BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 050958-EI

In the Matter of:

PETITION FOR APPROVAL OF NEW ENVIRONMENTAL PROGRAM FOR COST RECOVERY THROUGH ENVIRONMENTAL COST RECOVERY CLAUSE BY TAMPA ELECTRIC COMPANY.
_______________________________/

VOLUME 1
Pages 1 through 177

ELECTRONIC VERSIONS OF THIS TRANSCRIPT ARE
A CONVENIENCE COPY ONLY AND ARE NOT
THE OFFICIAL TRANSCRIPT OF THE HEARING,
THE .PDF VERSION INCLUDES PREFILED TESTIMONY.

| | |
|---|---|
| PROCEEDINGS: | HEARING |
| BEFORE: | CHAIRMAN LISA POLAK EDGAR<br>COMMISSIONER MATTHEW M. CARTER, II<br>COMMISSIONER KATRINA J. MCMURRIAN |
| DATE: | Monday, March 5, 2007 |
| TIME: | Commenced at 9:35 a.m.<br>Concluded at 12:00 p.m. |
| PLACE: | Betty Easley Conference Center<br>Room 148<br>4075 Esplanade Way<br>Tallahassee, Florida |
| REPORTED BY: | LINDA BOLES, CRR, RPR<br>Official FPSC Reporter<br>(850) 413-6734 |

DOCUMENT NUMBER-DATE
02200 MAR 12 ~
FPSC-COMMISSION CLERK

PARTICIPATING:

JAMES D. BEASLEY, ESQUIRE, and LEE L. WILLIS, ESQUIRE, Ausley & McMullen Law Firm, Post Office Box 391, Tallahassee, Florida 32302, appearing on behalf of Tampa Electric Company.

PATRICIA CHRISTENSEN, ESQUIRE, Office of Public Counsel, C/o The Florida Legislature, 111 West Madison Street, Room 812, Tallahassee, Florida 32399-1400, appearing on behalf of the Citizens of the State of Florida.

MARTHA BROWN, ESQUIRE, and KEINO YOUNG, ESQUIRE, FPSC General Counsel's Office, 2540 Shumard Oak Boulevard, Tallahassee, Florida 32399-0850, appearing on behalf of the Commission Staff.

# I N D E X

## WITNESSES

# I N D E X

WITNESSES

EXHIBITS

| NUMBER: | | ID. | ADMTD. |
|---|---|---|---|
| 1 | Exhibit List - 1 | 7 | 7 |
| 2 | Staff Consolidated Exhibit | 7 | 7 |
| 3 | GMN-1 | 7 | 62 |
| 4 | JVS-1 | 7 | 92 |
| 5 | JVS-2 | 7 | |
| 6 | PM-1 | 7 | 112 |
| 7 | TAH-1 | 7 | 144 |
| 8 | TAH-2 | 7 | 144 |
| 9 | TAH-3 | 7 | 144 |
| 10 | TAH-4 | 7 | 144 |
| 10A | TAH-5 | 144 | 144 |
| 11 | JSB-1 | 7 | 176 |
| 12 | JSB-2 | 7 | 176 |
| 13 | JSB-3 | 7 | 176 |
| 14 | JSB-4 | 7 | 176 |

P R O C E E D I N G S

CHAIRMAN EDGAR: Good morning. I call this hearing to order, and we'll begin by asking staff to read the notice.

MS. BROWN: By notice issued January 29th, 2007, this time and place was set for a hearing in Docket Number 050958-EI. The purpose of the hearing is set out in the notice.

CHAIRMAN EDGAR: Thank you. And we'll go ahead and take appearances.

MR. BEASLEY: Good morning, Commissioners. James D. Beasley and Lee L. Willis, both of the law firm of Ausley & McMullen in Tallahassee, Florida, representing Tampa Electric Company.

CHAIRMAN EDGAR: Thank you.

MS. CHRISTENSEN: Patty Christensen on behalf of the Office of Public Counsel.

CHAIRMAN EDGAR: Thank you. And staff.

MS. BROWN: Martha Carter Brown and Keino Young on behalf of the Commission.

CHAIRMAN EDGAR: Thank you.

Okay. Ms. Brown, any preliminary matters?

MS. BROWN: I'm not aware of any, Madam Chairman.

CHAIRMAN EDGAR: Anybody else?

MS. BROWN: I don't know about the parties.

CHAIRMAN EDGAR: No? Okay. Then let's take up the exhibits.

MS. BROWN: We have a comprehensive exhibit list that we've passed out to the parties and to the Commission and the clerk. It includes staff's stipulated composite exhibit and all exhibits prefiled with the parties' testimony. We ask that the exhibit list be marked as Exhibit 1 and all other exhibits be marked as identified on the list. We would like to ask that the list and Exhibit 2, that's staff's stipulated composite exhibit, be admitted into the record at this time, and the remaining exhibits on the list will be admitted after the witness has testified.

CHAIRMAN EDGAR: Okay. Thank you. Then we will mark the exhibit list as Exhibit 1 with the other exhibits as included and described in the list; 2 through 14 will be so marked and described. And Exhibit 1 and Exhibit 2 will be entered into the record.

(Exhibits 1 through 14 marked for identification.)

(Exhibits 1 and 2 admitted into the record.)

MS. BROWN: I would like to mention at this time also, Madam Chairman, that OPC has some corrections to their testimony that they passed out to you all at this time, but they'll deal with them when the witness takes the stand.

CHAIRMAN EDGAR: Fine. Any other matters?

MS. BROWN: Nothing until -- I think TECO has an opening statement to give.

CHAIRMAN EDGAR: Okay. Then, as per the prehearing order, ten minutes per side per opening statement. And, OPC, are you going to take advantage of the opportunity for an opening statement?

MS. CHRISTENSEN: Yes, very briefly.

CHAIRMAN EDGAR: Okay.

MS. CHRISTENSEN: And I guess I proceed first as the petitioning party.

CHAIRMAN EDGAR: Oh, I guess so. Mr. Beasley, does that work for you?

MR. BEASLEY: I'll be happy to proceed.

CHAIRMAN EDGAR: I don't feel strongly, so whichever. Ms. Christensen, do you have a preference?

MS. CHRISTENSEN: That's fine. He can proceed and then I'll follow.

CHAIRMAN EDGAR: Okay. All right. Mr. Beasley.

MR. BEASLEY: Thank you.

Good morning, Commissioners. On behalf of Tampa Electric, I want to thank you for convening this hearing to consider once again the propriety of Tampa Electric Company's Big Bend FGD Flue Gas Desulfurization System Reliability Program.

As you know, on June 20th of last year the Commission unanimously voted to approve the program together with Tampa Electric's cost recovery of prudently incurred costs in implementing this program. That decision was later embodied in your July 10, 2006, order, Proposed Agency Action order in which you found that the program will maintain system unit reliability and is an economically justified and beneficial environmental compliance option for Tampa Electric's customers. You also found that this program will allow for better utilization of the SO2 scrubbers at Big Bend Station and help maintain unit availability of Big Bend Units 1 through 3 at existing levels. Your staff carefully studied that environmental program the first time around and presented you with a well-thought-out, well-reasoned recommendation that you approve it, which you did.

The Office of Public Counsel did not oppose or even address this program prior to your first approval of it, and instead they filed a request for hearing on the last day of the PAA protest period, something we do not contest their right to do but something we're prepared to deal with here today.

In light of Public Counsel's protest, we are before you again with what we consider not to be a burden but instead the opportunity to reestablish for the record the propriety of your earlier vote to approve this program for ECRC cost recovery. We will present direct testimony of three Tampa Electric witnesses today establishing the following facts that support the reaffirmance of your prior PAA decision.

First, our witnesses will explain that prior to the

Consent Decree the generators at Big Bend Units 1 through 3 could be operated in an unscrubbed mode, that's without the FGD scrubbers operating, at any time those scrubbers serving the units were not operable. The evidence will also indicate that the Consent Decree imposes a phased-in reduction and later the total elimination of Tampa Electric's ability to run these units when the scrubbers serving them are not operational.

The evidence will also reveal that from the effective date of the Consent Decree through January 1 of 2010, and that's for Big Bend Unit 3, and through January 1, 2013, for Big Bend Units 1 and 2, the company has a certain number of days a year when these units can be operated when the scrubber serving them is out of order or out of service. Our witnesses will also explain that after the 2010 and 2013 deadlines these highly efficient coal-fired baseload economical units must be shut down at any time the scrubbers serving them are shut down for whatever reason.

Our witnesses will also explain that Tampa Electric utilized over 22 years of scrubber operating experience out at Big Bend Station and the expertise of its own in-house engineers, planners and other experts as well as the resources of outside expert consultants to develop the optimum components of the most cost-effective plan for meeting the 2010 and 2013 deadlines imposed by the Consent Decree.

Our witnesses will also explain that the goal behind that effort was to provide the same level of reliable, cost-effective electric service that the company has been able to provide prior to the effective date of those deadlines in the Consent Decree. The record will show that all of the costs of these projects for which Tampa Electric has requested ECRC cost recovery as opposed to base rate recovery, which some of them are, fully qualify to be recovered by Tampa Electric as proposed by the company. This is made clear in Section 366.8255 concerning ECRC and prior decisions of the Commission through numerous ECRC orders.

The evidence will also establish that but for the 2010 and 2013 deadlines in the Consent Decree, none of the costs of any of these 13 projects that make up the program would have to be incurred by Tampa Electric Company.

Finally, our witnesses will explain that based on conservative estimates the Big Bend FGD System Reliability Program will not only pay for itself, but it'll also provide Tampa Electric's customers approximately $34 million in additional savings over and above the cost of the program on a cumulative net present value basis compared to the base case of not implementing the program in advance of the 2010 and 2013 deadlines.

Commissioners, our rebuttal case will point out significant deficiencies in the testimony of OPC's witness Ms. Merchant and in the testimonies of OPC's outside consultants Mr. Stamberg and Mr. Hewson. Those include the fact that Section 366.8255 and the Commission's decisions implementing that statute provide a solid basis for the Commission's approval of the company's proposal to recover non-base rate portions of the Big Bend FGD System Reliability Program through the ECRC cost recovery mechanism, contrary to the suggestions to the contrary expressed in Ms. Merchant's testimony.

Our rebuttal witnesses also will address the critical fact that Mr. Stamberg has attempted to use operating data from prior to the Consent Decree deadlines to project post 2010 and 2013 deadline operating needs, something that is the epitome of an apples and oranges comparison that completely ignores the fact that Tampa Electric will not be able to operate Big Bend Units 1 through 3 unscrubbed after the deadline has passed; whereas, the company has been able to do so prior to those deadlines.

They will also address the fact that Mr. Stamberg has other serious deficiencies in his analysis including his confusing the use of military time for the commencement of an outage, for the duration of an outage expressed in total hours, something which totally undermines all that follows in his analysis and in his conclusion.

Our witnesses will also address the fact that Mr. Hewson fails to recognize the difference between the phased requirements of the Consent Decree. As Ms. Crouch will explain for Tampa Electric, Mr. Hewson confuses projects that relate to the earlier requirements of the Consent Decree when a limited number of days of unscrubbed operation of Big Bend Units 1 through 3 are permitted with those projects that relate to later phases of the Consent Decree which come into play in 2010 and 2013 when the company can no longer operate the units unscrubbed.

Commissioners, these are fundamental defects that are symptomatic of what clearly is only a superficial review by OPC's witnesses of what Tampa Electric is proposing.

In the final analysis, the record in this proceeding will show that Tampa Electric has used its best efforts and resources to develop the most cost-effective means of meeting the 20,000 or, excuse me, 2010 and 2013 deadlines imposed in the Consent Decree, and at the same time continuing to provide safe, adequate, reliable and reasonably priced electric service to its customers. Our evidence will establish that the projects that comprise the Big Bend FGD System Reliability Program are essential if we are to meet this challenge, and that these projects qualify for cost recovery in the manner the company has proposed. We are prepared to proceed with the evidence today and we thank you in advance for your time and consideration.

CHAIRMAN EDGAR: Thank you, Mr. Beasley.

Ms. Christensen.

MS. CHRISTENSEN: Good morning, Commissioners.

TECO's petition for recovery of its Big Bend Reliability Programs for the ECRC clause requires only one determination to be made, and that is whether the activities that they're requesting for recovery through the ECRC are required to comply with the governmentally imposed law or regulation. And if those activities are not required, then they are not eligible for recovery through the clause. And TECO's petition fails fundamentally on that point and no further inquiry needs to be made.

Citizens has examined TECO's Big Bend Reliability Program and has found that four of the proposed projects failed to meet the standard for ECRC recovery; that is, the activity is legally required to comply with an environmental law or regulation. The proposed electric isolation project, the split inlet duct and outlet duct projects and the gypsum fines filter projects are not necessary or required to comply with the Consent Decree or any other environmental law or regulation. There is no nexus or but for relationship between those projects and the deadlines in the Consent Decree; therefore, these costs are not eligible for recovery through the ECRC clause.

As the Commission noted in its Order PSC-94-0044-FOF-EI, projects which may be warranted and even desirable for other reasons but which are not necessary to comply with any governmentally imposed environmental compliance mandate cannot be passed through the ECRC clause. In other words, even discretionary environmentally related projects are not eligible through the ECRC clause even if they might be eligible for base rate recovery.

TECO's claim that these projects are needed to meet the new source performance standard deadlines that Big Bend Units 1 and 3 run scrubbed at all times is unfounded. Currently Big Bend Units 1 through 3 have all the equipment needed to run scrubbed and meet the requirement to remove 90 percent or 95, excuse me, percent of the SO2 emissions. Even in their quarterly reports to the EPA, TECO placed these projects under the modifications to the Big Bend units not required by the Consent Decree. And these projects were not identified as part of the Phase I and Phase II optimization plans required by the Consent Decree, nor has TECO sought, as witnesses will testify, to modify this plan. So based on TECO's own words to the EPA and the Florida DEP these projects are not required by the Consent Decree.

Because of the potential for abuse of the special mechanism due to shifting of costs which ought to be absorbed in base rates, vigilance is warranted to keep only those costs that are required to meet environmental law or regulations flowing through the clause. Thank you.

CHAIRMAN EDGAR: Thank you. Okay. I think we're ready to go ahead and swear in the witnesses. I believe we have six. We'll do it as a group. If the six witnesses will stand with me and raise your right hand.

(Witnesses collectively sworn.)

CHAIRMAN EDGAR: Thank you.

MR. BEASLEY: We would call Mr. Bryant.

HOWARD T. BRYANT

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

DIRECT EXAMINATION

BY MR. BEASLEY:

Q Sir, would you please state your name, address, occupation and your employer.

A My name is Howard D. Bryant. Excuse me. My business address is 702 North Franklin Street in Tampa. The zip code is 33602. I'm employed by Tampa Electric Company as the Manager of Rates in the Regulatory Affairs Department.

Q Mr. Bryant, did you prepare and submit in this proceeding a document entitled "Prepared Direct Testimony of Howard T. Bryant" dated November 17, 2006?

A Yes, I did.

Q If I were to ask you the questions contained in that direct testimony, would your answers be the same?

A Yes, they would.

MR. BEASLEY: I would ask that Mr. Bryant's testimony be inserted into the record as though read.

CHAIRMAN EDGAR: The prefiled direct testimony will be entered into the record as though read.

TAMPA ELECTRIC COMPANY
DOCKET NO. 050958-EI
FILED: NOVEMBER 17, 2006

**BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION**

**PREPARED DIRECT TESTIMONY**

**OF**

**HOWARD T. BRYANT**

**Q.** Please state your name, address, occupation and employer.

**A.** My name is Howard T. Bryant. My business address is 702 North Franklin Street, Tampa, Florida 33602. I am employed by Tampa Electric Company ("Tampa Electric" or "company") as Manager, Rates in the Regulatory Affairs Department.

**Q.** Please provide a brief outline of your educational background and business experience.

**A.** I graduated from the University of Florida in June 1973 with a Bachelor of Science degree in Business Administration. I have been employed at Tampa Electric since 1981. My work has included various positions in Customer Service, Energy Conservation Services, Demand Side Management ("DSM") Planning, Energy Management and Forecasting, and Regulatory Affairs. In my current position I am responsible for the company's Energy Conservation Cost Recovery ("ECCR") clause, the

Environmental Cost Recovery Clause ("ECRC"), and retail rate design.

Q. Have you previously testified before the Florida Public Service Commission ("Commission")?

A. Yes. I have testified before this Commission on conservation and load management activities, DSM goals and setting and DSM plan approval dockets, and other ECCR dockets since 1993, and ECRC activities since 2001.

Q. What is the purpose of your testimony in this proceeding?

A. My testimony supports approval of Tampa Electric's Big Bend Flue Gas Desulfurization System Reliability Program ("FGD Reliability Program") for cost recovery through the ECRC. I describe the program in general terms, why the company is pursuing it and how the project qualifies for cost recovery through the ECRC, and the three ways the company is seeking to recover the costs of the project. Finally, I address the timing of the recovery. I will also introduce the other Tampa Electric witnesses participating in this matter and briefly describe what they will address.

**Q.** What is the purpose of the FGD Reliability Program?

**A.** This program is designed to maximize the reliability of the flue gas desulfurization systems ("scrubbers") that serve Tampa Electric's Big Bend Units 1, 2 and 3. Such improvements are necessary in order for Tampa Electric to comply with environmental requirements of the United States Environmental Protection Agency Consent Decree ("CD"), issued February 29, 2000, and the Florida Department of Environmental Protection Consent Final Judgment ("CFJ"), entered December 16, 1999. Under these orders, Tampa Electric is prohibited from operating Big Bend Units 1, 2 and 3 unscrubbed at <u>any time</u> beginning in 2010 (for Big Bend Unit 3) and 2013 (for Big Bend Units 1 and 2). The reliability of these generating units, as well as Unit 4 that shares the Unit 3 FGD system, is limited by the reliability of their respective FGD systems.

**Q.** What does the FGD Reliability Program consist of?

**A.** The FGD Reliability program consists of 13 separate additions to and modifications of the FGD systems to maximize reliability of the individual scrubbers and to isolate scrubber components. Mr. John Smolenski, a

Senior Consultant for Tampa Electric and witness in this proceeding, will describe the components of the reliability program in greater detail. The individual activities are centered on improvements to FGD components which the company has identified as most likely to cause scrubber failure and, thus, generating unit outages.

**Q.** When do you propose to implement the FGD Reliability Program?

**A.** Tampa Electric performed modeling and cost benefit analyses to determine whether it would be more cost effective to implement this project in conjunction with already planned plant outages needed for the installation of selective catalytic reductions systems ("SCR") during the 2006 through 2009 period or wait until 2010 and 2013 when the deadlines for not operating the Big Bend units unscrubbed occur. The analysis showed it is more cost effective and beneficial to customers to implement the FGD Reliability Program and the SCR installations simultaneously to avoid additional generating unit outages and additional replacement fuel costs that would have to be incurred if these projects were implemented separately.

**Q.** What qualifies the FGD Reliability Program for cost recovery through the ECRC?

**A.** The costs Tampa Electric will incur for the FGD Reliability Program meet the ECRC recovery criteria established by this Commission in Docket No. 930613-EI, Order No. PSC-94-004-FOF-EI in that:

(a) all expenditures will be prudently incurred after April 13, 1993;

(b) the activities are legally required to comply with a governmentally imposed environmental regulation enacted, became effective, or whose effect was triggered after the company's last test year upon which rates are based; and

(c) none of the expenditures are being recovered through some other cost recovery mechanism or through base rates.

All expenditures associated with the FGD Reliability Program clearly will occur after April 13, 1993. These expenditures would not have to be incurred but for the 2010 and 2013 deadlines imposed by the CD and CFJ. Tampa Electric is not recovering and will not recover any of the requested ECRC expenditures through base rates or any other cost recovery mechanism.

Q. Has the Commission previously addressed the issue of whether costs of complying with the CD and CFJ qualify for cost recovery under the ECRC?

A. Yes it has. In Order No. PSC-05-0502-PAA-EI, issued May 9, 2005 in Docket No. 041376-EI, the Commission approved for ECRC cost recovery prudently incurred costs for the Big Bend Units 1 through 3 SCR and alkali injection systems. In so doing the Commission observed:

> The costs of complying with the settlement agreements [approved in the CD and CFJ] qualify as environmental compliance costs under Sections 366.8255(1)(c) and (2) because the settlement agreements are court orders. The Commission has previously approved cost recovery for activities required by the settlement agreements.

Order No. 05-0502 went on to set forth a table listing ten other prior orders of the Commission approving CD and CFJ compliance projects for cost recovery under the ECRC.

**Q.** What costs do you seek to recover through the ECRC in connection with the FGD Reliability Program?

**A.** The total estimated capital costs of the Big Bend FGD Reliability Program are $21,651,000. These program costs are allocated into three components for cost recovery: 1) an estimated $11,929,000 of capital investment costs associated with Big Bend Units 3 and 4 as the new ECRC Big Bend FGD Reliability Program; 2) an estimated $7,096,000 of incremental capital costs associated the scrubber that is the major component of the company's existing ECRC Big Bend Units 1 and 2 FGD Program; and 3) an estimated $2,626,000 in Big Bend Units 3 and 4 FGD costs which will be recovered through base rates. Only the incremental costs of this project, not already being recovered through base rates or through an existing ECRC program, are being sought for recovery through the ECRC.

**Q.** How do you propose to calculate depreciation for the proposed capital investments?

**A.** The depreciation rates used to calculate the depreciation expense for the proposed environmentally required capital investments should be the rates that are in effect during the period the capital investment is in service. Since the proposed capital investments will have no salvage value once the generating plant retires, the controlling depreciable life is the remaining life of the generating plant. The proposed plant additions will be recovered on a schedule consistent with the remaining life of the Big Bend generating station.

**Q.** How do you propose to allocate the FGD Reliability Program costs?

**A.** Tampa Electric proposes that the FGD Reliability Program costs be allocated to all rate classes on an energy basis consistent with Commission policy set by Order No. PSC-94-0044-FOF-EI, issued January 12, 1994, in Docket No. 930613-EI, In Re: Petition to establish an environmental cost recovery clause pursuant to Section 366.8255, Florida Statutes by Gulf Power Company. In that docket, the Commission ordered that costs associated with compliance with the Clean Air Act Amendments of 1990 ("CAAA") be allocated to the rate classes in the ECRC on an energy basis, due to the strong nexus between the level of emissions which the CAAA seeks to reduce and the number of kilowatt hours generated.

**Q.** Please identify the other witnesses for Tampa Electric testifying in support of the company's petition in this proceeding.

**A.** Gregory M. Nelson, Director, Environmental Policy and Compliance, will present testimony demonstrating that the activities for which Tampa Electric seeks cost recovery through the ECRC for the FGD Reliability Program are activities necessary for the company to comply with the CD and the CFJ. Mr. Nelson's testimony will discuss the background of the CAAA, the company's agreement with EPA and DEP requirements, and details of the CD with a particular focus on the requirements and deadlines in 2010 and 2013.

Mr. John Smolenski, Senior Consultant II - Advanced Technology, Engineering and Construction Services for Tampa Electric will present testimony regarding the cost effectiveness evaluations performed in the Big Bend Station FGD System Reliability Study. He will discuss the various alternatives that the company considered to comply with the CD and CFJ, the results of the analysis and the net savings to customers by following the selected approach. Mr. Smolenski will also provide an update on the progress the company has made with the FGD Reliability Program.

**Q.** Please summarize your testimony.

**A.** Tampa Electric entered into the CD and the CFJ with the United States Environmental Protection Agency and the Florida Department of Environmental Protection, respectively. Under these orders, Tampa Electric is prohibited from operating Big Bend Unit 3 unscrubbed at any time beginning in 2010. Furthermore, the prohibition of operating Big Bend Units 1 and 2 unscrubbed begins in 2013. In 2005, the company undertook a study and determined the most cost effective manner to meet these environmental requirements and associated deadlines was through the Big Bend FGD Reliability Program. This program would not have occurred but for the CD and CFJ. The Commission has previously approved for recovery through the ECRC prudent expenditures the company has incurred in meeting the CD and CFJ requirements. It is appropriate for the Commission to reaffirm its five-zero decision made at the June 20, 2006 Agenda Conference that approved the company's prudent costs associated with the Big Bend FGD Reliability Program for cost recovery through the ECRC.

**Q.** Does this conclude your testimony?

**A.** Yes it does.

BY MR. BEASLEY:

Q Thank you. Mr. Bryant, would you please summarize your direct testimony?

A Yes.

Good morning, Commissioners. My direct testimony addresses the support for approval by this Commission of Tampa Electric Company's cost recovery for the Big Bend Flue Gas Desulfurization System Reliability Program through the ECRC. Flue gas desulfurization, as we use it throughout the course of this proceeding, may also be identified as FGD System or it may also be identified as a scrubber. So as you hear those terms, they will be synonymous or the same as we go through the process.

Tampa Electric entered into a consent final judgment issued by the Florida Department of Environmental Protection in December of 1999 and a subsequent Consent Decree issued by the United States Environmental Protection Agency in February of 2000. Under these orders, and specifically the Consent Decree, Tampa Electric cannot operate the Big Bend coal-fired generating units unscrubbed at any time beginning in January 2010 for Big Bend Unit 3 and January 2013 for Big Bend Units 1 and 2.

In order to comply with the Consent Decree, Tampa Electric undertook a study to determine the most cost-effective way to meet the Consent Decree requirements. The study result defined 13 specific and integrated projects that comprise the Big Bend FGD System Reliability Program, a program designed to maximize the reliability of the two scrubbers that serve Big Bend Units 1 through 4 by addressing the most likely components that cause scrubber failure and, therefore, significant outages of highly efficient coal-fired generating units.

Additionally, the study clearly demonstrated the prudence Tampa Electric -- of Tampa Electric implementing the Big Bend FGD System Reliability Program in conjunction with a previously approved ECRC program, the Big Bend Selective Catalytic Reduction Program or SCR as it's come to be known. In essence, it's the two birds with one stone approach. System outages for the installation of the SCRs are occurring from 2006 through 2009 and, therefore, implementing the Big Bend FGD System Reliability Program concurrently with the SCR Program will avoid additional outages and will also avoid expensive replacement fuel purchases.

As Tampa Electric witness John Smolenski will explain, by using conservative estimates the company will save customers some $34 million over the next available option.

Tampa Electric petitioned this Commission for approval of the Big Bend FGD System Reliability Program on December 27th, 2005. The Commission approved the program at the June 20, 2006, Agenda Conference by a five-zero vote. The subsequent order from that Agenda was issued on July 10 of 2006, and in that order the Commission found two key facts. First, the costs incurred for the program will meet the criteria established by this Commission in what's been termed now the Gulf order back from 1994 and, therefore, will qualify for cost recovery through the ECRC.

The three criteria for ECRC cost recovery established in that Gulf order are as follows. First, the expenditures will be prudently incurred after April 13 of 1993. That's indeed the case because the work for this particular program under consideration today has begun in 2006.

Second, the activities are legally required to comply with a governmentally imposed environmental regulation enacted, became effective or whose effect was triggered after the company's last test year upon which rates are based. Again, for Tampa Electric we meet that criterion because our test year was 1994, so we're certainly past that hurdle.

And, third, none of the expenditures are being recovered through some other cost recovery mechanism or through base rates. As we have filed and supported throughout this proceeding, all of our expenditures we're asking for recovery of are incremental above and beyond what's already being incurred by Tampa Electric Company. That was the first fact.

The second fact is that the company's methodology for cost recovery of the total --

CHAIRMAN EDGAR: Mr. Bryant, I'm sorry. I'm going to have to interrupt you. It's two minutes for a summary and we're at four and a half. So I will show some latitude, but I will need to ask a summary to be a summary. Can you, can you sum up your summary?

THE WITNESS: Sure. Uh-huh.

CHAIRMAN EDGAR: Thank you.

THE WITNESS: Quickly, the second fact that was a part of that order was the fact that our costs were demonstrated to be appropriate for cost recovery, the total of $21.6 million. We clearly identified three methods of recovery: One through base rates, 2.6 of the total 21.6; two, through an existing ECRC program, about 7.1 million of that total 21.6; and then the third is the new program, the Big Bend FGD System Reliability Program, or an approximate 11.9 million of that total. That comprises the total.

But for the Consent Decree, Tampa Electric would not be engaged in the Big Bend FGD System Reliability Program. This Commission has issued some 13 previous orders approving Consent Decree and consent final judgment compliance programs for cost recovery under the clause, and based on your findings we ask the Commission today to apply again consistent judgment in the hearing of this matter before you. And that concludes the summary of my direct testimony.

MR. BEASLEY: Thank you. Mr. Bryant is available for questions.

CHAIRMAN EDGAR: Thank you.

Ms. Christensen.

CROSS EXAMINATION

BY MS. CHRISTENSEN:

Q Good morning, Mr. Bryant. You would agree the Big Bend Flue Gas Desulfurization Reliability Program is made up of 13 projects; correct?

A That is correct.

Q And of those 13 projects, four remain at issue in this proceeding; right?

A There are four at issue. Yes.

Q And would you agree those four projects are the electric isolation project, split inlet duct project, the split outlet duct project and the gypsum fines filter project?

A Yes.

Q Now TECO claims that none of the Big Bend FGD Reliability Programs would have been done but for the 2010 and 2013 deadlines in the Consent Decree; is that correct?

A Yes.

Q Would you agree that in PSC Order Number 94-0044-FOF it states that activities which are legally required to comply with a governmentally imposed environmental regulation are eligible for recovery through the ECRC?

A Yes. As I read, yes.

Q And you would agree that the Consent Decree requires that you run Big Bend Units 1 through 2, or through 3, excuse me, scrubbed when in operation after 2010 and 2013 dates?

A Correct.

Q And currently Big Bend Unit 4 must run scrubbed when in operation; correct?

A Yes.

Q Big Bend Units 3 and 4 share the same FGD system; correct?

A Yes, they do.

Q And Big Bend Unit 4 meets the requirement that it run scrubbed while in operation; correct?

A Well, we are required to do that and that's the only way we do operate Unit 4.

Q So to answer my question, yes, it does run scrubbed at all times; correct?

A Yes. Uh-huh.

Q And you would agree that Big Bend Units 1, 2 and 3 currently have operational FGD systems.

A They are tied into FGD systems, yes.

Q Okay. And those FGD systems allow Big Bend Units 1, 2 and 3 to run scrubbed now; is that correct?

A When they need to run scrubbed, they do. Yes. But also there is the provision for the unscrubbed days available to us up until the 2010 and 2013 deadlines for Units 1, 2 and 3.

Q But you would also agree that Big Bend Units 1, 2 and 3 have the FGD systems to require them to run scrubbed currently.

A Yes.

Q In your direct testimony on Pages 5 through 6 you claim that TECO will not recover any of these requested ECRC expenditures through base rates or any other cost recovery mechanism. Is that a correct summary of your testimony?

A Could you tell me specifically where you're pointing so I can read that?

Q Pages 5 through 6 of your direct testimony.

A Okay.

Q Starting at Line 24.

A Okay.

Q You state, "Tampa Electric is not recovering and will not recover any of the requested ECRC expenditures through base rates or any other cost recovery mechanism."

A Right. That's correct.

Q Would you agree that the Big Bend Units 3 and 4 FGD booster fan capacity expansion project and a portion of the mist eliminator upgrades will be recovered through base rates?

A If I'm not mistaken, subject to check, the booster fan was filed, I believe, as the program where we would want it to be recovered through base rates, and so it's not a part of what we are requesting for recovery through the clause.

Q As well as a portion of the mist eliminator projects; is that correct?

A That is correct.

Q Okay. And that means that the company will recoup the cost of those projects through the revenue it receives from the collection of base rates; is that correct?

A Yes.

Q So the projects recovered through the base rates, through base rates, the cost of those projects are, in fact, being recovered.

A The anticipation from the company's perspective is as we install them, those monies will go through the normal surveillance process and they will be handled as any other expenditure at Big Bend Station on base rate type expenditures.

Q And you will be recovering the cost of those projects through base rates; correct?

A Correct.

MS. CHRISTENSEN: Okay. No further questions.

CHAIRMAN EDGAR: Are there questions from staff?

MS. BROWN: Staff has no questions.

CHAIRMAN EDGAR: Mr. Beasley?

MR. BEASLEY: No redirect, ma'am.

CHAIRMAN EDGAR: Okay. And I see no exhibits; correct? Okay.

Then, Commissioners, any questions for this witness? No.

All right. The witness is excused. Thank you.

CHAIRMAN EDGAR: Mr. Beasley.

MR. BEASLEY: Call Ms. Crouch.

LAURA R. CROUCH

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

DIRECT EXAMINATION

BY MR. BEASLEY:

Q Could you please state your name, your address, your occupation and your employer.

A My name is Laura R. Crouch. My business address is 702 North Franklin Street, Tampa, Florida 33602. My employer is Tampa Electric Company, and my title is Manager, Land and Water Programs.

Q Ms. Crouch, have you read the prepared direct testimony of Tampa Electric witness Gregory M. Nelson that was filed in this proceeding on November 17, 2006?

A Yes, I have.

Q Have you assumed the duties and responsibilities that were assigned to Mr. Nelson prior to his departure from Tampa Electric Company?

A Yes, I have.

Q Do you adopt Mr. Nelson's direct testimony as your own for purposes of this proceeding?

A I do.

Q I would ask that Mr. Nelson's testimony as adopted by Ms. Crouch be inserted into the record as though read.

CHAIRMAN EDGAR: The prefiled testimony of Mr. Crouch as adopted by -- excuse me -- of Mr. Nelson as adopted by Ms. Crouch will be entered into the record as though read.

MR. BEASLEY: Thank you.

BY MR. BEASLEY:

Q Ms. Crouch, do you also wish to adopt and sponsor Mr. Nelson's Exhibit GMN-1 that accompanied his direct testimony?

A I do.

Q And I believe that, Madam Chairman, has been marked as Exhibit 3.

CHAIRMAN EDGAR: Number 3, yes.

TAMPA ELECTRIC COMPANY
DOCKET NO. 050958-EI
FILED: November 17, 2006

**BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION**

**PREPARED DIRECT TESTIMONY**

**OF**

**GREGORY M. NELSON**

**Q.** Please state your name, address, occupation and employer.

**A.** My name is Gregory M. Nelson. My business address is 702 North Franklin Street, Tampa, Florida 33602. I am employed by Tampa Electric Company ("Tampa Electric" or "company") as Director, Environmental Policy and Compliance in Regulatory Affairs.

**Q.** Please provide a brief outline of your educational background and business experience.

**A.** I received a Bachelors Degree in Mechanical Engineering from the Georgia Institute of Technology in 1982 and a Masters of Business Administration from the University of South Florida in 1987. I am a registered Professional Engineer in the State of Florida. I began my engineering career in 1982 in Tampa Electric's Engineering Development Program. In 1983, I worked in the Production Department where I was responsible for power plant performance projects. In 1986, I moved to the environmental department were I held various environmental permitting and compliance positions. In 1997, I was promoted to Administrator - Air Programs in the Environmental Planning Department. In this position, I was responsible for all air permitting and compliance programs. In 1998, I was promoted to Manager, Environmental Planning and in 2000 I became Director, Environmental Affairs. In 2003, I became Director, Environmental, Health and Safety where my responsibilities included the management of Tampa Electric's environmental permitting and compliance programs as well as generation safety programs. In 2006, I joined the Regulatory Affairs Department as Director, Environmental Policy and Compliance.

**Q.** Have you previously testified before the Florida Public Service Commission ("Commission")?

**A.** Yes, I have provided testimony regarding environmental projects and their associated environmental requirements in various Environmental Cost Recovery Clause ("ECRC") proceedings before this Commission.

**Q.** Did you prepare any exhibits in support of your testimony?

**A.** Yes. Exhibit ____ (GMN-1) consists of three documents. Document No. 1 contains a copy of paragraphs 29 and 30 of the United States Environmental Protection Agency ("EPA") Consent Decree ("CD") which define operating characteristics of the Flue Gas Desulfurization ("FGD" or "scrubber") systems at Big Bend Station. Document No. 2 is a copy of Tampa Electric's declaratory letter to EPA stating the company's decision to continue combusting coal at Big Bend Station. Document No. 3 contains a copy of paragraph 40 of the CD which requires Tampa Electric to further restrict the operation of Big Bend Units 1, 2 and 3 should the company decide to continue combusting coal at Big Bend Station.

**Q.** What is the purpose of your testimony in this proceeding?

**A.** The purpose of my testimony is to demonstrate that the activities for which Tampa Electric seeks cost recovery through the ECRC for the Big Bend Flue Gas Desulfurization System Reliability Program ("FGD Reliability Program") are activities necessary for the company to comply with environmental requirements of the EPA CD and the Florida Department of Environmental Protection ("DEP") Consent Final Judgment ("CFJ"). I will also provide a summary of Tampa Electric's programs to comply with the $SO_2$ emission reductions requirements of the Clean Air Act Amendments of 1990 ("CAAA") and compare these requirements to the $SO_2$ emission reductions requirements of the CD.

The FGD Reliability Program was previously approved for ECRC cost recovery by the Commission in Docket No. 050598-EI, Order No. PSC-06-0602-PAA-EI, issued July 10, 2006. By a five-zero vote, the Commission granted cost recovery approval for prudent costs associated with this project. However, on July 21, 2006, the Office of Public Counsel ("OPC") requested an evidentiary hearing.

**Q.** Please briefly describe how Tampa Electric met the $SO_2$ emissions reduction requirements of the CAAA.

**A.** The Acid Rain Program of 1990 set as its primary goal the nation-wide reduction of annual $SO_2$ emissions by 10 million tons below 1980 levels. To achieve these reductions, the law required a two-phase program which established annual $SO_2$ tonnage emission limits for fossil fuel-fired power plants. Compliance with Phase I was required by January 1, 1995 and compliance with Phase II was required by January 1, 2000.

Tampa Electric's compliance with Phase I was accomplished through a combination of fuel blending, allowance purchases and integrating the flue gas from Big Bend Unit 3 into the Big Bend Unit 4 scrubber. The Commission approved the company's cost of compliance with Phase I for cost recovery as part of its ECRC in Docket No. 960688-EI.

Tampa Electric's compliance with Phase II was accomplished through the installation of a scrubber that was designed to treat the flue gas from Big Bend Units 1 and 2. The Commission approved the company's cost of compliance with Phase II for cost recovery as part of its ECRC in Docket No. 980693-EI.

It is important to note that the scrubbers associated with compliance for both Phases I and II of the CAAA were designed to ensure $SO_2$ emissions were limited to the number of credits available under the approved compliance plans. The scrubbers were not designed to operate continuously whenever Big Bend Units 1, 2 and 3 were in operation.

**Q.** Please provide a brief overview of the litigation with EPA and DEP that resulted in the CD and CFJ.

**A.** On December 16, 1999, Tampa Electric and the DEP entered into the CFJ. On February 29, 2000, the EPA initiated a CD with Tampa Electric in the Federal District Court. Both the CD and CFJ embody the resolutions between the agencies and Tampa Electric stemming from disputed issues surrounding Tampa Electric's maintenance practices to its Big Bend and Gannon Stations that were alleged to be in violation of the EPA's New Source Review rules and New Source Performance Standards currently codified in Title I of the CAAA. The CD and CFJ have been previously provided to the Commission in Docket No. 000685-EI and have been referred to in numerous environmental proceedings before the Commission in the past six years.

**Q.** What does the CD require of Tampa Electric with regard to the scrubbers?

**A.** Paragraphs 29, 30, 36 and 40 of the CD require Tampa Electric to operate the FGD system for each of the units at Big Bend Station at all times subject to certain specifically defined exceptions contained in Paragraphs 29 and 30, as reflected in Document No. 1 of my Exhibit.

Paragraph 36 of the CD requires Tampa Electric to declare in writing whether the Big Bend Station units will continue combustion of coal, repower or shutdown. The declaration date for Big Bend Units 1 through 3 is May 1, 2007. Tampa Electric has already complied with this requirement by submitting a declaratory letter to EPA dated August 19, 2004 indicating Big Bend Station will continue to be fired by coal. Document No. 2 of my Exhibit provides a copy of the declaratory letter.

**Q.** What are the environmental requirements as a result of Tampa Electric's declaration to the EPA that Big Bend Station will remain coal-fired?

**A.** With Tampa Electric having declared that it will continue to burn coal at Big Bend Station, Paragraph 40 of the CD identifies operational requirements relative to $SO_2$ emissions for the Big Bend Units 1 through 3. Those operational requirements are set out in Document No. 3 of my Exhibit.

According to Paragraph 40 of the CD, Tampa Electric is required to operate the FGD systems at Big Bend Station whenever coal is combusted in the units with few exceptions. Under this paragraph, the currently allowed unscrubbed days will no longer be allowed beginning January 1, 2010 for Big Bend Unit 3 and January 1, 2013 for Big Bend Units 1 and 2. In other words, beginning in 2010, anytime the scrubber for Big Bend Unit 3 is off-line, unit 3 must also be taken off-line. The same requirement applies to Big Bend Units 1 and 2 starting in 2013 - anytime the scrubber is off-line, both units 1 and 2 must be taken off-line. Therefore, the reliability of the units at Big Bend Station is limited to the reliability of their respective scrubbers.

**Q.** What other requirements are contained in the CD and CFJ related to $SO_2$ emission reductions?

**A.** Both the CD and CFJ require Tampa Electric to create a plan for optimizing the availability and removal efficiency of the scrubbers. This plan was submitted to the EPA in two phases and both were approved.

Phase I of the plan requires that Tampa Electric work scrubber outages around the clock and with contract labor, when necessary, in order to speed the return of a malfunctioning scrubber to service. In addition, Phase I requires Tampa Electric to review all critical scrubber spare parts and increase the number and availability of spare parts to ensure a speedy return to service of a malfunctioning scrubber.

Phase II of the plan outlines capital projects that Tampa Electric must perform to upgrade each scrubber at Big Bend Station. It also addresses the use of environmental dispatching in the event of a scrubber outage.

All of the preliminary $SO_2$ emissions reduction projects have been completed. However, additional work must be performed in 2007 associated with the FGD Reliability Program to comply with the elimination of the allowed scrubber outage days starting in 2010 and 2013.

**Q.** How do the $SO_2$ emissions reduction requirements of the CD vary from the $SO_2$ emissions reduction requirements of the CAAA?

**A.** As previously stated, the scrubbers associated with compliance for both Phases I and II of the CAAA were designed to ensure $SO_2$ emissions were limited to the number of credits available to Tampa Electric. However, the scrubbers were not designed, nor ever intended, to operate continuously whenever Big Bend Units 1, 2 and 3 were in operation. The compliance plans associated with the CAAA have already been approved and implemented.

The CD requires that the scrubber for Big Bend Unit 3 operate at the specified removal efficiencies anytime that the unit is operating beginning on January 1, 2010. The CD also requires that the scrubber for Big Bend Units 1 and 2 operate at the specified removal efficiencies anytime either of those two units is operating beginning on January 1, 2013.

**Q.** Please summarize your testimony.

**A.** Tampa Electric's CD with EPA requires significant reductions in $SO_2$ emissions from Tampa Electric's Big Bend Station - reductions beyond those ever contemplated in the company's efforts to comply with the requirements of the CAAA. The CD established definite requirements and time frames in which these reductions must be made and result in reasonable and fair outcomes for Tampa Electric, its community and customers, and the environmental agencies.

If not for the CD, Tampa Electric would not need to implement the FGD Reliability Program. However, implementation of the FGD Reliability Program is essential and required for Tampa Electric to comply with the 2010 and 2013 $SO_2$ emissions reduction requirements delineated in the CD.

**Q.** Does this conclude your testimony?

**A.** Yes it does.

BY MR. BEASLEY:

Q Would you please summarize Mr. Nelson's direct testimony.

A Okay. Good morning, Commissioners. The direct testimony of Mr. Gregory M. Nelson of which I am adopting demonstrates that the activities for which Tampa Electric seeks cost recovery through the ECRC are necessary for the company to comply with the environmental requirements set forth by the Environmental Protection Agency Consent Decree and the Florida Department of Environmental Protection consent final judgment. The Consent Decree stemmed from disputed issues surrounding Tampa Electric's maintenance practices of its Big Bend and Gannon Stations that were alleged to be in violation of the EPA's new source review rules and new source performance standards currently codified in Title I of the Clean Air Act Amendments of 1990. Compliance with the provisions of the Consent Decree related to reductions in sulfur dioxide emissions are to be achieved in stages.

The intermediate compliance stage was addressed in the Big Bend Phase I and Phase II FGD optimization plans which consisted of projects to achieve the minimization of unscrubbed days. The final compliance stage is being addressed by the Big Bend FGD System Reliability Program which consists of the 13 projects before you today that are necessary to comply with the Consent Decree deadlines of 2010 and 2013 and the continued operation of Big Bend thereafter.

On August 19th, 2006, the company committed to continue to burn coal at its Big Bend Station, thereby accepting the deadlines of Paragraph 40 which require that in 2010 for Unit 3 and 2013 for Units 1 and 2 Big Bend cannot operate unscrubbed. The Big Bend FGD System Reliability Program is solely the result of the company's compliance with the final stage of sulfur dioxide emission reductions required by the Consent Decree in 2010 and 2013. The Big Bend FGD System Reliability Program was previously approved for ECR cost recovery by the Commission on June 20th, 2006, by a five-zero vote and is the most cost-effective way for Tampa Electric to comply with the Consent Decree. But for the Consent Decree, Tampa Electric would not have considered, studied or initiated this program in its 13 component projects. This concludes my summary of Mr. Nelson's direct testimony that I have adopted.

MR. BEASLEY: Ms. Crouch is available for questions.

CROSS EXAMINATION

BY MS. CHRISTENSEN:

Q Good morning, Ms. Crouch.

A Good morning.

Q I would like to start with asking you some questions about the Consent Decree. Do you have a copy of that in front of you?

A Yes, I do.

Q Okay. The Consent Decree was entered into between TECO and the U.S. government to address its SO2 emissions at the Big Bend units; is that correct?

A In part.

Q And the part that we're talking about with the FGD addresses the S02 emissions; is that correct?

A That's correct.

Q And the Big Bend Reliability Program focuses on SO2 emissions; correct?

A That's correct.

Q Okay. And Paragraph 29 of the Consent Decree creates a transition period to new, new source performance standards for Units 1 and 2; is that correct?

A That's not correct. Units 1 and 2 will not be at new source performance standards during the interim period.

Q But it creates a transition period from what they were before you signed the Consent Decree to when you will have to meet the deadlines in -- I think it's 2013 for Units 1 and 2.

A 2010, and 2013 for Units 1 and 2. That's correct. It allows us unscrubbed days during that time frame.

Q Right. But that creates a transition from --

A Uh-huh.

Q -- the period from when you signed the Consent Decree until when the deadlines become effective.

A Yes.

Q Okay. And in Paragraph 30 it creates the same transition period to the final new source performance standards for Units 3 and 4; is that correct?

A For Unit 3.

Q Oh, for Unit 3. Correct. Because Unit 4 currently is already meeting the new source performance standards; correct?

A That's correct.

Q And Paragraph 40 sets out the deadlines for Units 1, 2 and 3 when the transition to new source performance standards must be completed; that's correct?

A That's correct. Should we decide to remain on coal, which we have, then that becomes effective.

Q Okay. And unit or, excuse me, Paragraph 40 was in the Consent Decree when TECO signed it originally; is that correct?

A That's correct.

Q And you accepted that term and the condition that if you chose to continue to burn coal, that you would have those deadlines and that would be the final dates for the end of the transition period to new source performance standards; correct?

A Well, that would be the time when we would no longer have unscrubbed days.

Q After the January 10th, 2010, transition date completion deadline, excuse me, for Unit 3 and the January 2013 transition completion deadline for Units 1 and 2, those units will operate under the same parameters as Unit 4 does currently; is that correct?

A That's correct.

Q Okay. And under the availability criteria it specifically states, "Notwithstanding the preceding sentence, to the extent that the Clean Air Act new source performance standards identify circumstances during which Big Bend Unit 4 may operate without its scrubber, this Consent Decree shall allow Big Bend Units 1, 2 and/or 3 to operate when those same circumstances are present at the Big Bend Units 1, 2 and/or 3." Is that correct?

A That's correct.

Q So you would agree that under Paragraph 40 there are some circumstances that even after the 2010 and 2013 deadlines that the Big Bend units may run unscrubbed?

A There may be circumstances but they would be extremely limited.

Q Okay. And you would agree that the new source performance standards would allow the units to run unscrubbed under certain circumstances such as if it needs to meet demand because all other units are being run and the current purchase power is being used. So if it needs to meet current demand under emergency type situations --

A You're saying after 2010 and 2013?

Q Correct.

A No, that would not be the case.

Q The case would be that it would be allowed to run under certain circumstances? Can you explain what those circumstance, excuse me, certain circumstances would be?

A For Unit 4 to run unscrubbed at this point in time or any point in time going forward because it's an NSPS unit, you would have to ask permission of the administrator in order for that to happen and you would have to demonstrate a severe hardship for that to happen.

Q Okay. And then that would be the same standard that would apply to Units 1, 2 and 3.

A Right. You would have to actually ask the administrator for permission.

Q Okay.

A Unlike now where we actually have days that we have an ability to use as necessary if the unit, if the scrubber is down.

Q Okay. But you can ask the administrator after those deadlines. And under other, under -- excuse me. Other than those certain circumstances outlined in the new performance standards, another way that TECO could meet the transition period deadline is to operate all the operable FGD systems and bring back into operation any malfunctioning FGD system as soon as repairs are finished; would that be correct?

A I'm not sure I understand your question.

Q In other words, you could continue to use the Big Bend Station by operating all of the FGD systems which are functioning and put in emergency type maintenance towards the one FGD system that is down. Would that be correct?

A I think what you're referring to is environmental dispatch, which is a procedure which is in place during the interim period when we have unscrubbed days, and that procedure is that when we have a unit that is down or a scrubber that is down and the unit is operating, we have to get the scrubber back up as soon as possible. But that's an interim phase. That will no longer be applicable after the 2010 and 2013 deadlines. There will not be a need for an environmental dispatch procedure because we will not be running those units when they are not scrubbed.

Q Right. But you could apply the same principle to get those units which are down back up as soon as possible after the deadlines; correct?

A You know, I mean, you would be wanting to get those units back up. But, I mean, you wouldn't be in a situation where those units were still running. They'd be off.

Q Currently TECO has FGD systems and scrubbers in place that meet the requirements of Paragraph 29 and 30; correct?

A Yes.
Q And the requirements that TECO recover 95 percent of its SO2 emissions will not change after the 2010 or 2013 deadline; is that correct?
A That's correct.
Q And when TECO's current FGD system is in operation, they meet the requirement of removing 95 percent of the SO2 for the units' emissions; is that correct?
A That's correct.
Q In your testimony you claim that the scrubber system was not designed to operate continuously whenever Big Bend Units 1, 2 and 3 were in operation; is that correct?
A That's correct.
Q And TECO entered into the Consent Decree with the EPA which had the transition deadlines to do source performance standards which required that the scrubber units for 1, 2 and 3 operate continuously whenever the units are in operation; is that correct?
A With the exception of the unscrubbed days, yes.
Q But you entered into the Consent Decree knowing that there would be a deadline date and you would have to eventually meet those new source performance standards; correct?
A That's true.
Q Okay. In the Consent Decree TECO was to create a plan of optimizing the availability and removal efficiency of

the scrubbers, which TECO submitted in two phases; correct?

A That's correct.

Q And in Phase I TECO identified all the critical scrubber spare parts to ensure speedy return to service of malfunctioning scrubbers; correct?

A That's correct.

Q And in Phase II TECO identified the capital projects that had to be performed to upgrade each scrubber at the Big Bend to meet the Consent Decree; is that correct?

A That's not correct, no. The Phase I and 2 plans were specifically to address the requirements of Paragraphs 29 and 30 of the Consent Decree. There were capital projects involved, but it was primarily to deal with that intermediate time frame in order -- during which we had unscrubbed days.

Q Referring to --

A It did not identify all projects.

Q Okay. Referring to Mr. Nelson's --

A Nelson.

Q -- nelson's testimony, Page 9, Line 1 through 3, is it correct that it states, "Phase II of the plan outlines capital projects that Tampa Electric must perform to upgrade each scrubber at Big Bend Station"; is that correct?

A Right. In order to comply with Paragraphs 29 and 30 of the Consent Decree, which are the intermediate time frame or the intermediate requirements of the Consent Decree.

Q Okay. But you would agree that the Phase II optimization plans that TECO did submit to the EPA did not have the electric isolation, split inlet and outlet duct projects or the gypsum fines filter project listed in it; is that correct?

A That's correct. And that's because those two first, those -- the Phase I and II FGD optimization plans were specifically to deal with Paragraphs 29 and 30 of the Consent Decree, which were the paragraphs that allowed Tampa Electric to have unscrubbed days. So those plans were really meant to minimize our use of those unscrubbed days. These other projects that we're talking about today deal with Paragraph 40 of the Consent Decree, which is the point in time where we will no longer have those unscrubbed days.

MS. CHRISTENSEN: Can you point to me -- well, I have no further questions at this time.

CHAIRMAN EDGAR: Are there questions from staff?

MS. BROWN: Yes, Commissioner, we have a few questions.

CROSS EXAMINATION

BY MS. BROWN:

Q Good morning, Ms. Crouch. I'm Martha Brown with the Commission.

A Good morning.

Q We have a couple of questions that have to do with some time lines regarding the Consent Decree.

When did TECO submit its Phase II plan?

A It's Phase II plan -- let me see if I have the date in front of me here. They were submitted early in the compliance window of the Consent Decree. I don't have the exact date in front of me.

Q How about 2001? Would you accept that, subject to check?

A Yeah. We're talking 2000, 2001. Uh-huh. Subject to check.

Q And when did TECO make its declaration to the EPA that it would continue using coal at Big Bend?

A We made that declaration August 19th, 2004.

Q And which paragraph of the Consent Decree required that declaration?

A Let's see. I don't have the paragraph right in front of me, but I believe -- let's see.

Q Do you, Ms. Crouch, do you have that blue book in front of you?

A Yes.

Q That's staff's composite exhibit, and the first exhibit there is the full Consent Decree. If you'll look at Page 24.

A Yes. Paragraph 36.

Q Thank you. Was that declaration the event that triggered the operation of Paragraph 40 of the Consent Decree?

A Yes, it was.

Q And is it fair to say that the operation of Paragraph 40 triggered a change in the scope of TECO's activities to comply with the Consent Decree?

A Yes, it did.

Q Is it also fair to say that the Consent Decree contemplates a time line of phased compliance culminating in the stricter SO2 emission requirements of Paragraph 40?

A Yes, it does.

MS. BROWN: Thank you. No further questions.

CHAIRMAN EDGAR: Commissioners? No?

Mr. Beasley.

MR. BEASLEY: Brief redirect.

REDIRECT EXAMINATION

BY MR. BEASLEY:

Q Ms. Crouch, Ms. Christensen asked you some questions regarding your ability to operate the Big Bend baseload coal-fired units unscrubbed on a going-forward basis after the deadlines in 2010 and 2013. Do you recall those?

A Yes.

Q And you said that you would have to apply to the administrator to get a special circumstances hardship type permission.

A That's correct.

Q Is that -- are those types of requests routinely approved or rubber stamped?

A No, they're not. They're extremely rare. They typically have to go beyond the administrator for approval, and the only one I have in my recollection actually was related to hurricane activity. So it's extremely rare.

Q In your view would it be prudent to rely on a special circumstances permission from the administrator for day-to-day, year in, year out operation of your Big Bend baseload coal-fired units?

A Absolutely not.

MR. BEASLEY: Thank you. That's all I have. I'd like to move the admission of Mr. Nelson's exhibit.

CHAIRMAN EDGAR: Okay. The exhibit marked 3 will be entered into the record. And the witness is excused. Thank you.

(Exhibit 3 admitted into the record.)

MR. BEASLEY: Call Mr. Smolenski.

JOHN V. SMOLENSKI

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

DIRECT EXAMINATION

BY MR. BEASLEY:

Q Sir, would you please state your name, your address, your occupation and your employer.

A My name is John Victor Smolenski. I work for Tampa

Electric Company at 702 North Franklin Street, Tampa, Florida 33602. I'm a Senior Consultant II, Advanced Technology, in the Engineering and Construction Services Department.

Q Mr. Smolenski, did you prepare and submit a document entitled "Prepared Direct Testimony of John V. Smolenski" dated November 17th, 2006?

A Yes, I did.

Q If I were to ask you the questions contained in that prepared testimony, would your answers be the same?

A Yes, they would.

Q I'd ask that Mr. Smolenski's testimony be inserted into the record as though read.

CHAIRMAN EDGAR: The prefiled direct testimony will be entered into the record as though read.

BY MR. BEASLEY:

Q Sir, did you also prepare the Exhibit JVS-1 that accompanied your prepared direct testimony?

A Yes, I did.

MR. BEASLEY: Madam Chairman, I believe that's the document identified as hearing Exhibit 4 in the composite exhibit list.

CHAIRMAN EDGAR: Yes.

TAMPA ELECTRIC COMPANY
DOCKET NO. 050958-EI
FILED: NOVEMBER 17, 2006

**BEFORE THE PUBLIC SERVICE COMMISSION**

**PREPARED DIRECT TESTIMONY**

**OF**

**JOHN V. SMOLENSKI**

**Q.** Please state your name, address, occupation and employer.

**A.** My name is John V. Smolenski. My business address is 702 North Franklin Street, Tampa, Florida 33602. I am employed by Tampa Electric Company ("Tampa Electric" or "company") as Senior Consultant II - Advanced Technology, in the Engineering and Construction Services Department.

**Q.** Please provide a brief outline of your educational background and business experience.

**A.** I graduated from the Rutgers University in May 1974 with a Bachelor of Science degree in Environmental Science. I completed all of the course work towards a Master of Science degree in Environmental Engineering from the New Jersey Institute of Technology. I was employed at Combustion Engineering's Krisinger Development Laboratory as a Research and Product Development Engineer from May 1974 through January 1977 working on flue gas desulfurization and coal gasification. I was employed at

Research-Cottrell Inc, as a Research and Product Development Engineer from January 1977 through January 1978 working on flue gas desulfurization. I was employed at Stone & Webster Engineering Corp. as Lead Environmental Engineer and Flue Gas Desulfurization Specialist from January 1978 through October 1989. In 1989, I joined Tampa Electric Company as a Consultant in the Generation Engineering Department. In my current position as Senior Consultant II, I am a technical consultant to the project engineering groups responsible for the company's air pollution control projects. I am a member of the American Institute of Chemical Engineers, past Chairman of the Electric Power Research Institute's $SO_2$ Control Program Committee and have published over a dozen papers on air pollution control technology.

**Q.** Did you prepare any exhibits in support of your testimony?

**A.** Yes. Exhibit ____ (JVS-1) consists of one document which is Tampa Electric's Big Bend Flue Gas Desulfurization System Reliability Study.

**Q.** What is the purpose of your testimony in this proceeding?

**A.** The purpose of my testimony is to present, for the Commission's review and approval for cost recovery through the Environmental Cost Recovery Clause the Big Bend Flue Gas Desulfurization System Reliability Program ("FGD Reliability Program") based upon the process Tampa Electric used to determine the individual project components that are necessary to meet the 2010 and 2013 requirements of the Consent Decree ("CD") as discussed in the testimony of Tampa Electric's witness Gregory M. Nelson. I will discuss each component of the FGD Reliability Program and describe the methodology employed to determine its cost-effectiveness. Finally, I will address why Tampa Electric chose to perform the installation of the FGD Reliability Program concurrently with the ongoing installation of the selective catalytic reduction ("SCR") systems at Big Bend Station and provide the associated benefits.

**Q.** Why are the SCRs being installed at Big Bend Station?

**A.** The installation of the SCRs at Big Bend Station is a requirement of the CD based upon the company's decision to remain coal-fired at the generating facility. Tampa Electric made that declaration on August 19, 2004 in a letter to the United States Environmental Protection

Agency. A discussion and copy of the declaratory letter can be found in the testimony of Tampa Electric's witness Gregory M. Nelson. Additionally, the Commission has approved prudent expenditures associated with the SCR installations in Docket Nos. 040750-EI and 041376-EI.

**Q.** Did Tampa Electric conduct a study to determine the appropriate actions necessary for Big Bend Station to meet the more stringent 2010 and 2013 $SO_2$ emissions requirements of the CD?

**A.** Yes. Document No. 1 of my Exhibit is Tampa Electric's Big Bend Flue Gas Desulfurization System Reliability Study ("Study"). The Study had three main purposes which were to: 1) determine the specific projects that could provide reliability improvements to the FGD systems at Big Bend Station to meet the more stringent 2010 and 2013 requirements of the CD; 2) determine the cost-effectiveness of the proposed reliability improvements; and 3) determine the cost-effectiveness of performing several of the projects earlier than required to meet the 2010 and 2013 deadlines in the CD. This early work would coincide with the construction activities associated with the installation of SCRs occurring at Big Bend Station.

Q. Please summarize the results of the Study.

A. The Study determined 13 specific projects Tampa Electric must complete in order to meet the more stringent 2010 and 2013 requirements of the CD. Additionally, the Study examined the cost-effectiveness of these projects and found the range of cost-benefit-ratios to be from 1.2 to 21 while the net benefit to customers was estimated to be $34 million. Lastly, the Study provided an analysis that demonstrated the benefit of implementing the projects associated with Big Bend Units 1 and 2 concurrent with the installation of SCRs on those units. This benefit to customers is estimated to be $2.7 million. The FGD Reliability Program is the culmination of Tampa Electric's decision to implement the recommendations of the Study in order to meet the 2010 and 2013 requirements of the CD.

Q. Was an outside consultant used in the development of the projects associated with the FGD Reliability Program?

A. Yes. Tampa Electric engaged an experienced consulting firm, Sargent and Lundy, to provide costs and conceptual designs for a number of the projects associated with the FGD Reliability Program. However, Tampa Electric performed the cost-effectiveness analyses of the various projects and determined the related benefits.

**Q.** How did you identify the projects that could provide the needed reliability improvements to the FGD systems at Big Bend Station?

**A.** As part of the Study process, Tampa Electric identified and evaluated specific maintenance needs, outage requirements and previous or potential equipment failures on the FGD systems which would require a generating unit to come off line. These determinations were made from a combination of actual operating experiences and empirical knowledge of the FGD systems. From these determinations, corrective actions were devised to prevent, minimize or mitigate the detrimental effects of the identified occurrences. Once these corrective actions were identified, Tampa Electric established the reliability projects that were necessary to meet the 2010 and 2013 requirements in the CD.

**Q.** Please describe the various components of the FGD Reliability Program.

**A.** There are 13 individual projects that comprise the FGD

Reliability Program. A detailed description and an estimated cost of each project can be found in Document No. 1 of my Exhibit, pages 16 through 24 of the Study.

**Q.** How were the costs of the projects determined?

**A.** Project costs were estimated by either the company's outside consultant, Sargent and Lundy, or Tampa Electric. The estimation process began with conceptual engineering designs of the proposed projects. Once the designs were rendered, costs were assigned to each project using standard in-house cost estimating tools. These estimating tools used a combination of currently known commodity costs, vendor supplied estimates and currently known labor rates which were applied to the material estimates and construction man-hour forecasts derived from the conceptual engineering designs.

**Q.** How were the benefits determined for each project?

**A.** The benefits for each project were determined in several steps. First, the time necessary to complete repairs or perform necessary maintenance was established as if the project did not exist. Next, the unit outage duration was determined based on the time requirement from the first step. Finally, the associated purchased power and fuel costs associated with the unit outage was determined. These costs were then identified as being avoided due to the implementation of the various reliability projects and thus became the benefits for the projects.

**Q.** How was the cost-effectiveness of the reliability projects determined?

**A.** In order to determine the economic viability of the projects, the following steps were utilized:

- Establish a baseline by creating a base case;
- Modify the base case with the project specific improvements to Big Bend Station's availability to create a change case;
- Subtract the change case from the base case to provide the total system savings;
- Layer the total system savings into the capital costs of the project; and
- Calculate the net present value ("NPV") of the cases.

If NPV is positive for the impact of all projects, the FGD Reliability Program is determined to be beneficial to Tampa Electric customers.

**Q.** What were the results of the cost-effectiveness analysis on the FGD Reliability Program?

**A.** The results of the analysis performed by Tampa Electric demonstrated that all of the projects that comprise the FGD Reliability Program have positive benefits for the customers with cost-benefit-ratios ranging from 1.2 to 21. These favorable results were obtained by using conservatively estimated benefits. By utilizing the conservatively estimated benefits, the net savings to the customers is estimated to be $34 million.

**Q.** Why were some of the reliability projects grouped together as one item for the cost benefit analysis?

**A.** Some reliability projects were grouped together because of their interdependent functionality. For example, to improve the reliability of scrubbing flue gas, the entire absorber module must remain on line. Therefore, improvements to only one internal part of the module will not keep the module on line if the other parts are allowed to fail. This is analogous to a watch. If the function of the watch is defined strictly as the ability to display the time in hours, minutes and seconds and that all three time elements must be correctly displayed or the watch is to be considered inoperative, then each of the three independent mechanisms driving the three arms on the watch's dial must be made more reliable because the failure of any one mechanism would constitute the failure of all three.

**Q.** Why were some of the projects evaluated for early implementation as opposed to a later date that coincided with the applicable operating changes required by the CD?

**A.** The components of the FGD Reliability Program associated with Big Bend Units 1 and 2 were evaluated for early implementation for two reasons. First, there were obvious cost savings that would be realized by coordinating their construction activities in conjunction with the construction activities occurring for the Big Bend Station SCR projects. There would be cost savings realized by having a single site mobilization and demobilization of construction equipment and labor, and a shared construction management team and services. Second, maintaining the FGD de-integration days to the end of their calendar life would have required the expenditure of addition capital to accommodate the boiler draft modifications occurring in conjunction with the Big Bend Station SCR projects. This additional capital equipment would have been operational for only two to three years and then rendered inoperable in order to comply with the CD. Furthermore, the company would have incurred the additional capital and fuel costs to accommodate the very low sulfur coal requirements of the CD which would be in effect any time Big Bend Units 1 and 2 were operating unscrubbed from 2010 through 2012.

**Q.** How did you determine the cost-effectiveness of performing some of the reliability projects earlier than the deadlines defined in the CD?

**A.** Tampa Electric utilized ProMOD, the company's resource planning model, to calculate the net fuel and purchase power cost difference between the cases to account for the five additional days of maintenance outage per unit required with the early retirement of de-integration days. In addition, Tampa Electric accounted for the timing difference of the capital expenditures for the reliability projects and the value of the $SO_2$ credits that the company would lose by emitting more $SO_2$ when running the units un-scrubbed. The analysis also included the premium paid for very low sulfur coal as well as the capital costs to modify the duct work, add dampers and modify the generating units to accommodate for the burning of the low sulfur coal and thus allow for continued de-integration operation.

**Q.** Please describe the results of the analyses.

**A.** The result of the analyses performed by Tampa Electric to determine the cost-effectiveness of implementing certain components of the FGD Reliability Program early demonstrated a benefit to customers over $2.7 million. Again, this favorable result was obtained with conservatively estimated component benefits. Also, some benefits were not included, most notably the potential savings from equipment and labor site mobilization and demobilization costs achieved by performing the work simultaneously with the SCR construction.

**Q.** What alternatives were considered for inclusion in the FGD Reliability Program?

**A.** There were no specific alternatives extensively evaluated for each of the projects. Those measures that were identified with any potential for consideration were immediately dismissed for either technical or economic reasons. However, one general alternative was considered early in Tampa Electric's discussions and evaluations.

The alternative was to build a spare absorber tower of the same size as the Big Bend Units 1 and 2 absorber tower. But this alternative was quickly dismissed once it was determined that it would not provide as much reliability as the individual components of the FGD Reliability Program and the estimated cost would be in excess of $40 million, well in excess of the total estimated cost for the FGD Reliability Program.

**Q.** Would Tampa Electric perform the FGD Reliability Program but for the requirements of the CD?

**A.** No. In the absence of the CD Tampa Electric would be able to operate Big Bend Units 1, 2 and 3 without scrubbing the flue gas for an unlimited number of days per year. Consequently, reliability of the FGD system would have virtually no impact on the generating capability of the units. Therefore, increasing the reliability of the FGD systems would have virtually no beneficial economic impact to customers. It is solely the requirements of the CD that absolutely and directly tie unit generating capability to FGD system reliability. As for Big Bend Unit 4, FGD scrubbing has been a requirement since commercial operation began for that unit.

Q. If the CD had existed prior to the purchase and installation of the FGD system on Big Bend Units 1 and 2 and the integration of Big Bend Unit 3 into the FGD system on Big Bend Unit 4, would Tampa Electric have specified and purchased FGD systems of a different design for these units than those that currently exist at Big Bend Station?

A. Yes. The creation of a generating unit's operational dependency being tied to the uninterrupted functionality of its FGD system would have a definitive impact upon the design of the FGD systems for these units. This is clearly demonstrated by examining the design of the Big Bend Unit 4 FGD system where such a dependency has always existed. The Big Bend Unit 4 FGD system was designed with a spare absorber module, redundant rotating equipment for internal system functionality, spare tankage, redundant limestone preparation systems, redundant gypsum dewatering systems and a host of other spare and back up systems none of which exist on the other FGD systems.

Q. When are the individual projects of the FGD Reliability Program scheduled to be completed?

**A.** The individual projects of the FGD Reliability Program are scheduled to be completed by the following dates:

- Big Bend Units 1 through 4 Electric Isolation - 2010
- Big Bend Units 3 and 4 Split Inlet Duct - 2007
- Big Bend Units 3 and 4 Split Outlet Duct - 2007
- Big Bend Units 1 and 2 Gypsum Blow Down Line Addition - 2010
- Controls Additions - 2010
- Big Bend Units 3 and 4 FGD Booster Fan Capacity Expansion - 2008
- Big Bend Units 1 through 4 Mist Eliminator Upgrades - 2010
- Big Bend Units 1 through 4 On-line Mist Eliminator Wash System Addition - 2010
- Big Bend Units 1 though 4 On-line Nozzle Wash System Addition - 2007
- Big Bend Units 1 and 2 Recycle Pump Discharge Isolation Bladders Addition - 2008
- Big Bend Units 1 and 2 Inlet Duct C-276 Wallpaper Addition - 2006
- Gypsum Fines Filter Addition - 2009
- Gypsum Filter Vacuum Pump Upgrades - 2009

Start times for each of the projects have been identified. At the start, a Project Scope Authorization will be produced and a project team will be assembled from various departments throughout Tampa Electric. The project team is responsible for the detailed design, engineering, project management, construction and cost containment of the project.

**Q.** Describe how the projects will be monitored and progress reported.

**A.** Tampa Electric has a proven methodology to provide quality assurance and control on its construction activities. Specifically, a project administrator is selected for each project. The administrators monitor projects and lead the various project teams from project inception to completion and equipment start-up. Competitive bidding is integral to the process. Monthly expenditure and schedule reports are produced and reviewed for variances with adjustments made to maintain project budget and progress.

**Q.** What is the present status of the active projects?

**A.** There are already several active projects and their status are listed below.

- Big Bend Units 1 through 4 Electric Isolation - Detailed design and engineering has been initiated for this project and it is proceeding on schedule.

- Big Bend Units 3 and 4 Split Outlet Duct - The detailed design and engineering for this project has been completed. Also, the materials have been purchased, fabrication of components completed and delivery of product to the plant site has commenced with construction scheduled to occur during the fall 2006 outage of Big Bend Unit 4. The project completion is projected to be on time and under budget.
- Control Additions - For this project, preliminary design and engineering has begun and is proceeding on schedule.
- Big Bend Units 1 through 4 Mist Eliminator Upgrades - The detailed design and engineering, material purchases and fabrication of the new mist eliminators for Big Bend Units 3 and 4 have been completed. Product delivery to the plant site has begun and the installation is scheduled to occur during the fall 2006 outage of Big Bend Unit 4. The work associated with the new mist eliminators for Big Bend Units 1 and 2 is scheduled to commence next year.
- Big Bend Units 1 through 4 On-Line Nozzle Wash System - The preliminary design and engineering has begun for this project and is proceeding on schedule.
- Big Bend Units 1 and 2 Inlet Duct C-276 Wallpaper -

This project is complete and final costs are being compiled. The project is expected to be on budget.

**Q.** Please summarize your testimony.

**A.** Tampa Electric conducted a study with the assistance of an experienced consulting firm, Sargent and Lundy, to determine the appropriate actions necessary for Big Bend Station to meet the more stringent 2010 and 2013 $SO_2$ emissions requirements of the CD. After thorough evaluations, the company identified 13 specific projects that will cost effectively maximize the reliability of the generating units at Big Bend Station. These projects have cost-benefit-ratios ranging from 1.2 to 21 with an estimated net savings to customers of $34 million. Furthermore, the evaluations conducted by the company demonstrate that implementing some these projects earlier than required by the CD and in conjunction with the SCR installations occurring on the Big Bend generating units will result in additional savings to customers of approximately $2.7 million. The Commission has previously approved for recovery through the ECRC prudent expenditures the company has incurred in meeting the CD and CFJ requirements. It is appropriate for the Commission to reaffirm its five-zero decision made at the

June 20, 2006 Agenda Conference that approved the company's prudent costs associated with the Big Bend FGD Reliability Program for cost recovery through the ECRC.

**Q.** Does this conclude your testimony?

**A.** Yes it does.

BY MR. BEASLEY:

Q Mr. Smolenski, can you please summarize your direct testimony.

A Good morning, Commissioners. My direct testimony focuses on the Consent Decree deadlines when the generating units will have to be shut down whenever the FGD systems are unavailable and the projects that we are implementing to enable us to comply with those deadlines in a prudent and cost-effective manner. Those projects, 13 in number, make up the Big Bend FGD System Reliability Program. The intention of the FGD System Reliability Program is to improve the FGD system reliability such that the negative impacts of the Consent Decree requirements of 2010 and 13 upon the generating units' availability are cost-effectively minimized. This reliability improvement is necessary as a direct result of the Consent Decree requirement that Tampa Electric shut down Big Bend Units 1, 2 and 3 whenever the FGD systems are incapable of scrubbing all of the flue gas coming from the generating unit, and the Consent Decree requirement for, of January 1st, 2010, is for Big Bend Unit 3 and January 1st, 2013, for Big Bend Units 1 and 2.

Tampa Electric used its 22 years of FGD operating experience in combination with sound engineering judgment to identify the modifications necessary to the FGD system to minimize forced and maintenance outage time of the generating units once the Consent Decree requirements went into effect. Tampa Electric used the same combination of experience and judgment to forecast the amount of forced and maintenance outage time that would be saved by these modifications. These time savings became the basis for the determination of the monetary value of the benefits of the 13 projects that comprise the Big Bend FGD System Reliability Program. Tampa Electric developed the cost of these 13 projects through a combination of internal cost estimation using data from our latest capital projects and estimates developed by Sargent & Lundy, the engineering firm employed by Tampa Electric for the ECRC approved selective catalytic reduction programs.

These costs and benefits were then analyzed by Tampa Electric using our production cost model to develop the cost-benefit-ratios of the projects. The 13 projects all had positive cost-benefit-ratios of between 1.2 to 21, indicating their beneficial nature to the customers of approximately $34 million after paying for themselves.

Tampa Electric has demonstrated that the Big Bend FGD System Reliability Program is the most cost-effective way to comply with the Consent Decree deadlines of 2010 and 13. Further, Tampa Electric has demonstrated that the FGD Reliability Program will save our customers over $34 million after paying for itself. And it's important to note that but for the Consent Decree requirements that go into effect in

2010 and 13, the projects that make up the reliability program would not be necessary. That concludes my summary of my direct testimony.

MR. BEASLEY: Mr. Smolenski is available for questions.

CROSS EXAMINATION

BY MS. CHRISTENSEN:

Q Good morning, Mr. Smolenski.

A Good morning.

Q You would agree that a project is legally -- a project that is legally mandated by a governmentally imposed regulation or law is appropriate for recovery through the ECRC?

A Yes.

Q And you would also agree that if a project costs customers money and has no cost savings benefits to customers, if the activity is mandated by a governmental law or regulation, it is recoverable through the ECRC?

A Yes.

Q And isn't it also correct that any cost-benefit analysis is a secondary issue which is addressed only after you determine that an activity is legally required to comply with an environmental law or regulation?

A I don't know whether that's a secondary issue or whether it's one of the primary issues.

Could you repeat the question?

Q Certainly.

A The last part of the question.

Q Would you agree that any cost-benefit analysis is an issue that you address after you address whether or not that activity is legally required to comply with an environmental law or regulation?

A Yes.

Q And would you agree that if a cost is to be recovered through base rates and the company is still earning a fair rate of return once that cost is expended, that the cost has been recovered through base rates?

A Yes.

Q And would you agree that a cost-benefit analysis is important for management to make its determination of whether to commit funds for a project when those funds are coming through base rate, base rate revenues?

A Yes.

Q Okay. And so it would be appropriate for TECO's management to use the cost-benefit analysis done by Sargent & Lundy to determine the timing of projects recovered through base rates; correct?

A I'm not aware of any cost-benefit analysis done by Sargent & Lundy.

The cost-benefit analysis was done in-house by us. The estimates of construction costs and some, and some other issues were done by Sargent & Lundy, but the cost-benefit analysis was done internally at Tampa Electric.

Q Okay. And you would agree that it would be appropriate to look at that cost-benefit analysis to determine the timing of certain projects to be recovered through base rate revenues.

A Or through, through any recovery.

Q Okay. Referring to TECO's electric isolation project, TECO's electric isolation project proposes to put a 13.8 kVA input voltage transformer in; is that correct?

A That's one of the things it proposes to do.

Q Okay. And isn't it correct that the new transformer will not serve any electrical load for Big Bend Units 1, 2 or 4?

A That's correct.

Q Okay. So it would be correct to conclude that the only units served by the transformer will be Big Bend Unit 3?

A That's correct.

Q And the new transformer will serve the electric load for two new induced draft fans; is that correct?

A That's part of the load that they will serve, yes.

Q Okay. And those new fans will replace the function, the function of the current fans which are pulling air into the boiler system; correct?

A Incorrect. There are two forced draft fans at the head of the system, you might say, that are pushing combustion air and coal into the boiler and this will partially relieve some of their duty. But the majority of their duty is now to pull that air through, through the boiler and through the SCR system which is going in as part of the SCR project. The existing fan system there cannot accommodate the SCR project. So something has to be done to supply the additional amount of energy necessary to drive the flue gas through the system, including the SCR, and there were several approaches to doing that. The approach that Tampa Electric determined was, to be the most cost-effective was to go ahead and use ID fans or induced draft fans for that service.

Q And the two other projects or the two other suggestions proposed by Sargent & Lundy would not have required putting in a new transformer; is that correct?

A I don't know.

Q Would you agree that there are other reasons other than environmental laws which could cause TECO to decide to put in the ID fans?

A There are other benefits to having ID fans or an induced draft system or a balanced draft system; however, they are not the reasons that the ID fans went in. The ID fans went in solely because of the SCR project because the other reasons have existed since the first day of operation or inception of Big Bend's 1, 2 and 3, the beneficial reasons associated with

ID fans. And we've never made the change for those reasons in, what, some, over 20 years of operation. So it wasn't those reasons but the, the Consent Decree requirement that we put SCRs on those units that caused the need for the additional fans leading to the choice of using ID fans.

Q Well, let me refer you to the gypsum project. Gypsum is a byproduct of the coal burning and environmental process; is that correct?

A Gypsum?

Q Yes.

A Yeah. It's, it's the reaction product of the sulfur dioxide that you scrub out of the flue gas. It's reacted with a ground pulverized slurried limestone, and the sulfur dioxide, once its absorbed, reacts with the calcium carbonate in the limestone to finally form calcium sulfate, which is gypsum.

Q Okay. And you have, or TECO has two choices for disposing of the gypsum that's produced; is that correct? It could either put them in a landfill; is that correct?

A You could put it in a landfill or you could sell it. Those would be the two general overall choices.

Q Okay. And if you put it in the landfill, that would cost money; is that true?

A Yes. That would cost money to dispose of it.

Q And otherwise you sell the gypsum byproduct to commercial interests such as wallboard companies?

A Yes.

Q And TECO then receives money for the gypsum byproduct?

A Yes.

Q Okay. And it's correct that the existing gypsum equipment was designed to create disposable gypsum byproduct?

A No. All of the FGD systems were designed to produce commercial grade gypsum. Ever since the Big Bend 4 FGD system that went in service January of 1985 -- it was designed to produce commercial grade gypsum, as were the scrubbing of 1, 2 and 3.

Q Okay. Originally they -- well, let me ask you this. By adding the new gypsum fines filter, you'll end, is it correct to say that you'll end up removing more moisture from the gypsum byproducts, thereby making the new gypsum byproduct more commercially marketable?

A We won't sell anymore because the scrubber makes all of the gypsum and not the fines filter. There is potential that the value of the gypsum could increase as a result of being dryer.

Q Okay. And by lowering that moisture content in the gypsum, it's more commercially viable for the wallboard industry rather than a moister content gypsum; is that correct?

A It's already all sold to the wallboard industry. They take it all. And so it's not going to make it anymore commercially viable. Again, as I said, the only thing it may change is the, the price per ton that we might get for it.

Q Okay. And you said that, that would, is likely to increase. It'll make it more valuable.

A That could, that could increase, yes.

Q Okay. Let me refer you to the split inlet and outlet duct projects. Currently Big Bend Units 3 and 4 share common ductwork for their FGD system; is that correct?

A That's correct.

Q And you would agree that the Units 3 and 4 current FGD system meets the removal of the SO2 requirement set forth in the Consent Decree; correct?

A It meets the removal efficiency requirements. Yes.

Q Okay. And the Units 3 and 4 FGD system removes 95 percent of the SO2 from the flue gas as it is currently configured; correct?

A Yes.

Q Okay. And if the, and if the split ductwork projects were not done, the current FGD system would still remove 95 percent of the SO2; correct?

A Yes.

Q Okay. And if the split ductwork projects were done, the FGD system would still remove 95 percent of the SO2.

A Yes.

MS. CHRISTENSEN: I have no further questions of this witness.

MS. BROWN: Staff has no questions.

CHAIRMAN EDGAR: Commissioners? No?

Mr. Beasley.

MR. BEASLEY: One redirect.

REDIRECT EXAMINATION

BY MR. BEASLEY:

Q Mr. Smolenski, do your customers benefit from your gypsum sales?

A Yes, they do.

MR. BEASLEY: Thank you.

CHAIRMAN EDGAR: Okay. Let's take up the exhibit.

MR. BEASLEY: Move the admission of Exhibit 4.

CHAIRMAN EDGAR: Okay. Exhibit 4 will be entered into the record. The witness is excused.

(Exhibit 4 admitted into the record.)

MR. BEASLEY: That concludes our direct case.

CHAIRMAN EDGAR: And, Ms. Christensen, are you, are you ready to go?

MS. CHRISTENSEN: At the Chairman's pleasure, I believe we are.

CHAIRMAN EDGAR: Okay. We're ready.

MS. CHRISTENSEN: The first witness the Office of Public Counsel would like to call is Ms. Patricia Merchant.

PATRICIA W. MERCHANT

was called as a witness on behalf of the Citizens of the State of Florida and, having been duly sworn, testified as follows:

DIRECT EXAMINATION

BY MS. CHRISTENSEN:

Q Can you please state your name and address for the record, please.

A Yes. My name is Patricia W. Merchant. My address is 111 Madison Street, West Madison Street, Tallahassee, Florida 32399, and I'm employed with the Office of Public Counsel.

Q And, Ms. Merchant, did you cause to be prefiled in this docket direct testimony dated January 24th, 2007, consisting of 13 pages?

A Yes, I did.

Q And do you have any corrections to make to your testimony today?

A No, I don't.

Q Okay. And if I were to ask you the same questions today, would your answers be the same?

A Yes.

Q And did you also have prefiled exhibits PMW-1 (sic.) attached to your testimony?

A Yes. PWM-1.

Q Okay. And do you have any corrections to make to your exhibit?

A No, I do not.

Q Ms. Merchant, can you please summarize your testimony.

A Yes. My testimony addresses the proper regulatory treatment of costs associated with the FGD System Reliability Program which TECO seeks to recover through the ECRC. Of the 13 projects identified, TECO has requested that 12 be recovered through the ECRC and one through base rates. Citizens' witnesses Stamberg and Hewson testify about the specific projects and whether the projects are legally required by environmental regulation. I testify about the regulatory theory of base rate treatment as opposed to clause recovery.

OPC agrees with TECO that eight of the 12 projects are appropriate to be recovered through the ECRC. We believe that recovery of four of the 12 projects belongs in base rates. Since inception the cost recovery clauses have created financial incentives to steer as many costs as possible through recovery clauses. To allow normal base rate type costs to flow through a clause results in an unwarranted rate increase, an unwarranted increase in overall rates borne by customers, and this increase in earnings directly benefits shareholders to the detriment of ratepayers and can amount to double recovery of costs. For this reason the Commission should be vigilant for claims that new or unusual costs belong in a cost recovery clause as opposed to being absorbed in base rates.

The ECRC statute states that the environmental costs have to be incurred after 1993, the activity has to be legally required to comply with a governmentally imposed environmental regulation and the cost cannot be recovered by any other rate mechanism. The Commission outlined its ECRC recovery policy in Order Number 94-0044 and specifically disallowed discretionary nonmandated environmental projects in the ECRC even though those projects were commendable. Whether a company needs to file a base rate case is a management decision based on its analysis of its company's risk or its projected earnings. I'm not suggesting that a base rate case should be triggered by making these plant improvements or that TECO should be denied recovery of any of its requested costs. And this concludes my summary.

MS. CHRISTENSEN: We would ask to have Ms. Merchant's prefiled testimony inserted into the record as though read.

CHAIRMAN EDGAR: The prefiled testimony will be entered into the record as though read.

# DIRECT TESTIMONY

# OF

# PATRICIA W. MERCHANT, CPA

On Behalf of the Office of Public Counsel

Before the

Florida Public Service Commission

Docket No. 050958-EI

Introduction

Q. **PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.**

A. My name is Patricia W. Merchant. My business address is Room 812, 111 West Madison Street, Tallahassee Florida, 32399-1400.

Q. **BY WHOM ARE YOU EMPLOYED AND WHAT IS YOUR POSITION?**

A. I am a Certified Public Accountant licensed in the State of Florida and employed as a Senior Legislative Analyst with the Office of Public Counsel (OPC). I began my employment with OPC in March, 2005.

Q. **PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.**

A. In 1981, I received a Bachelor of Science degree with a major in accounting from Florida State University. In that same year, I was employed by the Florida Public Service Commission (PSC) as an auditor in the Division of Auditing and Financial Analysis. In 1983, I joined the PSC's Division of

Water and Sewer as an analyst in the Bureau of Accounting. From May, 1989 to February, 2005 I was a regulatory supervisor in the Division of Water and Wastewater which evolved into the Division of Economic Regulation.

**Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION?**

A. Yes, I have testified numerous times before the PSC. I have also testified before the Division of Administrative Hearings as an expert witness.

**Q. ARE YOU SPONSORING AN EXHIBIT IN THIS CASE?**

A. Yes. I am sponsoring one exhibit, which is attached to my testimony. Exhibit PWM-1 is a summary of my regulatory experience and qualifications.

**Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?**

A. The purpose of my testimony is to discuss the proper regulatory treatment of costs associated with the Big Bend Flue Gas Desulfurization ("FGD") System Reliability Program which Tampa Electric Company ("TECO") seeks to recover through the Environmental Cost Recovery Clause ("ECRC").

**Q. HAVE YOU REVIEWED TECO's PETITION FOR APPROVAL OF THE FGD SYSTEM RELIABILITY PROGRAM COSTS THROUGH THE ECRC?**

A. Yes. TECO is requesting $11,929,000 that it refers to as Big Bend FGD System Reliability (New ECRC Program) Costs should be recovered through the ECRC. It also has requested recovery of $7,096,000 in costs referred to as the Big Bend Units 1&2 FGD (Existing Program) through the ECRC. The company has also identified $2,626,000 in costs that it is requesting to be recovered through base rates.

**Q. ARE YOU PROVIDING TESTIMONY AS TO WHAT COSTS ARE PROPERLY RECOVERED IN THE ECRC?**

A. Yes. Citizen's witnesses Stamberg and Hewson testify about the specific requested projects and whether those costs are required by new environmental law, regulation or mandate. I am testifying as to the proper regulatory theory of base rate treatment as opposed to clause recovery, specifically through the ECRC in this case.

**Q. WHAT ARE THE TWO MAIN TYPES OF RATE RECOVERY MECHANISMS AVAILABLE TO ELECTRIC UTILITIES?**

A. The principal rate recovery mechanisms available for regulated electric utilities are base rates and special cost recovery clauses. Each recovery method has its defined role, and they are designed to work together to provide the utility with rates that are fair, just, reasonable and not unduly discriminatory.

**Q. PLEASE DESCRIBE THE BASE RATE RECOVERY MECHANISM.**

A. Base rates are designed to allow the utility the opportunity to recover its prudent operating costs and a reasonable rate of return on its investment in utility plant. In a base rate case, a test year is used to examine the levels of plant investment and operating costs that represent the levels that will be incurred when the rates go into effect. Adjustments are made to remove any unreasonable amounts and to normalize nonrecurring or extraordinary amounts in the test year. By analyzing the data included in the utility's rate request, the Commission determines the total amount of revenues the utility should be allowed to collect and then designs rates that will generate that revenue figure.

**Q. HOW DOES THE COMMISSION ALLOW THE UTILITY THE OPPORTUNITY TO RECOVER A REASONABLE RATE OF RETURN ON ITS INVESTMENT?**

A. In setting rates, the Commission determines the overall rate of return on the utility's investment in its utility plant. This overall cost of capital is based on the weighted average cost of debt, equity and other sources of capital. The cost of debt and other sources of capital are determined based on stated cost rates, and the cost of equity is based on the level of profit and business risk for which utility shareholders should be compensated.

**Q. HOW DOES REGULATORY THEORY ADDRESS THE ISSUE OF DESIGNING RATES TO BE SUFFICIENT FOR FUTURE PERIODS?**

A. Ratemaking principles recognize that after rates are set, the prospective relationships between costs and revenues will change from those levels used in setting the rates. The level of a particular cost may increase, decrease, or the cost may go away altogether. Costs that were non-existent during the test period may arise after the rates take effect. Projected revenue levels will also vary based on customer growth or changes in consumption or a combination of both. A particular expense level increase does not automatically cause a utility to earn less than its fair rate of return on its investment or to not recover the expense. In order to determine whether an increase in a single cost is affecting a utility adversely, it is necessary to consider the overall relationship of total revenues and total costs.

**Q. HOW ELSE DOES THE COMMISSION PROVIDE A SAFETY NET FOR EARNINGS LEVELS FOR REGULATED UTILITY COMPANIES?**

A. The Commission sets rates using the mid-point of the authorized rate of return on equity (ROE) and then establishes a range for the ROE. If the utility earns within the range, generally set at 100 basis points on either side of the mid-point, then the utility is earning a fair return on its investment and is recovering its prudent operating costs. If the utility is earning above or below the range on its ROE, then it is over- or under-earning, respectively.

**Q. PLEASE DESCRIBE THE VARIOUS COST RECOVERY CLAUSES AVAILABLE TO ELECTRIC COMPANIES.**

A. The cost recovery clauses available to electric companies are the Fuel and Purchased Power Cost Recovery Clause with generating performance incentive factor (Fuel Clause), the Energy Conservation Cost Recovery Clause (ECCR), and the Environmental Cost Recovery Clause (ECRC). The clauses enable companies to recover specific costs on a current basis outside of base rate considerations. Clauses provide guaranteed rate recovery of the specific costs identified for inclusion. They are a departure from the traditional base rate mechanism, under which the rates are designed to provide the utility an opportunity, not a guarantee, to recover its prudent costs and to earn a fair return.

The fuel clause provides recovery to the utility for the day to day fluctuations in the cost of fuel and other volatile fuel-related costs that cannot be anticipated in base rates. Pursuant to Section 366.82, Florida Statutes, the conservation clause allows utilities to recover costs to implement cost-effective demand side conservation programs. In the case of environmental costs, Section 366.8255, Florida Statutes, mandates the use of a cost recovery clause for qualifying expenditures. All of the cost recovery factors are reestablished annually and include projections for the prospective year. The factors also include a true-up of the current year projections based on actual expenses incurred, with over or under recoveries included in the next year's factor.

**Q. DO THE COST RECOVERY MECHANISMS CREATE AN INCENTIVE FOR THE UTILITY TO REQUEST RECOVERY OF NORMAL BASE RATE TYPE COSTS THROUGH A CLAUSE?**

A. Yes. The reason is simple. If a cost does not legitimately meet the definition of costs that qualify for a recovery clause, to allow the cost to flow through the clause will result in an unwarranted increase in overall rates borne by customers. This increase in revenues directly benefits shareholders to the detriment of ratepayers. Further, if the utility is earning within the range of its authorized rate of return, allowing recovery through a clause would amount to double recovery.

**Q. CAN YOU GIVE AN EXAMPLE TO MAKE THIS POINT?**

A. Yes. Assume a utility has a rate base (a utility's net investment in utility plant) of $1 billion, a Commission-authorized fair rate of return with a range of 9% to 11%, and net income of $100 million. Assume that the Commission must consider the following: a) allow the utility to collect an additional $1 million expense normally recovered in base rates through the fuel clause or b) require the utility to absorb the expense in earnings achieved from base rates. The achieved rate of return before the additional expense will be 10%, which is in the middle of the authorized range.

If the utility is allowed to collect the additional expense through the fuel clause, base rates will not change; but the customers will pay additional fuel revenues of $1 million. However, if the Commission denies the request to recover the expense through the clause, the utility will recover the expense through revenues generated by base rates. The customers' overall bill will not go up—both fuel revenues and base rate revenues will be unchanged. The income for the period becomes $99 million instead of $100 million and the return falls from 10% to 9.9%. Inasmuch, the return is still well within the range of the return that the Commission established as fair and reasonable.

Because special cost recovery clause treatment enables the utility to avoid absorbing the expense through base rate earnings, the utility has a powerful financial incentive to steer as many costs as possible through recovery clauses. For this reason, the Commission should be ever vigilant for claims that new or unusual costs belong in a cost recovery clause as opposed to being absorbed in base rates.

Q. **HAS THE COMMISSION ADDRESSED THE APPROPRIATE WAY TO DETERMINE WHAT TYPES OF COSTS ARE ALLOWED TO BE RECOVERED THROUGH THE ECRC?**

A. Yes. By Order No. PSC-94-0044-FOF-EI[1], the Commission outlined the most appropriate way to implement the intent of the ECRC statute as follows:

> Upon petition, we shall allow the recovery of costs associated with an environmental compliance activity through the environmental cost recovery factor if:
>
> 1. such costs were prudently incurred after April 13, 1993;
> 2. the activity is legally required to comply with a governmentally imposed environmental regulation enacted, became effective, or whose effect was triggered after the company's last test year upon which rates are based; and,
> 3. such costs are not recovered through some other cost recovery mechanism or through base rates.
>
> In addition, we shall consider that all costs associated with activities included in the test year of the utility's last rate case are being recovered in base rates unless there have been new legal

[1] Order No. PSC-94-0044-FOF-EI, issued January 12, 1994, in Docket No. 930613-EI, In re: Petition to establish an environmental cost recovery clause pursuant to Section 366.0825, Florida Statutes, by Gulf Power Company.

> environmental requirements which change the scope of previously approved activities and caused costs to change from the level included in the test year. If new legal requirements cause an increase, or decrease, in costs from the level included in the test year of the utility's last rate case, the amount recovered through base rates should be the determined to be the amount included in the test year. (Order at page 6-7.)

**Q. DID THE COMMISSION'S ORDER ADDRESS PROJECTS THAT WERE IMPLEMENTED AT MANAGEMENT'S DISCRETION?**

A. Yes. The Commission found that capital projects that were implemented at management's discretion, but were not necessary to comply with any governmentally imposed environmental compliance mandate, were not appropriate to be included in the ECRC even though the projects were commendable. Nor were projects allowed for compliance with future environmental amendments as the impacts were premature and could not be determined at that time. (Order at page 9)

**Q. WHAT IS YOUR TESTIMONY AS TO THE REQUESTED RECOVERY OF TECO'S BIG BEND FGD SYSTEM RELIABILITY PROGRAM COSTS THROUGH THE ECRC?**

A. Based on the testimony of OPC witnesses Stamberg and Hewson, five[2] of the thirteen projects included in TECO's request are not appropriate to be

[2] TECO requested that one of the projects, the Big Bend Units 3-4 FGD Booster Fan Capacity Expansion, be recovered through base rates not the ECRC. The cost reflected in TECO's petition was $1.849 million.

included in the ECRC. Those projects are not required by any new environmental regulation or environmental mandate and are projects to be implemented at management's discretion. The projects that are inappropriate for recovery through the ECRC are as follows:

| Project Description | Amounts |
|---|---|
| Big Bend Units 3-4 Split Inlet Duct | $116,000 |
| Big Bend Units 3-4 Split Outlet Duct | $4,829,000 |
| Gypsum Fines Filter | $2,866,000 |
| Big Bend Units 1-4 Electric Isolation | $6,600,000 |
| Total Reduction to ECRC Requested Costs | $14,411,000 |

**Q. ARE YOU TESTIFYING AS TO WHETHER TECO'S BASE RATES ARE SUFFICIENT TO RECOVER THESE COSTS WHEN THEY ARE INCURRED?**

A. No, I am not. The purpose of my testimony is to delineate the distinct differences between collecting revenues through base rates or clauses. I believe that to exceed the intended purpose and scope of any of the special cost recovery clauses distorts the overall purpose of cost recovery to the detriment of customers. In as much, the Commission should keep the relationships between these rate categories in mind as it considers TECO's request. In the instant case, either the costs qualify for ECRC or they do not. The Citizen's have provided testimony that some of the requested costs do not belong in the ECRC and as such can only be considered base rate costs. Whether a company needs to file a base rate case is a management decision based on each company's assessment of its levels of investment, projected earnings and perceived business risk. Further, I am by no means suggesting that a base rate case should be triggered by making these plant improvements.

**Q. ARE YOU RECOMMENDING THAT TECO BE DENIED RECOVERY OF ANY OF THE REQUESTED COSTS?**

A. No. If TECO has a sufficient level of earnings through base rates to recover these costs, then placing the costs in rate base and operating income allows full recovery by TECO. The argument that not allowing costs that normally are recovered through base rates to be recovered through any clause revenues somehow denies recovery to the utility is false.

Revenues and expenses are not static. Basic ratemaking assumes that, after the typical test year is constructed and rates are designed, a utility's costs, investment, and revenues will vary over time. In contrast to special cost recovery clauses, base rates are intended to operate generally and on an overall basis. Full cost recovery of a base rate-related item occurs if, after the expenditure is added to the ratemaking equation, the utility's operating revenues continue to exceed expenses and the utility has a positive net income. This is true whether or not the particular item was built into Minimum Filing Requirements or test year assumptions when base rates were last designed.

**Q WOULD YOUR VIEW OF THE PROPER FUNCTIONS OF BASE RATES AND COST RECOVERY CLAUSES CHANGE IF THE**

**UTILITY WAS EARNING LESS THAN A FAIR RATE OF RETURN AT THE TIME IT INCURS THE COST FOR WHICH IT SEEKS RECOVERY THROUGH A CLAUSE?**

A. No. If the utility is earning less than the bottom of the range of its authorized rate of return, then its appropriate recourse is to avail itself of the opportunity afforded it by statute to seek an adjustment in base rates. If it does so, then customers and the Commission will have an opportunity to assess the company's condition on an overall basis. Ultimately, the responsibility belongs solely with the utility's management to consider the need to seek base rate relief.

**Q. DOES THIS COMPLETE YOUR TESTIMONY?**

A. Yes, it does.

MS. CHRISTENSEN: And at this time we tender Ms. Merchant for cross-examination.

CHAIRMAN EDGAR: Mr. Beasley.

MR. BEASLEY: We have no questions.

CHAIRMAN EDGAR: Are there questions from staff?

MS. BROWN: Staff has just a few questions.

CROSS EXAMINATION

BY MS. BROWN:

Q Good morning, Ms. Merchant.

A Good morning.

Q You state in your testimony that you worked primarily on water and wastewater rate cases at the Commission; is that correct?

A I did for the majority of my career, but I was an auditor for two years and then I worked on a few electric cases toward the end.

Q Were you ever assigned to an environmental cost recovery clause docket?

A No, I was not.

Q Any of the clause dockets?

A No. But I worked a lot on rate cases and for water and wastewater companies, which is very similar to base rate cases for electric companies. The issues are very similar.

Q On Page 8, Lines 14 through 22, you provide a hypothetical there. Is that hypothetical a case involving the environmental cost recovery clause or the fuel clause?

A I don't think it matters. It could be either way. It's an example of a clause recovery as opposed to base rate recovery.

Q There is no statute that governs the scope and application of the fuel clause though like there is in the environmental clause; correct?

A There is no statute, but there's a lot of orders that, that dictate the policy for the fuel clause.

Q But there is no statute that dictates the policy; correct?

A That's correct.

Q On Page 12 of your testimony, Lines 5 through 22, are you describing the regulatory tool sometimes referred to as an earnings test there?

A It could be an earnings test or a rate case type analysis.

Q Are you testifying that the Commission should use an earnings test to determine whether any new environmental costs should be recovered through the environmental cost recovery clause?

A No. What I'm testifying to is that the statute and the Commission's Order 94-0044 dictate how, what types of costs are appropriate to be recovered through the ECRC. And if they're not recovered through the ECRC, then they have to be recovered through base rates. And my testimony here is that a company has to look at their own earnings to see if they can recover, if they can absorb these items in base rates, whether they need to seek relief from the Commission through a rate case to recover costs that are not approved to be in the ECRC.

Q And you just mentioned the Gulf order. Would you agree that the Gulf order addresses whether an earnings test is appropriate for considering recovery of costs through the environmental cost recovery clause?

A Yes, it does.

Q And what does it say about that?

A It has quite a lot of discussion on it, but one of the items, it says if that item was not specifically identified in the last rate case, as a line item in the last rate case, that it assumes that it wasn't recovered.

But my testimony today is that -- does it meet the statute? Does it comply -- is the project mandated by governmental -- is it legally required by governmental regulation? So if it's not required by governmental regulation, then it has to go through base rates. It's just one or the other. I think that an earnings test for the statute is not appropriate, but it's -- once it's determined that it's not, it goes into base rates.

MS. BROWN: All right. Thank you. No further questions.

CHAIRMAN EDGAR: Ms. Christensen.

MS. CHRISTENSEN: Yes, a few redirect.

REDIRECT EXAMINATION

BY MS. CHRISTENSEN:

Q I want to make sure, Ms. Merchant, that we're clear. Your testimony is not -- can you clarify whether or not you're testifying regarding whether or not an earnings test should be applied to the ECRC clause analysis?

A No, it does not need to. You don't have to have an earnings test to determine whether something goes through the ECRC.

Q Okay. And referring back to your hypothetical situation, you said that it was appropriate to apply that to either a fuel clause or an ECRC clause analysis; is that correct?

A Right. My, my example is a cost that doesn't belong in a clause. If you put it -- if it doesn't belong in the clause and you put it in the clause, then it can, it can give a double recovery. If it, if it belongs in the clause, it belongs in the clause. If it doesn't belong and it's inappropriately put in the clause, then you've got the double recovery situation.

MS. CHRISTENSEN: Okay. Thank you. No further questions.

CHAIRMAN EDGAR: Let's go ahead and take up the exhibit.

MS. CHRISTENSEN: I would ask to have Ms. Merchant's exhibit be --

CHAIRMAN EDGAR: Number 6.

MS. CHRISTENSEN: I'm sorry?

CHAIRMAN EDGAR: Number 6.

MS. CHRISTENSEN: Number 6 entered into the record.

CHAIRMAN EDGAR: Okay. Exhibit Number 6 will be entered into the record, and the witness is excused. Thank you.

(Exhibit 6 admitted into the record.)

MS. CHRISTENSEN: The next witness that the Office of Public Counsel would like to call is Mr. Tom Hewson, please.

THOMAS A. HEWSON, JR.

was called as a witness on behalf of the Citizens of the State of Florida and, having been duly sworn, testified as follows:

DIRECT EXAMINATION

BY MS. CHRISTENSEN:

Q Can you please state your name and business address for the record.

A My name is Thomas A. Hewson, Jr. I work at Energy Ventures Analysis, which is located at 1901 North Moore Street, Suite 1200 in Arlington, Virginia.

Q Mr. Hewson, did you cause to be filed in this docket prefiled testimony filed January 24th consisting of, excuse me, 20 pages or, I'm sorry, 19 pages?

A I think with the exhibits it was rather hefty.

Q The exhibits. I'm sorry. 17 pages.

A 17 pages of testimony, yes.

Q Okay. And did you have any corrections to your testimony?

A I did.

MS. CHRISTENSEN: Okay. And, Madam Chairman, for clarity we handed out a single page. The single page correction addresses, I think, most of the corrections that Mr. Hewson has. He may have one other minor correction to make to his testimony. I would ask that Mr. Hewson go ahead and make those corrections for the record.

THE WITNESS: Yes. On the page that was handed out on Page 13 on Line 10 there was a recalculation of the forced outage rate, which is contained also in Mr. Stamberg's testimony. And as he, Mr. Stamberg, recalculated the outage rate, I made those changes to be consistent with his.

It now reads, beginning on Line 9, "Based upon Big Bend FGD operational history, the project may reduce the forced outage rate by only 0.013 to 0.078 days per year." That was one change.

The second change which was not contained in that, it's on Page 5, Line 14. This refers to Section 29 of the Consent Decree dealing with Units Number 1 and 2. It says, "outages for up to," it should read "45," not 60, "unit calendar days per year until January 1st, 2009, if they combust specified alternative coals during outages and have first maximized capacity use of other scrubbed coal-fired capacity units, Units 3 and 4. For the period," and then you should strike out the "FGD bypass allowance is lowered to 45 calendar days per year and." It should just simply read, "For the period 2010 to 2012 a cleaner alternative coal must be used." The 45 calendar days continues until obviously 2013.

MS. CHRISTENSEN: And for clarification, I believe that may have started on Line 16 in the copy that was provided to the Commission if it wasn't 14.

CHAIRMAN EDGAR: I'm sorry. I'm not sure I got that. Could --

MS. CHRISTENSEN: In looking at the copy that I have that we submitted, I believe the correction started on Line 16 rather than Line 14, but --

CHAIRMAN EDGAR: Okay. On Page 5?

MS. CHRISTENSEN: Correct.

CHAIRMAN EDGAR: Referring to the 60-unit calendar days going to 45.

MS. CHRISTENSEN: Correct.

CHAIRMAN EDGAR: Okay. Commissioners, are you clear?

COMMISSIONER CARTER: Yes, ma'am.

CHAIRMAN EDGAR: Okay. All right. Thank you.

BY MS. CHRISTENSEN:

Q If I were to ask you the same questions today with the corrections you made here today, would your answers be the same?

A They would.

Q Okay. And did you prefile testimony consisting of four exhibits, TAH-1, TAH-2, TAH-3 and TAH-4?

A I believe there was also a TAH-5.

Q And the TAH-5 attached to your testimony?

A That's correct.

Q And do you have any corrections to those exhibits?

A I do not.

Q Okay. Mr. Hewson, can you give a brief summary of your testimony?

A I would be glad to.

The Office of Public Counsel asked EVA to review the Tampa Electric petition that requested the approval of $21.6 million for 13 capital improvement projects that were associated with the Big Bend FGD System Reliability Program. Specifically, EVA was asked to provide an independent assessment to determine if these projects were required to comply with the February 2000 Consent Decree requirements. In my testimony I review these capital projects and requirements of the Consent Decree. Mr. -- my colleague, Mr. John Stamberg, completed the engineering assessments of the 13 individual capital improvement projects.

It should be important that the difference between the current and final limits under the Consent Decree are primarily focused on the phaseout of scrubber bypass events. The percent of reduction limits do not change, and there is a small change in the floor limit.

Our investigation concludes that several of the requested projects in TECO's petition for cost recovery through the ECRC are not required to comply with the terms of the February 2000 Consent Decree or any other new environmental law or regulation. As a result, these projects should not be eligible for cost recovery under the ECRC. Specifically, these noneligible projects totaled $14.41 million that include the electric isolation project for Units 1 through 4, which was $6.6 million. This project was to provide a new transformer with a subelectrical circuit that would primarily service the Big Bend Unit Number 3's two new large induced draft fans, which would comprise 92.6 percent of the new circuit's load. These large ID fans would not, were not, would not be dedicated to the existing FGD system.

Secondly, the existing system configuration has been and will likely continue to remain highly reliable so that the electric isolation project should have no measurable effect on the FGD system reliability.

Finally, TECO itself has listed in its first phase of its electric isolation project as not being required by the Consent Decree in its October 2006 Quarterly Compliance Report.

The second project and third project is the split FGD outlet duct and inlet duct for Units 3 and 4. TECO originally elected to combine Units 3 and 4 into one existing scrubber to reduce its environmental compliance costs. Several other utilities have also elected to combine units into a common scrubber for the same reason. As discussed by Mr. Stamberg why this project would allow maintenance on either inlet or outlet duct without shutting down both units, it would not significantly improve the FGD system reliability. Based upon Big Bend FGD operational history, the project may reduce the forced outage rate by only 0.013 to 0.078 days per year.

Finally, TECO acknowledges in its quarterly compliance report that split inlet ductwork that was started during the third quarter of 2006 is not associated with Consent Decree requirements. TECO -- we would apply -- the same logic for the inlet should also apply to the split outlet duct.

The fourth project is the gypsum fines filter, which was $2.9 million or $2.866 million. The FGD systems were originally designed to produce a gypsum byproduct for disposal. The existing system is now operating within its original design parameters. The new gypsum fines filter investment is associated with a desire to produce a saleable byproduct and avoid landfill disposal costs. While this may make economic sense for TECO to invest in a filter to reduce landfill costs, it is not specifically required by the Consent Decree.

FGD -- there was -- EVA concluded the remaining requested projects outside the ones that were requested to be handled under base rates were reasonable and prudent operation maintenance projects that would improve and/or maintain the overall operation reliability of the FGD systems. These projects totaled $5.391 million, including mist eliminator upgrades, the online mist eliminator wash system for the Units 1 through 4, the online nozzle wash system for Units 1 through 4, the gypsum filter vacuum pump upgrade, the programmable controllers for FGD systems feeding Units 1 through 4, gypsum blowdown line for Units 1 through 2, Unit 1 through 2 recycle pump discharge isolation bladders and the inlet duct C-276 wallpaper.

That concludes my summary. Thank you.

MS. CHRISTENSEN: I would ask to have Mr. Hewson's testimony entered into the record as though read.

CHAIRMAN EDGAR: The prefiled direct testimony with the corrections noted will be entered into the record as though read.

BEFORE THE FLORIDA PUBLIC UTILITIES COMMISSION

**Petition of Tampa Electric Company )**
**For approval of a new environmental )**
**program for cost recovery through )**
**the Environmental Cost Recovery Clause ) Docket No: 050958-EI**

---

## PREFILED TESTIMONY OF THOMAS A. HEWSON JR.

## I. INTRODUCTION

**Q: Please state your name.**

A: My name is Thomas A. Hewson Jr.

**Q: On whose behalf are you submitting testimony?**

A: State of Florida's Office of Public Council (OPC).

**Q: How are you currently employed?**

A: Since 1981, I have been a principal at Energy Ventures Analysis, Inc (EVA), an energy consulting firm located at 1901 North Moore Street in Arlington, Virginia. Between 1976-1981, I had been employed as a project manager at Energy and Environmental Analysis Inc in Arlington, Virginia.

**Q: What are your qualifications for providing your testimony?**

A: For 30 years, I have provided numerous reports and provided testimony on the effects of environmental requirements on the electric utility industry operations for the electric utility industry, fuel suppliers, fuel transporters, electric utility commissions and industrial trade groups. I have a Bachelor of Science in Engineering degree in Civil Engineering from Princeton University (1976). My resume is attached as Exhibit TAH-1.

~~**Q: Have you previously testified before the Florida Public Service Commission?**~~

A: No, although I have completed other prior work for the OPC, I have not previously testified before the Florida Public Service Commission.

**Q: Have you previously testified as an environmental expert before other regulatory bodies?**

A: Yes, I have. I have testified as an environmental expert in the energy industry in proceedings before numerous other regulatory bodies in California, Delaware, Georgia, Maine, Maryland, Massachusetts, Minnesota, Pennsylvania, South Dakota, Vermont, and Virginia. I have also testified in legislative proceedings in Idaho, Massachusetts, New Hampshire and Wisconsin as well as the US Congress. I have also testified in legal judicial proceedings in West Virginia and Kentucky.

**Q: Please describe the assignment you were given by the Office of Public Council.**

A: EVA was asked to review the Tampa Electric Company (TECO) petition dated December 27, 2005 and revised March 16, 2006 as well as other information TECO has submitted as part of Florida Public Service Commission Docket No: 050958-EI. This petition requested approval for $21.651 million for 13 capital improvement projects associated with the Big Bend Flue Gas Desulfurization System (FGD) Reliability Program for cost recovery through the Environmental Cost Recovery Clause. TECO indicates in its petition that these 13 listed projects were required to improve the reliability of the FGD scrubbers servicing Big Bend Units #1, #2 and #3 and were necessary to comply with the February 2000 Consent Decree between the US Environmental Protection Agency (USEPA) and TECO. EVA was asked to provide an independent assessment to determine if these listed projects were required to comply with the Consent Decree requirements. I reviewed these capital projects and the requirements of the Consent Decree. Mr. John Stamberg of EVA completed the engineering assessments of the thirteen individual listed capital improvement projects.

## II. SUMMARY

**Q: Please summarize your findings.**

A: EVA's investigation concludes that several requested projects in TECO's petition for cost recovery through the Environmental Cost Recovery Clause (ECRC) are not required to comply with the terms of the February 2000 Consent Decree or any other new environmental law or regulation. As a result, these projects should not be eligible for cost recovery under the ECRC. Specifically, these non-eligible projects totaled $14.41 million[1] and include:

- Electric isolation project for units #1-4 ($6.6 million),

[1] This amount excludes the $1.849 million that TECO requested for expanding the unit #3-4 booster fan expansion that it requested would be recovered through base rates and therefore would be excluded from their ECRC request.

- Split FGD outlet duct for units #3-4 ($4.829 million),
- Split FGD inlet duct for units #3-4 ($0.116 million).
- Gypsum fines filter ($2.866 million)
- Unit 3&4 FGD booster fan capacity expansion ($1.849 million- to be recovered ~~through base rates)~~

EVA also concluded that the remaining requested projects in the TECO petition were reasonable and prudent operation & maintenance projects that would improve and/or maintain the overall operation and reliability of the FGD system. These $5.391 million FGD improvement projects include:

- Mist eliminator upgrades ($2.387 million of which $1.61 million would be recovered through the ECRC and $0.777 would be recovered through base rates )
- Online mist eliminator wash system for units #1-4 ($0.669 million)
- Online nozzle wash system for units #1-4 ($0.561 million)
- Gypsum filter vacuum pump upgrade ($0.623 million)
- Programmable controllers for FGD units feeding units #1-4 (($0.406 million)
- Gypsum blowdown line for units #1-2 ($0.284 million)
- Unit #1-2 recycle pump discharge isolation bladders ($0.227 million) and
- Inlet duct C-276 wallpaper ($0.234 million)

## III. FEBRUARY 2000 CONSENT DECREE REQUIREMENTS

**Q: In TECO's revised March 2006 petition, the company stated that thirteen FGD capital projects were needed to comply with the requirements of the February 2000 Consent Decree between the USEPA and Tampa Electric Company. Could you please identify the applicable sections of the Consent Decree that deal specifically ~~with the Big Bend FGD performance that are important to this proceeding?~~**

A: The Consent Decree sets much tighter emission requirements for SO2, NOx and particulates for the Big Bend Station. Since the FGD equipment is designed to meet only the SO2 emission requirements, the pertinent sections of the February 2000 Consent Decree for this proceeding that deal specifically with the Big Bend FGD performance are paragraphs 29, 30, 31, 40 and 44.

Section 29 sets the SO2 emission limitation and reliability requirements for the FGD scrubber that feeds Big Bend units #1-2 for the period of 2000-2012. Currently, the FGD must maintain a minimum of 95 percent reduction of SO2 contained in the inlet flue gas during scrubber operation. During this transition period through 2012, TECO will be allowed to bypass the FGD servicing units #1-2 during outages for up to ~~60~~ 45 unit-calendar days per year until January 1, 2009 if they combust specified alternative coals[2] during outages and have first maximized capacity use of their other scrubbed coal-fired capacity (units #3-4). For the period 2010-2012, ~~the FGD bypass allowance is lowered to 45 unit-calendar days per year and~~ a cleaner alternative coal must be used.

[2] The alternative coal is defined to be a coal with the sulfur content of no more than 2.2 #/MMBtu through 2009 (Section 4) and 1.2 #/MMBtu in calendar years 2010-2012 (Section 29.C- applies to units #1-2 only)

Section 30 sets the SO2 emission rate limitation and reliability requirements for the FGD servicing unit #3[3] for the period 2000-2009. Currently, the FGD must achieve a minimum of 95 percent reduction of SO2, or alternatively, meet an emission rate limitation of 0.30#SO2/MMBtu. During this transition period through 2009, TECO will be allowed to ~~bypass the FGD during outages for up to 30 calendar days per year if they combust~~ specified alternative coals during outages and have first maximized capacity use of their other scrubbed coal-fired capacity (units #1-2).

Section 40 sets the final Big Bend SO2 emission rate limitations for as long as Big Bend units #1-3 remain coal-fired. These final limits will require the FGD to achieve a minimum of 95 percent reduction of SO2, or alternatively, meet an emission rate limitation of 0.25#SO2/MMBtu. TECO will no longer be allowed to bypass the FGD equipment during outages except for those permitted circumstances allowed under the Clean Air Act's New Source Performance Standards (NSPS). *This no bypass requirement unless under emergency conditions already applies to Big Bend unit #4 and is common to many other NSPS scrubbed units*[4]. These final limitations will take effect on January 1, 2010 for Big Bend Unit #3 and on January 1, 2013 for Units #1-2. TECO's petition identifies that these tighter SO2 future requirements under section 40 are the primary reason for its FGD Reliability Program's listed capital improvement projects.

[3] One FGD services both units #3 and #4.

[4] When existing coal units undergo "major modifications," they may become subject to the same requirements as new units. EPA in its litigation against TECO had alleged that TECO had made major modifications to their units and were required to retrofit additional environmental controls. The February 2000 Consent Decree was the settlement agreement to end this litigation.

Section 31 requires TECO to submit for approval its plans to identify all operation & maintenance activities needed to optimize the availability of the FGD scrubbers servicing Big Bend units #1, #2, and #3 to minimize the instances in which SO2 emissions are not scrubbed. These required TECO Big Bend FGD optimization plans were submitted to ~~USEPA on May 31, 2000 (Phase 1) and February 20, 2001 (Phase II).~~

Finally, section 44 contains the parties' resolution of future claims and a covenant not to sue. The pertinent part of Section 44 for this proceeding is a requirement 44.B(2) that TECO must report all physical changes or changes in Big Bend method of operation <u>not required by the Consent Decree</u> (emphasis added) until December 31, 2012 that meet all the following criteria

1. TECO expects to spend more than $250,000;
2. TECO considers as a capital expenditure; and
3. Meets applicable criteria under 40 CFR Section 52.21(b)(9).

## IV. TECO FGD OPTIMIZATION PLANS

**Q: Under Section 31 of the Consent Decree, TECO was required to submit its plans that all operation & maintenance activities needed to optimize the availability of the FGD scrubbers servicing Big Bend units #1, #2 and #3 to minimize instances in which SO2 emissions are not scrubbed. Did these TECO approved plans include any of the listed thirteen FGD capital improvement projects listed in its December 2005 petition for cost recovery under ECRC?**

A: With two exceptions, the answer is no. The required TECO Big Bend FGD optimization plans were submitted to USEPA on May 31, 2000 (Phase 1) and February 20, 2001 (Phase II) and are attached as Exhibits TAH-2 and TAH-3 respectively. The approved plans listed capital projects that had already occurred as well those TECO had ~~planed to implement in the future. These plans also addressed use of overtime labor and~~ identification of necessary spare parts as part of this program.

The February 2001 Phase II plan listed twelve completed FGD capital improvement projects and sixteen yet-to-be completed FGD capital projects that TECO had planned to complete primarily during 2001. These future listed projects included some mist eliminator upgrades for units #3-4 (replace/redesign C tower absorber nozzles and D tower demister packing) and replacement/repair of the inlet duct of the FGD scrubber servicing units #1-2. These projects were designed to improve FGD system operation in the same manner as two of TECO's March 2006 petition's listed projects: C-276 wallpaper on the inlet FGD duct work for units #1-2 and the mist eliminator upgrade project.

Given that almost all the TECO's petition projects for ECRC cost recovery were not included in the Phase 1 or Phase 2 plan for optimizing the Big Bend FGD system, one must conclude that most of the petition's listed projects were not considered by TECO in February 2001 as being necessary to comply with the Consent Decree requirements—a full year after the initial start-up of the unit #1-2 scrubber and more than 6 years after the integration of unit #3 into the station's other scrubber.

**V. TECO QUARTERLY COMPLIANCE REPORTS**

**Q: Under the Consent Decree, does TECO submit quarterly compliance reports ~~to USEPA, Hillsboro County and Florida Department of Environmental Protection~~ to address compliance activities or progress with the Consent Decree provisions?**

A: Yes, TECO does submit a quarterly report addressing the company's activities to comply with the Consent Decree.

**Q: Have you reviewed Tampa Electric's Quarterly Compliance reports, which they filed with the EPA?**

A: Yes, I have.

**Q: Do these Quarterly Compliance Reports contain status reports and activities that TECO is implementing to improve the FGD optimization and to minimize the number of unscrubbed days?**

A: Yes, they do. As illustrated in TECO's 3rd Quarter 2006 Compliance Report (Exhibit-TAH-4), TECO response B.2 specifically identifies these activities undertaken to improve FGD operation to minimize the number of bypass events and to quantify the effectiveness of the measures taken to date.

**Q: Do any of TECO's B.2 responses in their Quarterly Compliance Reports contain information that the FGD capital improvement projects listed in the TECO's petition are required to minimize the number of unscrubbed days?**

A: The TECO Quarterly Compliance Report responses consistently discuss implementation of the Phase 1 and Phase II FGD Optimization plans that I discussed earlier. Through October 2006, no other additional FGD capital improvement projects were identified in TECO B.2 responses. Since almost all the petition's projects were not identified in the Phase 1 or Phase II reports, they have not been explicitly identified in TECO's Quarterly Compliance Reports' response as a required element of their approved plan to minimize the number of unscrubbed events.

TECO has stated in its October 26, 2006 Compliance Report for 3rd Quarter 2006 that they have already "*performed significant amount of improvement work in the FGD area to improve the reliability of the FGD systems and has stocked spare FGD parts for scrubber systems serving the coal-fired units at Big Bend Station. Together these efforts have reduced the number and duration of FGD outages at Big Bend Station and should continue to show positive benefits*" (3rd Quarterly 2006 Report pg ii- --Exhibit-TAH-4)

I would have expected that TECO would have included the thirteen projects (that are contained in their ECRC petition) as part of their Quarterly Compliance Report responses if they had been essential elements in their Consent Decree compliance.

**Q: Do the Quarterly Compliance Reports contain a listing of capital improvement projects that fall under section 44.B(2) of the Consent Decree?**

A: Yes, under section 44.B(2) of the Consent Decree, TECO does list capital improvement projects in their Quarterly Compliance Report submissions to the USEPA ~~as part of their response C.7 for all qualifying capital projects that have started and/or~~ been completed. Section 44.B(2) of the consent decree requires that TECO must report all physical changes or changes in Big Bend method of operation <u>not required by the Consent Decree</u> (emphasis added) until December 31, 2012 that meet all the following criteria

- TECO expects to spend more than $250,000,
- TECO considers as a capital expenditure
- Meets applicable criteria under 40 CFR Section 52.21(b)(9)

**Q: What Big Bend FGD related projects and petition-related projects does TECO provide in their Quarterly Compliance Report C.7 responses?**

A: The Big Bend FGD related projects and petition-related projects that TECO listed in their Quarterly Report C.7 responses as not being required by the Consent Decree are attached as <u>Exhibit-TAH-5</u>.

**Q: Are any of the listed projects the same as projects listed in the cost recovery petition?**

A: Yes, four Big Bend projects are listed on both the Quarterly Compliance Report response C.7 as <u>***not being required***</u> by the Consent Decree and in the TECO December

2005 petition for cost recovery under the ECRC ***as being required*** under the Consent Decree. These projects are:

- Split inlet duct for FGD feeding units #3-4 (started 3rd quarter 2006)
- Electric isolation work for units #3-4 (started 3rd quarter 2006)
- ~~Unit #1-2 FGD mist eliminator replacement (started 3rd quarter 2006)~~
- FGD Wallpaper inlet duct (started 3rd quarter 2006)

By placing these four projects on their Quarterly Compliance Report listing, TECO has explicitly acknowledged that they are not associated with compliance with the Consent Decree and therefore would not qualify for ECRC as a new environmental requirement.

## VI. PROJECT ELIGIBILITY UNDER ECRC

**Q: In EVA's assessment of the listed December 2005 petition projects, did it conclude that any projects should not be eligible for cost recovery through the ECRC clause?**

A: EVA's investigation concludes that five requested projects in TECO's petition for cost recovery through the Environmental Cost Recovery Clause (ECRC) are not required to comply with the terms of the February 2000 Consent Decree. As a result, these projects should not be eligible for cost recovery under the ECRC. Mr. Stamberg will provide an engineering assessment for these projects. Specifically, these non-eligible projects totaled $14.11 million[5] and include:

[5] This amount excludes the $1.849 million that TECO requested for expanding the unit #3-4 booster fan expansion that it requested would be recovered through base rates and therefore would be excluded from their ECRC request.

- Electric isolation project for units #1-4 ($6.6 million)—This project would provide a new transformer with a separate electrical circuit that would primarily service the station's large Induced Draft (ID) fans which would comprise 92.6 percent of new circuit's load (Stamberg testimony). These large ID fans are not ~~dedicated to the FGD system. Secondly, the electric system has been and will~~ likely continue to remain highly reliable so that the electric isolation project should have no measurable effect on FGD system reliability. Finally, TECO itself has listed its first phase of this electric isolation project as not being required by the Consent Decree in its October 2006 Quarterly Compliance Report.

- Split FGD outlet duct ($4.829 million) and inlet duct ($0.116 million) for units #3-4— TECO originally elected to combine units #3-4 into one existing scrubber to reduce its environmental compliance costs. Several other utilities have also elected to combine units into a common scrubber for this same reason. As discussed by Mr. John Stamberg, while this project would allow maintenance on either inlet or outlet duct without shutting down both units #3-4, it would not significantly improve the FGD system reliability. Based upon Big Bend FGD operational history, the project may reduce the forced outage rate by only ~~0.011~~ 0.013 to ~~0.082~~ 0.078 days per year. Finally, TECO acknowledges in its Quarterly Compliance Report that the split inlet duct work that was started during the 3rd quarter 2006 is not associated with the Consent Decree requirements. TECO's same logicfor the split inlet duct work should also apply to the split outlet duct work.

- Gypsum fines filter ($2.866 million)—FGD systems were originally designed to produce a gypsum byproduct for disposal. The existing system is operating within its original design parameters. The new gypsum fines filter investment is associated with the desire to produce a saleable byproduct and avoid landfill disposal costs. While it may make economic sense for TECO to invest in the filter to reduce landfill costs, it is not required by the Consent Decree.
- Unit 3&4 Booster fan capacity expansion ($1.849 million- requested recovery in base rates)- This project is being triggered because of the project to split the inlet and outlet ducts. As discussed above, these projects were not required by the Consent Decree, nor do they appreciably improve the system reliability. TECO's petition identifies this project as being recovered through the base rate.

**Q: In your opinion, are the projects listed above required to comply with a new requirement of an environmental law or regulation?**

A: No, for the reasons stated above, I do not believe that these projects are required to comply with a new requirement of an environmental law or regulation.

**Q: In your opinion, are the projects listed above required to comply with Section 40 of the Consent Decree?**

A: No, for the reasons stated above, I do not believe that these projects are required to comply with Section 40 of the Consent Decree.

**Q: Is the Consent Decree's future 2010 and 2013 implement dates for the final emission rate limitations a new environmental law or regulation?**

A: TECO, USEPA and State regulators have known about these final limitations since the Consent Decree was finalized in February 2000. Being roughly 6 years old, the ~~Consent Decree itself would not be considered a new law or regulation. However, like~~ the 1990 Clean Air Act, the Consent Decree requirements are phased in over a longer period (13 years for the Consent Decree, 9 years for the Title IV Acid Rain program under the 1990 Clean Air Act).

**Q: What about the remaining projects listed in TECO petition for ECRC?**

A: EVA concluded that based upon the information provided by TECO in this proceeding that the remaining requested projects in the TECO petition were reasonable and prudent operation & maintenance projects that would improve and/or maintain the overall operation and reliability of the FGD system. These $5.391 million FGD improvement projects include:

- Mist eliminator projects for units #1-4 including mist eliminator upgrades ($2.387 million of which $1.61 million was part of the ECRC request and $0.777 million was part of a base rate request), online mist eliminator wash systems ($0.669 million) and online nozzle wash system ($0.561 million)—Some past mist eliminator upgrade projects were integral parts of the approved FGD optimization plans submitted under Section 31 of the Consent Decree in February 2001. Secondly, plugging the mist eliminator system has historically caused forced outages and derates. Before the permitted bypass days are phased out, TECO will need to make the listed system improvements to better clean the mist eliminators with a higher pressure system during ongoing operations and thereby could significantly improve unit availability and performance.

- Gypsum filter vacuum pump upgrade ($0.623 million)—When TECO started to ~~use recycled water beginning in 2002, the vacuum seal water became more~~ corrosive and required the use of more corrosion resistant material for the pump casing. In addition, the equipment supplier currently suggests more air-flow capacity based upon their experience with newer FGD installations. EVA concluded that these vacuum pump upgrades would likely improve future FGD operation and reliability.
- Programmable controllers for FGD units feeding units #1-4 (($0.406 million)—The reliability objective for this project could have been addressed several different ways. However, it is one approach that could provide additional reliability.
- Gypsum blowdown line addition for units #1-2 ($0.284 million)—This project would add a new gypsum blowdown line to the single existing line for the FGD system servicing units #1-2. Given the potential for plugging, this project appears to be reasonable, prudent and cost effective method to improve the FGD system reliability.
- Unit #1-2 recycle pump discharge isolation bladders ($0.227 million) - This project was considered prudent. With the use of recycled water, the water could become more corrosive and require different materials. This project would be a logical engineering solution.

- Inlet duct C-276 wallpaper addition for FGD servicing units #1-2 ($0.234 million)—This project appears similar to past wallpaper projects that were listed in TECO's approved Phase II FGD optimization plan in February 2001. These wallpaper projects are designed to use more corrosion resistant material to reduce ~~leakage and improve FGD performance. However, this project also appears to be~~ the same as or similar to a $233,000 "FGD Wallpaper inlet duct project" that was listed as capital improvement project under Consent Decree Section 44(B)(2) that are for projects not specifically required by the Consent Decree. However, given the need to reduce leakage, this project appears to be reasonable and prudent to improving FGD operations and reliability.

**Q: Does this conclude your testimony?**

A: Yes it does.

MS. CHRISTENSEN: And the witness can be tendered for cross-examination.

CHAIRMAN EDGAR: Thank you.

Mr. Beasley.

MR. BEASLEY: We have no questions for this witness.

CHAIRMAN EDGAR: Okay. Questions from staff.

MS. BROWN: Just a few, Madam Chairman.

CROSS EXAMINATION

BY MS. BROWN:

Q Good morning, Mr. Hewson. I'm Martha Brown for the Commission.

A Good morning.

Q In your testimony at Page 7, Line 5, and Page 8, Lines 2 and 3, you state that TECO's Phase I and Phase II plans were filed with the EPA in 2000 and 2001.

A That's correct.

Q Those are the dates Ms. Crouch identified as well; correct?

A I think she agreed with you on Phase II. She didn't have it in front of her.

Q All right. On Page 7, Line 1, you state, "Section 31 requires TECO to submit for approval its plans to identify all operation and maintenance activities needed to optimize the availability of the FGD scrubbers."

A That's correct.

Q Am I reading that correctly?
A Uh-huh.
Q Does Paragraph 31 of the Consent Decree set any specific scrubber availability requirements?
A It simply states to try to minimize the bypass events.
Q But it does not set any other specific scrubber availability project requirements; correct?
A No, it's not explicit.
Q Does Paragraph 31 set requirements to shut down any of the Big Bend units if the scrubbers are not working?
A I believe that other than Section 4, Unit 4, it allows a transition period in which it allows them to bypass until the final limitations are implemented.
Q All right.
A Up to, you know, certain requirements.
Q All right. Paragraph 36 of the Consent Decree -- do you see that blue book there by you? It should be flagged there with a purple sticky note.
A Okay.
Q You're familiar with this paragraph, of course.
A Yes.
Q It allows TECO a period of time through May 2007 to determine whether or not to continue using coal at Big Bend Units 1, 2 and 3.

A That's correct.

Q And it's your understanding as well, isn't it, that TECO did announce continued use of coal at Big Bend August 19th, 2004?

A I didn't look up the date, but I think that's correct.

Q So just, just to clarify for a minute, TECO submitted it's Phase I and Phase II compliance plans in 2000 and 2001 as Paragraph 31 required, but it didn't submit its decision to continue burning coal at Big Bend units, at the Big Bend units as Paragraph 36 required until 2004.

A That's correct.

Q But your testimony on Page 8, Lines 18 through 23 --

A What page? Excuse me.

Q Page 8.

A Lines?

Q 18 through 23. Seems to suggest that TECO's 2000 and 2001 plans should have included all future FGD compliance projects under the assumption that TECO would decide to continue using coal, even though it hadn't actually made that decision yet. Is that a correct reading of your testimony?

A That as of February 2001 it was not considered necessary. That's correct.

Q But does your testimony contain the assumption that it would, that TECO would continue to decide using coal or am I overreading that?

A When they decided to continue on August 19th, 2004, in the, in the, under the, this particular section of the, of this Consent Decree they could go and modify the plans in order to optimize the scrubber. They're always free to add.

Q Okay. With respect to Paragraph 40 now, do you agree that TECO's submission to the EPA in 2004 triggered the operation of that paragraph of the Consent Decree?

A It became final, yes.

Q I'm sorry?

A Yes. It became final at that point in time.

Q Okay. Does Paragraph 40 of the Consent Decree set further SO2 reductions on TECO once the decision to continue to burn coal is made?

A What it does in the final limitations is it phases out the use of bypass days as one change. It also had a slight change in terms of the floor limit. They had the option of doing 95 percent or 0.3 pounds of SO2 per million Btu. In Paragraph 40 it goes to 0.25.

Q So what it really does is set specific scrubber availability requirements for TECO once the decision to burn coal is made. Is that --

A Well, at the end of the limitation as the, as the allowance for bypass is eliminated to make it like any other new source performance standard. And let's keep in mind that the purpose of the whole litigation was concerning whether or not it should be subject to new source performance standards. And so as of when the transition period is completed, it is subject to the same limitations in terms of allowance for bypass as the other NSPS unit, which is Unit 4.

MS. BROWN: All right. Thank you very much. No further questions.

CHAIRMAN EDGAR: Ms. Christensen.

REDIRECT EXAMINATION

BY MS. CHRISTENSEN:

Q Mr. Hewson, let me take you back to Paragraph 31, Section A of the Consent Decree. Is it correct in reading that paragraph that there -- that TECO would be allowed to modify its Phase I or Phase II optimization plans if it so chose after those plans had already been submitted to the EPA?

A Yes, it's very explicit. And Section 31(A)(1), the last sentence, it says, "Such plan may be modified from time to time with prior written approval of EPA."

Q And is the Consent Decree currently in effect?

A It is.

Q Okay. And in your opinion would TECO have had the opportunity to modify its Phase II plan after it made its decision to continue to burn coal at the Big Bend Units 1 through 3?

A It could change -- it can modify its plan at any time.

Q And that would include after its decision to --

A Right. Could change it today.

Q Okay. And has TECO in any document that you're aware of indicated whether or not it believed the projects that we're talking about were required by the Consent Decree?

A As contained in my testimony, I specifically -- Tampa submits each quarter a compliance report under the Consent Decree as part of those requirements, part of those reports. It reports those projects that aren't specifically required by the Consent Decree. And as contained in my, in my testimony, I identified some of those that were, on the surface appear to be the same as what they're requiring for in this docket.

Q Okay. And, Mr. Hewson, in your reading of Paragraph 40 is it your understanding that the deadlines that are being set forth in Paragraph 40 are essentially the end of the transition period for TECO to go to new source performance standards?

A That's correct.

Q And would those new source performance standards in your opinion have been known to TECO when it signed the Consent Decree?

A Well, yes, I would say it was known to the parties at the time that they signed and that it was written down.

Q Okay. And in your opinion was anything new or different that was unknown to TECO triggered by their declaration that they were going to maintain coal burning at Big Bend Units 1 through 3?

A I think that the August 19th declaration was greatly anticipated. We did not believe that they were going to shut down the Big Bend Stations. I think it was just a verification and, therefore, made it final in terms of the limitations under Section 40 were going to be implemented.

Q Okay. And those limitations were well known to TECO before that declaration date.

A It was known at the time that it was negotiated, and all the parties signed on the dotted line.

Q And, Mr. Hewson, can you explain a little bit further what the purpose of the litigation was regarding the Consent Decree?

A The litigation was one of a number done by the electric -- by the Environmental Protection Agency. They had alleged that there was, that Tampa Electric had made major modifications which in their opinion were sufficient to trigger new source performance standards limitations.

There was litigation that part of the agreement -- they came to a Consent Decree, which is the document that you see that they signed in February 2000.

Q And in triggering those major modifications would it have required TECO to meet the requirements that are set forth in Paragraph 40 at the time those major modifications had been done?

A At the time it would have been probably -- they would have -- once it was a major modification there would likely have been some sort of period to allow them to implement, to put in the controls. If you had a major modification, you would have had to have done the controls in order meet the new source performance standards limitations. So there would likely have been some time to allow them to implement all those from the major modification.

Q And would you agree that that's essentially what this Consent Decree does?

A That's the way I read it, yes.

MS. CHRISTENSEN: Okay. I have no further questions.

CHAIRMAN EDGAR: Okay. Let's look at the exhibits. And, Ms. Brown, I think we need to add TAH-5; is that correct?

MS. BROWN: Yes, Madam Chairman. I apologize. It got dropped off. We were thinking it could be 10A, marked as 10A perhaps.

CHAIRMAN EDGAR: Okay. We will mark it as 10A, TAH-5, Summary of Listed FGD Projects From TECO Quarterly Compliance Report. And with that, Ms. Christensen, you want to go ahead and we will enter 7, 8, 9, 10 and 10A into the record?

MS. CHRISTENSEN: Yes. I would ask that those be moved, so moved into the record.

CHAIRMAN EDGAR: Thank you. So moved.

(Exhibit 10A marked for identification.)

(Exhibits 7, 8, 9, 10 and 10A admitted into the record.)

CHAIRMAN EDGAR: Okay. The witness is excused. Thank you.

THE WITNESS: Thank you.

CHAIRMAN EDGAR: Let's go ahead and take up the next witness.

MS. CHRISTENSEN: Correct. The Office of Public Counsel would ask that Mr. John Stamberg please take the stand.

JOHN B. STAMBERG

was called as a witness on behalf of the Citizens of the State of Florida and, having been duly sworn, testified as follows:

DIRECT EXAMINATION

BY MS. CHRISTENSEN:

Q Can you please state your name and business address for the record.

A My name is John Stamberg. I work for Energy Ventures Analysis at 1901 North Moore Street, Arlington, Virginia, zip code 22209. I'm Vice President and I'm a Registered Professional Engineer.

Q And, Mr. Stamberg, did you cause to be prefiled in this matter testimony consisting of 20 pages on January 24th, 2007?

A Yes.

MS. CHRISTENSEN: And I would note for the record we have paid -- excuse me -- passed out three pages with corrections to a portion of Mr. Stamberg's testimony for the ease of all of us to follow the numbers. I know it can get a little confusing.

BY MS. CHRISTENSEN:

Q Mr. Stamberg, do you have any corrections to be made to your testimony today?

A Yes.

Q Can you please state those?

A Excuse me? Do you want me to go over those?

Q Yes. Can you please state them for the record.

A Yes. On Page 8, 9 and 10, on Line 17 to 19, I corrected the two attributable duct work events from "1.33" hours in the number one to "1.5" hours. And I corrected the first quarter of 2006 number to "7.82" hours. And then I added those together and I got a total of "9.32" hours instead of the "9.88" hours. And I corrected the arithmetic on Pages 9 and 10 respectively, and then the associated figure, Exhibit JBS-3.

Q Okay. With those corrections, if I were to ask you those questions today, would your answers be the same?

A Yes.

Q Okay. And you also have noted that you had exhibits attached to your testimony. That would be four exhibits, JBS-1, JBS-2, JBS-3 and JBS-4; is that correct?

A Yes.

Q And I think you had noted that you made a correction to one of your exhibits. Could you please state that correction again?

A Yes. Those are the corrections.

Q Okay. Do you have any other corrections to your exhibits?

A No.

Q Okay. At this time I'd ask you to please summarize your testimony. Can you please briefly summarize your testimony?

A Yes. First I'll go over the project that is called Big Bend Units 1 through 4 Electric Isolation. In the TECO petition in the Big Bend Reliability Study they stated much of the FGD equipment in Units 1 through 4 systems are fed from a common -- is fed from common transformers and motor control systems. It further goes on and says that, "Therefore, the loss of one of these sensors or transformers will cause forced outage of the entire FGD system, resulting in outages of Units 1 and 2 or Unit 3. In order to eliminate the possibility of this occurrence, the equipment feeds will be divided up among separate transformers and control centers to ensure that their losses can only affect a single unit." That is incorrect. The new transformer only serves Unit Number 3. The new transformer does not serve the FGD system. It's 92.6 percent serving two 6,000-horsepower new proposed variable frequency drive transformers, and then about 1 percent is divided between the FGD system and SCR equipment, and the other 6 or so percent is for miscellaneous motors and lights and equipment that wasn't identified. These new ID fans are to be used instead of the forced draft fans and the FGD booster fans that currently exist.

The study in Mr. Smolenski's rebuttal testimony, in the study that's called the "Tampa Bay Electric Big Bend Unit Number 3 SCR Project Evaluation of Alternatives," which is JVS-2, Document Number 3, that document says that the SCR system will require 750 kVA, not the 6,000-horsepower units that are being installed.

The fans themselves only cost about $717,000 according to the study, but need a new transformer which doesn't exist, which becomes the $6,600,000 Big Bend Units 1 to 4 isolation project.

Also, in the information that we collected there's never been a transformer outage that has resulted in any FGD problems, and the FGD system has backup equipment and transformers for all their things.

So in summary, the project does not connect to the FGD system. It is not correct that it serves -- because it only serves Unit 3. The transformers are not a source of forced outages. The new transformer does not need to be installed for reliability purposes, it's not needed for compliance with the Consent Decree, it is not cost-effective when you add the cost of the transformer to the equipment, and the variable frequency drive transformer is not the most cost-effective alternative to supply the 750 kVA or the extra horsepower or energy to supply the SCR system.

On the split duct, they were designed and the rationale for those was the ducts must be offline at the same time. The ductwork forced outages or derates amounts to the 9.32, which was a correction to the 9.8 hours in a five-year period, which works out to be about two hours. The FGD system is designed for --

CHAIRMAN EDGAR: Mr. Stamberg, I'm sorry, but you're way, way over your two minutes. And although Mr. Bryant was way over -- I'm going to show the same latitude on both sides, of course, but I do need you to --

THE WITNESS: Okay. Can I just finish a couple --

CHAIRMAN EDGAR: -- finish up, please. Yes, sir.

THE WITNESS: Okay. So basically the Units 3 and 4 are off 2,300 to 1,700 hours a year, which gives plenty of time to repair the ducts in downtime. And in looking at the records, TECO has done that when there's other outages or reasons for the units to be off. And then I'll real quickly go over the gypsum fines filter is really to add commercial value to the gypsum and gypsum sales.

CHAIRMAN EDGAR: Thank you, sir.

MS. CHRISTENSEN: I would ask that Mr. Stamberg's prefiled testimony, excuse me, be entered into the record as though read.

CHAIRMAN EDGAR: Okay. The prefiled testimony will be entered into the record as though read with the corrections noted.

# BEFORE THE FLORIDA PUBLIC UTILITIES COMMISSION

**Petition of Tampa Electric Company )**
**For approval of a new environmental )**
**program for cost recovery through )**
**the Environmental Cost Recovery Clause ) Docket No: 050958-EI**

## PREFILED TESTIMONY OF JOHN B. STAMBERG

## I. INTRODUCTION

**Q: Please state your name.**

A: My name is John B Stamberg, P.E.

**Q: On whose behalf are you submitting testimony?**

A: State of Florida's Office of Public Council (OPC).

**Q: How are you currently employed?**

A: Since 1981, I have been a Vice President at Energy Ventures Analysis, Inc (EVA), an energy consulting firm located at 1901 North Moore Street in Arlington, Virginia. Between 1974-1981, I had been employed as a Principal at Energy and Environmental Analysis Inc in Arlington, Virginia. During 1967 to 1974, I worked at the US Environmental Protection Agency in the Office of Air and Water Programs.

**Q: What are your qualifications for providing your testimony?**

A: I have a Bachelor of Science in Civil Engineering from the University of Maryland and a Master of Science Degree in Civil Engineering from Stanford University. I have been a licensed professional engineer since the mid 1990's.

I have conducted engineering and environmental analyses of numerous powerplants, industries and municipal systems. I have completed analyses of potential environmental control systems and cost at over 150 coal-fired powerplants and done engineering site visits of over 60 powerplants for various projects. My resume is attached as Exhibit JBS-1.

**Q: Have you previously testified before the Florida Public Service Commission?**

A: Yes, I have. I testified in Docket No: 031033-E1 as an engineer on behalf of CSX Transportation relating to potential rail car delivery versus the current barge delivery of coal to TECO's Big Bend and Polk County powerplants.

**Q: Have you previously testified as an environmental expert before other regulatory bodies?**

Yes, I have. I have testified in regulatory proceedings in Louisiana, New Jersey, Maryland, North Carolina, South Carolina and Virginia.

**Q: Please describe the assignment you were given by the Office of Public Council.**

A: EVA was asked to review the Tampa Electric Company (TECO) petition dated December 27, 2005 and revised March 16, 2006 that are part of Florida Public Service

Commission Docket No. 050958-EI and the materials that have been submitted by TECO as part of this docket. This petition requested approval for $21.651 million for 13 capital improvement projects associated with the Big Bend Flue Gas Desulfurization System (FGD) Reliability Program for cost recovery through the Environmental Cost Recovery Clause. TECO indicates in its petition that these 13 listed projects were required to improve the reliability of the FGD scrubbers servicing Big Bend Units #1, #2 and #3 and were necessary to comply with the February 2000 Consent Decree between the US Environmental Protection Agency (USEPA) and TECO. EVA was asked to provide an independent assessment on if these listed projects were required to comply with the Consent Decree requirements. I provided engineering assessments of the thirteen individual listed capital improvement projects.

**Q: What is the purpose of your testimony?**

A: To provide the results of an engineering assessment of the thirteen projects listed in the TECO petition and discuss their effect on FGD system operations and reliability. Secondly, to provide an opinion on if these projects were needed to comply with the future Consent Decree requirements.

## II. Big Bend Units 1-4 Electrical Isolation Project

**Q: What is the capital cost of the "Big Bend Units 1-4 Electrical Isolation" project that TECO has requested cost recovery through the Environmental Cost Recovery Clause (ECRC)?**

A. TECO has requested that $6,600,000 in capital cost be recovered under the ECRC per TECO's December 27, 2005 petition entitled "Petition of Tampa Electric Company for Approval of a New Environmental Program for Cost Recovery Through the Environmental Cost Recovery Program." TECO supported their request in Exhibit D "Tampa Electric Company – Big Bend Desulfurization System Reliability Study".

**Q: How was the $6,600,000 estimate prepared?**

A. Per Bates Stamp page 5755 of Tampa Electric Company Response to OPC Production of Documents #5, the cost components for this project were:

| | |
|---|---|
| Direct Cost | $3,822,723 |
| Indirect Cost | 181,238 |
| Administrative Cost | 134,203 |
| Adjustments/Escalation | 375,837 |
| Total | $4,514,000 |

According to page 5732 of this same Tampa Electric Company response, this estimate was first rounded upward to $5,000,000 and then added a $1.6 million contingency (32% of $5 million or alternatively 47.9% of the $4.514 million original project cost estimate).

**Q: What equipment would be served by the new electric isolation project transformer 3B?**

A: Per Tampa Electric Company Response to OPC Interrogatory No. 38 (1/12/07), this transformer with about 20,522 KVA would serve 6 downstream smaller transformers (B3003A, B3003B, B3004A, B3004B, B3005A, and B3005B). Four of these downstream transformers are small and two are large (B3004A and B3004B).

The two large downstream transformers on the circuit created by this project would serve variable frequency induced draft (I.D.) fans 3A and 3B that are part of the boiler system (not directly part of environmental control equipment). The I.D. fans would comprise 92.6 percent of the load that would be serviced by the project's new proposed transformer 3B (see Exhibit JBS-2). The variable frequency I.D. fans drive system has a high capital cost and is a deluxe I.D. fan feature that allows improved I.D. fan speed control that can reduce onsite electrical use.

**Q: What is the load would be served by the proposed new transformer from pollution control equipment and from other miscellaneous onsite uses?**

A: In comparison to the variable speed I.D. fans, the electricity load from pollution specific equipment served through the proposed new transformer 3B is trivial at 0.4% of the total projects load for FGD specific equipment and 0.6% for SCR specific equipment. Unidentified "motors and lights and other equipment" accounts for an additional 6.4% of the load. Without the two large I.D. fans, these smaller loads alone would not justify use of a 20,522 KVA transformer.

**Q: What are the existing I.D. fans 3A and 3B electrical loads? Will the transformer capacity that services these fans be considered surplus capacity and could be available for other use?**

**A.** The existing loads for I.D. fans 3A and 3B are approximately 19,000 KVA but are fixed frequency loads. Thus, if the proposed electric isolation project with a new transformer 3B is built, approximately 19,000 KVA from existing transformers elsewhere onsite will be freed up for other large electricity loads from other large onsite equipment loads.

**Q: What was the frequency of forced outages caused by the existing I.D. fans 3A and 3B failures due to transformer failure in the last 5 years?**

**A.** There were no recorded FGD related forced outages that have occurred within the past 5 years because of failure of transformer(s) servicing I.D. fans 3A and 3B.

**Q: What was the extent of forced derates caused by I.D. fans 3A and 3B failures due to transformer failure in the last 5 years?**

**A.** There were no recorded forced derates over the last 5 years because of transformer failure or lack of transformer capacity of I.D. fans 3A and 3B.

**Q: In your opinion, is the $6,600,000 electrical isolation project reasonable and prudent under the ECRC clause?**

**A.** No, it is neither reasonable nor prudent under the ECRC clause. Given the electrical systems demonstrated high availability and that it is designed to service primarily the large I.D. fan load that is not part of the pollution control system, the electrical isolation system project with its proposed new transformer is not necessary to achieve compliance with the consent decree or any other known environmental law or regulation. As discussed in Mr. Hewson's testimony, TECO concurs with this assessment by including the first phase of this project in their Quarterly Report listing of capital projects not required by the Consent Decree.

**Q: Are there other potential reasons outside of the environmental requirements to justify the proposed electric isolation project?**

**A.** The variable frequency (variable speed) driven 3A and 3B I.D. fan motors should provide energy efficiency benefits (lower onsite power consumption) and improved operational control. By placing them on a separate circuit with a new transformer, TECO would reduce the electrical loadings on other circuits and reduce the effect of any planned maintenance events on other parts of the plant.

Given the TECO material submitted on this project, it is difficult to determine if there may be other operational reasons outside environmental requirements to justify this project.

## III. Group A--Big Bend Units 3-4 (Split Inlet Duct and Split Outlet Duct)

**Q: What is the capital cost of the "Group A Big Bend Units 3-4 Split Inlet and Outlet Ducts" project that TECO has requested cost recovery through the Environmental Cost Recovery Clause (ECRC)?**

**A.** TECO has requested that $4,945,000 in capital cost be recovered under the ECRC per TECO's December 27, 2005 petition entitled "Petition of Tampa Electric Company for Approval of a New Environmental Program for Cost Recovery Through the Environmental Cost Recovery Program" imported with Exhibit D "Tampa Electric Company – Big Bend Desulfurization System Reliability Study".

**Q: What are the cost of each split duct project in Group A?**

A. The individual projects in TECO's petition are:

- Big Bend Units 3-4 Split Inlet Duct $116,000
- Big Bend Units 3-4 Split Outlet Duct $4,829,000

**Q: Would you agree with TECO's conclusion that the split duct projects will significantly improve the reliability of the environmental equipment?**

A: No, I do not.

**Q: Has there ever been a forced outage, forced derate or FGD bypass event(s) (a.k.a. de-integration events) of Big Bend Unit 3 or Unit 4 or both Units 3 and 4 attributed to failures or problems with existing common inlet duct or outlet duct for the FGD?**

A. Yes, according to TECO quarterly reports, there have been two bypass events cited in the disintegration reports being attributable to duct work.

(1) First Quarter 2005: "~~1.33~~ 1.50 hours for inspection and repair of duct work" with FGD bypass (de-integration)."

(2) First Quarter 2006: "~~8.55~~ 7.82 hours for FGD system and duct work maintenance" with FGD bypass (de-integration).

**Q: Had TECO no longer been allowed to bypass (future limitation), would these events have required a forced outage?**

A. Given the limited descriptions provided, one cannot definitively determine if the two events under the future limitations would have triggered a forced outage or could have been delayed to the next scheduled maintenance period and therefore I am forced to speculate. Based upon the little description provided, I would guess that the first quarter 2005, ~~1.33~~ 1.50-hour event would appear to cause an outage, or derate, while the first quarter 2006, ~~8.55~~ 7.92-hour event appears to be a FGD system problem in which the duct maintenance may have been discretionary and coordinated with other FGD system maintenance during the event. If the duct maintenance was discretionary, it alone would likely have not triggered a forced outage.

**Q: Based on the above history, what would the range of forced or maintenance outages be for the five year period?**

**A.** Based upon the five-year outage history provided by TECO, the lower range of the forced or maintenance outage rate would be ~~1.33~~ 1.50 hours per 5 years or ~~0.266~~ 0.30 hours per year, or ~~0.011~~ 0.013 days per year for one unit (No. 3). The upper forced or maintenance outage rate would be a combined ~~9.88~~ 9.32 hours (~~8.55~~ 7.82 hours plus ~~1.33~~ 1.50 hours) per 5 years or ~~1.976~~ 1.864 hours per year or ~~0.082~~ 0.078 days per year for one unit (No. 3).

**Q: What rate of force or maintenance outages were assumed in the "Tampa Electric Company Big Bend Station Flue Gas Desulfurization System Reliability Study for Group A Splitting of the Inlet and Outlet Ducts"?**

**A.** The TECO study assumptions were not developed based on historical record but instead were "based on experience" for which no supporting documentation was provided. The TECO study assumptions were:

- Forced Outages: 2.0 days/year per unit
- Maintenance Outages: 2.0 days/year per unit

**Q: Can you compare the assumptions for Group A used in the reliability study and the 5-year history rates for Group A outages?**

A: As is shown in Exhibit JBS-3, the TECO study's assumed avoided forced rate for the split duct Group A projects would total 192 hours per year. This is far higher that the documented 5 year historic rate that would be between ~~0.266~~ 0.30 hours and ~~1.976~~ 1.864 hours/year. The TECO assumption is between ~~97~~ 103 and ~~722~~ 640 times higher than the historic outage rate used for Group A projects.

**Q: Can you compare the project cost, net present value (NPV) of capital expenditures, NPV of savings, net savings and cost benefit ratio of TECO's assumptions in the reliability study to historic rates you presented earlier?**

**A.** Yes. This comparison is provided in Exhibit JBS-4. For the NPV estimate based upon the historical forced outage rate range, I have simply multiplied the TECO NPV estimate ($7.131 million) by the ratio of the 5-year historic outage rate (~~0.266~~ 0.30 hr/year (low) to ~~1.976~~ 1,864 hr/year (high)) to the TECO study outage rate (192 hr/year). By applying the 5-year historic outage rate range, the split duct projects would have a net present value of savings of only $10,000 to $73,500.

**Q: Based on historic performance rate, would you consider the Group A Split Duct projects reasonable and prudent under the ECRC?**

**A.** No, I would not. In my opinion, a NPV of savings of only $10,000 to $73,500 would not justify a nearly $5 million capital project.

**Q: Would you consider that the Group A projects are required to comply with the Consent Decree?**

**A.** No, I would not. First, the projects would not appreciably improve the reliability of the FGD system. Second, at the time the consent decree was negotiated and signed, the parties did not believe that splitting the ducts would be necessary to comply with the Consent Decree and therefore did not include them on their list of needed projects to optimize FGD performance (see Hewson testimony). Finally, TECO is not alone in electing to combine multiple units into a single FGD system in order to capture the economies of scale capital savings. Many utilities have considered combined systems to meet their facility reliability needs without splitting the ducts between units.

**Q: What has been the history of Group A projects in the 21 quarterly reports prepared by TECO as work pursuant to paragraph 44.B (2) of the Consent Decree of Civil Action No. 99-2524-CIV-T-23F?**

**A.** Only a few inlet duct related projects that have been included in the TECO Quarterly Compliance reports to USEPA. These projects were on the list of Section 44.B (2) projects that were not being required by the consent decree include:

- <u>Unit #3-4 common inlet duct replacement</u>- TECO reports that the common inlet duct replacements occurred during the 2$^{nd}$ quarter of 2003, 4$^{th}$ quarter of 2004 and the 2$^{nd}$ Quarter of 2006.

- Unit #3-4 split inlet duct — TECO reports that this project was started during the 3rd quarter 2006 with an estimated project cost of $4.8 million. This project estimate is far greater than the petition split inlet duct request for $0.116 million.

**Q: Why would TECO list the split inlet duct project as $4,800,000 during the 3rd quarter 2006 and as $116,000 in the December 2005/March 2006 petition?**

**A.** I do not know the answer. However, it appears that even in its petition TECO considers only a small portion of the split inlet duct project as being associated with the Consent Decree. As I discussed earlier above, I do not believe that any of this project is associated with the Consent Decree requirements.

## IV. Group C Big Bend Gypsum Projects

**Q: What is the capital cost of the "Group C Projects for Gypsum Processing" project that TECO has requested cost recovery through the Environmental Cost Recovery Clause (ECRC)?**

**A.** TECO has requested that $3,489,000 in 2006 dollars in capital cost be recovered under the ECRC per TECO's December 27, 2005 petition entitled "Petition of Tampa Electric Company for Approval of a New Environmental Program for Cost Recovery Through the Environmental Cost Recovery Program" imported with Exhibit D "Tampa Electric Company – Big Bend Desulfurization System Reliability Study".

**Q: What are the cost of each project in Group C?**

**A.** Per the above petition the individual projects are:

- Gypsum Fines Filter ($3,179,000)- $1,566,000 in 2008 and $1,613,000 in 2009.
- Gypsum Filter Vacuum Pump Upgrades ($691,000)- $340,000 in 2008 and $351,000 in 2009.

**Q: Has there ever been a forced outage or forced derate of any of the Big Bend units caused by the failure of the gypsum dewatering system?**

**A.** No forced outage or forced derate has been reported with the root cause being gypsum processing in the 5 years of quarterly reports to the U.S. EPA submitted by TECO under the Consent Decree for Civil Action No. 99-2524-T-23F.

**Q: In the TECO FGD Optimization Plan specifically identify any modifications to the gypsum dewatering system as being required to comply with the Consent Decree?**

A: As discussed in Mr. Hewson's testimony, the plan did not specifically list any specific elements of the gypsum dewatering as part of its needs to comply with the Consent Decree requirements. The plan had generally identified that a study would be conducted to determine what spare parts were needed for the full range of the station's process elements, including the gypsum dewatering system, would be needed to improve the system reliability. However, the results of this work were not included in the plan, nor did the subsequent quarterly compliance reports mention that a gypsum fine filter was a needed spare part.

**Q: Did the vendor of the gypsum vacuum filter provide a performance guarantee with the existing system?**

**A:** Yes. Raytheon Engineers and Constructors, Inc. provided a performance guarantee with item 1c that states "feed solids must have a minimum average size of 41 microns with no more than 5% of the particles having a size less than 5 microns . . ."

**Q: Does it appear that the gypsum solids are substantially finer or have a particle size distribution below the guarantee level?**

**A.** The one particle size distribution supplied by TECO (Results: Analysis Report, Run 17, Record Number 332, Analyzed Friday, December 22, 2006, 1:30 p.m.) showed particle size distribution similar to the criteria in the guarantee.

**Q: Are the problems identified as failures by TECO in its response to Citizen's Interrogatory No. 24, a result of bad engineering or a result of poor operation?**

**A.** It is likely neither bad engineering or poor operation. Gypsum, which is created in the FGD system, is a gritty material (same as in drywall when dry) is tough on equipment and requires operator attention. The gypsum transitions from a pumpable slurry, to a thick/pasty consistency and eventually to a cake in gypsum processing. It is this difficulty of operation that resulted in the original design to have 100% redundancy.

**Q: It is reasonable and prudent to pursue the Group C as an environmental project under the ECRC clause?**

**A.** For the most part, the answer is no. The additional funds for gypsum filter system and vacuum filter appear to make an improved gypsum suitable for sale into the gypsum market as a more economical choice than making gypsum suitable for disposal. The system was originally designed and was operated in the past to make gypsum suitable for disposal. While upgrading the gypsum to salable grades may be laudable and maybe economical, it would not be considered as necessary to comply with the requirements of the Consent Decree. Since this project is also not required to meet a new environmental requirement, it should not be eligible for recovery under the ECRC clause.

However, the gypsum filter pump upgrade project may be appropriate to include in the ECRC. When TECO started to use recycled water beginning in 2002, the vacuum seal water became more corrosive and required the use of more corrosion resistant material for the pump casing. In addition, the equipment supplier currently suggests more air-flow capacity based upon their experience with newer FGD installations. EVA concluded that these vacuum pump upgrades would likely improve future FGD operation and reliability and thereby would be an appropriate maintenance item to include in the ECRC.

## V. Big Bend Units 3-4 FGD Booster Fan Capacity Expansion

**Q: What is the capital cost of the "Big Bend Units 3-4 FGD Booster Fan Capacity Expansion" project that TECO has requested cost recovery?**

**A.** TECO has petitioned that $1,849,000 in capital cost be recovered through the base rates and not through the ECRC per TECO's March 2006 petition.

**Q: Has TECO already completed the 3-4 FGD booster capacity project?**

**A.** Yes. The project to boost unit #3 and #4 FGD capacity has been completed for the existing combined Units 3 and 4 duct configuration. Per the Fourth Quarter 2004, TECO reported completion of one portion of the project at a cost of $923,000 and in the Second Quarter 2005 TECO reported completion of a $400,000 additional cost for another portion of the project. Thus, TECO has already completed this project at a cost of $1,323,000 for the existing combined Unit 3 and Unit 4 duct.

**Q: Why is the newly proposed "Big Bend Units 3-4 FGD Booster Fan Capacity Expansion" needed if the problem has already been reported as complete?**

**A.** This new project is needed only if the Units 3 and 4 existing combined duct is split into two ducts. The split duct will require more booster fan capacity than the existing combined duct.

**Q: If the Group A Big Bend Units 3-4 (Split Inlet Duct and Split Outlet Duct), is not reasonable and prudent under the ECRC as you earlier have stated, is this new Units 3-4 FGD Booster Fan Capacity Expansion also not reasonable or prudent under ECRC?**

**A.** Yes. This $1,849,000 project is not reasonable or prudent for recovery under the ECRC since it is not associated with compliance with a new environmental law or regulation. As a result, the determination about the prudence of this equipment should be part of a base rate determination as requested by TECO.

**Q: In summary, if the Group A duct split projects are built at $4,945,000, does it require another $1,849,000 investment in booster fans?**

**A.** Yes. The splitting of the ducts for Units 3 and 4 requires an investment of $6,788,000 and must include both projects.

## VI. Group B Mist Eliminator Projects

**Q: What is the capital cost of the "Group B Mist Eliminator Projects" that TECO has requested cost recovery through the Environmental Cost Recovery Clause (ECRC)?**

**A.** TECO has requested that $3,617,000 in capital cost be recovered under the ECRC per TECO's December 27, 2005 petition entitled "Petition of Tampa Electric Company for Approval of a New Environmental Program for Cost Recovery Through the Environmental Cost Recovery Program" imported with Exhibit D "Tampa Electric Company – Big Bend Desulfurization System Reliability Study".

**Q: What are the cost of each project in Group B?**

**A.** Per the above petition the individual projects are:

- Big Bend Units 1-4 Mist Eliminator Upgrades at $834,000 in 2006, $789,000 in 2007, $66,000 in 2008 and $870,000 in 2009.
- Big Bend On Line Mist Eliminator Wash System at $753,000 in 2009.

- Big Bend On Line Nozzle Wash System at $30,000 in 2006 and $564,000 in 2007.

**Q: Was the "Group B Projects" included in the "Flue Gas Desulfurization System Optimization Plan – Phase I" presented to the U.S. EPA, Region IV in TECO's May 31, 2000 plan prepared pursuant to the Consent Decree; Civil Action No. 99-2524-CIV-T-23F?**

**A.** Yes. A, B, C and D tower demister changes were included in the Plan for Units 3 and 4.

**Q: Was the "Group B Projects" included in the "Flue Gas Desulfurization System Optimization Plan – Phase II" presented to the U.S. EPA, Region IV in TECO's February 20, 2001 plan prepared pursuant to the Consent Decree; Civil Action No. 99-2524-CIV-T-23F?**

**A.** Yes, as stated above.

**Q: Was the "Group B Mist Eliminators for Units 1 and 2" included in any of the quarterly reports that presents scope of work pursuant to Paragraph 44.3(2) of the Consent Decree; Civil Action No. 99-2524-CIV-T-23F?**

**A.** Yes. The must eliminator upgrades for Units 1 and 2 were included in the First Quarter 2006 (4/27/06). By including this project on a listing of projects not specifically required under the consent decree, TECO acknowledges that they may not be specifically associated with the Consent Decree compliance.

**Q: Have the plugging of Mist Eliminators caused or could cause forced outages or forced derates of Big Bend Units 1-4?**

**A.** Yes, it has according to data supplied by TECO.

**Q: Are the Group B Mist Eliminator Projects reasonable and prudent environmental projects from an engineering perspective?**

**A.** Yes, I believe that they are. The plugging of the must eliminators have caused historic derates that could be reduced through Group B project implementation. Once by-pass (de-integration) is phased out under the consent decree, TECO will need to clean the must eliminators "on the run". Thus, I consider that these projects are necessary upgrades to improve the FGD system reliability.

## VII. Big Bend Other Upgrade and Maintenance Projects

**Q: What other projects capital costs were requested by TECO to be recovered under the ECRC clause per TECO's December 27, 2005 petition?**

**A.** There were four "Other Projects" not previously discussed:

- Big Bend Units 1-2 Gypsum Blow Down Line at $284,000.
- Big Bend Units 1-2 Recycle Pump Discharge Isolation Bladders at $227,000.
- Big Bend Units 1-2 Inlet Duct C-276 Wallpaper at $234,000.
- Control Additions at $406,000.

**Q: Are these projects reasonable and prudent projects to comply with environmental requirements and eligible for cost recovery under the ECRC?**

**A.** Yes. The TECO reliability study justifies these maintenance upgrades for reliability of Unit 1 and 2 FGD systems to meet the terms of the Consent Decree without unreasonable forced outages or forced derates of these units. Also, control system failures and malfunctions of the control systems have been historically documented and improvements are needed to prevent unreasonable forced outages or derates cause by control system failures.

**Q: Does this conclude your testimony?**

A: Yes it does.

MS. CHRISTENSEN: And I would tender Mr. Stamberg for cross-examination.

CHAIRMAN EDGAR: Thank you.

Commissioner Carter.

COMMISSIONER CARTER: Excuse me, Madam Chair. Did you add a JBS-5 or was it JBS-1, JBS-2, JBS-3 and JBS-4? Was there an additional exhibit to this witness?

CHAIRMAN EDGAR: That was the previous witness.

COMMISSIONER CARTER: Okay. Thank you.

CHAIRMAN EDGAR: Uh-huh.

Mr. Beasley.

MR. BEASLEY: Madam Chairman, we have no questions for this witness.

CHAIRMAN EDGAR: Okay. Questions from staff.

MS. BROWN: Just one, Madam Chairman.

CROSS EXAMINATION

BY MS. BROWN:

Q Good morning, Mr. Stamberg. It's still morning, I think. Yeah.

On Page 20 of your prefiled testimony, Lines 1 through 8, if you want to turn to that, you discuss --

A Let me get there.

Q Oh, okay. Sorry.

A Page 20?

Q Yes. Page 20, Lines 1 through 8.

A Yes.

Q There you are discussing four other projects that you believe are reasonable and prudent projects to comply with environmental requirements and thus eligible for cost recovery through the ECRC; is that right?

A Could you restate the question?

Q Yes. At those lines on Page 20 of your testimony --

A Yes.

Q -- you discuss four other projects that you believe are reasonable and prudent projects to comply with environmental requirements and thus eligible for cost recovery through the ECRC; correct?

A Yes.

Q Then you go on to state that TECO's reliability study justifies those maintenance upgrades for reliability of Units 1 and 2 to meet the terms of the Consent Decree without unreasonable forced outages or forced derates.

A Yes. That's correct.

Q My question is can you give me an example of what an unreasonable forced outage or forced derate would be?

A What I did is, unlike the transformer and the ducts where there's ample time to have, you know, time to repair that, the Towers A, B, C and D were plagued with frequent plugging up and they had to clean those and derate the units. And that's an ongoing problem that occurred frequently and when it was actually running and being needed to be used. And so, therefore, I thought those things were justified and prudent. Also from an electrical standpoint, not the transformer but the breakers were tripping, and those type of incidents were also frequent and interrupted the unit when it was working. The ductwork -- their history of work orders suggest that these leaks and all that could be planned and repaired ahead of time.

MS. BROWN: All right. Thank you. No further questions.

REDIRECT EXAMINATION

BY MS. CHRISTENSEN:

Q Mr. Stamberg, let me make sure that I'm clear.

For the remaining projects that we're not contesting in this docket, you did the evaluation and determined that those, as you said, were reasonable and prudent for recovery through the ECRC?

A Yes.

Q Okay. Is it your testimony today that the other four remaining projects, the electric isolation, the split inlet and outlet duct projects and the gypsum fines filter projects, are not reasonable for recovery through the ECRC?

A They are not necessary for the ECRC recovery.

Q Okay. And is your evaluation dependent on whether or not there's deadlines about when they have to burn or meet the SO2 deadlines or new source performance standards?

A No. It's independent of that.

Q Okay. And is your evaluation based on what those projects in and of themselves actually are doing?

A Correct.

Q Okay. And so is it your testimony that the electric isolation project is not necessary to meet any --

MS. BROWN: Madam Chairman, I object. I asked a question about unreasonable outages and that was it. I think these redirect questions are beyond the scope of what I asked.

MR. BEASLEY: I would object on the grounds that they're leading questions as well.

CHAIRMAN EDGAR: Ms. Christensen.

MS. CHRISTENSEN: Let me --

CHAIRMAN EDGAR: Rephrase.

MS. CHRISTENSEN: -- rephrase.

BY MS. CHRISTENSEN:

Q Let me just summarize. As far as forced outages, do you believe that any of the forced outages, when you reviewed the four remaining projects, warrant -- do any of the forced outages that you, in the documentation that you examined warrant the four remaining projects?

A No.

MS. CHRISTENSEN: Okay. I have no further questions.

CHAIRMAN EDGAR: Okay. Let's take up the exhibits. And I think I heard Mr. Stamberg say that with one of the exhibits there was also a correction that needed to be made to coincide with the corrections he noted to the prefiled testimony; is that correct?

MS. CHRISTENSEN: That is correct. And I would ask Mr. Stamberg to identify that exhibit number again, the exhibit number in which you had a correction to coincide with the outage information that you corrected.

THE WITNESS: Yes.

MS. CHRISTENSEN: The exhibit number is for that correction?

CHAIRMAN EDGAR: I think he said JBS-3, but you need to confirm that.

THE WITNESS: Yes.

MS. CHRISTENSEN: Was it JBS-3 that had the correction in it?

THE WITNESS: Yes.

MS. CHRISTENSEN: Okay. Yes. JBS-3 then, Madam Chairman.

CHAIRMAN EDGAR: Okay. Just so I have it all here in front of me, can you -- it's just one page. Can you show us what that -- is it a change of a number or -- I didn't quite get that.

THE WITNESS: On JBS Exhibit 3 the low range should be .3 hours per year. The high range should be 1.864 hours per year. And then on JBS-4, the net present value --

CHAIRMAN EDGAR: Hold on. Just let us get there.

Okay. If you could, again, for our benefit, I know the court reporter has it, but for our benefit go over the changes on JBS-3 again. It's the second, the second little box, spreadsheet over to the right; correct?

THE WITNESS: In JBS-3 on Line -- the second part of the table entitled "Big Bend Five-Year History of Possible Group A Outages," the total outage number under low risk should be ".3" hours per year instead of ".266" hours per year. The high range should be "1.864" hours per year and not the "1.976" hours per year.

CHAIRMAN EDGAR: Okay. Thank you. And then there's also a change to JBS-4 that you can go over for us.

THE WITNESS: Yes. In that table, JBS-4, under Net Present Value, under Historic Low Rate, which is the third number, it's not "$10,000" but should be "$11,142." And the historic high range would be "$69,230," and the cost-benefit-ratio should be changed on the low rate from ".0022" to ".0025," and the historic high range should go from ".0165" to ".0155."

CHAIRMAN EDGAR: All right. Thank you.

Ms. Christensen.

MS. CHRISTENSEN: With those changes, I would ask to have hearing Exhibits 11 through 14 moved into the record.

CHAIRMAN EDGAR: Mr. Beasley, any objection?

MR. BEASLEY: No objection.

CHAIRMAN EDGAR: Okay. Okay. Exhibits 11, 12, 13 and 14 will be entered into the record with the changes as just noted by the witness to Exhibits 13 and 14. And the witness is excused. Thank you.

(Exhibits 11, 12, 13 and 14 admitted into the record.)

MR. BEASLEY: Recall Mr. Bryant.

MS. CHRISTENSEN: Madam Chair, can I ask for a brief five-minute break?

CHAIRMAN EDGAR: Yes. Absolutely. Commissioners, how about we take ten and come back. Does that work?

Okay. We'll take ten minutes and then we'll come back to Mr. Beasley.

MS. CHRISTENSEN: Thank you.

(Recess taken.)

(Transcript continues in sequence with Volume 2.)

STATE OF FLORIDA )
: CERTIFICATE OF REPORTER
COUNTY OF LEON )

I, LINDA BOLES, CRR, RPR, Official Commission Reporter, do hereby certify that the foregoing proceeding was heard at the time and place herein stated.

IT IS FURTHER CERTIFIED that I stenographically reported the said proceedings; that the same has been transcribed under my direct supervision; and that this transcript constitutes a true transcription of my notes of said proceedings.

I FURTHER CERTIFY that I am not a relative, employee, attorney or counsel of any of the parties, nor am I a relative or employee of any of the parties' attorneys or counsel connected with the action, nor am I financially interested in the action.

DATED THIS 27th day of March, 2006.

Linda Boles

LINDA BOLES, CRR, RPR
FPSC Official Commission Reporter
(850) 413-6734