20 years?

A I would expect both of those units to operate in excess of an additional 20 years.

Q Will they continue to operate at the same degree of efficiency in the last half of their life that they did the first half of their life?

A With proper operation and maintenance practices, I believe they can.

Q In your professional experience have you

found that older units continue to function at maximum level throughout their life?

A In general, yes, sir, I do.

Q When you installed the scrubber for Big Bend 3 and 4, what emission reduction in SO2 did you achieve?

A Let me check that. (Pause)

I'm sorry, we don't have that information with us.

Q In August through October of 1997, as I understand it, Big Bend 1 and 2 had some operating difficulties. Am I correct in that or were those other units?

A What was the time frame again?

Q About this same period of time, August through October of 1997.

A I don't recall any particular operating problems that we experienced on those units during that time.

Q Were you experiencing operating problems on any units at that time?

A Some of the units at Gannon were experiencing some maintenance issues. We had some wet coal issues at some of the Gannon units, but not on Big Bend 1 and 2.

Q Have you ever had any maintenance problems at Big Bend 1 and 2 of a major nature?

A What would you consider major?

Q I would consider anything that caused the plant to be shut down for a period of more than two weeks as a major maintenance issue.

A Our maintenance outage planning typically has those units out of service in excess of two weeks on a planned basis, and that happens periodically through their life to maintain the normal maintenance. In addition, there has been outage events that have occurred on the life of those units that were in excess of two weeks.

Q Have there been any outages of that nature in the recent past?

A I can't say for certain. I would be surprised if there were not.

COMMISSIONER CLARK: So you think there have been.

WITNESS BLACK: Yes, ma'am.

Q **(By Mr. McWhirter)** It appears to me that you are putting your CAAA compliance eggs in one basket as opposed to spreading it out through the various generators that create a problem. Do you have backup plans that you intend to fall back on should

there be operating problems with Big Bend 1 and 2 that eliminate your ability to comply?

A If the problems were with the Big Bend 1 and 2 units, that would significantly reduce our emissions in and of itself since they would not be generating electricity. Beyond that, we have the flexibility to use on an interim basis low sulfur fuel and/or purchase SO2 allowances to comply with any situation that may be short term in nature.

Q What is that emergency allowance?

A I'm sorry?

Q What is that emergency plan? You said in addition you have a plan. What is the plan?

A In addition we would have the opportunity to utilize low sulfur fuel and purchase additional allowances.

Q Do you have the low sulfur fuel in inventory at the plant site at the present time?

A Currently our Phase I compliance strategy requires the use of a lower sulfur fuel and we do have it in inventory at this time.

Q In the FIPUG interrogatories to Tampa Electric Company in connection with this case we asked you to give the book value and the salvage value of Big Bend 1 and 2. And the answers we received were

that the book value of Big Bend 1 was $52.1 million -- 52.2 rounding it up, and its salvage value is $59.5 million. Can you explain to me why the salvage value would be greater than the existing book value?

A Let me check. (Pause)

I don't have that information, Mr. McWhirter. I think Mr. Hernandez could address that.

Q In your professional opinion as an engineer, is it surprising to you that the unit is worth more dead than alive?

A I'm not sure the basis of those numbers, and I can't comment on that.

Q We have the same phenomenon -- or a similar phenomenon with respect to Big Bend 2. Its book value is 48.4 million as it stands and its salvage value is $47.6 million. Are those numbers consistent with your understanding of the value of these systems, if you know?

MR. LONG: Excuse me. Madam Chairman, I would object to this mode of questioning. Mr. McWhirter is testifying and assuming those facts to go on to ask follow-on questions.

CHAIRMAN JOHNSON: There's an objection? Would you like to respond?

MR. McWHIRTER: If I may respond to that,

I'm quoting information that was provided in response to interrogatories by Tampa Electric. And I'm asking him to test the credibility of that information, if in his professional opinion the information supplied by Tampa Electric in response to discovery is consistent with his professional opinion as to value of these plants. I'm not testifying. I'm merely providing information -- I mean, using information that Tampa Electric provided to ask him questions about it.

CHAIRMAN JOHNSON: Mr. Long.

MR. LONG: Madam Chairman, I think it's a simple enough matter for counsel simply to show the witness the data request response that he's referring to and ask the witness questions about that response. If the witness knows, he can answer.

MR. McWHIRTER: I'd be happy to do that but it's fairly simplistic.

(Counsel moves over to witness stand and hands document to witness.)

MR. McWHIRTER: This is the salvage value (indicating), this is the book value. This is the book value of 2, this is salvage value of 2. (Indicating to witness pages in book.)

(Counsel returns to his seat.)

MR. McWHIRTER: Do we have a pending

question or would you like me to repeat the question?

WITNESS BLACK: I'd like you to repeat it, please.

Q **(By Mr. McWhirter)** From your -- in your professional opinion, is it unusual that at this point in a generating station's life, that the salvage value is equal to or may exceed the book value of the plant?

A As indicated on the interrogatories, Mr. Hernandez sponsored those interrogatories and I was not involved in putting together the information that's represented there, so I'm really not able to comment on that.

Q I'm not asking you about the veracity of the information. I'm asking you about your professional opinion as to whether or not it's unusual or ordinary that the salvage value might exceed the book value of a plant at this point in its life?

A With respect to my professional opinion I feel much more confident in speaking on matters of technical nature and engineering as opposed to accounting issues. I'm not an accountant. And I just really can't comment on that.

Q All right. Then I won't explore that further with you.

Did you take the salvage value of these

units into consideration in your compliance plan?

A That would have been addressed in the cost-effectiveness studies that were performed by Mr. Hernandez. And I don't know the details of whether it was considered or not.

Q Would you give a description of the proposed action and alternative actions considered by Tampa Electric to comply with the nitrogen oxide emission rates required by the Clean Air Act?

A Yes, sir. We currently are in negotiations with the Environmental Protection Agency with respect to the nitrous oxide emission limits for the Tampa Electric boilers.

We have a situation where five of -- our five largest boilers are of an unique design. They are the only five boilers of that design that we're aware of in the world. And we have taken a position with the EPA that the emission limits that they finalized last year should be reviewed for appropriateness with respect to this unique equipment. So those discussions are ongoing.

The emission limits that were set, we are moving towards those limits by making combustion modifications to the units which involve the replacement of the classification equipment, which

allows us to better balance the fuel flow to the boilers, which allows us to reduce the amount of excess oxygen that is required for the combustion process and that reduction of the excess oxygen provides a benefit in reducing the NOX work.

The classification modifications and combustion mods. We are hopeful that will get us down to a point where we can comply with the existing EPA rules even if we're unsuccessful in convincing them that we should have a different limit.

To the extent that we are not successful with our combustion modifications, the next level of NOX compliance would be the installation of a selective catalytic reduction clean-up technology on the tail end of one of our large boilers. Based on the test results that we've obtained so far on the combustion modification and the classifier revisions, we're confident that if that does not bring us into compliance with EPA's numbers by itself, that the addition of one SCR unit would be sufficient to bring us into compliance.

So we're taking a staged approach for our NOX compliance. We are looking at the least cost alternative first, and we want to verify that that either is or is not totally acceptable. If it's not,

then we move to the next control technology to achieve the limits.

The current estimate for the combustion modification cost is in the order of $8- to $10 million of capital cost. If we have to move beyond that, the installation, the capital cost associated with a SCR on one of our large boilers we estimate to be in the order of $20 million. The technologies that we utilize for NOX control are totally separate from those that we are employing for SO2 control. And because of the fact that no single technology that we're aware of can deal with both of those issues, we're treating them as totally unrelated. And the approach that we're taking on our NOX compliance has no effect on the options that we would select with respect to our SO2 compliance. And even if you look at the cost of the SCR case and compare that to other options for dealing with NOX and SO2 in a combined nature, that still is by far the most cost-effective solution.

Q What are your current NOX emissions into the atmosphere?

A Let me check. (Pause)

The information that I have with me is expressed in rate of NOX production as opposed to

total tons.

For the year 1995 our NOX emissions were 1.226 pounds of NOX per million Btus. Subsequent to that time we've entered into a Memo of Understanding with Hillsborough County to proceed on a NOX reduction plan that precedes the requirements of the Clean Air Act Amendments. And the rate that we've committed for 1998 is 1.03 pounds per million Btus, and we're confident that we can achieve that rate through the combustion modifications we're employing to the units.

Q How would you go about converting the pounds per MMBtu into tons per year?

A We would have to go back and look at the particular emission rates for each unit times the number of millions of Btus consumed in that unit for year and do the conversion.

Q Is the Clean Air Act requirement expressed in total tons or is it expressed in rate of pounds per MMBtu?

A It's expressed as a rate of pounds per million Btus.

Q So if you have a less efficient unit, the rate would be higher than for a more efficient unit?

A I'm sorry, I didn't understand that.

Q Well, I would imagine the heat rate of your

unit comes into play with respect to the determination of the NOX rate of pounds, does it not?

A Total pounds.

Q Yes, sir.

A Yes, sir.

Q Hillsborough County has required 1.03 pounds per MMBtu. What does the EPA and DEP require?

A I'll check. (Pause)

The 1.03 number that I quoted for Hillsborough County is not a Hillsborough County requirement, that's a number that's represented in a voluntary agreement that we've entered into with Hillsborough County.

The Clean Air Act Amendment requirements for NOX rates is for Gannon Unit 3 and 4, which are cyclone boilers, .86 pounds per million Btus. Gannon 5 and 6 and Big Bend 1, 2 and 3, which are the more unique units that I spoke of earlier, the emission limit currently set is .84 pounds per million Btus. Our Unit 4 at Big Bend was covered by a specific NOX requirement when it went into service and its emission limit is .45 pounds per million Btu.

Q And the EPA and the DEP -- the DEP is the agent for the EPA in Florida to enforce the Clean Air Act compliance. Am I correct in that?

A I'm not sure how that works, Mr. McWhirter.

Q Essentially you must achieve about a 30% reduction in your current rate of NOX emissions in order to comply with the Clean Air Act?

A Something on the 20 to 30% range, that's correct.

Q And it's your testimony that the expenditure of $8- to $20 million will enable you to achieve the Clean Air Act requirements for NOX removal irrespective of whether you achieve your request for modification from the Environmental Protection Agency?

A The dollar numbers that you quoted, the combustion modifications, we expect that to be $8 to $10 million. If we have to install as SCR, that's an additional $20 million. So the range would be from $8- to $30 million. But with that correction, yes, I agree with the statement you made.

Q Is that $8- to $30 million per unit or for all units under consideration?

A That's for all units under consideration.

Q With respect to your Clean Air Act compliance plan, are there any other major expenditures that you contemplate in order to bring your utility into compliance with the Act?

A No, sir, not at this time.

Q What does that rule, PM 25, the particulate emission rule; what are you going to do to comply with that?

A PM 2.5 emission limitations. PM 2.5 is particulate matter less than 2.5 microns in size, so it's on fine particle requirement.

There were rules passed in 1997 by the EPA that limits PM 2.5 emissions. But as part of that rule, there's an extended schedule for action there. The rule basically says between 1998 and the year 2001 they will collect data. The other important area on PM 2.5 is that it's an ambient air quality standard, not an unit-specific emission limitation. So compliance for PM 2.5 would be done on a geographic area basis, not as related to a particular company or a particular unit within a company.

Between 1998 and 2001 the EPA would cause data to be collected. And between 2002 and 2005 they would take that data, reverify that the limits that they have established are appropriate and determine which areas of the United States, if any, are in noncompliance for the 2.5 rule.

If an area is in -- or non-attainment for 2.5 at that time frame, then between the time 2005 and 2008 actions would be taken by the federal, state and

local governments to bring those areas into compliance with 2.5. So at this time we're not aware that Hillsborough County has a problem with 2.5. It's going to be sometime before we know exactly where we are.

In our planning work -- Mr. Hernandez can speak to this in more detail, but the time period at which the cumulative benefits of the FGD system at Big Bend exceed the cumulative cost is between the fifth and sixth year, which should occur prior to the time that we would have to make any modifications if Hillsborough County was determined to be in noncompliance.

MR. McWHIRTER: I tender the witness.

CHAIRMAN JOHNSON: Mr. Howe.

COMMISSIONER CLARK: Before Mr. Howe gets started, I have to confess that Mr. McWhirter asked you about total emissions and it seemed like you were emitting in excess of right around 200,000 tons. I'm having trouble equating that to your testimony as far as allowances.

WITNESS BLACK: Okay. Is that Exhibit 1, or Page 1 of the exhibit?

COMMISSIONER CLARK: Actually I'm looking at Page 4 of your testimony, but maybe that would help.

What is the figure -- well, I guess it was for Phase I you had a total of 86,485 allowances; is that right?

WITNESS BLACK: Yes, ma'am.

COMMISSIONER CLARK: Does that mean how many tons of sulfur dioxide you can emit in a year from all your plants?

WITNESS BLACK: Under Phase I the only affected units for SO2 were Big Bend 1, 2 and 3. So that specified the total tons of emissions that were allowed from those three units.

COMMISSIONER CLARK: Okay. Now, let me ask you another thing. You say you voluntarily submitted Big Bend 4. Why did you do that? What was the advantage voluntarily submitting it to Phase I? I do know it got you more allowances, but what was the benefit in doing that?

WITNESS BLACK: It was basically the additional allowances that it generated. Big Bend 4 was governed by new source performance standards when it was put into service, so it went into service with a scrubber. And by going ahead and voluntarily substituting it into the program, it provided us additional allowances to be used for the other affected units.

COMMISSIONER CLARK: So that reduced your overall cost.

WITNESS BLACK: Yes, ma'am.

COMMISSIONER CLARK: Do you purchase allowances now?

WITNESS BLACK: Yes, ma'am.

COMMISSIONER CLARK: How many do you purchase a year?

WITNESS BLACK: It varies from year to year. We have purchased, or actually utilized approximately 20,000 allowances per year. Other years we have been down in the 8- to 10,000 range.

COMMISSIONER CLARK: Now, you make the statement that the Clean Air Act 2 applies to all your units now, all current and future Tampa Electric units.

WITNESS BLACK: Yes, ma'am.

COMMISSIONER CLARK: Except Phillips and existing combustion turbines. Is that all coal-fired generation that applies to you?

WITNESS BLACK: All coal-fired generation and oil-fired. So it would include the Hookers Point station as well.

COMMISSIONER CLARK: So the 83,882 allowances that you're allotted in Phase II will

affect which units?

WITNESS BLACK: Big Bend's Unit 1, 2, 3 and 4. Gannon's 1, 2, 3, 4, 5 and 6. Hookers Point 1, 2, 3, 4, and 5. And Polk unit No. 1.

COMMISSIONER CLARK: What is an SCR unit?

WITNESS BLACK: It's a selective catalytic reduction equipment. It's installed in the backpass of the boiler. It's a system that has a catalyst bed in it. The flue gas moves across this bed. You inject ammonia into the reaction bed, and as the flue gas crosses the catalyst with the amomnia, the NOX is reduce to elemental nitrogen and the NOX compounds are reduced.

COMMISSIONER CLARK: Okay. I'd like to be clear. Which units that have to comply with SO2 reductions also have to comply with NOX reductions, is it the same units?

WITNESS BLACK: The NOX reductions would be the same units with the exception of -- let me check that to make sure. (Pause)

The unit at Hookers Point would not be covered under the NOX rule, and Gannon Unit 1 and 2 would not be covered.

COMMISSIONER CLARK: So Big Bend 1, 2, 3 and 4 will have, if your plan goes forward, will have the

scrubbers, will also be subject to NOX requirements.

WITNESS BLACK: Yes, ma'am.

COMMISSIONER CLARK: Now, is it your testimony that efficiency of the scrubbers and their ability to meet the projections you have in this docket will not be affected by anything you have to do to produce NOX; that anything you may have to do in the future to reduce NOX will not affect your projections in here?

WITNESS BLACK: Yes, ma'am, that's correct.

COMMISSIONER CLARK: Okay.

CROSS EXAMINATION

BY MR. HOWE:

Q Hello, Mr. Black.

A Good morning.

Q I'm going to start out by backing up a little bit and asking about Tampa Electric's prior experience with scrubbers. Big Bend 4 was the first unit on Tampa Electric's system that was scrubbed, was it not?

A That's correct.

Q Are you familiar with the construction of Big Bend 4?

A Yes, sir.

Q What is your familiarity with that

construction?

A At the time Big Bend 4 was constructed I was in the power plant engineering group that was participating with the engineering construction of that unit in the capacity as manager of instrumentation and control engineering.

Q How familiar are you with the scrubber technology on Big Bend 4?

A Somewhat familiar. I'm not an expert but I'm generally familiar with it.

Q Let me phrase it this way. I did a little research of some publications on the Internet. And, for example, tell me if this description of the Big Bend 4 scrubber is accurate, and I'm looking at a January 1st, 1996 edition of "Power Magazine," and it say "The 475 megawatt Unit 4 was already equipped with a double loop wet limestone forced oxidation flue gas desulfurization system consisting of four absorber towers, three of which operate in parallel with the fourth tower serving as a maintenance spare." Does that sound accurate?

A That was accurate at the time the unit went into the service, that is correct.

Q The unit went into service when?

A In February 1985.

Q Okay. Your answer suggests that there were some changes made in the scrubber at Big Bend 4. When were those changes made?

A I don't recall the exact date. It was late '96, or early '97, but it was when we integrated Unit 3 into the Unit 4 scrubber that was part of our Phase I compliance plan.

Q Were there earlier changes to Big Bend Unit 4's scrubber? By that I mean some technological changes in the 1989 time frame?

A I'm not sure of the time frame, Mr. Howe. But as we put that scrubber in service there were some technical issues with it. Our engineering personnel worked to resolve some of those technical issues and actually ended up being awarded a patent for some of the scrubber technology that were developed by Tampa Electric people on Big Bend 4.

Q I was going to ask you a couple questions about that patent. Again, looking at the same excerpt from this "Power Magazine" document it says "The design changes at Big Bend 4 scrubber were so innovative that TECO was granted a patent for the idea in 1989." Does that sound accurate?

A Yes, sir.

Q First of all, who got the patent? Was it

Tampa Electric or somebody else in the TECO Energy total company?

A As I understand the way patents work, they have to be issued to an individual or group of individuals, but the patent is owned by Tampa Electric Company.

Q Tampa Electric Company. And Tampa Electric would then have the right to license that innovative technology to others, would it not?

A Yes, sir.

Q Would you agree that Tampa Electric, because of the patent, would be motivated to continue to use scrubbers as an alternative to meet Clean Air Act compliance plans because it would be able to take advantage of its own patented technology?

A No, sir, not necessarily. The patent that was achieved was very specific to the type of scrubber that we have on Big Bend 4. And, in fact, Tampa Electric has licensed that technology, the patent that we have, to other utilities in the U. S. and has received royalty payments for that. But to the extent the scrubber technology is different than what we used on Big Bend 4, the value of our patent would not be there.

COMMISSIONER DEASON: If you know, how do

you account for those royalty payments?

WITNESS BLACK: I'm not sure how they are accounted for, sir.

COMMISSIONER DEASON: Would Mr. Hernandez know that?

WITNESS BLACK: Yes, sir, I believe he would.

Q **(By Mr. Howe)** Mr. Black, what was the effect of these technological improvements for which Tampa Electric received a patent? For example, did it increase the capacity of the scrubber on Big Bend 4?

A I wasn't directly involved with it. My understanding is that the modifications were in the part of the system that took the solid by-product and converted it to commercial grade gypsum; basically completed the oxidation of that material such that it could be sold. But it did not increase the capacity of the system.

Q Did it increase the efficiency of it?

A I'm not sure.

Q Let me try to ask a question that gets more to the point. Did the technological advances made on the Big Bend 4 scrubber make possible in any way the combination that allowed you to scrub Big Bend 3 with the Big Bend 4 scrubber?

A The technology that was developed on the Big Bend 4 scrubber that resulted in this patent really was more associated with getting the Big Bend 4 scrubber to perform in accordance with our expectations.

The technology that allowed us to integrate Unit 3 was basically technology developed by Tampa Electric working with the Electric Power Research Institute with respect to some additives that could be added to the scrubber system, which significantly increased its efficiencies. We did not have a patent on that technology and that was separate from the technology you discussed earlier.

Q All right. Did this latter innovation, is that what allowed Tampa Electric to scrub Big Bend 3 with Big Bend 4's scrubber; to combine the two systems -- the two units, I should say?

A It was very instrumental in allowing that combination. The original design of the Big Bend 4 scrubber also facilitated that, but this technology improvement really allowed that to happen.

Q I'm going to back up from that and we'll return to this in just a minute.

Would you agree that Tampa Electric's original plan to comply with the Phase I requirements

of the Clean Air Act Amendments of 1990 was to use lower sulfur coal at Big Bend Units 1, 2 and 3?

A Yes.

Q Now, it was those three units that were particularly affected, was it not, by the Phase I requirements?

A Big Bend Units 1, 2 and 3.

Q Yes, sir.

A Yes.

Q Did Tampa Electric find out that low sulfur coal for Big Bend Units 1, 2 and 3 increased their fuel cost?

A I can't speak specifically. Generally higher sulfur fuel is somewhat more expensive than -- I mean lower sulfur fuel is somewhat more expensive than higher sulfur fuel.

Q And did the combination of Big Bend 3 -- of scrubbing Big Bend 3 with Big Bend 4's scrubber reduce Tampa Electric's fuel cost?

A I believe that it did.

Q When did Tampa Electric make the decision -- what was the earliest date that you're aware of that Tampa Electric decided to scrub Big Bend 3 with Big Bend 4's scrubber?

A Let me check. (Pause)

The Unit 3 scrubber integration went in service in mid-'96. And the decision was sometime ahead of that, Mr. Howe, but I don't know when it was.

Q You mentioned in mid-'96 you also, in your summary, Mr. Black, refer to the fact that the Commission had addressed Tampa Electric's plans to meet Phase I compliance. And I wrote down the docket number 960668. Was it more properly stated as 960688?

A Yes, sir, it was.

Q Now, you stated that's when the Commission approved your Phase I compliance plan; is that correct?

A My understanding is that in that docket they approved our recovery of our cost associated with Phase I compliance.

Q Again, Mr. Black, looking at the various publications, for example, "Electric Utility Week" for Monday, April 17th, 1995, referring to the combination of Big Bend Units 3 and 4 with a common scrubber, it states that, quote -- it says, "The project is designed to help bring the utility in compliance with Phase II of the 1990 clean air, acid rain rules." Is that a correct statement?

A Not that I'm aware of, Mr. Howe. The requirements for that -- for meeting Phase II are not

operative until January of the year 2000.

Q Again, looking at a Utility Environment Report, dated Friday, April 14th, 1995, it states, and I'll quote, "The scrubber conversion is designed to bring TECO into compliance with Phase II of the 1990 clean air, acid rain rules." Would you disagree with that statement?

A I don't know what the basis of that statement was or where that information came from but that's not my understanding.

Q Mr. Black, I'm going to ask you to take a look at the Public Service Commission's Order No. PSC-96-1048-FOF-EI, issued August 14th, 1996, in Docket No. 960688-EI. The docket was styled, In Re: Petition for Approval of Certain Environmental Compliance Activities for Purposes of Cost Recovery by Tampa Electric Company.

(Hands document to witness.)

Would you read the highlighted sentence? I believe it's on Page 2 of that Order.

A It reads "This project satisfies the requirements of both Phase I and Phase II of the Clean Air Act Amendments of 1990 (CAAA)."

Q Would that lead you to believe that the Commission, at least at the time it issued that Order

in mid-1996, believed that the combination of units -- of the scrubbing of Big Bend Units 3 and 4 through the Big Bend 4 scrubber was designed to meet both Phase I and Phase II requirements of the Clean Air Act amendments?

A I would not come to that conclusion. I would think that the -- again, not knowing the context in which this was made, but my interpretation of that statement would be that for Unit 3, the integration of the Unit 3 with the Unit 4 scrubber would meet the requirements for Unit 3 associated with Phase I and Phase II but not necessarily provide benefits across our whole system that would allow us to comply.

Q What is the date of that order, please? I read it into the record, I believe, but if you could give it to me again. It's on the very front on the top right, I believe.

A August 14, 1996.

Q And when did you say the project came into service, and by that I mean the project to scrub Big Bend 3 through the Big Bend 4 scrubber?

A I'm not sure of the exact date but it was in mid-1996.

Q So that order was issued at the time -- around the time that the project was actually placed

in service; is that correct?

A Yes, sir.

Q Did Tampa Electric ever ask the Commission for prior approval of its project to scrub Big Bend 3 through Big Bend 4's scrubber?

A The project to integrate the Big Bend 3 system into Big Bend 4, because of the nature of the project, was on the order of -- my recollection is right on the order of $8 million, and for that size project we did not, to my knowledge, seek prior approval.

Q With the integration of Big Bend 3 and 4 with a common scrubber, did Tampa Electric have to construct an additional chimney for Big Bend 3 and/or 4?

A No, sir.

Q Am I correct that the current configuration of the combined scrubber at Big Bend 3 and 4, that although emissions from both units are scrubbed with a common scrubber, each is fed back to its respective chimney?

A Let me verify that. (Pause)

The scrubber is common. The gases then go back to the respective stacks. There is a stack for Unit 3; one for Unit 4. The way it is configured, if

for some reason Unit 4 could not use its Unit 4 stack, it could use the No. 3 stack, so they are interconnected somewhat.

Also a correction to something I said earlier. The in-service date for the Big Bend 3 integration was mid '95.

Q Mid '95. Would it be correct then that the company did not ask for cost recovery until approximately one year later?

A That's when the Order was issue. When we actually made a petition, I don't have that with me.

Q Mr. Black, I'm looking at one of the pages from your -- exhibit to your prefiled testimony, Document No. 3, Page 1 of 1, which is the graphical representation of the Big Bend 1 and 2 scrubber system.

A Yes, sir.

Q Now, it refers to -- in this illustration it refers to -- it shows an existing chimney, singular, and a new chimney, singular. Are there one or two chimneys right now at Big Bend Units 1 and 2?

A Currently there's one.

Q So is one chimney used then for both units?

A That's correct.

Q And apparently when you integrated the Big

Bend 3 and 4 through a common scrubber, you did not see the need to build a new chimney?

A Unit 3 went into service with its own chimney, as did Unit 4, so there is a -- two chimneys for two units. Currently on Units 1 and 2 there's only one chimney for two units.

Q Correct. Now, why is it necessary to construct another chimney for the Big Bend 1 and 2 integration?

A It's necessary to use the existing chimney as a bypass stack to allow us to operate the units in the event that the scrubbers are out of service for any reason. It does not impact the generation of the units. We can generate through the bypass stack.

Q Is there any substantial technological difference between the scrubber that you plan to build for Big Bend Units 1 and 2 and that that's already in place for Big Bend Units 3 and 4?

A The basic design of the systems are similar. As far as any differences in the technology, I'm not an expert.

The tower velocity is somewhat higher in the scrubbers that will be provided for Units 1 and 2 than certainly the Unit 4 scrubber was bought for, and is higher than the Unit 3/4 integration is operated at.

That's one of the major differences.

Q I want to go on to a separate line right now.

COMMISSIONER JACOBS: Could I ask a quick question? It sounds like that if the scrubber goes out, Units 1 and 2 could be operated absent it.

WITNESS BLACK: Operate the generating units? Yes, sir, we could.

COMMISSIONER JACOBS: How would that impact on our compliance?

WITNESS BLACK: We would have to -- the compliance number is a yearly allowance number that's set, so we would have to adjust through the balance of the year by overscrubbing, utilizing lower sulfur fuel or buying allowances to cover that difference.

MR. HOWE: Thank you, Commissioner Jacob. You made me realize that I'm not done with this area.

Q **(By Mr. Howe)** Mr. Black, still on the issue of the Big Bend 3 and 4 and the Big Bend 1 and 2 integrations, would it be correct to say that Tampa Electric was the first utility to integrate two coal-fired generating units with a common scrubber when it did so with Big Bend 3 and 4?

A To my knowledge that's correct.

Q Has anybody done that since?

A Not that I'm aware of.

Q Would it be fair to say that when you integrated Big Bend 3 with 4's scrubber that that freed up emission allowances in Phase I for Big Bend Unit 3 that you could then use in Phase II?

A The allowances are awarded on an annual basis.

Q Yes, sir. And you would continue to be awarded allowances in Phase I for Big Bend 3?

A Correct.

Q But you would need far fewer allowances for Big Bend 3 in Phase I because now you've scrubbed it; isn't that correct?

A Depending on what kind of fuel that we burned in the unit, by virtue of scrubbing Big Bend 3 it allowed for greater utilization of petroleum coke, which is a higher sulfur fuel. It depends on what sort of sulfur levels we utilized on the rest of our system to optimize our fuel cost. So it's not that these allowances would be put in a bank someplace to be necessarily used for Phase II.

Q But they could be, could they not?

A They could be.

Q In other words, allowances once issued are available for use at any time in the future, are they

not?

A Allowances that are issued for a given year, such as a '98 allowance, is good in any year after that. There is a market for future allowances but they are only good in the year you buy them.

Q Mr. Black, how are other utilities around the country planning on meeting their Clean Air Act Phase II requirements starting in the year 2000?

A Primarily by virtue of switching to lower sulfur fuels.

Q How many utilities are you aware of that are currently planning on building scrubbers to come into service in the year 2000 other than Tampa Electric?

A I'm not aware of any.

Q How many units around the country would you assume -- let's speak here of coal-fired units just to make it manageable -- how many coal-fired units around the country would you guess are going to be -- the utilities that own them are going to meet Phase II requirements by fuel switching?

A I don't have any idea.

Q Would it be a number, for example, in the hundreds?

A I would think so.

Q So Tampa Electric would kind of stand alone,

would it not, right now as the utility that's chosen to go with scrubber technology in the year 2000?

A Yes.

Q Would it be generally true that there's a sense in the industry that utilities might be better off to use fuel switching, at least early on, in Phase II to see how deregulation shakes out so they won't end up with potential stranded investment by expending large sums to build scrubbers.

A My understanding is that many of the utilities, particularly those located in the Midwest, were able to fuel switch to very low sulfur fuel from the Powder River Basin area in Wyoming. They did that in Phase I. They were able to essentially bank allowances that they did not use in Phase I to be used in Phase II. And while those utilities are not putting in scrubbers, January 1, 2000, to comply with Phase II, our expectation is, is that in the year 2003, 2004 or 2005 as that bank is depleted that other utilities also will be putting in scrubbing equipment to meet their Phase II requirements.

The use of the Powder River Basin fuel was not an option for Tampa Electric Company because, again, of the unique nature of these five large boilers that we have and the Powder River Basin fuel

is an unacceptable fuel source for those boilers. So that was not an option that was available to us.

Q But it is an option, is it not, for Tampa Electric to use its banked allowances or to purchase additional allowances beginning in January 1st in the year 2000 to meet its Phase II requirements?

A With respect to the banked allowances, our strategy to date has been to keep an amount of allowances available that would be necessary to support any upset situations or operating difficulties that we had on the unit. We basically optimize our fuel plan to minimize the fuel cost dollars, not to maximize SO2 banking.

With respect to the option of buying SO2 allowances in the year 2000 moving forward, that was one of the options that were evaluated in the cost-effectiveness work that Mr. Hernandez did and proved not to be a cost-effective solution for us.

Q Yes. I understand it was determined to be not cost-effective, but isn't it true that Tampa Electric under its current construction schedule intends to bring the integrated Big Bend 1 and 2 scrubber on line in mid-year 2000?

A That's the current schedule, yes, sir.

Q And for the first, say, six months, Tampa

Electric tends to burn low sulfur coal and either purchase or use allowances; is that correct?

A Yes. We're currently in the process of trying to expedite that schedule and move it back to January, but to the extent there's a gap between our in-service date and when the requirement becomes effective, we would have to manage the system through fuel cost and/or allowance purchases to compensate for that. Or if we were able to achieve higher scrubbing efficiencies from the Unit 1 and 2 system than we have projected in our planning work, essentially overscrub those units, that may provide enough benefits on an annual basis that we would not have to expend any additional funds. But we won't know that until we get out there.

Q If a scrubber is a less cost alternative -- by scrubber I mean for Big Bend 1 and 2 -- is a less cost alternative than fuel switching and allowance, purchase or use, why didn't Tampa Electric plan on having the scrubber for Big Bend 1 and 2 in place January 1, 2000?

A As we did our evaluation work, we were very cognizant of the size of this capital investment and we wanted to ensure that we were working with as accurate and complete information as we could before

we initiated that level of capital investment.

The second detailed engineering estimate that I spoke of in my testimony earlier was kind of the last piece of that. And we felt that it was appropriate to take the time we needed to ensure that the scrubber was being based on the most complete and accurate information available to us. And that's basically what took us a little bit longer.

By virtue of the fact of achieving this work release that we have gotten from the Florida Department of Environmental Protection, we believe that that allows us to make significant improvements in the schedule, and we think we can be a whole lot closer to January 1 than the mid-year number.

Q Would you agree that nothing really prevented you from scheduling all of this to come on line January 1, 2000?

A There's nothing that would prevent us from scheduling it that way. As we went through the evaluation, not knowing where that evaluation was going to lead us, we scheduled the evaluation a normal schedule. By the nature that the evaluation indicated that the scrubber was the preferred option, that required -- because of the capital investment, that required us to go back and do another check on the

layouts and the details and the cost before we were ready to pull the trigger on that. Had a different option come out of that analysis, we would have been able to support the schedule.

Q With the success of the Big Bend 3 and 4 integration in 1995 was it immediately apparent to Tampa Electric that an integrated scrubber for Big Bend Units 1 and 2 might be a viable option for meeting Phase II requirements on those units?

A It was one of the options that was evaluated. It was in the screening analysis and moved its way through the cost-effectiveness work, but it wasn't an obvious correct solution. It was a result of the cost-effectiveness work that we did.

Q What's your earliest memory of Tampa Electric giving serious consideration to an integrated scrubber for Big Bend Units 1 and 2?

A That was one of the options that was reviewed in the screening analysis that dates back to the '96 time frame.

Q Now, I'm going to change subjects and you gave me a bit of a lead in, Mr. Black, with your reference to petroleum coke. Are you familiar with Mr. Hernandez's testimony?

A Somewhat.

Q I'll just read a sentence from his and you'll see why it's coming back to you. On Page 9 of his prefiled testimony on Lines 20 and 21 Mr. Hernandez states, and I quote, "The specific fuel price forecast utilized in the cost-effectiveness studies are described in detail by Mr. Black." Can you tell me where you did that?

A Where we did what?

Q Where you described -- where the fuel price forecast utilized in the cost-effectiveness studies is described in detail by Mr. Black. And I'm looking at Page 9 of Mr. Hernandez's prefiled testimony.

A Beginning on Page 8 of my direct testimony, Line 12, the question of "How did Tampa Electric forecast fuel and SO2 allowance prices utilized in the economic analysis?" That part of my direct testimony includes a description of how those forecasts were generated. And as I said earlier, the detailed analysis or the specific forecast was the same forecast that we had submitted in detail in our Ten Year Site Plan filing.

Q Your reference earlier to petroleum coke, would it be correct to state that Tampa Electric first started experimenting with burning coke in its Big Bend units in the 1995 time frame?

A That sounds right, but I'm not sure of the exact date.

Q And would you agree that Tampa Electric's current plans are to burn petroleum coke in some of its Big Bend units?

A Yes, sir.

Q Which units will they burn petroleum coke in?

A We currently have permits to allow the use of pet coke in Units 3 and Unit 4.

Q Did that require -- the decision to burn petroleum coke, did that require Tampa Electric to change any of its permitting for Big Bend Units 3 and 4?

A It required us to get permit permission to do that, yes.

Q When did you do so?

A I don't have the exact dates.

Q Mr. Black, would you agree that with reference to Mr. Hernandez's testimony, if the Commission is looking for a detailed price forecast utilizing the cost-effectiveness studies as it pertains to petroleum coke in your testimony, if that's where they are looking, they are not going to find it?

A I would agree with that. The utilization of petroleum coke in the Big Bend Unit 1 and 2 scrubber analysis was not included.

Q How about the actual source of the coal that's going to be burned in your units for compliance with Phase II, is that identified anywhere in your testimony?

A It was identified in a general sense in one of the interrogatory responses.

Q But not in your testimony?

A No.

Q Mr. Black, could you refer now, please, to Document No. 4, Page 1 of 1, in exhibits to your testimony, which have been previously identified as Exhibit 2.

A Okay.

Q I note that early on, I believe in answering some questions from Mr. McWhirter, you stated that you're not an accountant; is that correct?

A That's correct.

Q Well, I'm afraid I've got to ask you some accountant-type questions anyway and you just have to tell me if they can be answered.

For example, these dollar amounts shown here as the detailed A/E engineering estimate, are these in

total dollars or are these on a regulatory basis like a 13-month average? How are these expressed?

A My understanding is that this is the -- the reference to A/E is the architect/engineers that we retained to produce the detailed estimate. And this is an estimate of what they believe the total expended dollars would be at the completion of the project.

Q Now, we show -- or you show a subtotal A/E estimate of $57,149,720. Is that the amount that was provided to you by the architect/engineer?

A For the specific scope we asked the architect/engineer to provide an estimate for, that's his total direct cost.

Q Who is the architect/engineer providing these estimates?

A The initial estimate was based on worked that was performed by Stone Webster Corporation. The second independent engineering estimate was provided by Sergeant and Lundy (ph).

Q Did I see reference in any of the documentation to architect/engineer services being provided by Raytheon?

A As we initiated the project, we put out a bid to actually provide architect/engineer services for the implementation of the project and Raytheon was

awarded the bid. So they are the engineers actually performing the engineering work on the project.

Q The second group of numbers, the TECO provided cost information, that would be as it's stated, provide by Tampa Electric Company; is that correct?

A Yes. That covers scope items that we did not include in the work that we asked the engineer to provide estimates for.

Q Who is actually going to build the FGD system, the scrubber?

A The scrubber module itself, we went out to bid for that piece of equipment. The vendor that was selected is a company called Wheelabrator. They will provide the supply and the erection of the scrubber itself. The balance of plant construction has not been awarded at this time.

Q When were the bids issued? When did you -- I guess, the request for proposal or however you treat -- when did you seek bids --

A For the scrubber?

Q -- for the scrubber.

A Let me check. (Pause)

The bids were issued in the January-February 1998 time frame.

Q How big is the contract for Wheelabrator? Is this a rough approximation, the 25,477,000 figure?

A That's an approximation, yes, sir.

Q Is that pretty close to what the contract was actually awarded for?

A Yeah. I don't have the exact number but that's in the ball park.

Q Which activity listed here on your document No. 4 would include the construction of the new chimney?

A Let me check. (Pause)

I believe that would be in the structural concrete line item.

Q Is that chimney being built right now?

A The work authorization that we received from the Department of Environmental Protection allowed us to commence the instruction. The first activity is the placement of piling. That activity is underway. The actual chimney construction is not currently underway.

Q How long does it take to build a chimney for a unit like this?

A On the order of three to five months.

Q In this list of expenditures under -- that lead up to the subtotal for the architect/engineer

estimate, which contracts have been awarded. We've already covered the FGD system itself, I believe, with Wheelabrator?

A That's correct.

Q Which other cost categories here have you awarded contracts on?

A My recollection is that we've awarded a site development contract. We've awarded a piling contract. We have awarded a fan contract. The FGD system, as we talked about previously.

Q Excuse me, you said a fan contract?

A Yes.

Q Which category would that fall under?

A That would be under mechanical process equipment.

Q All right.

A Let me check for a more complete list. (Pause)

That's all I know of in that part of the estimate.

Q Mr. Black, would it be fair to say that Tampa Electric is proceeding on the assumption that they are actually going to construct as integrated scrubber for Big Bend Units 1 and 2?

A In order to get the scrubber in service in

the time frame we need it, we're proceeding on the basis to implement the scrubber project taking appropriate provisions in the contracting for that equipment and services with the appropriate termination provisions and cancellation provisions to limit our exposure if some cause comes about that causes us to take a different tack.

Q As a practical matter, if the Commission were to decide that the scrubber doesn't appear to be the least cost alternative, what could Tampa Electric do between now and mid-year 2000 other than fuel switch and purchase allowances?

A In order to be in compliance?

Q Phase II requirements.

A Those are basically the only options that would be available to us.

Q If this Commission were to decide that it did not have information to grant prior approval to Tampa Electric's plans, construct an integrated scrubber at Big Bend Units 1 and 2, but does not announce that the scrubber looks like a bad idea, how would Tampa Electric proceed?

A I'm not sure we've determined that, Mr. Howe. We'd have to give that one some consideration.

COMMISSIONER CLARK: Mr. Howe, would you ask your question again, please?

MR. HOWE: I am never able to ask exactly the same question.

Q **(By Mr. Howe)** Basically my question was if the Commission was to determine that the information being provided was inadequate to grant prior approval for the scrubber project, but the Commission does not reject the scrubber itself as a viable alternative, how would Tampa Electric proceed after this docket is over? I think that's close to what I asked.

COMMISSIONER CLARK: And would you repeat the answer?

WITNESS BLACK: The answer was that we've not made that determination yet. We believe that it is appropriate for the Commission to acknowledge that this is the least cost way to comply, and it is not appropriate -- well, that it is appropriate that we get that determination, and that's what we would like to achieve.

COMMISSIONER CLARK: Just so I'm clear, what other options beyond buying allowances, fuel switching and a scrubber are available?

WITNESS BLACK: From a practical standpoint, those are the options that are available to us. The

other option that could be looked at that was looked at in the cost-effectiveness study and proved to be extremely un-cost competitive is some sort of replacement of those megawatts with a gas-fired replacement. But that, switching to lower sulfur fuel or buying allowances would be the only options available to us other than the construction of the scrubber.

COMMISSIONER CLARK: Or a different unit.

WITNESS BLACK: I'm sorry?

COMMISSIONER CLARK: Or a different unit, a gas unit.

WITNESS BLACK: Yes, ma'am.

Q **(By Mr. Howe)** Mr. Black, looking at the lower half of the page on your Document No. 4, Page 1 of 1 of Exhibit No. 2, these are the TECO-provided costs; is that correct?

A Those are costs for items that were not in the scope that we asked the A/E to estimate that we provided estimates with our internal resources.

Q How many of these estimates come from Tampa Electric and how many from other TECO Energy affiliates?

A To my knowledge, Mr. Howe, they all come from Tampa Electric.

Q How many of these -- are any of these activities under TECO-provided cost information being provided under contract?

A The professional engineering services that was awarded to Raytheon is under contract. The construction management services were also awarded to Raytheon. That is also under contract. I believe that's all.

Q From your answer what I understand correctly then that not all of they was costs shown as TECO-provided cost information are costs that are going to be -- costs to be incurred by Tampa Electric itself?

A All of the costs of the project will be incurred by Tampa Electric. The ones that I just noted were ones that are existing under contract. The other line items are activities that we intend to proceed with. We've just not got those awarded and under contract yet.

Q Where would your salary appear in this list?

A That would be in the owners control cost.

Q That's the amount of $7,299,863?

A Yes, sir.

Q Using your salary as an example, Mr. Black, were this project not ongoing and let's -- for

illustration purposes, let's assume no major construction project is ongoing for the next couple of years -- would the owner controlled costs be within Tampa Electric's base rates?

A I can't speak to the regulatory treatment of whether they are in base rates or not. From a practical standpoint, as we have capital going on as well as O&M work, I do a time sheet every month and allocate my salary to the things that I work on and it's charged out that way.

Q Mr. Black, are there any costs shown on your Document No. 4, Page 1 of 1, that absent this project would be reflected in Tampa Electric's surveillance reports as included in their base rates, but for which in this proceeding you're indicating that the company intends to charge AFUDC and charge the customers both in base rates and as AFUDC, and to recover those same costs again through the environmental cost recovery clause?

A It's not the company's intent to double dip in either case between the AFUDC and the base rates. And I'm not the appropriate person to talk about how all of that shakes out.

With respect to the owner personnel that is included in this owner control cost, these are our

engineering people, construction people, our procurement people that are working on the project. To the extent that we were not doing this project, we may have different staffing levels. To the extent that we are applying our own internal engineering resources to do this project, we have had to subcontract out engineering work to other engineering companies that we normally would have done in-house. So there is additional cost there. It's difficult to quantify it on an one-to-one basis, but it's not totally correct to say that those costs would be there independent of whether we did the scrubber or not.

Q Would it be fair to say that Tampa Electric has not attempted in this proceeding to identify any cost that would be included in base rates were this construction project not undertaken?

A I'm not aware of any but I'm not the best one to ask about that.

Q Is there anybody who would be the best one to ask that's being offered as a witness in this case?

A I would ask Mr. Hernandez.

COMMISSIONER CLARK: The other chemical engineer who is also an accountant.

WITNESS BLACK: Yes.

Q **(By Mr. Howe)** I must ask you, a pretty big

line item there is your AFUDC entry in the amount of $7,245,954. How is that AFUDC calculated?

A To the best of my knowledge the project team provided an expected cash flow curve for the expenditures on the project to our regulatory group and they input that cash flow into their models that generate AFUDC numbers and that's the number that came back.

Q What do they charge AFUDC on, sir?

A I'm not sure.

Q Do you know whether they charged AFUDC on everything that's listed here, all the other activities, both the architect, engineer and TECO-provided cost information?

A I don't know for sure.

Q Do you know whether the AFUDC rate was calculated consistent with the Commission's order -- I'm sorry, Commission Rule 25-6.0141?

A No, sir, I don't know.

Q Do you know whether in this calculation of AFUDC, whoever did the computations, excluded the amount of CWIP allowed in rate base in the company's last rate case?

A I don't know.

COMMISSIONER CLARK: Mr. Howe, can I ask you

a question? I thought in this proceeding, what specific costs were not -- that might be recoverable one way or the other were not at issue.

MR. HOWE: That's a good question.

COMMISSIONER CLARK: Is that what you're going to, or does it have relevance to the cost-effectiveness of this?

MR. HOWE: No, it's neither. It's a cost that will be accrued during the time period this project is being constructed. So what will happen is the company will approve costs currently so it's not -- you see it's not a question of cost recovery.

COMMISSIONER CLARK: I guess what I'm asking, isn't that for -- don't they have -- aren't we here today to decide if it's eligible, and then the specific cost is in the later --

MR. HOWE: Commissioner Clark, I wouldn't mind waiting until then, but I think you would have to ask the company then do they want a decision now whether they are allowed to accrue AFUDC --

COMMISSIONER CLARK: That's right, they did ask for that.

MR. HOWE: -- between this time and the time they appear in the subsequent docket to seek cost recovery.

COMMISSIONER CLARK: Okay.

MR. HOWE: I believe the AFUDC line itself is the one element that is going to affect what they book as cost and what is potentially going to be allowed for cost recovery in the future in the intervening period.

COMMISSIONER CLARK: So that in this proceeding they are asking that an AFUDC rate be approved?

MR. HOWE: Not an AFUDC rate per se. That's not mentioned that I know of in the Company's testimony.

MR. LONG: Commissioner Clark, what we're asking is for the permission of the Commission to begin accruing AFUDC, and accruing AFUDC is different than recovering AFUDC.

COMMISSIONER CLARK: I understand that. And are you asking now for the permission to accrue the AFUDC, to add it to whatever you might ask for recovery in the conservation -- I mean, in the recovery clause?

MR. LONG: Yes.

COMMISSIONER CLARK: Okay.

Q **(By Mr. Howe)** Mr. Black, on that line, why is the company including an AFUDC line or even showing

the AFUDC accrual if the Commission has a rule that covers AFUDC, won't that control? And if the Commission has an order from the company's last rate case which states that the amount of CWIP used in the last rate case will be the threshold below which the company cannot accrue AFUDC, why is it a relevant matter in this proceeding?

MR. LONG: It's a question of cost recovery. And the parties have worked diligently to assure that cost recovery issues are separated to a later proceeding.

Q **(By Mr. Howe)** Mr. Black, is Tampa Electric intending to accrue AFUDC on this project below the 36 million of CWIP allowed in the company's last rate case?

A I'm not aware of the exact mechanism that we intend to use.

Q I just did a kind of rough calculation, Mr. Black, and I note that the AFUDC appears to be approximately 8.854% of the total project without AFUDC. Would that -- does that lead you to draw any conclusions as to whether the company intends to charge AFUDC with or without regard to the amount of CWIP allowed in rate base?

A I don't understand the mechanism of how that

works well enough to address that.

Q Mr. Black, would you agree that at least as far as this AFUDC line on your Document No. 4, Page 1 of 1, your expertise is not in the area of accounting, and that your expertise, such as it is, is not able to provide an opinion in support of the reasonableness of the $7,245,954 figure shown on your Document No. 4?

A Yes.

MR. HOWE: I have no further questions. Thank you very much, Mr. Black.

MS. KAMARAS: Could I ask the Commission's indulgence for a five-minute break, if Commissioner Clark didn't just ask that question. (Laughter)

COMMISSIONER CLARK: I just did.

CHAIRMAN JOHNSON: We'll take a 30-minute lunch break.

(Thereupon, lunch recess was taken at 12:00 p.m.)

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(Transcript continues in sequence in Volume 2.)