BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 030001-EI

In the Matter of

FUEL AND PURCHASED POWER COST RECOVERY CLAUSE WITH GENERATING PERFORMANCE INCENTIVE FACTOR.
_______________________________________/

VOLUME 1

Pages 1 through 200a

PROCEEDINGS: HEARING

BEFORE: CHAIRMAN LILA A. JABER
COMMISSIONER J. TERRY DEASON
COMMISSIONER BRAULIO L. BAEZ
COMMISSIONER RUDOLPH BRADLEY
COMMISSIONER CHARLES M. DAVIDSON

DATE: Wednesday, November 12, 2003

TIME: Commenced at 9:30 a.m.
Adjourned at 5:34 p.m.

PLACE: Betty Easley Conference Center
Room 148
4075 Esplanade Way
Tallahassee, Florida

REPORTED BY: JANE FAUROT, RPR
Chief, Office of Hearing Reporter Services
FPSC Division of Commission Clerk and Administrative Services
(850) 413-6732

APPEARANCES:

JOHN T. BUTLER, ESQUIRE, P.A., Steel Law Firm, Suite 4000, 200 South Biscayne Boulevard, Miami, Florida 33131-2398, Florida Power & Light Company, 700 Universe Blvd., Juno Beach, Florida 33408-0420, appearing on behalf of Florida Power & Light Company.

LEE L. WILLIS, ESQUIRE, KENNETH R. HART, ESQUIRE, and JAMES D. BEASLEY, ESQUIRE, Ausley Law Firm, P.O. Box 391, Tallahassee, Florida 32302, appearing on behalf of Tampa Electric Company.

JOHN W. MCWHIRTER, JR., Florida Industrial Power Users Group, McWhirter Reeves 400 North Tampa Street, Suite 2450, Tampa, Florida 33602 and VICKI KAUFMAN, ESQUIRE, McWhirter Law Firm, 117 S. Gadsden St., Tallahassee, Florida 32301, appearing on behalf of Florida Industrial Power Users Group.

NORMAN H. HORTON, JR., ESQUIRE, Messer Law Firm, P.O. Box 1876, Tallahassee, Florida 32302-1876, appearing on behalf of Florida Public Utilities Company.

APPEARANCES CONTINUED:

RUSSELL BADDERS, ESQUIRE, Beggs & Lane Law Firm, P.O. Box 12950, Pensacola, Florida appearing on behalf of Gulf Power Company.

ROB VANDIVER, ESQUIRE, Office of Public Counsel, c/o The Florida Legislature, 111 W. Madison St., #812, Tallahassee, Florida 32399-1400, appearing on behalf of Office of Public Counsel.

JAMES MCGEE, ESQUIRE and BONNIE DAVIS, ESQUIRE, Progress Energy Florida, Inc. (St. Petersburg), P. O. Box 14042, St. Petersburg, Florida 33733-4042, appearing on behalf of Progress Energy Florida, Inc.

MICHAEL B. TWOMEY, ESQUIRE, P. O. Box 5256, Tallahassee, Florida 32314-5256, appearing on behalf of Sugarmill Woods Civic Association.

RONALD LAFACE, ESQUIRE, Greenberg, Traurig Law Firm (Tall), 101 E. College Ave., Tallahassee, Florida 32301, appearing on behalf of Florida Retail Federation.

COCHRAN KEATING, ESQUIRE, JENNIFER RODAN, ESQUIRE, FPSC General Counsel's Office, 2540 Shumard Oak Boulevard, Tallahassee, Florida 32399-0850, appearing on behalf of Commission Staff.

I N D E X

WITNESSES

EXHIBITS

NUMBER:		ID.	ADMTD.
1	FI-1 and FI-2	21	21
2	GMB-1 and GMB-2	21	21
3	HRB-1 and HRB-3	21	21
4	LSN-1 and LSN-2	21	21
5	HHR-1	21	21
6	PRM-1 and PRM-2	21	21
7	MFJ-1 and MFJ-2	21	21
8	WAS-1 and WAS-2	21	21
9	MEB-1 and MEB-2	21	21
10	JYS-1 and JYS-2	21	21
11	GYI-1 and GYI-2	21	21
12	TAD-1, TAD-2 and TAD-3	21	21

PROCEEDINGS

CHAIRMAN JABER: And that takes us to Docket 01.

Mr. Keating, are you ready to get started on the 01 docket?

MR. KEATING: Yes, Chairman.

CHAIRMAN JABER: Go right ahead. Are there any preliminary matters?

MR. KEATING: There are a few preliminary matters to go through. First, I would point out that all of the pending motions and confidentiality requests that are listed in the prehearing order have been addressed by order of the prehearing officer.

CHAIRMAN JABER: So acknowledged.

MR. KEATING: Second, and I believe the Commissioners got a copy of a document, a two-page document that showed four additional stipulated issues that have been stipulated since the time the prehearing order was issued. Those issues are 13F, 13G, 14A, and 16A. And if the parties need a copy of that, I have additional copies with me. That simply reflects some stipulations that occurred on Monday.

CHAIRMAN JABER: Okay. Mr. Keating, will we -- at the beginning of the witnesses coming onto the stand, do you want us to go ahead and rule on the issues that have proposed stipulations, or are you proposing we leave that to the end? I can't remember what we have done in the past. It seems more efficient to get those done first.

MR. KEATING: We have two companies whose issues are entirely stipulated. And I think for those two, it would make sense to go ahead and vote those out, so that they don't have to stick around if they don't want to. The other three companies involved are going to have some disputed issues on the table, as well, and it may make sense just to wait and do those three companies at the end of the close of evidence in the hearing. There are both stipulated and disputed issues.

CHAIRMAN JABER: Let's come back to that, then. Just remind me, parties. Keep us straight on what we can go ahead and get out of the way this morning, I would very much appreciate. What else?

MR. KEATING: I also wanted to point out on Issue 13E we provided to the Commissioners and the parties a position, an agreed position of Progress Energy and staff. And to be clear, this issue still remains in dispute. Public Counsel, FIPUG, and perhaps Mr. Twomey, who has recently intervened, do not agree with that position, but I wanted to provide it to everybody to make sure that was clear what the parties' positions were.

CHAIRMAN JABER: Now, that is a change to the position in the prehearing order?

MR. KEATING: It is. The position in the prehearing order indicated that staff and the company were continuing to work towards some sort of agreed position, and that if we had one before the hearing we would provide that.

CHAIRMAN JABER: Okay. So do I need to acknowledge a change to staff's position in Issue 13E, is that what you need me to do?

MR. KEATING: I think so.

CHAIRMAN JABER: Okay.

MR. KEATING: It is mostly just informational, I think.

CHAIRMAN JABER: Page 24 of the prehearing order, Issue 13E, your position has changed and you have given a copy of your revised position to all the parties, is that correct?

MR. KEATING: Correct.

CHAIRMAN JABER: So acknowledged. Now, who else? Does this also affect Progress' position?

MR. KEATING: Right. That would be Progress' position, as well.

CHAIRMAN JABER: Okay. And the position originally taken in the prehearing order by Progress has also been modified to reflect what is in the handout today. What else?

MR. KEATING: With the stipulation of Issue 16A that I mentioned earlier, there should be no Gulf Power issues still in dispute. And I have received some confirmation from staff that staff can agree to Gulf Power's position as stated on Issues 1 through 8 in the prehearing order that are not yet shown as stipulated. With that, I believe that Gulf Power's remaining witness, Terry Davis, could be excused if no other parties have questions.

CHAIRMAN JABER: Okay. See, I keep coming back to -- I think it would be more efficient for us to go ahead and insert the prefiled testimony of the witnesses where there has been some stipulation, and then to go ahead and resolve those proposed stipulated issues.

MR. KEATING: Okay.

CHAIRMAN JABER: Do you have a list of who those witnesses are, Mr. Keating?

MR. KEATING: I do. And that would start on Page 7 of the prehearing order.

CHAIRMAN JABER: And, parties, I'm going to depend on you to speak up if you have objections to inserting any testimony into the record as we go through the list. Go ahead, Mr. Keating.

MR. KEATING: And to be clear, Chairman, would you like to include all the witnesses who could be excused today, or just the witnesses for those companies whose issues can be entirely stipulated today?

CHAIRMAN JABER: Both. Let's do it all.

MR. KEATING: Okay. Starting on Page 7 of the prehearing order, F. Irizarry, FPL witness could be excused and have his prefiled testimony moved into the record.

CHAIRMAN JABER: The prefiled testimony of F. Irizarry shall be inserted into the record as though read and his testimony?

MR. KEATING: Correct. His testimony includes one Exhibit FI-1, that could be marked for identification and moved.

CHAIRMAN JABER: FI-1 is identified as Exhibit 1, and Mr. Irizarry can be excused. We will admit all the exhibits into the record at the end.

MR. KEATING: Okay.

CHAIRMAN JABER: Go ahead.

MR. KEATING: I will go ahead and read through the rest of the remaining witnesses that could be excused. George Bachman, FPUC.

CHAIRMAN JABER: Mr. Bachman's testimony shall be inserted into the record as though read.

MR. KEATING: H.R. Ball for Gulf Power.

CHAIRMAN JABER: Wait. Does he have any exhibits?

MR. KEATING: I'm sorry, Mr. Bachman, yes, he does have Exhibit GMB-1 and GMB-2.

CHAIRMAN JABER: GMB-1 and GMB-2 are identified as Composite Exhibit 2. And Mr. Bachman may be excused from the hearing.

MR. KEATING: H.R. Ball, Gulf Power Company.

CHAIRMAN JABER: H.R. Ball's testimony shall be inserted into the record as though read. Exhibits?

MR. KEATING: Exhibits HRB-1 and HRB-2.

CHAIRMAN JABER: Are identified as Composite Exhibit 3, and Mr. Ball may be excused from the hearing.

MR. KEATING: L.S. Noack, Gulf Power.

CHAIRMAN JABER: Is that Mr. or Ms.? Ms. Noack's testimony shall be inserted into the record as though read. She may be excused. Are there exhibits?

MR. KEATING: Exhibits LSN-1 and LSN-2.

CHAIRMAN JABER: Are identified as Composite Exhibit 4.

MR. KEATING: H. Homer Bell, III, Gulf Power.

CHAIRMAN JABER: Mr. Bell's testimony shall be inserted into the record as though read. Exhibits?

MR. KEATING: Exhibits HHB-1, and that is Mr. Bell's only exhibit.

CHAIRMAN JABER: Will be identified as Exhibit 5, and Mr. Bell may be excused from the hearing.

MR. KEATING: Pamela R. Murphy, Progress Energy.

CHAIRMAN JABER: The prefiled testimony of Pamela R. Murphy shall be inserted into the record as though read. She may be excused from the hearing. Are there exhibits?

MR. KEATING: Exhibits PRM-1 and PRM-2.

CHAIRMAN JABER: Will be identified as Composite Exhibit 6.

MR. KEATING: Michael F. Jacob, Progress Energy.

CHAIRMAN JABER: The prefiled testimony of Michael F. Jacob shall be inserted into the record as though read. He may be excused from the hearing. Are there exhibits?

MR. KEATING: Exhibits MFJ-1 and MFJ-2.

CHAIRMAN JABER: Will be identified as Composite Exhibit 7.

MR. BEASLEY: Madam Chairman, if I could at this juncture, Tampa Electric's witness, William A. Smotherman, is not listed as a stipulated witness because we had listed him as a witness for the company on Issue 17I and 23A. 23A has been withdrawn, and 17I he no longer needs to be listed as a witness for that issue, so that only leaves him with Issues 18 and 19, which are the GPIF issues, which I think are stipulated. So we would ask that he be excused if that is agreeable.

CHAIRMAN JABER: Well, you haven't had an opportunity to check with the parties to see if his testimony could be inserted into the record?

MR. BEASLEY: I have not, but I will be glad to do that.

CHAIRMAN JABER: Let me just ask. Parties, have you had an opportunity to evaluate whether Mr. Smotherman testimony can be inserted into the record without cross?

MS. KAUFMAN: Madam Chairman, we have no objection to that.

MR. VANDIVER: No objection.

MR. LAFACE: No objection.

CHAIRMAN JABER: Thank you. Staff?

MR. KEATING: Staff has no questions for Mr. Smotherman, so we have no objection.

CHAIRMAN JABER: Okay. Recognizing that Issue 23A has been withdrawn, and Mr. Smotherman is no longer a witness for Issue 17I, the prefiled testimony of William A. Smotherman will be inserted into the record as though read, and he may be excused from the hearing. Are there exhibits?

MR. KEATING: Yes. Exhibits WAS-1 and WAS-2.

CHAIRMAN JABER: Are identified as Composite Exhibit 8.

Thank you, Mr. Beasley.

MR. BEASLEY: Thank you.

MR. BUTLER: Madam Chairman, I apologize. I thought probably we would be coming to this after we had gotten through all the people with asterisks, but there is at least one witness for FPL that I think may be excusable and is not identified, if that is the right term, on the list with an asterisk that --

CHAIRMAN JABER: I suppose it depends on who you ask.

MR. BUTLER: That's right. That being Mr. Hartzog. I don't believe there are any questions or any issues that remain open, disputed among the parties that he testifies to, and so I would like to see if he could be excused.

CHAIRMAN JABER: Oh, I skipped a page. Well, now keep up, Mr. Butler, that is taking us backwards. But, hey.

MR. BUTLER: It is. I'm sorry. That's why I apologized for raising it at this point. I just thought perhaps Mr. Keating was going to go through all the ones that had already been identified and come back to them. But now that Mr. Beasley has broken the ice, I'm following in his footsteps.

CHAIRMAN JABER: Well, we appreciate you bringing it to our attention. So is it correct that no one has any objection to inserting Mr. Hartzog's testimony into the record?

MS. KAUFMAN: We have no objection.

MR. VANDIVER: No objection.

CHAIRMAN JABER: Staff?

MR. KEATING: Staff has no objection.

MR. BADDERS: Gulf Power actually has a witness in a similar position, but I believe you were going to address 16, 13F, 13G, and these other stipulations at another time.

CHAIRMAN JABER: Okay. Hold onto that thought, Mr. Badders.

MR. BADDERS: Okay.

CHAIRMAN JABER: All right. The prefiled testimony of J.R. Hartzog shall be inserted into the record as though read and he may be excused from the hearing. And, Mr. Keating, what exhibits does he have?

MR. KEATING: I do not show any exhibits for Mr. Hartzog.

CHAIRMAN JABER: Mr. Butler, is that correct?

MR. BUTLER: That's correct.

CHAIRMAN JABER: Okay, great.

MR. KEATING: And let me make one correction. I just realized that for Mr. Irizarry, the first witness that we went through, for exhibits we identified as Exhibit 1 his FI-1, he also has an Exhibit FI-2 that we could include in that Composite Exhibit 1.

CHAIRMAN JABER: Okay. Let the record reflect that Mr. Irizarry actually had two exhibits, FI-1 and FI-2, and they will be identified as Composite Exhibit 1 rather than Exhibit 1. Okay. Mr. Keating, let's get back to -- we have dealt with Mr. Smotherman. Who was next on your list?

What we will do is we will play clean-up at the end, but let's let Mr. Keating go through his list.

MR. KEATING: I'm just going to go through the -- there are only two more with an asterisk next to them. I think we can go back through perhaps a couple more after that.

CHAIRMAN JABER: Great.

MR. KEATING: The two remaining with an asterisk, first, Michael E. Buckley testifying on behalf of staff.

CHAIRMAN JABER: The prefiled testimony of Michael E.

Buckley shall are inserted into the record as if read. He may be excused from the hearing. Does he have exhibits?

MR. KEATING: He has Exhibits MEB-1 and MEB-2.

CHAIRMAN JABER: MEB-1 and MEB-2 are identified as Composite Exhibit 9.

MR. KEATING: And Jocelyn Y. Stephens on behalf of staff.

CHAIRMAN JABER: The prefiled testimony of Jocelyn Y. Stephens shall be inserted into the record as though read. She may be excused from the hearing. Are there exhibits?

MR. KEATING: She has Exhibits JYS-1 and JYS-2.

CHAIRMAN JABER: Her exhibits will be identified as Composite Exhibit 10. Okay. Let's go back to the parties. Mr. Beasley, did you have any other witnesses?

MR. BEASLEY: Yes, I did, Madam Chairman. Owing to the deferral of Issues 17E, F, and H, Mr. Brent Dibner will not be having his testimony moved into the record and I ask that he be excused from this hearing.

CHAIRMAN JABER: It is just asking that he be excused, his testimony won't be inserted into the record?

MR. BEASLEY: That is correct.

CHAIRMAN JABER: Okay. And give me his name one more time?

MR. BEASLEY: Brent Dibner, D-I-B-N-E-R.

CHAIRMAN JABER: Okay. Mr. Dibner shall be excused from the hearing.

MR. BEASLEY: It is my understanding, as well, Chairman, that Mr. McNulty's testimony will not be inserted into this record because of the deferral of those three issues.

MR. KEATING: Correct. But to be clear, Mr. McNulty has two sets of testimony, one addressing the TECO issues and one addressing Progress Energy issues. We will not be moving his testimony related to the deferred Tampa Electric issues in this proceeding.

CHAIRMAN JABER: But he does testify with regard to other issues?

MR. KEATING: That is correct.

CHAIRMAN JABER: Okay. So when he gets up on the stand, we will just make clear what part of his testimony will be inserted.

MR. KEATING: Yes.

CHAIRMAN JABER: Anything else, Mr. Beasley?

MR. BEASLEY: That should do it on witnesses.

MR. KEATING: At this point, before we leave Tampa Electric, I would ask Mr. Beasley if Joann Wehle's rebuttal testimony also is something that would not be moved into the record.

MR. BEASLEY: That is correct.

MR. KEATING: I believe that relates only to those deferred issues.

MR. BEASLEY: Good catch. That will not be moved into the record of this hearing.

CHAIRMAN JABER: So she needs to be excused?

MR. BEASLEY: Yes, please. Just with respect to the rebuttal testimony. She does have direct testimony.

CHAIRMAN JABER: Okay. Well, then there is no need to take any action at all. She has to be here anyway is what you are saying.

MR. BEASLEY: Right.

CHAIRMAN JABER: Okay. Mr. Butler.

MR. BUTLER: I think that staff and FPL have reached agreement on the hedging expenses that FPL is seeking to recover, which would be -- well, that and other existing stipulations, but if the last part of that is true, then I don't think that Mr. Yupp would need to testify, and I believe staff has indicated they have no questions for him. Sort of a similar point applies to Ms. Dubin's testimony, except she does have rebuttal testimony, and so by the rule you just outlined she would not get excused. But I think for Mr. Yupp that I would at least propose that he could be excused from testifying.

CHAIRMAN JABER: And that his testimony be inserted into the record without cross?

MR. BUTLER: That's right.

CHAIRMAN JABER: Parties, do you have any objections to that?

MS. KAUFMAN: We have no objection, Madam Chair.

MR. VANDIVER: No objection.

MR. KEATING: And staff has no objection.

CHAIRMAN JABER: The prefiled testimony of -- it is Gordon, isn't it? What's his first name?

MR. BUTLER: Gerard.

CHAIRMAN JABER: Gerard Yupp shall be inserted into the record as though read. He may be excused from the hearing. Does he have exhibits?

MR. KEATING: He has, sorry, Exhibits JY-1 and JY-2. I'm sorry, GY-1 and GY-2.

CHAIRMAN JABER: GY-1 and GY-2 are identified as Composite Exhibit 11. Okay. Who is next on the list here?

Mr. Badders, let's go ahead and take up your witnesses.

MR. BADDERS: We have one more witness who could be excused, that is T.A. Davis. As a result of a stipulation that we have reached on Issue 16A, she would not need to take the stand. And that would also leave us with stipulated issues on Issue 1, 2, 3, 5, 6, and 8, which are the fallout issues from that.

CHAIRMAN JABER: Okay. Without objection the prefiled testimony of T.A. Davis shall be inserted into the record as though read. And what exhibits does she have?

MR. KEATING: Exhibits TAD-1, TAD-2, and TAD-3.

CHAIRMAN JABER: Will be identified as Composite Exhibit 12. Okay. Progress.

MR. McGEE: The remaining witness of Progress Energy, Mr. Portuondo, has several remaining issues, and the other two Progress Energy witnesses have already been excused, so I think we are set.

CHAIRMAN JABER: Okay. Thank you. FIPUG, you are set?

MS. KAUFMAN: Yes, ma'am.

CHAIRMAN JABER: OPC?

MR. VANDIVER: I think we are set.

CHAIRMAN JABER: Okay. Staff?

MR. KEATING: I believe with the agreement that we have on the remaining issues with FPL, that the testimony of Kathy Welch may be moved into the record, that she may be -- to used Mr. Butler's term -- excusable today, but I would like for Mr. Butler and the other parties to confirm that.

CHAIRMAN JABER: Parties, do you have any objection to inserting Ms. Welch's testimony into the record as though read and inserting her exhibits into the record?

MR. BUTLER: With the understanding that there is the stipulation as to FPL's position on the hedging cost issue and then its fallouts in the other dollar issues, we would have no objection to that.

MS. KAUFMAN: Commissioner, I'm confused. I'm unaware of what the stipulation is that involves Ms. Welch, so at this time I don't think I can agree to that. Maybe when we have a break we can discuss it.

CHAIRMAN JABER: Okay. Or in taking up the issue, which we are going to get to next. So let's leave that an open question for now. We will come back to it. Don't let me forget, though.

MR. KEATING: Okay.

CHAIRMAN JABER: Okay. Any other staff witnesses, Mr. Keating, that can be excused?

MR. KEATING: I don't believe so.

CHAIRMAN JABER: Okay. With that, let the record reflect that Composite Exhibits 1 through 12 are admitted into the record.

(Composite Exhibits 1 through 12 marked for identification and admitted into the record.)

(Transcript continues in sequence with Volume 2.)

BEFORE THE PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

TESTIMONY OF F. IRIZARRY

DOCKET NO. 030001-EI

APRIL 1, 2003

Q. Please state your name and business address.

A. My name is Frank Irizarry and my business address is 700 Universe Boulevard, Juno Beach, Florida 33408.

Q. Mr. Irizarry, would you please state your present position with Florida Power and Light Company (FPL).

A. I am the Manager of Business Services in the Power Generation Division of FPL.

Q. Mr. Irizarry, have you previously testified in the predecessor to this Docket?

A. Yes, I have

Q. Mr. Irizarry, what is the purpose of your testimony?

A. The purpose of my testimony is to report the actual performance for the Equivalent Availability Factor (EAF) and Average Net Operating Heat Rate (ANOHR) for the twenty-two (22) generating units used to determine the Generating Performance Incentive Factor (GPIF). I have compared the actual performance of each unit to the targets that were approved in Commission Order No. PSC-01-2516-FOF-EI issued December 26, 2001, for the period January through December 2002, and have performed the calculations prescribed by the GPIF Rule based on this comparison. My testimony presents the result of my calculations, which is an incentive reward for the period.

Q. Have you prepared, or caused to have prepared under your direction, supervision or control, an exhibit in this proceeding?

A. Yes, I have. It consists of one document. Page 1 of that document is an index to the contents of the document.

Q. What is the incentive amount you have calculated for the period January through December, 2002?

A. I have calculated a GPIF incentive reward of $7,449,429.

Q. Please explain how the reward amount is calculated.

A. The steps involved in making this calculation are provided in Document No. 1. Page 2 of Document No. 1 provides the GPIF Reward/Penalty Table (Actual) which shows an overall GPIF performance point value of +3.43 corresponding to a GPIF reward of $7,449,429. Page 3 provides the calculation of the maximum allowed incentive dollars. The calculation of the system actual GPIF performance points is shown on page 4. This page lists each unit, the unit's performance indicators (ANOHR and EAF), the weighting factors and the associated GPIF points.

Page 5 is the actual EAF and adjustments summary. This page lists each of the twenty-two (22) units, the actual outage factors and the actual EAF, in columns 1 through 5. Column 6 is the target EAF. Column 7 is the adjustment for planned outage variation and Column 8 is the adjusted actual EAF, which is calculated on page 6. Column 9 contains the Generating Performance Incentive Points for availability as determined from the tables submitted to, and approved by, the Commission prior to the start of the period. These tables are shown on pages 8 through 29.

Page 7 shows the adjustments to ANOHR. For each of the twenty-two (22) units, it shows the target heat rate formula, the actual Net Output Factor (NOF) and the actual ANOHR in columns 1 through 4. Since heat rate varies with NOF, it is necessary to determine both the target and actual heat rates at the same NOF. This adjustment is to provide a common basis for comparison purposes and is shown numerically for each GPIF unit in columns 5 through 8. Column 9 contains the Generating Performance Incentive Points that have been determined from the table submitted for each unit and approved by the Commission prior to the beginning of the period. These tables are also shown on pages 8 through 29.

Q. Are there any changes to the targets approved through Commission Order No. PSC-01-2516-FOF-EI?

A. No, the approved targets have not changed.

Q. Please explain the primary reason or reasons why FPL will be rewarded under the GPIF for the January through December, 2002 period?

A. The primary reason that FPL will receive a reward for the period was that Turkey Point Nuclear Units 3 and 4 and St. Lucie Nuclear Units 1 and 2 achieved better availability than was targeted.

Q. Please summarize the effect of FPL's nuclear unit availability on the GPIF reward.

A. Turkey Point Unit 3 operated at an adjusted actual EAF of 100% compared to its target of 93.6%. This results in a +10.00 point reward, which corresponds to a GPIF reward of $1,833,417.

Turkey Point Unit 4 operated at an adjusted actual EAF of 91.6% compared to its target of 86.0%. This results in a +10.00 point reward, which corresponds to a GPIF reward of $1,680,753.

St. Lucie Unit 1 operated at an adjusted actual EAF of 91.7% compared to its target of 86.0%. This results in a +10.00 point reward, which corresponds to a GPIF reward of $2,047,846.

St. Lucie Unit 2 operated at an adjusted actual EAF of 100% compared to its target of 93.6%. This results in a +10.00 point reward, which corresponds to a GPIF reward of $1,885,094.

The total GPIF reward due to the nuclear units' actual availability performance is $7,447,111.

Q. Please summarize each nuclear unit's performance as it relates to the ANOHR of the units.

A. Turkey Point Unit 3 operated with an adjusted actual ANOHR of 11,193 Btu/kWh. This ANOHR is within the ± 75 Btu/kWh deadband around the projected target; therefore, there is no GPIF reward or penalty.

Turkey Point Unit 4 operated with an adjusted actual ANOHR of 11,117 Btu/kWh. This ANOHR is within the ± 75 Btu/kWh deadband around the projected target; therefore, there is no GPIF reward or penalty.

St. Lucie Unit 1 operated with an adjusted actual ANOHR of 10,811 Btu/kWh. This ANOHR is within the ± 75 Btu/kWh deadband around the projected target; therefore, there is no GPIF reward or penalty.

St. Lucie Unit 2 operated with an adjusted actual ANOHR of 10,850 Btu/kWh. This ANOHR is within the ± 75 Btu/kWh deadband around the projected target; therefore, there is no GPIF reward or penalty.

In total, the nuclear units' heat rate performance results in no GPIF reward or penalty.

Q. What is the total GPIF incentive reward for FPL's nuclear units?

A. $7,447,111

Q. Mr. Irizarry, would you summarize the performance of FPL's fossil units?

A. Yes, fourteen (14) of the eighteen (18) fossil generating units performed better than their availability targets, while the remaining units performed worse than their targets. The combined fossil unit availability performance results in a GPIF reward of $1,145,301.

Four (4) of the eighteen (18) fossil units operated with ANOHR that were better than their projected target and six (6) units operated with ANOHRs that were worse than their projected targets. The remaining eight (8) units operated with ANOHRs that were within the ± 75 Btu/kWh deadband around the projected targets and they will receive no incentive reward or penalty. In total, the combined fossil units heat rate performance results in a GPIF penalty of $1,142,983.

In total, the GPIF reward for FPL's fossil units for the period of January through December 2002 is $2,318.

Q. Does this conclude your testimony?

A. Yes, it does.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

TESTIMONY OF F. IRIZARRY

DOCKET NO. 030001-EI

SEPTEMBER 12, 2003

Q. Please state your name and business address.

A. My name is Frank Irizarry and my business address is 700 Universe Boulevard, Juno Beach, Florida 33408.

Q. Mr. Irizarry, would you please state your present position with Florida Power and Light Company (FPL).

A. I am the Manager of Business Services in the Power Generation Division of FPL.

Q. Mr. Irizarry, have you previously had testimony presented in this docket?

A. Yes, I have.

Q. Mr. Irizarry, what is the purpose of your testimony?

A. The purpose of my testimony is to present the target unit equivalent availability factors (EAF) and the target unit average net operating heat rates (ANOHR) for the period of January through December, 2004, for use in determining the Generating Performance Incentive Factor (GPIF).

Q. Mr. Irizarry, please summarize the 2004 system targets for EAF and ANOHR for the units to be considered in establishing the GPIF for FPL.

A. For the period of January through December, 2004, FPL projects a weighted system equivalent planned outage factor of 7.8% and a weighted system equivalent unplanned outage factor of 6.2%, which yield a weighted system equivalent availability target of 86.0%. The targets for this period reflect planned refueling outages for three nuclear units. FPL also projects a weighted system average net operating heat rate target of 9,087 btu/kwh for the period January through December, 2004. As discussed later in this testimony, these targets represent fair and reasonable values when compared to historical data. Therefore, FPL requests that the targets for these performance indicators be approved by the Commission.

Q. Have you prepared, or caused to have prepared under your direction, supervision or control, an exhibit in this proceeding?

A. Yes, I have. It consists of one document. The first page of this document is an index to the contents of the document. All other pages are numbered according to the latest revisions of the GPIF Manual as approved by the Commission.

Q. Have you established target levels of performance for the units to be considered in establishing the GPIF for FPL?

A. Yes, I have. Document No.1, pages 6 and 7, contains the information summarizing the targets and ranges for EAF and ANOHR for the 16 generating units which FPL proposes to be considered as GPIF units for the period of January through December, 2004. The Sheets presented in these pages were prepared in accordance with the latest revisions of the GPIF Manual. All of these targets have been derived utilizing methodologies as adopted in the GPIF Manual.

Q. Please summarize FPL's methodology for determining equivalent availability targets?

A. The GPIF Manual requires that the EAF target for each unit be determined as the difference between 100% and the sum of the planned outage factor (POF) and the unplanned outage factor (UOF). The POF for each unit is determined by the length of the planned outage during the projected period. The UOF is determined by the sum of the historical average forced outage factor (FOF) and maintenance outage factor (MOF). The UOF is then adjusted to reflect recent unit performance and known unit modifications or equipment changes. This adjustment is applied to units, which have had, during the historical period, or are forecasted to have, during the projection period, planned outages.

Q. Mr. Irizarry, were the EAF targets for the GPIF units determined using the methodology as described in the GPIF Operating Manual?

A. Yes, they were.

Q. How did you select the units to be considered when establishing the GPIF for FPL?

A. The GPIF units were selected in accordance with the GPIF Manual using the estimated net generation for each unit taken from the production costing simulation program, POWRSYM, which forms the basis for the projected levelized fuel cost recovery factor for the period. The 16 units which FPL proposes to use for the period of January through December, 2004, represent the top 81.8% of the total forecasted system net generation for this period. This excludes three units: the Ft. Myers repowered unit and the Sanford repowered units 4 and 5. The repowering of these units from conventional steam units to combined cycle units constitute a major design change affecting both their generation capacity and their performance. As a result, the future performance of these units will not be comparable to their historical performance. Therefore, consistent with the GPIF Manual, these units should be excluded from the GPIF calculations until we establish a minimal history to use in projecting future performance.

Q. Mr. Irizarry, from the heat rate targets and equivalent availability range projections, do FPL's generation performance targets represent a reasonable level of efficiency?

A. Yes, they do.

Q. Does this conclude your testimony?

A. Yes, it does.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

Docket No. 030001-EI
Fuel and Purchased Power Cost Recovery Clause

Direct Testimony of
George M. Bachman
on behalf of
<u>Florida Public Utilities Company</u>

Q. Please state your name and business address.

A. George M. Bachman, 401 South Dixie Highway, West Palm Beach, Florida 33401.

Q. By whom are you employed?

A. I am employed by Florida Public Utilities Company.

Q. Could you give a brief description of your background and business experience?

A. I have a Bachelor of Science Degree in Business Administration from Indiana University in 1981, with a concentration in Accounting. I subsequently joined Southeastern Public Service Company, and served as the Assistant controller at the time of my departure in January 1985, when I joined Florida Public Utilities Company. My positions through 1998 included General Accounting Office Manager, Accounting Manager, and Controller.

In 1999 I was appointed to my current position, Chief Financial Officer and Treasurer of Florida Public Utilities Company. As the senior financial and accounting official of the Company I have overall fiduciary responsibility and oversee the accounting and finance department with all related functions.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present the calculation of the Jan. 2003 through Dec. 2003 purchased power costs for recovery in the Jan. - Dec. 2004 period. These calculations are based on six months of actual data and six months of estimated data.

Q. Have you prepared any exhibits to support your testimony?

A. Yes. Exhibit ______ (GMB-1) consists of Schedules E1-A, E1-B, and E1-B1 for the Marianna and Fernandina Beach Divisions. These schedules were prepared from the records of the company.

Q. What has FPUC calculated as the net true-up amount to be applied in the Jan. - Dec. 2004?

A. For Marianna the net true-up amount to be recovered is an underrecovery of $343,777. For Fernandina Beach the calculation is an overrecovery of $1,302,700.

Q. How were these amounts calculated?

A. They are the sum of the final true-up amount for the Jan. - Dec. 2002 period and the actual/estimated amount for the Jan. - Dec. 2003 period.

Q. What was the final true-up amount for Jan. - Dec. 2002?

A. For Marianna it was $78,631 underrecovery and for Fernandina Beach it was $1,167,570.

Q. What have you calculated to be the true-up amount for the Jan. - Dec. 2003 period?

A. Using six months actual and six months estimated amounts, we calculate an underrecovery for Marianna of $265,146 and an overrecovery of $135,130 for Fernandina Beach.

Q. Does this conclude your direct testimony?

A. Yes, it does.

BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 030001-EI
CONTINUING SURVEILLANCE AND REVIEW OF
FUEL COST RECOVERY CLAUSES OF ELECTRIC UTILITIES

Direct Testimony of
George M. Bachman
On Behalf of
Florida Public Utilities Company

Q. Please state your name and business address.

A. George M. Bachman, 401 South Dixie Highway, West Palm Beach, FL 33401.

Q. By whom are you employed?

A. I am employed by Florida Public Utilities Company.

Q. Have you previously testified in this Docket?

A. Yes.

Q. What is the purpose of your testimony at this time?

A. I will briefly describe the basis for the computations that were made in the preparation of the various Schedules that we have submitted in support of the January 2004 - December 2004 fuel cost recovery adjustments for our two electric divisions. In addition, I will advise the Commission of the projected differences between the revenues collected under the levelized fuel adjustment and the purchased power costs allowed in developing the levelized fuel adjustment for the period January 2003 – December 2003 and to establish a "true-up" amount to be collected or refunded during January 2004 - December 2004.

Q. Were the schedules filed by your Company completed under your direction?

A. Yes.

Q. Which of the Staff's set of schedules has your company completed and filed?

A. We have filed Schedules E1, E1A, E2, E7, and E10 for Marianna and

E1, E1A, E2, E7, E8, and E10 for Fernandina Beach. They are included in Composite Prehearing Identification Number GMB-2. Schedule E1-B and E1-B1 for both Marianna and Fernandina Beach were filed last month in Composite Prehearing Identification Number GMB-1.

These schedules support the calculation of the levelized fuel adjustment factor for January 2004 - December 2004. Schedule E1-B shows the Calculation of Purchased Power Costs and Calculation of True-Up and Interest Provision for the period January 2003 - December 2003 based on 6 Months Actual and 6 Months Estimated data.

Q. In derivation of the projected cost factor for the January 2004 - December 2004, period, did you follow the same procedures that were used in the prior period filings?

A. Yes.

Q Why has the GSLD1 rate class for Fernandina Beach been excluded from these computations?

A. Demand and other purchased power costs are assigned to the GSLD1 rate class directly based on their actual CP KW and their actual KWH consumption. That procedure for the GSLD1 class has been in use for several years and has not been changed herein. Costs to be recovered from all other classes are determined after deducting from total purchased power costs those costs directly assigned to GSLD1.

Q. How will the demand cost recovery factors for the other rate classes be used?

A. The demand cost recovery factors for each of the RS, GS, GSD, GSLD, GSLD1 and OL-SL rate classes will become one element of the total cost recovery factor for those classes. All other costs of purchased power will be recovered by the use of the levelized factor that is the same for all those rate classes. Thus the total factor for each class will be the sum of the respective demand cost factor and the levelized factor for all other costs.

Q. Please address the calculation of the total true-up amount to be collected or refunded during the January 2004 - December 2004.

A. We have determined that at the end of December 2002 based on six months actual and six months estimated, we will have under-recovered $343,777 in purchased power costs in our Marianna division. Based on estimated sales for the period January 2004 - December 2004, it will be necessary to add .11373¢ per KWH to collect this under-recovery.

In Fernandina Beach we will have over-recovered $1,302,700 in purchased power costs. This amount will be refunded at .38363¢ per KWH during the January 2004 - December 2004 period (excludes GSLD customers). Page 3 and 10 of Composite Prehearing Identification Number GMB-2 provides a detail of the calculation of the true-up amounts.

Q. Looking back upon the January 2002 - December 2002 period, what were the actual End of Period - True-Up amounts for Marianna and Fernandina Beach, and their significance, if any?

A. The Marianna Division experienced an under-recovery of $74,421 and Fernandina Beach Division over-recovered $1,168,835. The amounts both represent fluctuations of less than 10% from the total fuel charges for the period and are not considered significant variances from projections.

Q. What are the final remaining true-up amounts for the period January 2002 - December 2002 for both divisions?

A. In Marianna the final remaining true-up amount was an under-recovery of $78,631. The final remaining true-up amount for

Fernandina Beach was over-recovery of $1,167,570.

Q. What are the estimated true-up amounts for the period of January 2003 - December 2003?

A. In Marianna, there is an estimated under-recovery of $265,146. Fernandina Beach has an estimated over-recovery of $135,130.

Q. What will the total fuel adjustment factor, excluding demand cost recovery, be for both divisions for the period?

A. In Marianna the total fuel adjustment factor as shown on Line 33, Schedule E1, is 2.430¢ per KWH. In Fernandina Beach the total fuel adjustment factor for "other classes", as shown on Line 43, Schedule E1, amounts to 1.569¢ per KWH.

Q. Please advise what a residential customer using 1,000 KWH will pay for the period January 2003 - December 2003 including base rates, conservation cost recovery factors, and fuel adjustment factor and after application of a line loss multiplier.

A. In Marianna a residential customer using 1,000 KWH will pay $63.36, an increase of 2.11 from the previous period. In Fernandina Beach a customer will pay $49.88, a decrease of $7.94 from the previous period.

Q. Does the company want to implement consolidated electric fuel rates for their Marianna and Fernandina Beach Division?

A. Yes, the company requests that the fuel rates be consolidated effective with the date of the revised consolidated base rates associated with our current rate proceeding filed with the PSC on August 14, 2003, Docket No. 030438-EI. The company expects these rates to be effective on or before June 1, 2004 and would like to coincide the implementation of consolidated fuel rates on the same effective date of the new base rates. The company feels this is appropriate based on the consolidation of electric rates between the two divisions, which will match methodologies used by most electric utilities that have standard rates for all customers. At most other electric utilities, fuel rates are consolidated even though costs from production capacity or off-system purchases vary based on many factors. This fuel rate consolidation will allow FPUC to standardize fuel costs as is done by other utilities and will assist in stabilizing fuel rate charges to all customers in the future.

Q. Does this conclude your testimony?

A. Yes.

GULF POWER COMPANY

Before the Florida Public Service Commission
Prepared Direct Testimony and Exhibit of
H. R. Ball
Docket No. 030001-EI
Date of Filing: April 1, 2003

Q. Please state your name, business address and occupation.

A. My name is H. R. Ball. My business address is One Energy Place, Pensacola, Florida 32520-0780. I am the Fuel Manager for Gulf Power Company.

Q. Please briefly describe your educational background and business experience.

A. I graduated from the University of Southern Mississippi in Hattiesburg, Mississippi in 1978 with a Bachelor of Science Degree in Chemistry and graduated from the University of Southern Mississippi in Long Beach, Mississippi in 1988 with a Masters of Business Administration. In 1978, I began my employment with the Southern Company at Mississippi Power Company (MPC) as a Plant Chemist at Plant Daniel. In 1982, I transferred to MPC's Fuel Services Department as a Fuel Business Analyst. In 1987, I was promoted to Supervisor of Chemistry and Regulatory Compliance at Plant Daniel. In 1998, I was promoted to Supervisor of Coal Logistics with Southern Company Services Fuel Services Department located in Birmingham, Alabama. My responsibilities in this position included administering coal supply and transportation agreements and managing the coal inventory program for the Southern Electric System. In March, 2003, I was promoted to my current position as Fuel Manager for Gulf Power Company

Q. What are your duties as Fuel Manager for Gulf Power Company?

A. I manage the Company's fuel procurement, inventory, transportation, budgeting, contract administration, and quality assurance programs to ensure that the generating plants operated by Gulf Power are supplied with an adequate quantity of fuel in a timely manner and at the lowest practical cost.

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

A. The purpose of my testimony is to summarize Gulf Power Company's fuel expenses and to certify that these expenses were properly incurred during the period January, 2002 through December, 2002. Also, it is my intent to be available to answer questions that may arise among the parties to this docket concerning Gulf Power Company's fuel expenses.

Q. Have you prepared an exhibit that contains information to which you will refer in your testimony?

A. Yes, I have.

Counsel: We ask that Mr. Ball's Exhibit consisting of two schedules be marked as Exhibit No. _____(HRB-1).

Q. During the period January, 2002 through December, 2002 how did Gulf Power Company's recoverable fuel expenses compare with the projected expenses?

A. Gulf's recoverable fuel expense was $269,468,985 or 11.29% below the projected amount of $303,747,744. Actual generation was 13,141,724 MWH compared to the projected generation of 15,005,870 or 12.42% below projections. The resulting actual average fuel cost was $2.0505 per MWH or 1.3% above the projected amount of $2.0242 per MWH. The lower total fuel expense is attributed to the lower total net generation for the period. The higher average per unit fuel cost is attributed to a higher percentage of generation from natural gas fired units than projected. A portion of this increase is due to Plant Smith Unit 3 beginning commercial operation on April 22, 2002 which was several weeks ahead of schedule.

Q. How much spot coal did Gulf Power Company purchase during the period?

A. Excluding Plant Scherer Unit 3, Gulf purchased 984,200 tons of coal on the spot market. Schedule 1 of my exhibit consists of a list of contract and spot coal purchases for the period.

Q. How did the total projected cost of coal purchased compare with the actual cost?

A. The total actual cost of coal purchased was $174,717,576 compared to the projected cost of $220,280,250 or 20.7% less than projected. The lower purchases were primarily due to lower than expected coal fired generation.

Q How did the total projected cost of coal burned compared to the actual cost?

A. The total cost of coal burned was $189,236,088 which is the sum of lines 3 and 3A on Schedule A-3. This is 16.04% lower than our projection of $225,401,546. On a fuel cost per MMBTU basis, the actual cost was $1.69 per MMBTU which is 1.2% greater than the projected cost of $1.67 per MMBTU. The higher per unit cost of coal is attributed to higher than anticipated costs for Powder River Basin coal burned at Plant Scherer.

Q. How did the total projected cost of natural gas burned compare to the actual cost?

A. The total cost of natural gas burned for generation was $80,154,832 which is from line 60 on Schedule A-5. This is 4.86% higher than our projection of $76,439,814. The increase can be attributed to Gulf's new combined cycle unit, Smith 3, being placed in commercial operation on April 22, 2002 which is earlier than the projected date of June 1, 2002 and the additional cost of natural gas used for unit start-up testing during January through April. On a natural gas cost per unit basis, the actual cost was $4.63 per MMBTU which is 11.64% less than the projected cost of $5.24 per MMBTU.

Q. For the period in question, what volume of natural gas was actual hedged using a fixed price contract or instrument?

A. Gulf Power's hedging program was not approved until the fall of 2002. The company hedged 1,050,000 MMBTU of natural gas for the months of

November and December of 2002 using fixed price financial swaps.

Q. What types of hedging instruments were used by Gulf Power Company and what type and volume of fuel was hedged by each type of instrument?

A. Natural gas was hedged using financial swaps that fixed the price of gas to a certain price. These swaps settled against either a NYMEX Last Day price or Gas Daily price. The entire amount (1,050,000 MMBTU) of gas hedged was hedged using these financial instruments as reflected on Schedule 2 of my exhibit.

Q. What was the average period of each hedge?

A. One month.

Q. What was the actual total cost (e.g., fees, commissions, option premiums, futures gains and losses, swap settlements) associated with each type of hedging instrument?

A. Schedule 2 in my exhibit consists of a table of all natural gas hedge transactions and associated costs. No fees, commissions, or option premiums were paid. Gulf's 2002 hedging program resulted in a net financial gain of $238,750.

Q. Were there any other significant developments in Gulf's fuel procurement program during the period?

A. No.

Q. Should Gulf's fuel purchases for the period be accepted as reasonable and prudent?

A. Yes, Gulf's coal supply program is based on a mixture of long term contracts and spot purchases at market prices. Coal suppliers are selected using procedures that assure reliable coal supply, consistent quality, and competitive delivered pricing. The terms and conditions of coal supply agreements have been administered appropriately. Natural gas is purchased using agreements that tie price to published market index schedules and is transported using a combination of firm and interruptible gas transportation agreements. Natural gas storage is utilized to assure that supply is available during times when gas supply is curtailed or unavailable. Gulf's fuel oil purchases were made from qualified vendors using an open bid process to assure competitive pricing and reliable supply.

Q. Mr. Ball, does this complete your testimony?

A. Yes.

GULF POWER COMPANY

Before the Florida Public Service Commission
Prepared Direct Testimony of
H. R. Ball
Docket No. 030001-EI
Date of Filing: August 12, 2003

Q. Please state your name and business address.

A. My name is H. R. Ball. My business address is One Energy Place, Pensacola, Florida 32520-0335. I am the Fuel Manager for Gulf Power Company.

Q. Please briefly describe your educational background and business experience.

A. I graduated from the University of Southern Mississippi in Hattiesburg, Mississippi in 1978 with a Bachelor of Science Degree in Chemistry and graduated from the University of Southern Mississippi in Long Beach, Mississippi in 1988 with a Masters of Business Administration. In 1978, I began my employment with the Southern Company at Mississippi Power Company (MPC) as a Plant Chemist at Plant Daniel. In 1982, I transferred to MPC's Fuel Services Department as a Fuel Business Analyst. In 1987, I was promoted to Supervisor of Chemistry and Regulatory Compliance at Plant Daniel. In 1998, I was promoted to Supervisor of Coal Logistics with Southern Company Services Fuel Services Department located in Birmingham, Alabama. My responsibilities in this position included administering coal supply and transportation agreements and managing the coal inventory program for the Southern Electric System. In March, 2003, I was promoted to my current position as Fuel Manager for Gulf Power Company.

Q. What are your duties as Fuel Manager for Gulf Power Company?

A. I manage the Company's fuel procurement, inventory, transportation, budgeting, contract administration, and quality assurance programs to ensure that the generating plants operated by Gulf Power are supplied with an adequate quantity of fuel in a timely manner and at the lowest practical cost.

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

A. The purpose of my testimony is to compare Gulf Power Company's projected fuel expenses with estimated/actual costs for the period January, 2003 through December, 2003 and to summarize any noteworthy developments in Gulf's fuel program. Also, it is my intent to be available to answer questions that may arise among the parties to this docket concerning Gulf Power Company's fuel expenses.

Q. During the period January, 2003 through December, 2003 how will Gulf Power Company's recoverable fuel expenses compare with the original projection of expenses?

A. Gulf's projected recoverable fuel expense for the period is currently $317,899,005 or 1.62% above the original projected amount of $312,843,836. Total net system generation is expected to be 15,509,942 MWH compared to the original projected generation of 15,926,090 MWH or 2.61% below projections. The resulting average fuel cost is expected to be

2.05 cents per KWH or 4.59% above the original projected amount of 1.96 cents per KWH. The higher total fuel expense and average per unit fuel cost is attributed to higher than projected coal and natural gas prices for the period.

Q. How did the total projected cost of coal burned compare to the actual cost for the first seven months of 2003?

A. The total cost of coal burned was $120,468,390 which is 2.46% greater than our projection of $117,573,324. On a fuel cost per KWH basis, the actual cost was 1.68 cents per KWH which is 2.44% greater than the projected cost of 1.64 cents per KWH.

Q. How did the total projected cost of natural gas burned compare to the actual cost during the first seven months of 2003?

A. The total cost of natural gas burned for generation was $53,639,623 which is 12.68% lower than our projection of $61,426,211. On a natural gas cost per unit basis, the actual cost was 5.32 cents per KWH which is 53.76% greater than the projected cost of 3.46 cents per KWH. Gas fired generation and associated total cost is lower than projected due to higher than projected natural gas prices making these units less economical to operate than alternative sources of generation on the system,

Q. For the period in question, what volume of natural gas was actually hedged using a fixed price contract or instrument?

A. Gulf Power hedged 4,000,000 MMBTU of natural gas, for the period

January through July of 2003 using fixed price financial swaps.

Q. What types of hedging instruments were used by Gulf Power Company and what type and volume of fuel was hedged by each type of instrument?

A. Natural gas was hedged using financial swaps that fixed the price of gas to a certain price. These swaps settled against either a NYMEX Last Day price or Gas Daily price. The entire amount (4,000,000 MMBTU) of gas hedged was hedged using these financial instruments.

Q. What was the actual total cost (e.g., fees, commission, option premiums, futures gains and losses, swap settlements) associated with each type of hedging instrument?

A. No fees, commission, or option premiums were paid. Gulf's gas hedging program has resulted in a net financial gain of $5,562,005.00 for the period January through July 2003.

Q. Were Gulf Power's actions through July 31, 2003 to mitigate fuel and purchased power price volatility through implementation of its non-speculative financial and/or physical hedging programs prudent?

A. Yes, Gulf's physical and financial fuel hedging programs have resulted in more stable fuel prices and lower fuel costs than would have otherwise occurred if these programs had not been utilized.

Q. Are Gulf Power's actual and projected operation and maintenance expenses for 2003 for its non-speculative financial hedging programs to mitigate fuel and purchased power price volatility reasonable for cost recovery purposes?

A. Yes, the O&M costs associated with managing the fuel hedging programs are a small percentage of the total benefit received from these programs. As an example, the budgeted recoverable O&M cost of managing the gas hedging program for the period January through December, 2003 is $79,240 while the total financial gain credited to fuel expense from the gas hedging program through July 2003 was $5,562,005.

Q. Were there any other significant developments in Gulf's fuel procurement program during the period?

A. No.

Q. Should Gulf's fuel purchases for the period be accepted as reasonable and prudent?

Q. Yes, Gulf's coal supply program is based on a mixture of long term contracts and spot purchases at market prices. Coal suppliers are selected using procedures that assure reliable coal supply, consistent quality, and competitive delivered pricing. The terms and conditions of coal supply agreements have been administered appropriately. Natural gas is purchased using agreements that tie price to published market index schedules and is transported using a combination of firm and interruptible gas transportation agreements. Natural gas storage is utilized to assure that supply is available during times when gas supply is curtailed or unavailable. Gulf's fuel oil purchases were made from qualified vendors using an open bid process to assure competitive pricing and reliable supply.

Q. Mr. Ball, does this complete your testimony?

A. Yes, it does.

GULF POWER COMPANY

Before the Florida Public Service Commission
Prepared Direct Testimony and Exhibit of H. R. Ball
Docket No. 030001-EI
Fuel and Purchased Power Capacity Cost Recovery
Date of Filing: September 12, 2003

Q. Please state your name and business address and occupation.

A. My name is H. R. Ball. My business address is One Energy Place, Pensacola, Florida 32520-0335. I am the Fuel Manager for Gulf Power Company.

Q. Please briefly describe your educational background and business experience.

A. I graduated from the University of Southern Mississippi in Hattiesburg, Mississippi in 1978 with a Bachelor of Science Degree in Chemistry and graduated from the University of Southern Mississippi in Long Beach, Mississippi in 1988 with a Masters of Business Administration. In 1978, I began my employment with the Southern Company at Mississippi Power Company (MPC) as a Plant Chemist at Plant Daniel. In 1982, I transferred to MPC's Fuel Services Department as a Fuel Business Analyst. In 1987, I was promoted to Supervisor of Chemistry and Regulatory Compliance at MPC Plant Daniel. In 1998, I was promoted to Supervisor of Coal Logistics with Southern Company Fuel Services Department located in Birmingham, Alabama. My responsibilities in this position included administering coal supply and transportation agreements and managing the coal inventory program for the Southern Electric System. In March, 2003, I was promoted to my current position as Fuel

Manager for Gulf Power Company.

Q. What are your duties as Fuel Manager for Gulf Power Company?

A. I manage the Company's fuel procurement, inventory, transportation, budgeting, contract administration, and quality assurance programs to ensure that the generating plants operated by Gulf Power are supplied with an adequate quantity of fuel in a timely manner and at the lowest practical cost.

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

A. The purpose of my testimony is to support Gulf Power Company's projection of fuel expenses for the period January 1, 2004 through December 31, 2004. Also, it is my intent to be available to answer questions that may arise among the parties to this docket concerning Gulf Power Company's fuel expense projections.

Q. Have you prepared an exhibit that contains information to which you will refer in your testimony?

A. Yes, I have prepared an exhibit that compares actual and projected fuel costs for the past ten years. The purpose of this exhibit is to indicate the accuracy of Gulf's short term fuel expense projections.

Counsel: We ask that Mr. Ball's Exhibit consisting of one schedule be marked as Exhibit No. ______ (HRB-1).

Q. Has Gulf Power Company made any changes to its methods for projecting fuel expenses for this period?

A. No.

Q. Does the 2004 projection of fuel expenses reflect any major changes in Gulf's fuel procurement program for this period?

A. No. Gulf will receive 1.9 million tons of coal under an existing contract with Peabody Coal Sales. The remaining coal requirements will be purchased in the market through the Request for Proposal (RFP) process that has been used by Southern Company Services Fuel as agent for Gulf for many years. Coal will be delivered under existing coal transportation contracts. Natural gas requirements will be purchased from various suppliers using firm quantity agreements with market pricing for base needs and on the daily spot market for peak needs when necessary. Natural gas transportation will be secured using a combination of firm and spot transportation agreements.

Q. What fuel price hedging programs will be utilized by Gulf to protect the customer from fuel price spikes?

A. Natural gas prices will be hedged financially using instruments that conform to Gulf's established guidelines for hedging activity. Coal supply and transportation prices will be hedged physically using term agreements with either fixed pricing or pricing tied to various published market price indexes. This is consistent with Gulf's Risk Management Plan previously filed in this docket.

Q. How does the total projected fuel cost for the 2004 period compare to the projected fuel cost for the same period in 2003?

A. The total cost of fuel to meet system net generation needs was projected to be $312,747,000 in 2003. The projected total cost of fuel to meet system net generation needs in 2004 is $340,227,000. This is an increase of $27,480,000 or 8.79%. On a fuel cost per MWH basis, the 2003 projected cost was $19.64 per MWH and the 2004 projected fuel cost is $20.93 per MWH. This is an increase of $1.29 per MWH or 6.57%. The higher fuel costs reflect a significant increase in the projected market price of natural gas and a modest increase in the projected market price of coal.

Q. Mr. Ball, does this complete your testimony?

A. Yes, it does.

GULF POWER COMPANY
Before the Florida Public Service Commission
Direct Testimony and Exhibit of
L. S. Noack
Docket No. 030001-EI
Date of Filing April 1, 2003

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

A. My name is Lonzelle S. Noack. My business address is One Energy Place, Pensacola, Florida 32520-0335. My current job position is Power Generation Specialist, Senior for Gulf Power Company.

Q. Please describe your educational and business background.

A. I received my Bachelor of Science degree in Environmental Engineering from the University of Florida in 1995 and received my Master of Business Administration degree from the University of West Florida in 2000. I joined Gulf Power in 1995 as an Environmental Engineer and served in that role with increasing levels of responsibility for over six years. Major responsibilities included coordination of federal and state air-related compliance testing for all Gulf Power generating units, management of the Continuous Emission Monitoring (CEM) System program at each of the Company's generating facilities, and coordination of the Company's air compliance reporting to state and federal regulatory agencies. I was also responsible for serving as Gulf's Environmental Subject Matter Expert on Company and system-wide compliance teams. As previously mentioned in my testimony, my current job position is Power Generation Specialist, Senior at Gulf Power Company. In this position, I am responsible for preparing all GPIF filings as well as other generating plant reliability and heat rate performance reporting.

Q. Ms. Noack, what is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is to present GPIF results for Gulf Power Company for the period of January 1, 2002, through December 31, 2002.

Q. Ms. Noack, have you prepared an exhibit that contains information to which you will refer in your testimony?

A. Yes. I have prepared an exhibit consisting of five schedules.

Q. Ms. Noack, was this exhibit prepared by you or under your direction and supervision?

A. Yes. It was.

Counsel: We ask that Ms. Noack's exhibit, consisting of five schedules, be marked for identification as exhibit___(LSN-1).

Q. Ms. Noack, were average net operating heat rate (ANOHR) targets that included the new BTU/LB independent variable used for plant Daniel Units 1 & 2 in this period?

A. No. As mentioned in the Direct Testimony of J. R. Douglass, Docket No. 010001-EI, filed September 20, 2001, use of the BTU/LB independent variable in the heat rate regression equations has been discontinued. This is due to regression analysis, which determined that this variable is not significant to a 90% confidence interval for either unit. It is anticipated that high-BTU coal, with a reasonably consistent average heat content, will be used at Plant Daniel for the foreseeable future, and the resulting heat rate equations are valid for those conditions.

Q. Ms. Noack, is there any other information which has been supplied to the Commission pertaining to this GPIF period which requires amendment?

A. No. There is not.

Q. Ms. Noack, would you now review the Company's equivalent availability results for the period?

A. Actual equivalent availability and adjusted actual equivalent availability figures for each of the Company's GPIF units are shown on page 14 of Schedule 5. Pages 3 through 9 of Schedule 2 contain the calculations for the adjusted actual equivalent availabilities.

A calculation of GPIF availability points based on these availabilities and the targets established by Commission Order PSC-01-2516-FOF-EI is on page 10 of Schedule 2. The results are: Crist 4, +10.00; Crist 6, +4.76 points; Crist 7, +10.00 points; Smith 1, +10.00 points; Smith 2, -10.00 points; Daniel 1, +10.00 points; and Daniel 2, +10.00 points.

Q. Ms. Noack, what were the heat rate results for the period?

A. The detailed calculations of the actual average net operating heat rates for the Company's GPIF units are on pages 2 through 8 of Schedule 3.

As was done for the prior GPIF periods, and as indicated on pages 9 through 15 of Schedule 3, the target equations were used to adjust actual results to the target bases. These equations, submitted in September 2001, are shown on page 17 of Schedule 3.

As calculated on page 18 of Schedule 3, the adjusted actual average net operating heat rates correspond to the following GPIF unit heat rate points: -10.00 for Crist 4, -1.16 for Crist 6, 0.00 for Crist 7; -3.39 for Smith 1, -8.14 for Smith 2; +5.41 for Daniel 1; and 0.00 for Daniel 2.

Q. Ms. Noack, what number of Company points was achieved during the period, and what reward or penalty is indicated by these points according to the GPIF procedure?

A. Using the unit equivalent availability and heat rate points previously mentioned, along with the appropriate weighting factors, the number of Company points achieved is +2.02, as indicated on page 2 of Schedule 4. This calculated to a reward in the amount of $431,920.

Q. Ms. Noack, would you please summarize your testimony?

A. Yes. In view of the adjusted actual equivalent availabilities, as shown on page 10 of Schedule 2, and the adjusted actual average net operating heat rates achieved, as shown on page 18 of Schedule 3, evidencing the Company's performance for the period, Gulf calculates a reward in the amount of $431,920 as provided for by the GPIF plan.

Q. Ms. Noack, does this conclude your testimony?
A. Yes.

GULF POWER COMPANY
Before the Florida Public Service Commission
Direct Testimony of
L. S. Noack
Docket No. 030001-EI
Date of Filing September 12, 2003

Q. Please state your name, address and occupation.

A. My name is Lonzelle S. Noack. My business address is One Energy Place, Pensacola, Florida 32520-0335. My current job position is Power Generation Specialist, Senior for Gulf Power Company.

Q. Please describe your educational and business background.

A. I received my Bachelor of Science degree in Environmental Engineering from the University of Florida in 1995 and received my Master of Business Administration degree from the University of West Florida in 2000. I joined Gulf Power in 1995 as an Environmental Engineer and served in that role with increasing levels of responsibility for over six years. Major responsibilities included coordination of federal and state air-related compliance testing for all Gulf Power generating units, management of the Continuous Emission Monitoring (CEM) System program at each of the Company's generating facilities, and coordination of the Company's air compliance reporting to state and federal regulatory agencies. I was also responsible for serving as Gulf's Environmental Subject Matter Expert on Company and system-wide compliance teams. As previously mentioned in my testimony, my current job position is Power Generation Specialist, Senior at Gulf Power Company. In this position, I am responsible for preparing all GPIF filings as well as other generating plant reliability and heat rate performance reporting.

Q. What is the purpose of your testimony in this proceeding?
A. The purpose of my testimony is to present GPIF targets for Gulf Power Company for the period of January 1, 2004 through December 31, 2004.

Q. Have you prepared an exhibit that contains information to which you will refer in your testimony?
A. Yes. I have prepared one exhibit consisting of three schedules.

Q. Was this exhibit prepared by you or under your direction and supervision?
A. Yes, it was.

Counsel: We ask that Ms. Noack's exhibit be marked for identification as Exhibit__(LSN-2).

Q. Which units does Gulf propose to include under the GPIF for the subject period?

A. We propose that Crist Units 4, 5, 6, and 7, Smith Units 1 and 2, and Daniel Units 1 and 2 continue to be the Company's GPIF units. The projected net generation from these units is approximately 82% of Gulf's projected net generation for 2004.

Q. What are the target heat rates Gulf proposes to use in the GPIF for these units for the performance period January 1, 2004 through December 31, 2004?

A. I would like to refer you to Page 43 of Schedule 1 of my Exhibit___(LSN-2) where these targets are listed.

Q. How were these proposed target heat rates determined?

A. They were determined according to the GPIF implementation manual procedures for Gulf.

Q. Describe how the targets were determined for Gulf's proposed GPIF units.

A. Page 2 of Schedule 1 of Exhibit___(LSN-2) shows the target average net operating heat rate equations for the proposed GPIF units, and pages 4 through 39 of Schedule 1 contain the weekly historical data used for the statistical development of these equations. Pages 40 through 42 of Schedule 1 present the calculations that provide the unit target heat rates from the target equations.

Q. Were the maximum and minimum attainable heat rates for each proposed GPIF unit, indicated on page 43 of Schedule 1 of Exhibit___(LSN-2), calculated according to the appropriate GPIF implementation manual procedures?

A. Yes.

Q. What are the proposed target, maximum, and minimum equivalent availabilities for Gulf's units?

A. The target, maximum, and minimum equivalent availabilities are listed on page 4 of Schedule 2 of Exhibit___(LSN-2).

Q. How are the target equivalent availabilities determined?

A. The target equivalent availabilities were determined according to the standard GPIF implementation manual procedures for Gulf and are presented on page 2 of

Schedule 2 of Exhibit___(LSN-2).

Q. How were the maximum and minimum attainable equivalent availabilities determined for each unit?

A. The maximum and minimum attainable equivalent availabilities, which are presented along with their respective target availabilities on page 4 of Schedule 2 of Exhibit___(LSN-2), were determined per GPIF manual procedures for Gulf.

Q. Ms. Noack, has Gulf completed the GPIF minimum filing requirements data package?

A. Yes, we have completed the minimum filing requirements data package. Schedule 3 of my Exhibit___(LSN-2) contains this information.

Q. Ms. Noack, would you please summarize your testimony?

A. Yes. Gulf asks that the Commission accept:

1. Crist Units 4, 5, 6 and 7, Smith Units 1 and 2, and Daniel Units 1 and 2 for inclusion under the GPIF for the period of January 1, 2004 through December 31, 2004.

2. The target, maximum attainable, and minimum attainable average net operating heat rates, as

proposed by the Company and as shown on page 43 of Schedule 1 and also page 5 of Schedule 3 of my Exhibit___(LSN-2).

3. The target, maximum attainable, and minimum attainable equivalent availabilities, as proposed by the Company and as shown on Page 4 of Schedule 2 and also page 5 of Schedule 3 of my Exhibit___(LSN-2).

4. The weekly average net operating heat rate least squares regression equations, shown on page 2 of Schedule 1 and also pages 20 through 35 of Schedule 3 of my Exhibit___(LSN-2), for use in adjusting the annual actual unit heat rates to target conditions.

Q. Ms. Noack, does this conclude your testimony?

A. Yes.

GULF POWER COMPANY

Before the Florida Public Service Commission
Direct Testimony of
H. Homer Bell
Docket No. 030001-EI
Date of Filing: April 1, 2003

Q. Please state your name, business address and occupation.

A. My name is H. Homer Bell, and my business address is One Energy Place, Pensacola, Florida 32520. I am a Senior Engineer in the Generation Services Department of Gulf Power Company (Gulf).

Q. Have you previously filed testimony with this Commission?

A. Yes. I have filed testimony in support of Gulf's estimated/actual true-up projections of capacity and energy costs for the January 2002 through December 2002 recovery period and Gulf's projections of capacity and energy costs for the January 2003 through December 2003 recovery period.

Q. Please summarize your educational and professional background.

A. I received my Bachelor of Science Degree in Electrical Engineering from Mississippi State University in 1980 and I received my Master of Business Administration Degree from the University of Southern Mississippi in 1982. That year I joined Gulf as an associate engineer in the Company's Pensacola District Engineering Department, and have since held engineering positions in the Rates and Regulatory Matters Department and the Transmission and System Control Department. I was promoted to my current position as Senior Engineer in the Generation Services Department in 2002. I am primarily responsible for the administration of Gulf's Intercompany Interchange Contract (IIC) and coordination of Gulf's generation planning activities.

During my years of service with the Company, I have gained experience in the areas of distribution operation, maintenance, and construction; retail and wholesale electric service tariff administration; wholesale transmission service tariff administration; IIC and bulk power sales contract administration; and transmission and control center operations.

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

A. The purpose of my testimony is to summarize Gulf Power Company's (Gulf) purchased power recoverable costs for energy purchases and sales that were incurred during the January 2002 through December 2002 recovery period. I will then compare these actual costs to the amounts originally projected in Gulf's September 2001 fuel filing for the period and discuss the reasons for the differences.

I will also summarize the actual capacity expenses that were incurred during the January 2002 through December 2002 recovery period. I will compare this figure to the amount originally projected in Gulf's September 2001 fuel filing and discuss the reason for the difference.

Q. During the period January 2002 through December 2002, what was Gulf's actual purchased power recoverable cost for energy purchases and how did it compare with the projected amount?

A. Gulf's actual total purchased power recoverable cost for energy purchases, as shown on line 12 of the December 2002 Period-to-Date Schedule A-1 was \$43,473,017 for 2,449,554,670 KWH as compared to the originally projected amount of \$21,710,832 for 755,649,000 KWH that was filed September 20, 2001. The actual cost per KWH purchased was 1.7747 ¢/KWH as compared to the projected amount of 2.8731 ¢/KWH, or 38% under the projection.

Q. What were the events that influenced Gulf's purchase of energy?

A. During the January 2002 through December 2002 recovery period, a slowdown in economic activity in the Southeast United States combined with slightly milder regional weather to produce lower than forecasted loads across most of the Southern electric system (SES). These factors led to an increased availability of lower priced energy from the SES. While SES territorial loads were 1.4% lower than projected, the above mentioned conditions did not directly affect Gulf's load. Gulf's actual load was 5.2% over budget. Gulf's greater energy needs in 2002 required the Company to purchase more energy to meet its load requirements. Gulf was able to purchase this energy at a lower unit cost because lower cost SES pool resources were not needed to serve the other operating companies' system loads. Therefore, Gulf purchased more energy at a lower price than was forecasted during the January 2002 through

December 2002 recovery period in order to meet its higher load obligations.

Q. During the 2002 recovery period, what was the fuel cost effect of Gulf's increased purchases?

A. Although Gulf was able to purchase energy at a lower unit cost, the significant increase in the volume of purchases to serve Gulf's higher actual load requirements resulted in a net cost increase that contributed to Gulf's higher 2002 recoverable fuel costs.

Q. During the period January 2002 through December 2002, what was Gulf's actual purchased power fuel cost for energy sales and how did it compare with the projected amount?

A. Gulf's actual total purchased power fuel cost for energy sales, as shown on line 18 of the December 2002 Period-to-Date Schedule A-1 was $62,984,977 for 3,693,633,668 KWH as compared to the projected amount of $105,918,000 for 4,456,170,000 KWH. The actual fuel cost per KWH sold was 1.7052 ¢/KWH, or 28% under the projected amount of 2.3769 ¢/KWH.

Q. What were the events that influenced Gulf's sale of energy?

A. The same unfavorable economic conditions and milder weather that influenced Gulf's level of purchases significantly reduced Gulf's actual sales during the 2002 recovery period. Because of the lower loads experienced by other SES operating companies, Gulf did not have as many opportunities to sell its energy to SES pool members as anticipated in the forecast. Therefore, during the January 2002 through December 2002 recovery period, Gulf sold less energy to the pool at a lower than projected unit cost.

Q. During the 2002 recovery period, what was the fuel cost effect of Gulf's lower sales?

A. Because the volume of actual sales was lower than projected, and the unit cost for actual sales was also lower, Gulf's fuel and purchased power costs were not reduced as much as forecasted by the recoverable revenue produced by these sales.

Q. During the period January 2002 through December 2002, how did Gulf's actual net purchased power capacity cost compare with the net projected cost?

A. The actual net capacity cost for the January 2002 through December 2002 recovery period, shown on line 4 of Schedule CCA-2, was $3,185,812. Gulf's projected net purchased power capacity cost for the same period was $3,584,605, as indicated on Line 5 of Schedule CCE-1 that was filed September 21, 2001 in Docket No. 010001-EI. The difference between the actual net capacity cost and the projected net capacity cost for the recovery period is $398,793, or a decrease of 11%.

Q. Please explain the reason for the decrease in Gulf's capacity cost.

A. The total net capacity cost decrease for the January 2002 through

December 2002 recovery period is attributable to Gulf's lower than projected net market capacity purchase costs and higher transmission revenues. Gulf's actual net market capacity costs decreased by $230,113 due to higher sales revenues, while actual transmission revenues associated with energy sales were $223,367 above the September 2001 projection. These increased revenues more than offset the slight IIC reserve sharing cost increase of $54,687 to produce an overall $398,793 capacity cost decrease for the January 2002 through December 2002 cost recovery period.

Q. Does this conclude your testimony?
A. Yes.

GULF POWER COMPANY

Before the Florida Public Service Commission
Direct Testimony of
H. Homer Bell
Docket No. 030001-EI
Date of Filing: August 12, 2003

Q. Please state your name, business address and occupation.

A. My name is H. Homer Bell, and my business address is One Energy Place, Pensacola, Florida 32520. I am a Senior Engineer in the Generation Services Department of Gulf Power Company.

Q. Have you previously filed testimony in this Docket?

A. Yes.

Q. Please summarize your educational and professional background.

A. I received my Bachelor of Science Degree in Electrical Engineering from Mississippi State University in 1980 and I received my Master of Business Administration Degree from the University of Southern Mississippi in 1982. I joined Gulf Power Company (Gulf) as an associate engineer in Gulf's Pensacola District Engineering Department, and have since held engineering positions in the Rates and Regulatory Matters Department and the Transmission and System Control Department. I was promoted to my current position as Senior Engineer in the Generation Services Department in 2002. I am primarily responsible for the administration of Gulf's Intercompany Interchange Contract (IIC) and coordination of Gulf's generation planning activities.

During my years of service with the company, I have gained experience in the areas of distribution operation, maintenance, and construction; retail and wholesale electric service tariff administration; wholesale transmission service tariff administration; IIC and bulk power sales contract administration; and transmission and control center operations.

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

A. The purpose of my testimony is to summarize Gulf 's actual / estimated true-up projections of purchased power recoverable energy purchases and sales for the January 2003 through December 2003 recovery period. I will compare these January 2003 through December 2003 estimated true-up amounts to the amounts originally projected in Gulf's September 2002 fuel filing for the period and discuss the reason for the difference.

I will also summarize the actual / estimated true-up projection of net capacity expenses for the January 2003 through December 2003 recovery period. I will compare these figures to the amounts projected in Gulf's October 2002 revised capacity filing for the period and discuss the reason for the difference.

Q. During the period January 2003 through December 2003, what is Gulf's actual / estimated purchased power recoverable cost for energy purchases and how does it compare with the September 2002 projected amount?

A. Using actual data for January through July 2003 and a revised projection for August through December 2003, Gulf's total estimated purchased power recoverable cost for energy purchases, shown on line 12 of the January 2003 - December 2003 Schedule E-1B-1 is $24,781,930. The estimated amount of purchased energy is 1,090,939,811 KWH. The September 2002 projected cost of energy purchases was $6,912,775 for 285,605,000 KWH. The estimated true-up cost per KWH purchased is 2.2716 ¢/KWH as compared to the originally projected cost of 2.4204 ¢/KWH, or 6% under the projection made last fall.

Q. What are the primary reasons for the difference between Gulf's original projection and the current projection of Gulf's energy purchases?

A. During the period January through July 2003, Gulf purchased a higher than projected volume of energy due to the combination of January's cold weather, a planned outage for Smith Unit 3 in March that was not yet scheduled at the time of the September 2002 projection, and the availability of lower cost energy from the resources of the Southern electric system (SES). With the exception of January and March, when Gulf experienced higher average unit costs for its energy purchases, Gulf purchased this additional energy from the SES power pool at a lower cost per KWH due to lower than projected SES loads and greater availability of SES nuclear and hydro generation. As a result, Gulf's overall purchase activity for January through July 2003 produced an increased amount of energy purchases at a lower cost per KWH.

Gulf has revised its purchased power projection for August through December 2003 to incorporate updates to the SES generating unit marginal fuel prices and system loads. This revised projection indicates that Gulf will purchase more energy at a lower average cost than was originally projected for August through December 2003. Therefore, the actual energy purchase results through July 2003, combined with the new projection for August through December 2003, produce a higher projected volume of energy purchases at a lower cost per KWH for the January 2003 through December 2003 recovery period.

Q. During the period January 2003 through December 2003, what is Gulf's actual / estimated purchased power fuel cost for energy sales and how does it compare with the amount projected in September 2002?

A. Using actual data for January through July 2003 and a revised projection for August through December 2003, Gulf's total estimated purchased power fuel cost for energy sales for January through December 2003, shown on line 18 of the January 2003 - December 2003 Schedule E-1B-1, is $94,399,317. The estimated amount of energy sales is 4,942,065,794 KWH. The originally projected amount was $98,584,000 for 4,822,911,000 KWH. The estimated / actual true-up cost per KWH sold is 1.9101 ¢/KWH as compared to 2.0441 ¢/KWH, or 7% lower than originally projected.

Q. What is the primary reason for the difference between Gulf's original projection and the current projection of Gulf's energy sales?

A. During January through July of the current recovery period, Gulf sold less energy at a lower average cost than was projected in September 2002 due to lower loads experienced by other SES operating companies for most of the months through July 2003. These lower loads, caused by milder than anticipated weather in the months following January and unfavorable regional economic conditions, caused Gulf's units to generate a lower than anticipated amount of energy for SES companies' needs. Therefore, during the first seven months of 2003, Gulf sold less energy to the pool at a lower than projected average unit cost.

Gulf's revised energy sales projection for August through December 2003, that reflects SES marginal fuel price and system load updates, indicates a slightly higher amount of energy sales at a lower average unit cost than originally projected. Therefore, the lower actual energy sales through July 2003, combined with the new projection for August through December 2003, produce a higher projected volume of energy sales at a lower cost per KWH for the entire 2003 recovery period.

Q. During the period January 2003 through December 2003, what is Gulf's projection of actual / estimated net purchased power capacity transactions and how does it compare with the October 2002 revised projection of net capacity transactions?

A. As shown on Line 5 of Schedule CCE-1b, Gulf's total estimated net capacity cost for the January 2003 through December 2003 recovery period, consisting of January through July actual amounts and the previously projected amounts for August through December, is $7,356,844. Gulf's projected net capacity cost of $8,210,882 for the recovery period is shown on Line 4 of Schedule CCE-1 that was revised in

October 2002. The difference between these projections is a cost decrease of $854,038, or 10% lower than the cost that was filed in October 2002.

Q. Please explain the reason for the decrease in capacity cost.

A. The overall capacity cost decrease projected for the January 2003 through December 2003 period is primarily due to Gulf's lower Intercompany Interchange Contract (IIC) reserve sharing cost. Through July 2003, the actual megawatts of owned capacity for other SES companies that was included in the IIC reserve sharing calculation was lower than originally projected. At the same time, Gulf's owned capacity remained near the originally projected level. Therefore, other SES companies were responsible for sharing a greater percentage of system reserves, and Gulf became a lower net purchaser of capacity reserves through the IIC during the January through July 2003 period.

Gulf's IIC reserve sharing cost in August through December 2003 is not expected to differ significantly from those included in the October 2003 projection for these months. Therefore, Gulf's lower reserve requirement as compared to other SES operating companies' requirements during January through July is the primary reason for Gulf's $854,038 capacity cost decrease during the January 2003 through December 2003 cost recovery period.

Q. Does this conclude your testimony?

A. Yes.

GULF POWER COMPANY

Before the Florida Public Service Commission
Direct Testimony of
H. Homer Bell
Docket No. 030001-EI
Date of Filing: September 12, 2003

Q. Please state your name, business address and occupation.

A. My name is H. Homer Bell, and my business address is One Energy Place, Pensacola, Florida 32520. I am a Senior Engineer in the Generation Services Department of Gulf Power Company.

Q. Have you previously filed testimony with this Commission?

A. Yes. I have filed testimony in support of Gulf Power Company's projection and true-up of capacity and energy costs in this docket.

Q. Please summarize your educational and professional background.

A. I received my Bachelor of Science Degree in Electrical Engineering from Mississippi State University in 1980 and I received my Master of Business Administration Degree from the University of Southern Mississippi in 1982. That year I joined Gulf Power Company (Gulf) as an associate engineer in Gulf's Pensacola District Engineering Department, and have since held engineering positions in the Rates and Regulatory Matters Department and the Transmission and System Control Department. I was promoted to my current position as Senior Engineer in the Generation Services Department in 2002. I am primarily responsible for the administration of Gulf's Intercompany Interchange Contract (IIC) and coordination of Gulf's generation planning activities.

During my years of service with the company, I have gained experience in the areas of distribution operation, maintenance, and construction; retail and wholesale electric service tariff administration; wholesale transmission service tariff administration; IIC and bulk power sales contract administration; and transmission and control center operations.

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

A. The purpose of my testimony is to support Gulf Power Company's (Gulf) projection of purchased power recoverable costs for energy purchases and sales for the period January 2004 - December 2004. I will also support Gulf's projection of purchased power capacity costs for the January 2004 - December 2004 recovery period.

Q. Have you prepared an exhibit that contains information to which you will refer in your testimony?

A. Yes. I have one exhibit to which I will refer.

Counsel: We ask that Mr. Bell's Exhibit HHB-1 be marked for identification as Exhibit_____(HHB-1).

Q. What is Gulf's projected purchased power recoverable cost for energy purchases for the January 2004 - December 2004 recovery period?
A. Gulf's projected recoverable cost for energy purchases, shown on line 13 of Schedule E-1 of the fuel filing, is $12,776,000. These purchases result from Gulf's participation in the coordinated operation of the Southern electric system (SES) power pool. This amount is used by Gulf's witness Ms. Davis as an input in the calculation of the fuel and purchased power cost adjustment factor.

Q. What is Gulf's projected purchased power fuel cost for energy sales for the January 2004 - December 2004 recovery period?
A. The projected fuel cost for energy sales, shown on line 19 of Schedule E-1, is $108,525,000. These sales are a product of Gulf's participation in the coordinated operation of the SES power pool. This amount is used by Gulf's witness Ms. Davis as an input in the calculation of the fuel and purchased power cost adjustment factor.

Q. Please compare Gulf's projected purchased power recoverable costs for energy purchases and sales for the January 2004 - December 2004 recovery period to those projected costs for January 2003 - December 2003 recovery period and explain the reasons the differences.
A. Gulf's projected purchased power recoverable cost for energy purchases for the 2004 recovery period is $12,776,000, or $5,863,225 more than projected for the 2003 recovery period. This increase in energy purchase cost results from an increase in Gulf's projected customer loads that will

require the company to purchase more SES pool energy in 2004.

Gulf's projected purchased power fuel cost for energy sales in 2004 is $108,525,000, or $9,941,000 more than projected for the 2003 recovery period. This increase is primarily driven by an increase in the volume of Unit Power Sales to off-system customers and higher expected average prices for sales to other SES operating companies. Of course, the increased cost related to these sales is fully paid by the purchasing utility. Gulf's customers thus receive credit for the cost of energy generation, as well as the vast majority of any mark-up on opportunity sales.

Q. What information is contained in your exhibit?

A. My exhibit lists the long-term power contracts that are included for capacity cost recovery, their associated megawatt amounts, and the resulting capacity dollar amounts. Also listed on my exhibit are the revenues produced by the same non-firm market capacity sales agreements between the SES operating companies and utilities outside the system that were included in Gulf's 2003 projection.

Q. Which power contracts produce capacity transactions that are recovered through Gulf's purchased power capacity cost adjustment factor?

A. Two power contracts that produce recoverable capacity transactions through Gulf's purchased power capacity adjustment factor are the SES Intercompany Interchange Contract (IIC), under which Gulf participates in the SES reserve equalization process, and Gulf's cogeneration purchased power contract with Solutia. The Commission has authorized the

Company to include capacity transactions under the IIC for recovery through the purchased power capacity cost adjustment factor. Gulf will continue to have IIC capacity transactions during the January 2004 - December 2004 recovery period. The energy transactions under this contract are recovered through the fuel cost adjustment factor.

The Gulf/Solutia cogeneration purchased power contract enables Gulf to purchase 19 megawatts of firm capacity until June 1, 2005. Gulf has included the contract's annual cost for the January 2004 - December 2004 recovery period in this projection. The energy transactions under this contract have also been approved by the Commission for recovery, and these costs are included for cost recovery purposes through the fuel cost adjustment factor.

Q. Are there any other arrangements that produce capacity transactions that are recovered through Gulf's purchased power capacity cost adjustment factor?

A. Yes. Gulf, as a member of the SES, continues to participate in the same two agreements to sell non-firm market capacity to non-associated utilities that were included in Gulf's capacity cost projections for the January 2003 - December 2003 recovery period. During the 2004 recovery period, Gulf will continue to receive capacity revenues associated with these contracts. The revenues from these non-firm sales will produce credits that will lower the overall 2004 projected capacity costs. Any scheduled energy transactions associated with these capacity sales are handled for cost recovery purposes through the fuel cost adjustment factor.

Q. What are Gulf's IIC capacity transactions that are projected for the January 2004 - December 2004 recovery period?

A. As shown on my Exhibit HHB-1, IIC capacity purchases in the amount of $19,027,487 are projected for the 2004 recovery period.

Q. What is the cost of Gulf's capacity purchase from Solutia that is projected for the January 2004 - December 2004 recovery period?

A. As shown on my Exhibit HHB-1, Gulf is projected to pay $746,424, or $62,202 per month, to Solutia for the firm capacity purchase made pursuant to the Commission approved contract. This amount has not changed from the amount that was projected for recovery in 2003.

Q. What amount of revenues associated with Gulf's market capacity sales is projected for the January 2004 - December 2004 recovery period?

A. As shown on my Exhibit HHB-1, Gulf is projected to receive a total of $119,004 from the sale of non-firm capacity to non-associated utilities.

Q. Are there other projected revenues that Gulf has included in its capacity cost recovery clause for the 2004 recovery period?

A. Yes. In accordance with Florida Public Service Commission Order No. PSC-99-2512-FOF-EI, issued December 22, 1999, Gulf will continue to include an estimate of transmission revenues in its capacity cost recovery clause. For the 2004 recovery period, Gulf expects to receive transmission revenues in the amount of $112,000. This amount is shown on Schedule CCE-1 of Gulf's witness Ms. Davis' testimony.

Q. What are Gulf's total projected net capacity transactions for the January 2004 - December 2004 recovery period?

A. As shown on my Exhibit HHB-1, the IIC capacity purchases, the Solutia contract purchases, and the non-firm market capacity sales will result in a projected net capacity cost of $19,654,907. Including the estimated transmission revenues that are shown on Schedule CCE-1, Gulf's total projected net capacity cost for the 2004 recovery period is $19,542,907. This figure is used by Gulf's witness Ms. Davis as an input into the calculation of the total capacity transactions to be recovered through the purchased power capacity cost adjustment factor for this annual recovery period.

Q. Please compare Gulf's January 2004 - December 2004 total projected net capacity cost to those projected costs for January 2003 - December 2003 recovery period and explain the reason for the difference.

A. Gulf's 2004 net capacity cost is projected to be $11,332,025 higher than its October 2003 estimate of $8,210,882 due primarily to Gulf's higher IIC capacity reserve sharing cost that is produced by Gulf's higher purchases of SES capacity reserves under the provisions of the IIC.

Q. What factors contribute to Gulf's increased purchases of SES capacity reserves during the January 2004 – December 2004 recovery period?

A. The primary factor is that Gulf's load is actually increasing, whereas most other utilities in the SES are seeing declines in their loads. Therefore, Gulf must purchase more capacity to serve its increasing load.

The continued slowdown in economic activity in areas of the Southeastern United States has caused several SES operating companies to lower their load forecasts for 2004. Also, improved SES generating unit availability factors have resulted in more SES generating capacity available to serve projected system load which increases the bulk power reliability of the grid. This produces a higher level of system capacity reserves to be shared, or equalized, by all SES operating companies.

In conjunction with these factors that produce higher system reserves, Gulf is projected to be responsible for a higher load ratio share of these reserves because of Gulf's higher historical loads that are used to calculate its reserve responsibility ratio. The fact that Gulf's load is growing relatively faster than the other companies' loads means more generation must be available to maintain reliability on the grid. Therefore, Gulf will need to purchase more system capacity, and its IIC capacity cost will be correspondingly higher during the January 2004 - December 2004 recovery period.

Q. Does this conclude your testimony?
A. Yes.

PROGRESS ENERGY FLORIDA

DOCKET NO. 030001-EI

Fuel and Capacity Cost Recovery
Final True-Up for the Period
January through December, 2002

DIRECT TESTIMONY OF PAMELA R. MURPHY

Q. Please state your name and business address.

A. My name is Pamela R. Murphy. My business address is P. O. Box 1551, Raleigh, North Carolina 27602.

Q. By whom are you employed and in what capacity?

A. I am employed by Progress Energy Carolinas in the capacity of Director, Gas & Oil Trading.

Q. Have your duties and responsibilities remained the same since you last submitted testimony in this proceeding?

A. Yes, my responsibilities for the procurement and trading of natural gas and oil on behalf of Progress Energy Florida (Progress Energy or the Company) have remained the same.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present and address Progress Energy's Risk Management Plan for fuel procurement in 2004. In addition, I will address Staff's preliminary Issues 13F, regarding the Company's actions to mitigate price volatility through hedging programs, and 13G, regarding the Company's operation and maintenance expenses for its hedging programs.

Q. Has Progress Energy developed its Risk Management Plan for fuel procurement in 2004 in accordance with the Resolution of Issues proposed by Staff and approved by the Commission in Docket No. 011605-EI?

A. Yes. Progress Energy's Risk Management Plan was prepared in accordance with paragraph 2 of the Resolution of Issues and is attached to my prepared testimony as Exhibit No. ___ (PRM-1). Certain information in the exhibit has been redacted, consistent with the Company's request for confidential classification of this information.

Q. In what types of hedging activities does Progress Energy expect to engage during 2004?

A. Progress Energy has been conducting and will continue to conduct physical hedging while in the process of implementing Phase 1 and 2 of a new energy trading software system for both power and natural gas. Phase 2 of this new system will consist of the testing and implementation of specialized natural gas software (the Gas Management System) that will be used for physical and financial transactions, and is expected to be operational in mid-2004. Additionally, in August 2003, management approval was given to an expansion of the Company's hedging strategy under which its forecasted 2004 minimum monthly natural gas requirements will be hedged as a base level. The objective of this expanded hedging strategy is to provide greater fuel price stability to customers and thereby reduce the likelihood of future mid-course corrections, while attempting to capture savings if and when market opportunities present themselves. The newly approved strategy has already been implemented and, to date, Progress Energy has hedged a significant portion of its forecasted annual natural gas requirements for 2004.

Q. What are Progress Energy's plans for hedging residual oil in 2004?

A. Consistent with its hedging strategy for natural gas described above, Progress Energy is in the process of finalizing the adoption of a more active strategy for hedging residual (No. 6) oil. Under the revised strategy, the Company will physically hedge its forecasted 2004 minimum monthly No. 6 oil requirements as a base level, which represents nearly 70% of its forecasted annual requirements. This strategy has the same objective as the Company's natural gas hedging strategy described above.

Q. What is Progress Energy's time frame for hedging forward prices of natural gas and residual oil?

A. The Company's current hedging strategy extends for a two-year rolling period. For example, in the summer of 2003, Progress Energy will consider hedges forward through the summer of 2005 under a phased hedging approach.

Q. What is meant by the term "phased hedging approach"?

A. Progress Energy reviews its market view on forward pricing on a weekly basis. The Company's strategy is to enter into multiple transactions over time so that its hedging portfolio will be representative of the changing market dynamics, as opposed to hedging its requirements all at one time.

Q. Were Progress Energy's actions through July 2003 to mitigate fuel and purchased power price volatility through implementation of its non-speculative hedging programs prudent? (Staff Issue 13F)

A. Yes. For the seven-month period from January through July 2003, Progress Energy hedged approximately 29% of its natural gas purchases, which was the appropriate level for the period. Market conditions did not, in the Company's judgment, warrant hedging additional purchases, since natural gas prices during this period were already at high levels. This posed an unacceptable risk that additional hedges would have locked in above-market prices at the time delivery was to be taken.

Q. What were the results of Progress Energy's hedging activities during the January through July period?

A. The Company's hedging activities for the period produced customer savings of approximately $14 million. In addition, in May 2003, the Company renegotiated a long-term contract for residual (No. 6) oil that is expected to save its customers approximately $13.8 million through the end of 2007.

Q. Are Progress Energy's actual and projected operation and maintenance expenses for 2002 through 2004 for its non-speculative financial and/or physical hedging programs to mitigate fuel and purchased power price volatility reasonable for cost recovery purposes? (Staff Issue 13G)

A. Progress Energy will not incur any charges for the implementation of its new financial hedging program until Phase 2 of the program's software system becomes operational, which, as I described earlier, is expected to be mid-2004. At this time, the Company's allocated share of these charges has not been finalized. Therefore, the Company proposes to book the charges when they are incurred and address their reasonableness in subsequent true-up testimony.

Q. Does this conclude your testimony?

A. Yes, it does.

PROGRESS ENERGY FLORIDA

DOCKET NO. 030001-EI

Levelized Fuel and Capacity Cost Recovery Factors January through December 2004

DIRECT TESTIMONY OF JAVIER PORTUONDO

Q. Please state your name and business address.

A. My name is Javier Portuondo. My business address is Post Office Box 14042, St. Petersburg, Florida 33733.

Q. By whom are you employed and in what capacity?

A. I am employed by Progress Energy Service Company, LLC, in the capacity of Director, Regulatory Services - Florida.

Q. Have your duties and responsibilities remained the same since your testimony was last filed in this docket?

A. Yes.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present for Commission approval the levelized fuel and capacity cost factors of Progress Energy Florida (Progress Energy or the Company) for the period of January through December 2004. In addition, I will address Staff preliminary Issue 13D regarding the Company's market price proxy for waterborne coal transportation, including a detailed discussion of the circumstances that led to the Commission's adoption of the market proxy mechanism. I will then address Staff Issues 13A, 13B and 13C regarding ongoing Commission practices for the treatment of certain costs related to Progress Fuels Corporation, Issue 13E regarding Progress Energy's purchase of synthetic coal in 2002, and a new matter of which Staff has recently advised the Company regarding the treatment of Progress Fuel's FOB Barge coal purchases in 2002. Finally, I will address an issue raised by the Company in an attempt to resolve any uncertainty that may exists regarding the appropriate baseline O&M expenses to be used in determining recoverable incremental costs in this proceeding.

Q. Do you have an exhibit to your testimony?

A. Yes. I have prepared an exhibit attached to my prepared testimony consisting of Parts A through F and the Commission's minimum filing requirements for these proceedings, Schedules E1 through E10 and H1, which contain the Company's levelized fuel cost factors and the supporting data. Parts A through C contain the assumptions which support the Company's cost projections, Part D contains the Company's capacity cost recovery factors and supporting data, Part E contains the calculation of recoverable depreciation expense and return on capital associated with Progress Energy's new Hines Unit 2 in accordance with the rate case stipulation and settlement approved by the Commission in April 2002, and

Part F contains a graphic depiction of the Company's incremental cost evaluation process.

FUEL COST RECOVERY

Q. Please describe the levelized fuel cost factors calculated by the Company for the upcoming projection period.

A. Schedule E1, page 1 of the "E" Schedules in my exhibit, shows the calculation of the Company's basic fuel cost factor of 3.453 ¢/kWh (before metering voltage adjustments). The basic factor consists of a fuel cost for the projection period of 2.90246 ¢/kWh (adjusted for jurisdictional losses), a GPIF reward of 0.00714 ¢/kWh, and an estimated prior period true-up of 0.54052 ¢/kWh.

Utilizing this basic factor, Schedule E1-D shows the calculation and supporting data for the Company's final levelized fuel cost factors for service received at secondary, primary, and transmission metering voltage levels. To perform this calculation, effective jurisdictional sales at the secondary level are calculated by applying 1% and 2% metering reduction factors to primary and transmission sales, respectively (forecasted at meter level). This is consistent with the methodology used in the development of the capacity cost recovery factors. The final fuel cost factor for residential service is 3.458 ¢/kWh.

Schedule E1-E develops the Time Of Use (TOU) multipliers of 1.310 On-peak and 0.865 Off-peak. The multipliers are then applied to the levelized fuel cost factors for each metering voltage level, which results in the final TOU fuel factors for application to customer bills during the projection period.

Q. What is the change in the fuel factor for the projection period from the fuel factor currently in effect?

A. The projected average fuel factor for 2004 of 3.453 ¢/kWh is an increase of 0.717 ¢/kWh, or 26.2%, from the 2003 midcourse fuel factor of 2.736 ¢/kWh.

Q. Please explain the reasons for the increase.

A. The increase is primarily driven by the recovery of the projected 2003 true-up balance of $210.4 million. Also contributing to the higher fuel factor is an increase in the projected fuel cost of oil and natural gas, as well as a slight increase due to recovery of actual energy costs, since the regulatory asset associated with the 1997 buyout of the Tiger Bay purchase power agreements (PPAs) has been fully amortized. In 2004, Tiger Bay will be treated as a company owned generating facility rather than a contractual cogenerator. Partially offsetting this increase is a reduction in coal prices and higher nuclear generation due to no refueling outage scheduled for 2004.

Q. What is included in Schedule E1, line 4, "Adjustments to Fuel Cost"?

A. Line 4 shows the recovery of the costs associated with conversion of combustion turbine units to burn natural gas instead of distillate oil ($124,000), the annual payment to the Department of Energy for the decommissioning and decontamination of their enrichment facilities ($1,743,831), and the recovery of the depreciation and return associated with Hines Unit 2 ($42,589,716). These fuel cost adjustments total $44,457,547.

Q. Is the cost of purchasing emission allowances still included in Schedule E1, line 4, "Adjustments to Fuel Cost"?

A. No. Beginning in 2004, the cost of emission allowances will be recovered through the Environmental Cost Recovery Clause (ECRC). Order No. PSC-95-0450-FOF-EI in Docket No. 950001-EI allowed emission allowances to be recovered through the Fuel and Purchased Power Cost Recovery Clause if a utility was not participating in an ECRC. Progress Energy began utilizing the ECRC on January 1, 2003 and received Commission approval to move emission allowances to that clause in 2004.

Q. What is included in Schedule E1, line 6, "Energy Cost of Purchased Power"?

A. Line 6 includes energy costs for the purchase of 60 MWs from Tampa Electric Company and the purchase of 414 MWs under a Unit Power Sales (UPS) agreement with the Southern Company. The capacity payments associated with the UPS contract are based on the original contract of 400 MWs. The additional 14 MWs are the result of revised SERC ratings for the five units involved in the unit power purchase, providing a benefit to Progress Energy in the form of reduced costs per kW. Both of these contracts have been approved for cost recovery by the Commission. The capacity costs associated with these purchases are included in the capacity cost recovery factor.

Q. What is included in Schedule E1, line 8, "Energy Cost of Economy Purchases"?

A. Line 8 consists primarily of economy purchases from within or outside the state. Line 8 also includes energy costs for purchases from Seminole Electric Cooperative, Inc. (SECI) for load following, and off-peak hydroelectric purchases from the Southeast Electric Power Agency (SEPA). The SECI contract is an ongoing contract under which the Company purchases energy from SECI at 95% of its avoided fuel cost. Purchases from SEPA are on an as-available basis. There are no capacity payments associated with either of these purchases. Other purchases may have non-fuel charges, but since such purchases are made only if the total cost of the purchase is lower than the Company's cost to generate the energy, it is appropriate to recover the associated non-fuel costs through the fuel adjustment clause rather than the capacity cost recovery clause. Such non-fuel charges, if any, are reported on line 10.

Q. How was the Gain on Other Power Sales, shown on Schedule E-1, Line 15a, developed?

A. Progress Energy estimates the total gain on non-separated sales during 2004 to be $4,584,880, which is below the three-year rolling average for such sales of $8,239,266 by $3,654,386. Based on the sharing mechanism approved by the Commission in Docket No. 991779-EI, the total gain will be distributed to customers.

Q. How was Progress Energy's three-year rolling average gain on economy sales determined?

A. The three-year rolling average of $8,239,266 is based on calendar years 2001 through 2003, and was calculated in accordance with Order No. PSC-00-1744-PAA-EI, issued September 26, 2000 in Docket 991779-EI.

Q. Why has the depreciation expense and return on capital associated with Hines Unit 2 been included in the Adjustments to Fuel Cost entry you described earlier?

A. The stipulation approved by the Commission in April 2002 for Progress Energy's base rate review proceeding (Docket No. 000824-EI) provides that the Company will be allowed the opportunity to recover the depreciation expenses and return on capital for its new Hines Unit 2 through the fuel clause beginning with the unit's commercial operation through the end of 2005, subject to the limitation that the costs of Hines Unit 2 recovered over this period may not exceed the cumulative fuel savings provided by the unit over the same period. Because Hines Unit 2 is scheduled to begin commercial operation in December 2003, these two cost components of the unit for 2004 have been included in the projection period for recovery in accordance with the stipulation. Part E of my exhibit shows the calculation of the depreciation expense and return on capital associated with Hines Unit 2.

Q. Please explain the entry on Schedule E1, line 17, "Fuel Cost of Stratified Sales."

A. Progress Energy has several wholesale contracts with Seminole, some of which represent Seminole's own firm resources, and others that provide for the sale of supplemental energy to supply the portion of their load in excess of Seminole's own resources, 1528 MW in 2004. The fuel costs charged to Seminole for supplemental sales are calculated on a "stratified" basis, in a manner which recovers the higher cost of intermediate/peaking generation used to provide the energy. New contracts for fixed amounts of intermediate and peaking capacity began in January of 2000. While those sales are not necessarily priced at average cost, Progress Energy is crediting average fuel cost of the appropriate stratification (intermediate or peaking) in accordance with Order No. PSC-97-0262-FOF-EI. The fuel costs of wholesale sales are normally included in the total cost of fuel and net power transactions used to calculate the average system cost per kWh for fuel adjustment purposes. However, since the fuel costs of the stratified sales are not recovered on an average system cost basis, an adjustment has been made to remove these costs and the related kWh sales from the fuel adjustment calculation in the same manner that interchange sales are removed from the calculation. This adjustment is necessary to avoid an over-recovery by the Company which would result from the treatment of these fuel costs on an average system cost basis in this proceeding, while actually recovering the costs from these customers on a higher, stratified cost basis.

Line 17 also includes the fuel cost of sales made to the City of Tallahassee in accordance with Order No. PSC-99-1741-PAA-EI. The stratified sales shown on Schedule E6 include 100,140 MWh, of which 93% is priced at average nuclear fuel cost, the balance at an estimated incremental cost of $25 per MWh. Other transactions included on Line 17 are the 50 MW sale to Florida Power & Light and a 15 MW sale to the City of Homestead.

Q. Please explain the procedure for forecasting the unit cost of nuclear fuel.

A. The cost per million BTU of the nuclear fuel which will be in the reactor during the projection period (Cycle 14) was developed from the unamortized investment cost of the fuel in the reactor. Cycle 14 consists of several "batches" of fuel assemblies which are separately accounted for throughout their life in several fuel cycles. The cost for each batch is determined from the actual cost incurred by the Company, which is audited and reviewed by the Commission's field auditors. The expected available energy from each batch over its life is developed from an evaluation of various fuel management schemes and estimated fuel cycle lengths. From this information, a cost per unit of energy (cents per million BTU) is calculated for each batch. However, since the rate of energy consumption is not uniform among the individual fuel assemblies and batches within the reactor core, an estimate of consumption within each batch must be made to properly weigh the batch unit costs in calculating a composite unit cost for the overall fuel cycle.

Q. How was the rate of energy consumption for each batch within Cycle 14 estimated for the upcoming projection period?

A. The consumption rate of each batch has been estimated by utilizing a core physics computer program which simulates reactor operations over the projection period. When this consumption pattern is applied to the individual batch costs, the resultant composite cost of Cycle 14 is $.35 per million BTU.

Q. Please give a brief overview of the procedure used in developing the projected fuel cost data from which the Company's basic fuel cost recovery factor was calculated.

A. The process begins with the fuel price forecast and the system sales forecast. These forecasts are input into the Company's production cost model, PROSYM, along with purchased power information, generating unit operating characteristics, maintenance schedules, and other pertinent data. PROSYM then computes system fuel consumption, replacement fuel costs, and energy purchases and costs. This information is the basis for the calculation of the Company's levelized fuel cost factors and supporting schedules.

Q. What is the source of the system sales forecast?

A. The system sales forecast is made by the forecasting section of the Financial Planning & Regulatory Services Department using the most recent data available. The forecast used for this projection period was prepared in June 2003.

Q. Is the methodology used to produce the sales forecast for this projection period the same as previously used by the Company in these proceedings?

A. Yes. The methodology employed to produce the forecast for the projection period is the same as used in the Company's most recent filings, and was developed with an econometric forecasting model. The forecast assumptions are shown in Part A of my exhibit.

Q. What is the source of the Company's fuel price forecast?

A. The fuel price forecast was made by the Regulated Commercial Operations Department based on forecast assumptions for residual (#6) oil, distillate (#2) oil, natural gas, and coal. The assumptions for the projection period are shown in Part B of my exhibit. The forecasted prices for each fuel type are shown in Part C.

CAPACITY COST RECOVERY

Q. How was the Capacity Cost Recovery factor developed?

A. The calculation of the capacity cost recovery (CCR) factor is shown in Part D of my exhibit. The factor allocates capacity costs to rate classes in the same manner that they would be allocated if they were recovered in base rates. A brief explanation of the schedules in the exhibit follows.

<u>Sheet 1: Projected Capacity Payments.</u> This schedule contains system capacity payments for UPS, TECO and QF purchases. The retail portion of the capacity payments is calculated using separation factors from

the Company's most recent Jurisdictional Separation Study available at the time this filing was prepared.

Sheet 2: Estimated/Actual True-Up. This schedule presents the actual ending true-up balance as of July, 2003 and re-forecasts the over/(under) recovery balances for the next five months to obtain an ending balance for the current period. This estimated/actual balance of $3,309,148 is then carried forward to Sheet 1, to be refunded during the January through December, 2004 period.

Sheet 3: Development of Jurisdictional Loss Multipliers. The same delivery efficiencies and loss multipliers presented on Schedule E1-F.

Sheet 4: Calculation of 12 CP and Annual Average Demand. The calculation of average 12 CP and annual average demand is based on 2003 load research data and the delivery efficiencies on Sheet 3.

Sheet 5: Calculation of Capacity Cost Recovery Factors. The total demand allocators in column (7) are computed by adding 12/13 of the 12 CP demand allocators to 1/13 of the annual average demand allocators. The CCR factor for each secondary delivery rate class in cents per kWh is the product of total jurisdictional capacity costs (including revenue taxes) from Sheet 1, times the class demand allocation factor, divided by projected effective sales at the secondary level. The CCR factor for primary and transmission rate classes reflects the application of metering reduction factors of 1% and 2% from the secondary CCR factor.

Q. Please explain the decrease in the CCR factor for the projection period compared to the CCR factor currently in effect.

A. The projected average retail CCR factor of 0.77482 ¢/kWh is 13.6% lower than the 2003 mid-course factor of 0.89702 ¢/kWh. The decrease is primarily due to the elimination of the capacity payments associated with the buyout of the Tiger Bay PPAs, since the regulatory asset has been fully amortized. Partially offsetting this decrease is the annual contractual escalation in capacity payments.

Q. Has Progress Energy included incremental security charges in the 2004 projected capacity amount?

A. Yes. The Company has included $4,644,108 related to incremental security charges for 2004.

Q. What additional internal and/or external security initiatives have taken place or are anticipated to take place that will impact Progress Energy's request for recovery through the Capacity Cost Recovery Clause in 2004?

A. On April 29, 2003, the U.S. Nuclear Regulatory Commission (NRC) issued three orders intended to strengthen protection requirements for nuclear reactors (Design Basis Threat or DBT), limit working hours for security personnel, and improve training for guards. Licensees must submit revised DBT plans to the Commission for review and approval by April 29, 2004 and implement by October 29, 2004. Progress Energy is currently assessing this risk. The Company is also assessing the impact of limiting guard working hours and enhancing training. Licensees must start implementation immediately and must complete by October 29, 2004. The estimated cost of these NRC requirements is included in the total recoverable amount above. The NRC has also increased its annual license fee partly to cover the costs of making plants safe from terror attacks.

In addition to the NRC orders, the Coast Guard, Department of Homeland Security (DHS) issued on July 1, 2003 a series of interim rules to promulgate maritime security requirements mandated by the Maritime Transportation Security Act of 2002. The six interim rules consist of: Implementation of National Maritime Security Initiatives, Area Maritime Security, Vessel Security, Facility Security, Outer Continental Shelf Facility Security, and Automatic Identification System. The final rule is expected to be issued before November 25, 2003. The rule is expected to impact the following sites: Bartow Plant, Anclote Plant, Crystal River Complex, Higgins Plant, and Bayboro Station. These sites are expected to require such things as additional security officers, additional gates, and closed circuit television (CCTV) systems. The timing of this rule's issuance has not allowed Progress Energy enough time to thoroughly quantify the financial impact of its implementation. Therefore we have not included an estimate of the implementation cost but rather will include the actual cost incurred as part of the Company's Actual True-up filing. The costs will be accounted for in accordance with Order PSC-02-1761-FOF-EI, which states on page 10 that:

> "(B)ecause of the extraordinary nature of the costs in question and the unique circumstances under which they arose, we find that these costs do not clearly fall within the classification of 'items which traditionally and historically would be recovered through base rates'."

. . . Because these costs are extraordinary, these costs shall be treated as current year expenses. Further, we require that these expenses be separately accounted to enhance our staff's ability to audit them."

WATERBORNE COAL TRANSPORTATION

Q. Before addressing Staff Issue 13D regarding Progress Energy's market price proxy, please describe the background of waterborne coal transportation to the Company's Crystal River plant site and its regulation by the Commission?

A. The origin of the current arrangement for waterborne transportation of coal to the Crystal River plant site took place in 1976. At that time the Company, then Florida Power Corporation (FPC), had two units at the Crystal River site that had been previously converted from coal to oil and were then in the process of being converted back to coal. These units, Crystal River 1 and 2, had a combined capacity of approximately 750 MW and would require about 2 million tons of coal annually. At the same time, FPC was in the design and pre-construction stages of two new coal-fired units, Crystal River 4 and 5, with a combined capacity of approximately 1,450 MW and annual coal requirements of nearly 4 million tons per year.

Faced with the need to arrange for the procurement and delivery of up to 6 million tons of coal a year starting almost from scratch, the Company elected a strategy aimed at securing a greater degree of control over the costs and reliability of its long-term coal supply and transportation needs than it could obtain as simply a purchaser of these services subject to the vagaries of an uncertain market. Under this strategy, the Company would acquire business expertise and ownership leverage through capital investment in partnerships with organizations experienced in the various segments of the coal supply and transportation business, particularly those segments lacking a competitive market. However, it would have been problematic for FPC to engage in such a business venture itself due to serious legal and tax impediments associated with multi-state operations and asset ownership and other key aspects of the strategy's business plan.

As a result, Electric Fuels Corporation (EFC), the predecessor of Progress Fuels Corporation (PFC), was formed in March 1976 as a wholly-owned subsidiary of FPC to carry out this long-term strategy for supplying the coal requirements of the Crystal River plant site.

Q. How did EFC implement this strategy with respect to waterborne coal transportation?

A. The most critical implementation issues were the absence of competitive markets in two key segments of the waterborne transportation route; (1) the storage and transloading of coal from river barges to Gulf barges at the mouth of the Mississippi River, and (2) the trans-Gulf transportation of coal to the Crystal River plant site. Neither segment had facilities with sufficient capacity to handle the approximately 2 million tons of waterborne coal annually that EFC needed to deliver to the Crystal River site (the requirements of the site remaining after maximum rail deliveries). This meant that a long-term commitment would have to be made for the construction of additional facilities to increase tonnage capacity in both segments. EFC chose to make that commitment through an ownership interest in the facilities, rather than entering into long-term contracts with third-party owners of the new facilities.

With respect to the river-to-Gulf transloading segment, EFC acquired a one-third ownership interest with two other experienced partners in International Marine Terminals (IMT), which began the construction of a new transloading and storage terminal on the Mississippi River approximately 60 miles south of New Orleans. In a similar vein, EFC acquired a 65% ownership interest in a partnership with Dixie Carriers, an experienced operator of ocean-going carrier vessels, for the transportation of coal to the Crystal River plant site. Since no carrier vessels capable of navigating the site's shallow, narrow channel were available, specially designed ocean-going tug-barge units had to be constructed by the partnership, Dixie Fuels Limited (DFL).

In addition to its investment in these two major undertakings, EFC also acquired ownership interests in several smaller upriver terminals, where coal delivered from the mines is loaded onto river barges. Due to the limited availability of upriver terminal capacity, these investments allowed EFC to obtain priority at existing terminals and to develop additional capacity by constructing new terminals. Since sufficient capacity existed at the time in the upriver mine-to-river (or "short-haul") transportation segment and the river barge transportation segment, EFC contracted with third-party suppliers of those services.

Q. What was the regulatory response of the Commission to the coal procurement and transportation responsibilities the Company placed with EFC?

A. As I indicated earlier, but for the legal and tax consequences it faced in 1976 (and still faces), the Company could have implemented its coal procurement and transportation strategy itself, through an internal operating division or department. Functionally, however, EFC served in much the same capacity and was indirectly regulated by the Commission in a similar manner. I use the term "indirectly regulated" because even though the Commission had no regulatory authority over EFC itself, the Commission had more than ample authority over the coal procurement and transportation costs the Company was allowed to recover through its fuel clause. And since FPC chose to pursue its strategy through an affiliate solely for business considerations, it supported the Commission's treatment of EFC in a utility-like manner.

Under this regulatory treatment, FPC was allowed to recover EFC's prudently incurred costs to procure and deliver coal to the Company, including a utility rate of return on its capital investment IMT and DFL. In return, any profits EFC earned from these investments would be returned to the Company and credited to the cost of coal charged to its customers. For example, because of its ownership interest in DFL, EFC receives 65% of DFL's profits. However, under the Commission's regulatory treatment, EFC would also earn a rate of return on its capital investment in DFL. Therefore, EFC would credit its DFL profits dollar-for-dollar against the cost of coal charged to the Company and, ultimately, its customers.

Q. How did this regulatory treatment of EFC work over time?

A. Initially, quite well. By 1986, however, several concerns about the continued use of this regulatory treatment, then referred to as "cost-plus" pricing, led the Commission to initiate an investigation into the matter (Docket No. 860001-EI-G). The investigation continued for nearly three years and included several hearings covering various aspects of EFC's operation. The following quotation from the Commission's final order concluding the investigation, although somewhat lengthy, best summarizes its findings and policy determinations, and also sets the stage for the currently pending issue regarding PFC's waterborne transportation market proxy mechanism:

> "[W]e believe and find that a change from cost-plus pricing is warranted. While we believe that the current system has been generally successful in allowing only reasonable and prudent cost to be passed through the utilities' fuel adjustment clauses, we believe that it has been administratively costly, caused unnecessary regulatory tension, and left the lingering suspicion that it has resulted in higher costs to the utility's customers. Implicit in cost-plus pricing is the requirement that one is capable of conducting a cost-of-service analysis of a business to determine that its expenses are both necessary and reasonable. This is a methodology that is demanded for monopoly utility services, and which usually proves to be complex, expensive and time consuming. It is a methodology which requires a high degree of familiarity with the capital requirements and expenses necessitated by the operation of the business being reviewed. Cost-

of-service analysis of affiliated operations places additional demands upon the regulatory agency in terms of time, expense and acquiring additional expertise. All come at some additional cost that must eventually be borne by the ratepayer, either in his role as customer or as a taxpayer. Furthermore, there seems to be no end to the types of affiliate business that we are expected to become sufficiently familiar with so that we might judge that reasonableness of their cost on a cost-of-services basis.

"Considering the many advantages offered by a market pricing system, we, as a policy matter, shall require its adoption for all affiliate fuel transactions for which a comparable market price may be found or constructed.

"In concluding, we note the following: (1) from the record in this case, we are convinced that market prices can be established for the affiliate coal; (2) market prices for the transportation-related services should be established if possible, but if not, methodologies for reasonably allocating the cost should be suggested; [and] (3) cost-of-service methodologies should be avoided, if possible; ... ." (Order No. 20604, issued January 13, 1989 in Docket No. 860001-EI-G.)

Q. With respect to the Commission's finding that "market prices for the transportation-related services should be established if possible," was a market price for EFC's waterborne transportation service eventually established pursuant to this finding?

A. In a strict sense, no. Unlike the situation with coal purchased by EFC from an affiliated supplier for which a market pricing mechanism was approved, the Commission recognized that comparable prices could not be found for some of the waterborne transportation services purchased by EFC from affiliates. In fact, this is the very reason EFC purchased these services from affiliates. As I described earlier, a market for river-to-Gulf transloading services and trans-Gulf transportation services to the Crystal River plant site did not exist at the time EFC was formed. That remained the situation when Order No. 20604 was issued, as it does today. This is particularly problematic with respect to the trans-Gulf transportation services provided by DFL's tug-barge units, which had to be custom made because of the unique and hazardous channel to the Crystal River plant site. There simply are no other vessels with the capacity to meet the waterborne coal requirements of the site that are capable of safely traversing the site's shallow, narrow channel.

Nonetheless, it was clear to the Company that the Commission expected an alternative to cost-plus pricing for EFC's waterborne transportation, even if a true market pricing mechanism could not be established. To this end, the Company began a series of negotiations with Staff, Public Counsel and FIPUG which ultimately led to the development of a pricing mechanism that the parties considered to be a reasonable alternative, or proxy, for a true market pricing mechanism. This alternative, referred to as a "market price proxy", was presented to the Commission at the August 1993 fuel adjustment hearing as a stipulated issue and was approved by Order No. PSC-93-1331-FOF-EI, issued September 13, 1993 in Docket No. 930001-EI.

Q. Please describe the market price proxy approved by the Commission?

The market price proxy became effective as of January 1993, and consists of a base price and a composite index used to escalate or de-escalate the base price annually. The base price of $23.00 per ton was derived from EFC's actual 1992 costs incurred for waterborne transportation services in delivering coal to the Crystal River plant site. The base price would then be adjusted as of January 1st each subsequent year using a composite index that consists of five individually weighted indices commonly used to adjust contract prices in the transportation services business. The total weighting of these indices is set at 90%, with 10% of the base price remaining fixed. In addition, the market proxy price may be adjusted for increases or decreases in EFC's waterborne transportation costs which result from governmental impositions on its transportation suppliers not in effect as of December 31, 1992.

Established and adjusted in this manner, the market proxy price is then paid to EFC in lieu of any payment for the costs it incurs to obtain waterborne transportation services in any of the five waterborne transportation segments; *i.e.*, short haul transportation to the upriver terminal, upriver storage and loading onto river barges, river barge transportation, storage and transloading from river barges to Gulf barges, and trans-Gulf transportation to the Crystal River plant site. In addition, EFC will no longer receive a return on its investment in IMT or DFL. In other words, compared to the price it will be paid under the market proxy mechanism, EFC will receive the benefit of any cost reductions it can achieve in providing waterborne transportation services to the Company, and it will incur the risk of any cost increases beyond its control, including the risk of catastrophic loss such as the loss of a DFL vessel at sea.

Q. With that background, please address Staff Issue 13D: Should the Commission modify or eliminate the method for calculating Progress Energy Florida's market price proxy for waterborne coal transportation that was established in Order No. PSC-93-1331-FOF-EI, issued September 13, 1993, in Docket No. 930001-EI?

A. I am not aware of any reason put forward by Staff or a party regarding a flaw or deficiency in the market proxy mechanism or a change of circumstances since the mechanism was approved by the Commission that would suggest it should be modified or eliminated. Nor am I aware of any reason to believe the mechanism has not performed reasonably in approximating the market price of waterborne coal transportation to the Crystal River plant site. To the contrary, when the market price proxy is measured against the benefits and objectives of market pricing articulated by the Commission in Order No. 20604 and quoted earlier in my testimony, I believe this consensus proposal developed jointly by the Company, Staff and other parties has served its intended purpose well. Moreover, the basis for the market price proxy remains conceptually sound. According to the Bureau of Labor Statistics (BLS), indices of the kind used in the market proxy mechanism are typically the basis for contract escalation. The indices used to escalate the market proxy base price are focused on the economic conditions that would reasonably and logically result in increases to the base price over time; and therefore result in an escalated price that fairly tracks these economic conditions, which the BLS quantified in the development of these indices.

In short, absent compelling reasons for change that have not yet been provided, the market price proxy developed to comply with the policy requirements of Order No. 20604, and which met the satisfaction of the Commission, Staff, the parties, and the Company, should remain in effect.

OTHER ISSUES

Q. Has Progress Energy confirmed the validity of the methodology used to determine the equity component of Progress Fuels Corporation's capital structure for calendar year 2002? (Staff Issue 13A)

A. Yes. Progress Energy's Audit Services department has reviewed the analysis performed by PFC. The revenue requirements under a full utility-type regulatory treatment methodology using the actual average cost of debt and equity required to support the Company's regulated business was compared to revenues billed using an equity component based on 55% of net long-term assets (the "short cut method"). The analysis showed that for 2002, the short cut method resulted in revenue requirements which were $47,749, or 0.01%, higher than revenue requirements under the full utility-type regulatory treatment methodology. Progress Energy submits that this analysis confirms again the appropriateness and continued validity of the short cut method.

Q. Has Progress Energy properly calculated the market price true-up for coal purchases from Powell Mountain? (Staff Issue 13B)

A. Yes. The calculation has been made in accordance with the market pricing methodology approved by the Commission in Docket No. 860001-EI-G.

Q. Has Progress Energy properly calculated the 2002 price for waterborne transportation services provided by Progress Fuels Corporation? (Staff Issue 13C)

A. Yes. Progress Energy has performed its calculation of the 2002 waterborne transportation price under the same methodology as the previous calculations that have been approved by the Commission.

Q. Were Progress Energy Florida's purchases of synthetic coal during 2002 cost effective? (Staff Issue 13E)

A. Yes. Progress Energy's purchases of synthetic coal (synfuel) in 2002 were made under an arrangement that allowed these purchases to substitute for purchases that would have been required under a contract for regular compliance coal at a price $2.00 per ton higher than was paid for the synfuel purchases. This resulted in fuel savings of over $1.3 million.

Q. In consideration of Order No. PSC-93-1331-FOF-EI, in Docket No. 930001-EI, issued September 13, 1993, should the Commission make an adjustment to Progress Energy Florida's 2002 waterborne coal transportation costs to account for upriver costs from mine to barge

for coal commodity contracts which are quoted FOB Barge? (New Staff Issue)

A. No adjustment is needed, since the Company and PFC have scrupulously followed the letter and spirit of the waterborne market proxy with respect to FOB Barge coal purchases. The market proxy's base price was determined from the waterborne transportation costs of PFC (then Electric Fuels Corporation, or EFC) in 1992. In that year, 27.8% of EFC's upriver waterborne coal was purchased at an FOB Barge price. This means that for these purchases the upriver "short-haul" transportation costs were included in the commodity purchase price, and were not included in the market proxy's waterborne transportations costs.

To avoid any significant over or under-recovery of these short-haul costs under the market proxy, PFC has attempted to maintain approximately the same ratio of purchases at an FOB Barge price since the inception of the market proxy in 1993. Over the ten-year period through 2002, PFC's purchases at the FOB Barge price have averaged 24.5%, meaning PFC has under-recovered the short-haul costs reflected in the market proxy through 2002. In 2002 itself, PFC's upriver waterborne coal purchases were 1,774,617 tons, of which 504,288 tons were purchased at an FOB Barge price, or 28.4% of its total upriver purchases. This slight imprecision in the 2002 ratio compared to the 27.8% base year guideline is not only small compared to the 24.5% 10-year average or the 2001 ratio of 19.0%, but is particularly small considering the complexities of optimizing individual purchase quantities, scheduling constraints, and periodic adjustments to the Company's coal requirements that PFC must take into account throughout the course of any given year.

Q. At the outset of your testimony you indicated a desire on Progress Energy's part to resolve any uncertainty that currently exists regarding the appropriate baseline expenses to be used in determining recoverable incremental costs. Please explain what you mean by the term "baseline expenses" as it is used in the determination of incremental costs.

A. The need to determine incremental costs in this proceeding arises because from time to time the Commission, under long-established policy, authorizes the recovery of certain O&M expenses through the fuel adjustment clause rather than base rates. Typically, this occurs when O&M expenses for an activity related to the adjustment clause are in excess of those that existed when the utility's base rates were last set. A recent example of this is the Commission's decision to authorize recovery of post-9/11 power plant security costs. Before actual recovery can begin, however, the Commission must assure itself that any portion of these expenses which may be included in base rates is not recovered twice – once through base rates and again through the clause. Therefore, to determine the level of incremental O&M expenses recoverable through the clause, the necessary first step is to establish the amount, if any, of these expenses included in the utility's base rates. This amount is sometimes referred to as the utility's "baseline expenses."

Q. Why has Progress Energy raised an issue regarding the appropriate baseline expenses to be used in determining recoverable incremental costs?

A. In each instance where the recovery of incremental costs has been requested by the Company and approved by the Commission since the 2002 rate case settlement went into effect, the baseline O&M expenses used to determine the recoverable amount of the incremental costs have been derived from the MFRs in that proceeding. Progress Energy believes that using the 2002 MFRs for that purpose is entirely appropriate. However, the continued use of these MFRs to establish the Company's baseline expenses has surfaced as a potential issue in pending matters.

To the extent any uncertainty exists as to the appropriateness of using the 2002 MFRs as source of baseline expenses, Progress Energy desires to have it resolved, since the need to establish baseline expenses is an ongoing one. Dealing with this issue on a case-by-case basis each time the recovery of incremental costs is sought appears unwise and inefficient. This is particularly so when the underlying question is the same in each instance: What baseline expenses best reflect the level of O&M expenses included in base rates? If the Company's base rates are unchanged, the answer to this question should be the same each time it arises.

For this reason, I believe that all concerned would benefit from the establishment of a uniform approach for setting the baseline level of O&M expenses when determining recoverable incremental costs. Doing so will allow everyone to know in advance how incremental costs are to be treated, and thus avoid the need to continually deal with this question on a case-by-case basis.

Q. Does Progress Energy seek to recover any incremental costs in this proceeding today that have been calculated using baseline O&M expenses from the Company's 2002 MFRs?

A. Yes. Based on the Commissions decision authorizing recovery of post-9/11 power plant security costs, these costs have been included in Progress Energy's true-up balance and in its projections for 2004 submitted for Commission approval in this proceeding. The Company has calculated the amount of its recoverable incremental power plant security costs using baseline expenses derived from the 2002 MFRs, as I will explain in greater detail latter in my testimony.

Q. Why is the use of baseline expenses derived from the Company's 2002 rate case MFRs the appropriate way to determine recoverable incremental costs?

A. The 2002 MFRs have been and should continue to be used by Progress Energy to establish baseline O&M expenses when determining recoverable incremental costs because they most accurately reflect the level of expenses included in the Company's current base rates. Based on long standing practice, I think it is clear that the MFRs would have been used for this purposes had the 2002 rate case been resolved in the traditional manner, *i.e.*, by a Commission decision based on the evidentiary record from a lengthy adversarial hearing. However, the fact that the 2002 rate case was resolved through settlement – a resolution that all agree is far superior to contentious, inefficient and costly litigation – provides no basis for a different conclusion about the appropriateness of using fully developed, rate case quality expense data in subsequent incremental cost determinations.

The 2002 MFRs were extensively reviewed and evaluated through discovery and testimony by Staff and the parties to the settlement negotiations. As has been previously noted, the Commission conducted a full rate case in every sense, except for the final hearing that was superceded by a negotiated settlement. The MFRs were a product of that fully developed rate case process and, as such, they and the related discovery and testimony served as a foundation for negotiations that led to the settlement and for Staff and Commission review and approval of the settlement. The use of the MFRs for incremental cost purpose is not only appropriate for this reason, but also because there simply is no other credible alternative for establishing baseline O&M expenses that reflects the level of expenses in current rates.

To summarize, by establishing a uniform treatment for the way in which baseline O&M expenses are determined, the Commission will resolve any uncertainty that now exist, avoid the need to address the issue on an inefficient and potentially inconsistent case-by-case basis, and allow all concerned to know the rules of the game in advance. By establishing the use of the Company's 2002 MFRs as that uniform treatment, the Commission will have selected the best, if not only, source of baseline O&M expenses that reflects the level included in the Company's currently approved base rates, as it must to ensure against double recovery of these expenses.

Q. Please describe the evaluation process used by Progress Energy to determine the incremental costs it submits for recovery through the adjustment clauses.

A. The evaluation process used by Progress Energy incorporates the Commission's long standing practice for determining recoverable incremental costs by removing any O&M expenses associated with the project that were included in the MFRs from the rate proceeding that established the Company's current base rates. Therefore, from the time Progress Energy's current rates were approved at the conclusion of its 2002 rate proceeding, the Company has evaluated the incremental costs associated with all projects submitted for adjustment clause recovery, including the incremental costs currently before the Commission, by first examining the 2002 rate case MFRs to determine whether any of the project's costs have been included. If none are found, all project costs are eligible for further evaluation. Any costs that are found to have been included in the MFRs are excluded from the project's recoverable costs at that point.

After this initial review, the second step is to identify any specific project costs that, although not associated directly with the project in the MFRs, are reflected elsewhere in base rates,. This step is performed by determining whether the cost would be incurred regardless of the new project. The following list provides an example of how several project cost component are broken down for analysis in this step.

- Labor from positions that were part of the last set of MFRs:
  - Regular labor is not considered incremental since is would be incurred regardless of the new project or task.
  - Overtime labor is considered incremental as it results only from the need to complete this new project or task.
  - Regular and Overtime labor for net new positions are considered incremental if it results only from the need to complete this new project or task.
- Outside Contract Labor is considered incremental since the expenditure would not have been incurred were it not for the new project or task.
- Outside Professional Services are considered incremental since the expenditure would not have been incurred were it not for the new project or task.
- Materials and Supplies are considered incremental since the expenditure would not have been incurred were it not for the new project or task.
- Travel is considered incremental since the expenditure would not have been incurred were it not for the new project or task.

The third step is to determine whether the new project will create any offsetting O&M savings associated with related activities, in which case the savings are credited to the project or task to reduce its total cost. Part F of my exhibit is a decision tree that graphically depicts the Company's incremental cost evaluation process using its post-9/11 power plant security project as an example.

Q. Does this conclude your testimony?

A. Yes, it does.

PROGRESS ENERGY FLORIDA

DOCKET NO. 030001-EI

Fuel and Capacity Cost Recovery
Final True-Up for the Period
January through December, 2002

DIRECT TESTIMONY OF PAMELA R. MURPHY

Q. Please state your name and business address.

A. My name is Pamela R. Murphy. My business address is P. O. Box 1551, Raleigh, North Carolina 27602.

Q. By whom are you employed and in what capacity?

A. I am employed by Progress Energy Carolinas in the capacity of Director, Gas & Oil Trading.

Q. Have your duties and responsibilities remained the same since you last testified in this proceeding?

A. Yes, my responsibilities for the procurement and trading of natural gas and oil on behalf of Progress Energy Florida (Progress Energy or the Company) have remained the same.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to (1) summarize the success of Progress Energy's Risk Management Plan for 2002, and (2) provide the hedging-related information required by Order No. PSC-02-1484-FOF-EI, issued in Docket No. 011605-EI.

Q. Have you prepared exhibits to your testimony?

A. Yes, I have prepared a three-page summary of the success of the Risk Management Plan, which is attached to my testimony as Exhibit No. ___ (PRM-1) and a one-page summary of hedging information attached as Exhibit No. ___ (PRM-2).

Q. Did Progress Energy encounter any force majeure events in 2002?

A. Yes, Progress Energy encountered four force majeure events. Two of those occurred on Florida Gas Transmission pipeline system. The other two events were the result of a tropical storm and hurricane in the Gulf of Mexico that disrupted a portion of our contracted natural gas supplies.

Q. What measures did Progress Energy take during these force majeure events to maintain the load of its customers?

A. Progress Energy continued to serve customer load through the increased use of residual (No. 6) and distillate (No. 2) oil during the force majeure events that occurred on Florida Gas Transmission pipeline system. During the tropical storm and hurricane force majeure events, the Company again used No. 2 fuel oil to the extent necessary, and worked with Gulfstream Natural Gas to use a portion of the excess gas in their pipeline until production resumed. When necessary, the Company also initiated demand-side management and voltage reductions during the force majeure periods.

Q. What measures did Progress Energy undertake to minimize other risks identified in its Risk Management Plan?

A. Progress Energy continued to perform its daily management activities outlined in the Plan to monitor and, to the extent possible, mitigate risks to customers.

Q. Did Progress Energy follow the processes and guidelines outlined in the Plan?

A. Yes, all processes and guidelines were followed.

Q. What actions, including hedging activities, did Progress Energy take in 2002 to control the cost of fuel and wholesale power transactions?

A. With respect to natural gas, Progress Energy elected to enter into a zero-cost collar (a price floor and ceiling obtained at no cost) for 20,000 mmbtu per day supply of gas for the three-month period of December 2002 through February 2003. Although prices were within the collar in December and therefore had no effect on 2002 fuel costs, it provided savings of $198,800 over the remaining two months in 2003. Progress Energy also has one fixed price contract it acquired with the purchase of its Tiger Bay generating unit that resulted in an additional cost to the ratepayers of $2,098,791 in 2002. However, this contract has now turned around relative to the market, and currently has a projected net savings to customers through 2010 of approximately $33 million.

With respect to residual oil, the Company continued to utilize a option under one of its contracts to fix the price on selected shipments. Although this resulted in a net additional cost to customers of $1,533,222 in 2002, it has produced additional savings in the first two months of 2003 of $356,333.

In addition, the Company made economic off-system wholesale power purchases, as well as wholesale power sales to third parties, that resulted in reduced fuel costs to its customers of $12,641,859.

Overall, the total net value created for customers in 2002 by these fuel and wholesale power activities was a savings of over $9 million.

Q. Does this conclude your testimony?

A. Yes, it does.

PROGRESS ENERGY FLORIDA

Docket No. 030001-EI

GPIF Reward/Penalty Amount for January through December 2002

DIRECT TESTIMONY OF MICHAEL F. JACOB

Q. Please state your name and business address.

A. My name is Michael F. Jacob. My business address is 410 South Wilmington Street, Raleigh, North Carolina, 27601.

Q. By whom are you employed and in what capacity?

A. I am employed by Progress Energy Carolinas as Manager of Generation Modeling and Analysis.

Q. Have your responsibilities as Manager of Generation Modeling and Analysis remained the same since you last testified in this proceeding?

A. Yes, my responsibilities regarding the preparation of the Generation Performance Incentive Factor (GPIF) filing requirements for Progress Energy Florida (the Company) have remained the same.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to describe the calculation of the Company's GPIF reward/penalty amount for the period of January through December 2002. This calculation was based on a comparison of 2002 actual performance data for the Company's nine GPIF generating units with the approved performance targets set for these units prior to the period.

Q. Do you have an exhibit to your testimony in this proceeding?

A. Yes, I am sponsoring Exhibit No. _______ (MFJ-1), which consists of the schedules required by the GPIF Implementation Manual to support the development of the incentive amount. This 28-page exhibit is attached to my prepared testimony and includes as its first page an index to the contents of the exhibit.

Q. What GPIF incentive amount have you calculated for this period?

A. I have calculated the Company's GPIF incentive amount to be a reward of $2,781,223. This amount was developed in a manner consistent with the GPIF Implementation Manual. Page 2 of my exhibit shows the calculation of system GPIF points and the corresponding reward. The summary of weighted incentive points earned by each individual unit can be found on page 4 of my exhibit.

Q. How were the incentive points for equivalent availability and heat rate calculated for the individual GPIF units?

A. The calculation of incentive points is made by comparing the adjusted actual performance data for equivalent availability and heat rate to the target performance indicators for each unit. This comparison is shown on each unit's Generating Performance Incentive Points Table found on pages 9 through 17 of my exhibit.

Q. Why is it necessary to make adjustments to the actual performance data for comparison with the targets?

A. Adjustments to the actual equivalent availability and heat rate data are necessary to allow their comparison with the "target" Point Tables exactly as approved by the Commission prior to the period. These adjustments are described in the Implementation Manual and are further explained by a Staff memorandum, dated October 23, 1981, directed to the GPIF utilities. The adjustments to actual equivalent availability concern primarily the differences between target and actual planned outage hours, and are shown on page 7 of my exhibit. The heat rate adjustments concern the differences between the target and actual Net Output Factor (NOF), and are shown on page 8. The methodology for both the equivalent availability and heat rate adjustments are explained in the Staff memorandum.

Q. Have you provided the as-worked planned outage schedules for the Company's GPIF units to support your adjustments to actual equivalent availability?

A. Yes. Page 27 of my exhibit summarizes the planned outages experienced by the Company's GPIF units during the period. Page 28 presents an as-worked schedule for each individual planned outage.

Q. Does this conclude your testimony?

A. Yes.

PROGRESS ENERGY FLORIDA

DOCKET NO. 030001-EI

GPIF Targets and Ranges for January through December 2004

DIRECT TESTIMONY OF MICHAEL F. JACOB

Q. Please state your name and business address.

A. My name is Michael F. Jacob. My business address is 410 South Wilmington Street, Raleigh, North Carolina, 27601.

Q. By whom are you employed and in what capacity?

A. I am employed by Progress Energy Carolinas as Manager of Generation Modeling and Analysis.

Q. Have your responsibilities as Manager of Generation Modeling and Analysis remained the same since you last filed testimony in this proceeding?

A. Yes, my responsibilities regarding the preparation of the Generation Performance Incentive Factor (GPIF) filing requirements for Progress Energy Florida (the Company) have remained the same.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present the development of the Company's GPIF targets and ranges for the period of January through December 2004. These GPIF targets and ranges have been developed from individual unit equivalent availability and average net operating heat rate targets and improvement/degradation ranges for each of the Company's GPIF generating units, in accordance with the Commission's GPIF Implementation Manual.

Q. Do you have an exhibit to your testimony in this proceeding?

A. Yes, I am sponsoring Exhibit No. ____ (MFJ-1) which consists of the GPIF standard form schedules prescribed in the GPIF Implementation Manual and supporting data, including unplanned outage rates, net operating heat rates, and computer analyses and graphs for each of the individual GPIF units. This 95-page exhibit is attached to my prepared testimony and includes as its first page an index to the contents of the exhibit.

Q. Which of the Company's generating units have you included in the GPIF program for the upcoming projection period?

A. For the 2004 projection period, the GPIF units are the same as for the current period, Anclote Unit 2, Crystal River Units 1 through 5, and Hines Unit 1, plus two additional units, Anclote Unit 1 and Tiger Bay. Combined, these units account for 81.7% of the estimated total system net generation for the period.

The Company's Hines Unit 2, which is expected to achieve commercial operation in late 2003, was not included for the upcoming projection period since there is no performance history on which to set targets for the unit. However, the additional generation the unit is expected to provide required the inclusion of Anclote Unit 1 and Tiger Bay to satisfy the requirement that GPIF units account for at least 80% of total system net generation.

Q. Have you determined the equivalent availability targets and improvement/degradation ranges for the Company's GPIF units?

A. Yes. This information is included in the GPIF Target and Range Summary on page 4 of my exhibit.

Q. How were the equivalent availability targets developed?

A. The equivalent availability targets were developed using the methodology established for the Company's GPIF units, as set forth in Section 4 of the GPIF Implementation Manual. This includes the formulation of graphs based on each unit's historic performance data for the four individual unplanned outage rates (i.e., forced, partial forced, maintenance and partial maintenance outage rates), which in combination constitute the unit's equivalent unplanned outage rate (EUOR). From operational data and these graphs, the individual target rates are determined by inspecting two years of twelve-month rolling averages and the scatter of monthly data points during the two-year period. The unit's four target rates are then used to calculate its unplanned outage hours for the projection period. When the unit's projected planned outage hours are taken into account, the hours calculated from these individual unplanned outage rates can then be converted into an overall equivalent unplanned outage factor (EUOF). Because factors are additive (unlike rates), the unplanned and planned outage factors (EUOF and POF) when added to the equivalent availability factor (EAF) will always equal 100%. For example, an EUOF of 15% and POF of 10% results in an EAF of 75%.

The supporting tables and graphs for the target and range rates are contained in pages 49-95 of my exhibit in the section entitled "Unplanned Outage Rate Tables and Graphs."

Q. Please describe the methodology utilized to develop the improvement/degradation ranges for each GPIF unit's availability targets?

A. The methodology described in the GPIF Implementation Manual was used. Ranges were first established for each of the four unplanned outage rates associated with each unit. From an analysis of the unplanned outage graphs, units with small historical variations in outage rates were assigned narrow ranges and units with large variations were assigned wider ranges. These individual ranges, expressed in term of rates, were then converted into a single unit availability range, expressed in terms of a factor, using the same procedure described above for converting the availability targets from rates to factors.

Q. Have you determined the net operating heat rate targets and ranges for the Company's GPIF units?

A. Yes. This information is included in the Target and Range Summary on page 4 of my exhibit.

Q. How were these heat rate targets and ranges developed?

A. The development of the heat rate targets and ranges for the upcoming period utilized historical data from the past three years, as described in the GPIF Implementation Manual. A "least squares" procedure was used to curve-fit the heat rate data within ranges having a 90% confidence level of including all data. The analyses and data plots used to develop the heat rate targets and ranges for each of the GPIF units are contained in pages 30-48 of my exhibit in the section entitled "Average Net Operating Heat Rate Curves."

Q. How were the GPIF incentive points developed for the unit availability and heat rate ranges?

A. GPIF incentive points for availability and heat rate were developed by evenly spreading the positive and negative point values from the target to the maximum and minimum values in case of availability, and from the neutral band to the maximum and minimum values in the case of heat rate. The fuel savings (loss) dollars were evenly spread over the range in the same manner as described for incentive points. The maximum savings (loss) dollars are the same as those used in the calculation of the weighting factors.

Q. How were the GPIF weighting factors determined?

A. To determine the weighting factors for availability, a series of PROSYM simulations were made in which each unit's maximum equivalent availability was substituted for the target value to obtain a new system fuel cost. The differences in fuel costs between these cases and the target case determines the contribution of each unit's availability to fuel savings. The heat rate contribution of each unit to fuel savings was determined by multiplying the BTU savings between the minimum and target heat rates (at constant generation) by the average cost per BTU for that unit. Weighting factors were then calculated by dividing each individual unit's fuel savings by total system fuel savings.

Q. What was the basis for determining the estimated maximum incentive amount?

A. The determination of the maximum reward or penalty was based upon monthly common equity projections obtained from a detailed financial simulation performed by the Company's Corporate Model.

Q. What is the Company's estimated maximum incentive amount for 2004?

A. The estimated maximum incentive for the Company is $8,552,779. The calculation of the estimated maximum incentive is shown on page 3 of my exhibit.

Q. Does this conclude your testimony?

A. Yes, it does.

TAMPA ELECTRIC COMPANY
DOCKET NO. 030001-EI
FILED: 04/01/03

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

WILLIAM A. SMOTHERMAN

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

A. My name is William A. Smotherman. My mailing and business address is Post Office Box 111, Tampa, Florida 33601. I am employed by Tampa Electric Company ("Tampa Electric" or "company") in the position of Director, Resource Planning in the Resource Planning Department.

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

A. I received a Bachelor of Electrical Engineering degree in 1986 from University of South Florida in Tampa, Florida. In May 1986, I joined Tampa Electric as an associate engineer. I have been employed by Tampa Electric for 15 years working in the areas of system planning, commercial/ industrial account management and wholesale power marketing. In February 2001, I was promoted to Director, Resource Planning. My present responsibilities include the areas of system reliability, generation expansion and system fuel and purchased power forecasting and related economic analyses.

Q. What is the purpose of your testimony?

A. My testimony presents Tampa Electric's actual performance results from unit equivalent availability and station heat rate used to determine the Generating Performance Incentive Factor (GPIF) for the period January 2002 through December 2002. I will also compare these results to the targets established prior to the beginning of the period.

Q. Have you prepared any exhibits to support your testimony?

A. Yes, Exhibit No. _____ (WAS-1), consisting of two documents, was prepared under my direction and supervision. Document No. 1, entitled "Tampa Electric Company, Generating Performance Incentive Factor, January 2002 - December 2002, True-up" is consistent with the GPIF Implementation Manual previously approved by the Commission. In addition, Document No. 2, provides the company's Actual Unit Performance Data for the January 2002 - December 2002 period.

Q. Which generating units on Tampa Electric's system are included in the determination of the GPIF?

A. Seven of the company's units are included. These are Big Bend Station Units 1, 2, 3, and 4, Gannon Station Units 5 and 6, and Polk Station Unit 1.

Q. Have you calculated the results of Tampa Electric's performance under the GPIF during this period?

A. Yes, this is shown on Document No. 1, page 4 of 32. Based upon -4.385 GPIF points, the result is a penalty amount of $2,496,021 for the period.

Q. Please proceed with your review of the actual results for the January 2002 - December 2002 period.

A. On Document No. 1, page 3 of 32, the actual average common equity for the period is shown on line 14 as $1,452,018,692. This produces the maximum penalty or reward figure of $5,691,728 as shown on line 21.

Q. Will you please explain how you arrived at the actual equivalent availability results for the seven included within the GPIF?

A. Yes, operating data on each of our units is filed monthly with the Florida Public Service Commission on the Actual Unit

Performance Data form. Additionally, outage information is reported to the Commission on a monthly basis. A summary of this data for the twelve months provides the basis for the GPIF.

Q. Are the equivalent availability results shown on Document No. 1, page 6 of 32, column 2, directly applicable to the GPIF table?

A. Not exactly. Adjustments to equivalent availability may be required as noted in section 4.3.3 of the GPIF Manual. The actual equivalent availability including the required adjustment is shown on Document No. 1, page 6 of 32. The necessary adjustments as prescribed in the GPIF Manual are further defined by a letter dated October 23, 1981, from Mr. J.H. Hoffsis of the Commission's Staff. The adjustments for each unit are as follows:

Big Bend Unit No. 1

On this unit, 336 planned outage hours were originally scheduled for 2002. Actual outage activities required 372.6 planned outage hours. Consequently, the actual equivalent availability of 70.7% is adjusted to 71.1% as shown on Document No. 1, page 7 of 32.

Big Bend Unit No. 2

On this unit, 1,681 planned outage hours were originally scheduled for 2002. Actual outage activities required 2,038.5 planned outage hours. Consequently, the actual equivalent availability of 49.6% is adjusted to 52.4% as shown on Document No. 1, page 8 of 32.

Big Bend Unit No. 3

On this unit, 1,344 planned outage hours were originally scheduled for 2002. Actual outage activities required 1,420.6 planned outage hours. Consequently, the actual equivalent availability of 53.2% is adjusted to 53.8% as shown on Document No. 1, page 9 of 32.

Big Bend Unit No. 4

On this unit, 504 planned outage hours were originally scheduled for 2002. Actual outage activities required 537.8 planned outage hours. Consequently, the actual equivalent availability of 84.0% is adjusted to 84.3% as shown on Document No. 1, page 10 of 32.

Gannon Unit No. 5

On this unit, 1,344 planned outage hours were originally scheduled for 2002. Actual outage activities required 1,824.2 planned outage hours. Consequently, the actual equivalent availability of 61.0% is adjusted to 65.2% as shown on Document No. 1, page 11 of 32.

Gannon Unit No. 6

On this unit, 1,584 planned outage hours were originally scheduled for 2002. Actual outage activities required 1,803.5 planned outage hours. Consequently, the actual equivalent availability of 59.8% is adjusted to 61.6%, as shown on Document No. 1, page 12 of 32.

Polk Unit No. 1

On this unit, 672 planned outage hours were originally scheduled for 2002. Actual outage activities required 199.1 planned outage hours. Consequently, the actual equivalent availability of 89.5% is adjusted to 84.6%, as shown on Document No. 1, page 13 of 32.

Q. How did you arrive at the applicable equivalent availability points for each unit?

A. The final adjusted equivalent availabilities for each unit are shown on Document No. 1, page 6 of 32, column 4. This number is entered into the respective Generating Performance Incentive Point (GPIP) Table for each particular unit on pages 24 of 32 through 30 of 32. Page 4 of 32 summarizes the equivalent availability points to be awarded or penalized.

Q. Will you please explain the heat rate results relative to the GPIF?

A. The actual heat rate and adjusted actual heat rate for Big Bend Units 1, 2, 3, and 4, Gannon Units 5 and 6 and Polk Unit 1 are shown on page Document No. 1, page 6 of 32. The adjustment was developed based on the guidelines of section 4.3.16 of the GPIF Manual. This procedure is further defined by a letter dated October 23, 1981, from Mr. J.H. Hoffsis of the FPSC Staff. The final adjusted actual heat rates are also shown on page 5 of 32. This heat rate number is entered into the respective GPIP table for the particular unit, shown on pages 24 of 32 through 30 of 32. Page 4 of 32 summarizes the weighted heat rate and equivalent availability points to be awarded.

Q. What is the overall GPIP for Tampa Electric Company during this twelve month period?

A. This is shown on Document No. 1, page 32 of 32. Essentially, the weighting factors shown on page 4 of 32, column 3, plus the equivalent availability points and the heat rate points shown on page 4 of 32, column 4, are substituted within the equation. This resultant value, -4.385, is then entered into the GPIF table on page 2 of 32. Using linear interpolation, a penalty amount of $2,496,021 is calculated.

Q. Does this conclude your testimony?

A. Yes, it does.

TAMPA ELECTRIC COMPANY
DOCKET NO. 030001-EI
FILED: 9/12/03

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

WILLIAM A. SMOTHERMAN

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

A. My name is William A. Smotherman. My mailing and business address is 702 N. Franklin Street, Tampa, Florida 33602. I am employed by Tampa Electric Company ("Tampa Electric" or "company") as the Director of the Resource Planning Department.

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

A. I received a Bachelor of Electrical Engineering degree in 1986 from the University of South Florida. In May 1986, I joined Tampa Electric as an associate engineer, and I have worked in the areas of system planning, commercial/ industrial account management and wholesale power marketing. In February 2001, I was promoted to Director, Resource Planning. My present responsibilities include the areas of system reliability, generation expansion and system fuel and purchased power forecasting and related economic analyses.

Q. What is the purpose of your testimony?

A. My testimony presents Tampa Electric's methodology for determining the various factors required to compute the Generating Performance Incentive Factor (GPIF) as ordered by the Commission.

Q. Have you prepared any exhibits to support your testimony?

A. Yes, Exhibit No. _____ (WAS-2), consisting of two documents, was prepared under my direction and supervision. Document No. 1 is titled "Generating Performance Incentive Factor January 2004 - December 2004." Document No. 2 is a summary of the GPIF targets for the 2004 period.

Q. Which generating units on Tampa Electric's system are included in the determination of the GPIF?

A. Four of the company's coal-fired units and one integrated gasification combined cycle unit are included. These are Big Bend Station Units 1, 2, 3, and 4, and Polk Power

Station Unit 1.

Q. Do the exhibits you have prepared comply with Commission-approved GPIF methodology?

A. Yes, the documents are consistent with the GPIF Implementation Manual previously approved by the Commission, with the exception of the criterion that the company shall include generating units that will represent not less than 80 percent of projected system net generation.

Q. Please explain.

A. Due to the repowering of Gannon Units 5 and 6 to Bayside Units 1 and 2, the remaining GPIF units do not represent 80 percent of projected system net generation. Although Bayside Unit 1 began operation in 2003, the repowered unit is not included in the GPIF calculations because the company does not have the historical operational data required by the GPIF Implementation manual to set GPIF targets. For the same reason, Bayside Unit 2, which is expected to be in service in January 2004, is not included in the GPIF calculations. Tampa Electric has no other base load generating units to substitute for Gannon Units

5 and 6. Therefore, Tampa Electric requests approval of its 2004 GPIF calculation excluding the repowered units, as provided for by Section 3.2 of the GPIF Implementation Manual, which states that the Commission will approve exclusion of units from the calculation of the GPIF on a case-by-case basis.

Q. Did the shutdown of Gannon Units 1 through 4 in 2003 affect the calculation of Tampa Electric's GPIF targets and ranges?

A. No. First, these Gannon Units have never been included in the GPIF calculation. Second, the GPIF units are base load units that are all economically dispatched prior to Gannon Units 1 through 4. Therefore, as the GPIF units' availabilities vary, the absolute system fuel cost numerical value may be different, but the relative penalty or savings for each of the GPIF units is not affected.

Q. Please describe how Tampa Electric developed the various factors associated with the GPIF.

A. Targets were established for equivalent availability and heat rate for each unit considered for the 2004 period. A range of potential improvements and degradations was determined for each of these parameters.

Q. How were the target values for unit availability determined?

A. The Planned Outage Factor ("POF") and the Equivalent Unplanned Outage Factor ("EUOF") were subtracted from 100% to determine the target Equivalent Availability Factor ("EAF"). The factors for each of the five units included within the GPIF are shown on page 5 of Document No. 1.

To give an example for the 2004 period, the projected Equivalent Unplanned Outage Factor for Big Bend Unit 1 is 27.11% and the Planned Outage Factor is 5.74%. Therefore, the target equivalent availability factor for Big Bend Unit 1 equals 67.15% or:

$$100\% - [(27.11\% + 5.74\%)] = 67.15\%$$

This is shown on page 4, column 3 of Document No. 1.

Q. How was the potential for unit availability improvement determined?

A. Maximum equivalent availability is derived by using the following formula:

$$EAF_{MAX} = 100\% - [0.8\ (EUOF_T) + 0.95\ (POF_T)]$$

The factors included in the above equations are the same factors that determine the target equivalent availability. To determine the maximum incentive points, a 20% reduction in Equivalent Forced Outage Factor ("EUOF") and Equivalent Maintenance Outage Factor ("EMOF"), plus a 5% reduction in the Planned Outage Factor are necessary. Continuing with the Big Bend Unit 1 example:

$$EAF_{MAX} = 100\% - [0.8\ (27.11\%) + 0.95\ (5.74\%)] = 72.90\%$$

This is shown on page 4, column 4 of Document No. 1.

Q. How was the potential for unit availability degradation determined?

A. The potential for unit availability degradation is significantly greater than the potential for unit availability improvement. This concept was discussed extensively and approved in earlier hearings before the Commission. To incorporate this biased effect into the unit availability tables, Tampa Electric uses a potential degradation range equal to twice the potential improvement. Consequently, minimum equivalent availability is calculated using the following formula:

$$EAF_{MIN} = 100\% - [1.4 \ (EUOF_T) + 1.10 \ (POF_T)]$$

Again, continuing with the Big Bend Unit 1 example,

$$EAF_{MIN} = 100\% - [1.4 \ (27.11\%) + 1.1 \ (5.74\%)] = 55.73\%$$

The equivalent availability MAX and MIN for the other four units is computed in a similar manner.

Q. How did Tampa Electric determine the Planned Outage, Maintenance Outage, and Forced Outage Factors?

A. The company's planned outages for January 2004 through December 2004 are shown on page 17 of Document No. 1. Since no GPIF units have a major outage (greater than 28 days) in 2004 no Critical Path Method diagrams are provided in this testimony. Planned Outage Factors are calculated for each unit. For example, Big Bend Unit 1 is scheduled for a planned outage November 13, 2004 through December 3, 2004. There are 504 planned outage hours scheduled for the 2004 period, and a total of 8,784 hours during this 12-month period. Consequently, the Planned Outage Factor for Unit 1 at Big Bend is 5.74% or:

$$\frac{504}{8{,}784} \times 100\% = 5.74\%$$

The factor for each unit is shown on pages 5 and 12 through 16 of Document No. 1. Big Bend Unit 2 has a Planned Outage Factor of 5.74%. Big Bend Unit 3 has a Planned Outage Factor of 5.74%. Big Bend 4 has a Planned Outage Factor of 5.74%. Polk Unit 1 has a Planned Outage Factor of 4.37%.

Q. How did you determine the Forced Outage and Maintenance Outage Factors for each unit?

A. Graphs for both factors (adjusted for planned outages) versus time were prepared. Monthly data and 12-month rolling average data were recorded. For each unit the most current 12-month ending value, June 2003, was used as a basis for the projection. This value was adjusted by analyzing trends and causes for recent forced and maintenance outages. All projected factors are based upon historical unit performance, engineering judgment, time since last planned outage, and equipment performance resulting in a forced or maintenance outage. These target factors are additive and result in an Equivalent Unplanned Outage Factor of 27.11% for Big Bend Unit 1. The

Equivalent Unplanned Outage Factor for Big Bend Unit 1 is verified by the data shown on page 12, lines 3, 5, 10 and 11 of Document No. 1 and calculated using the following formula:

$$EUOF = \frac{(FOH + EFOH + MOH + EMOH)}{\text{Period Hours}} \times 100$$

Or

$$EUOF = \frac{(1,875.1 + 506.4)}{8,784} \times 100 = 27.11\%$$

Relative to Big Bend Unit 1, the EUOF of 27.11% forms the basis of the equivalent availability target development as shown on pages 4 and 5 of Document No. 1.

Big Bend Unit 1

The projected Equivalent Unplanned Outage Factor for this unit is 27.11%. This unit will have a planned outage in 2004 and the Planned Outage Factor is 5.74%. Therefore, the target equivalent availability for this unit is 67.15%.

Big Bend Unit 2

The projected Equivalent Unplanned Outage Factor for this unit is 27.57%. This unit will have a planned outage in

2004 and the Planned Outage Factor is 5.74%. Therefore, the target equivalent availability for this unit is 66.69%.

Big Bend Unit 3

The projected Equivalent Unplanned Outage Factor for this unit is 26.66%. This unit will have a planned outage in 2004 and the Planned Outage Factor is 5.74%. Therefore, the target equivalent availability for this unit is 67.60%.

Big Bend Unit 4

The projected Equivalent Unplanned Outage Factor for this unit is 16.09%. This unit will have a planned outage in 2004 and the Planned Outage Factor is 5.74%. Therefore, the target equivalent availability for this unit is 78.18%.

Polk Unit 1

The projected Equivalent Unplanned Outage Factor for this unit is 10.03%. This unit will have a planned outage in 2004 and the Planned Outage Factor is 4.37%. Therefore, the target equivalent availability for this unit is 85.60%.

Q. Please summarize your testimony regarding Equivalent Availability Factor.

A. The GPIF system weighted Equivalent Availability Factor of 69.8% is shown on Page 5 of Document No. 1. This target compares favorably to the July 2002 - June 2003 GPIF period.

Q. When graphing and monitoring Forced and Maintenance Outage Factors, why are they adjusted for planned outage hours?

A. The adjustment makes the factors more accurate and comparable. Obviously, a unit in a planned outage stage or reserve shutdown stage will not incur a forced or maintenance outage. Since the units in the GPIF are usually base loaded, reserve shutdown is generally not a factor.

To demonstrate the effects of a planned outage, note the Equivalent Unplanned Outage Rate and Equivalent Unplanned Outage Factor for Big Bend Unit 1 on page 12 of Document No. 1. During the months of January through October, the Equivalent Unplanned Outage Rate and the Equivalent Unplanned Outage Factor are equal. This is due to the fact that no planned outages are scheduled during these months. During the months of November and December, Equivalent Unplanned Outage Rate exceeds Equivalent Unplanned Outage Factor due to the scheduling of a planned outage. Therefore, the adjusted factors apply to the period hours after the planned outage hours have been extracted.

Q. Does this mean that both rate and factor data are used in calculated data?

A. Yes. Rates provide a proper and accurate method of determining the unit parameters, which are subsequently converted to factors. Therefore,

$$FOF + MOF + POF + EAF = 100\%$$

Since factors are additive, they are easier to work with and to understand.

Q. Has Tampa Electric prepared the necessary heat rate data required for the determination of the GPIF?

A. Yes. Target heat rates as well as ranges of potential operation have been developed as required.

Q. How were these targets determined?

A. Net heat rate data for the three most recent July through June annual periods formed the basis of the target development. The historical data and the target values are analyzed to assure applicability to current conditions of operation. This provides assurance that any periods of abnormal operations or equipment modifications having material effect on heat rate can be taken into consideration.

Q. The accomplishment of scrubbing the flue gas from Big Bend Units 1 and 2 requires an additional amount of station service power. How did you address the associated effect to net heat rate for GPIF purposes?

A. The change in heat rate for these units resulting from utilization of the new scrubber can be quantified. In past filings, the operational history with the scrubber was short of GPIF guidelines; and therefore, targets for Big Bend Units 1 and 2 were developed using data without scrubber power. This method was approved by the Commission for Big Bend Unit 3 when it began scrubbing operation. Tampa Electric has previously stated that it would utilize the aforementioned method until there was sufficient history to meet target preparation guidelines. There now exists sufficient history with the scrubber operating to meet the GPIF target preparation guidelines. Therefore, Tampa Electric calculated the 2004 heat rate targets for these units with scrubber power included and will calculate it in the same way for the 2004 period true-up filing to ensure compatibility of data for all GPIF calculations.

Q. Have you developed the heat rate targets in accordance with GPIF guidelines?

A. Yes.

Q. How were the ranges of heat rate improvement and heat rate degradation determined?

A. The ranges were determined through analysis of historical net heat rate and net output factor data. This is the same data from which the net heat rate versus net output factor curves have been developed for each unit. This information is shown on pages 24 through 28 of Document No. 1.

Q. Please elaborate on the analysis used in the determination of the ranges.

A. The net heat rate versus net output factor curves are the result of a first order curve fit to historical data. The standard error of the estimate of this data was determined, and a factor was applied to produce a band of potential improvement and degradation. Both the curve fit and the standard error of the estimate were performed by computer program for each unit. These curves are also used in post period adjustments to actual heat rates to account for unanticipated changes in unit dispatch.

Q. Please summarize your heat rate projection (Btu/Net kWh) and the range about each target to allow for potential improvement or degradation for the 2004 period.

A. The heat rate target for Big Bend Unit 1 is 10,708 Btu/Net kWh. The range about this value, to allow for potential improvement or degradation, is ±504 Btu/Net kWh. The heat rate target for Big Bend Unit 2 is 10,384 Btu/Net kWh with a range of ±563 Btu/Net kWh. The heat rate target for Big Bend Unit 3 is 10,278 Btu/Net kWh, with a range of ±656 Btu/Net kWh. The heat rate target for Big Bend Unit 4 is 10,272 Btu/Net kWh with a range of ±505 Btu/Net kWh. The heat rate target for Polk Unit 1 is 10,569 Btu/Net kWh with a range of ±434 Btu/Net kWh. A zone of tolerance of ±75 Btu/Net kWh is included within the range for each target. This is shown on page 4, and pages 7 through 11 of Document No. 1.

Q. Do the heat rate targets and ranges in Tampa Electric's projection meet the criteria of the GPIF and the philosophy of the Commission?

A. Yes.

Q. After determining the target values and ranges for average net operating heat rate and equivalent availability, what is the next step in the GPIF?

A. The next step is to calculate the savings and weighting factor to be used for both average net operating heat rate and equivalent availability. This is shown on pages 7 through 11. The a baseline production costing analysis was performed to calculate the total system fuel cost if all units operated at target heat rate and target availability for the period. This total system fuel cost of $665,093 is shown on page 6, column 2.

Multiple production costing simulations were then performed to calculate total system fuel cost with each unit individually operating at maximum improvement in equivalent availability and each station operating at maximum improvement in average net operating heat rate. The respective savings are shown on page 6, column 4 of Document No. 1.

After all of the individual savings are calculated column 4 totals $27,344,800, which reflects the savings if all of the units operated at maximum improvement. A weighting factor for each parameter is then calculated by dividing individual savings by the total. For Big Bend Unit 1, the weighting factor for equivalent availability is 14.90% as shown in the right-hand column on page 6. Pages 7 through 11 of Document No. 1 show the point table, the Fuel Savings/(Loss) and the equivalent availability or heat rate value. The individual weighting factor is also shown. For example, on Big Bend Unit 1, page 7, if the unit operates at 72.9% equivalent availability, fuel savings would equal $4,074,500 and ten equivalent availability points would be awarded.

The GPIF Reward/Penalty Table on page 2 is a summary of the tables on pages 7 through 11. The left-hand column of this document shows the incentive points for Tampa

Electric. The center column shows the total fuel savings and is the same amount as shown on page 6, column 4, $27,344,800. The right hand column of page 2 is the estimated reward or penalty based upon performance.

Q. How were the maximum allowed incentive dollars determined?

A. Referring to page 3, line 14, the estimated average common equity for the period January through December 2004 is $1,450,831,850. This produces the maximum allowed jurisdictional incentive dollars of $5,752,609 shown on line 21.

Q. Are there any other constraints set forth by the Commission regarding the magnitude of incentive dollars?

A. Yes. Incentive dollars are not to exceed 50 percent of fuel savings. Page 2 of Document No. 1 demonstrates that this constraint is met.

Q. Please summarize your testimony on the GPIF.

A. Tampa Electric has complied with the Commission's directions, philosophy, and methodology in our determination of GPIF. The GPIF is determined by the following formula for calculating Generating Performance Incentive Points (GPIP):

$$GPIP: = (0.1490\ EAP_{BB1} + 0.1604\ EAP_{BB2} + 0.1398\ EAP_{BB3} + 0.1047\ EAP_{BB4} + 0.0209\ EAP_{PK1} + 0.0758\ HRP_{BB1} + 0.0885\ HRP_{BB2} + 0.1033\ HRP_{BB3} + 0.1030\ HRP_{BB4} + 0.0546\ HRP_{PK1})$$

Where:

GPIP = Generating Performance Incentive Points.

EAP = Equivalent Availability Points awarded/deducted for Big Bend Units 1, 2, 3 and 4 and Polk Unit 1.

HRP = Average Net Heat Rate Points awarded/deducted for Big Bend Units 1, 2, 3 and 4 and Polk Unit 1.

Q. Have you prepared a document summarizing the GPIF targets for the January 2004 - December 2004 period?

A. Yes. Document No. 2 entitled "Tampa Electric Company, Summary of GPIF Targets, January 2004 - December 2004" provides the availability and heat rate targets for each unit.

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

TESTIMONY OF J. R. HARTZOG

DOCKET NO. 030001-EI

September 12, 2003

Q. Please state your name and address.

A. My name is John R. Hartzog. My business address is 700 Universe Boulevard, Juno Beach, Florida 33408.

Q. By whom are you employed and what is your position?

A. I am employed by Florida Power & Light Company (FPL) as Manager, Nuclear Financial & Information Services in the Nuclear Business Unit.

Q. Have you previously testified in this docket?

A. Yes, I have.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present and explain FPL's projections of nuclear fuel costs for the thermal energy (MMBTU) to be produced by our nuclear units, costs of disposal of spent nuclear fuel, costs of decontamination and decommissioning (D&D), additional plant security costs, the St. Lucie Unit 2 steam generator replacement, to update the inspections and repairs to the reactor pressure vessel heads since the issuance of NRC Bulletin (IEB) 2002-02, and to update the status of certain litigation that affects FPL's nuclear fuel costs. Both nuclear fuel and disposal of spent nuclear fuel costs were input values to POWERSYM used to calculate the costs to be included in the proposed fuel cost recovery factors for the period January 2004 through December 2004.

Nuclear Fuel Costs

Q. What is the basis for FPL's projections of nuclear fuel costs?

A. FPL's nuclear fuel cost projections are developed using energy production at our nuclear units and their operating schedules, for the period January 2004 through December 2004.

Spent Nuclear Fuel Disposal Costs

Q. Please provide FPL's projection for nuclear fuel unit costs and energy for the period January 2004 through December 2004.

A. FPL projects the nuclear units will produce 255,783,364 MMBTU of energy at a cost of $0.2699 per MMBTU, excluding spent fuel disposal costs, for the period January 2004 through December 2004.

Projections by nuclear unit and by month are in Appendix II, on Schedule E-3, starting on page 12.

Q. Please provide FPL's projections for spent nuclear fuel disposal costs for the period January 2004 through December 2004 and explain the basis for FPL's projections.

A. FPL's projections for spent nuclear fuel disposal costs of approximately $21.7 million are provided in Appendix II, on Schedule E-2, starting on page 10. These projections are based on FPL's contract with the U.S. Department of Energy (DOE), which sets the spent fuel disposal fee at 0.9303 mills per net kWh generated, which includes transmission and distribution line losses.

<u>Decontamination and Decommissioning Costs</u>

Q. Please provide FPL's projection for Decontamination and Decommissioning (D&D) costs to be paid in the period January 2004 through December 2004 and explain the basis for FPL's projection.

A. FPL's projection of $6.67 million for D&D costs is based on the amount to be paid during the Period January 2004 through December 2004 and is included in Appendix II, on Schedule E-2 starting on page 10.

Nuclear Plant Security Costs

Q. Please provide FPL's projection for heightened security costs to be paid in the period January 2004 through December 2004 and explain the basis for FPL's projection.

A. FPL's projection of $12 million for heightened security costs is based on the amount to be paid during the period January 2004 through December 2004. These costs are necessary to ensure FPL is in compliance with Nuclear Regulatory Commission (NRC) Order No. EA-02-26 dated February 25, 2002 and NRC Order Nos. EA-03-038, EA-03-039 and EA-03-086 dated April 29, 2003. Costs relate to additional security personnel, training, and equipment. Details on these security measures cannot be disclosed because such details have been determined to be "Safeguards Information" by the NRC, thereby prohibiting public disclosure.

Q. Please provide a summary of NRC Orders No. EA-03-038, EA-03-039 & EA-03-086 issued on April 29, 2003.

A. The NRC approved changes to the Design Basis Threat (DBT) and issued three Orders for Nuclear Power Plants to further enhance security. These Orders build on the changes made by Order EA-02-026 issued on February 25, 2002.

EA-03-086 requires power plants to implement additional protective actions to protect against sabotage by terrorist and other adversaries. Under NRC regulations, power reactor licensees must ensure that the physical protection plan for each site is designed and implemented to provide high assurance in defending against the DBT to ensure adequate protection of public health and safety and common defense security. This Order will result in extensive changes in those physical protection plans and will be subject to NRC approval. The details of the DBT are Safeguards Information and cannot be released to the public.

EA-03-038 describes additional measures related to security force personnel fitness for duty and security work hours. It is to ensure that excessive work hours do not compromise the ability of nuclear power plant security forces to remain vigilant and effectively perform their duties in protecting the plants.

EA-03-037 describes additional requirements related to the development and application of an enhanced training and qualification program for armed security personnel at power reactor facilities. These additional measures include security drills and exercises appropriate for the protective strategies and capabilities required to protect the nuclear power plants against sabotage by an assaulting force. This Order requires more frequent firearms training and qualification under a broader range of conditions consistent with site-specific protective strategies. The details of the enhanced training requirements are Safeguards Information, which cannot be released to the public.

Q. When are the NRC Orders issued on April 29, 2003 required to be implemented?

A. NRC Orders EA-03-086 and EA-03-039 must be fully implemented by October 29, 2004. EA-03-038 must be fully implemented by October 29, 2003. Of course, the process of implementing these orders takes a considerable period of time, so FPL's implementation efforts are already well underway.

Q. Provide a brief description of new items requested for clause recovery as a result of the NRC Orders issued on April 29, 2003.

A. Items requested include additional security personnel resulting from implementation of the fatigue order; increase in frequency of firearms training, drills, tactical training and increased physical agility criteria resulting from the training order; and addition of delay barriers, bullet resistant positions, additional weapons, vehicle barrier evaluations/modifications, strengthening of security plans, cyber security evaluations, & developing of a human reliability program resulting from the DBT order.

Q. Why is the Nuclear Regulatory Commission increasing the Part 171 Fees?

A. The NRC is amending its regulations for the licensing, inspection and annual fees it charges applicants and licensees for fiscal year (FY) 2003.

By law, the NRC must recover 94 percent of its budget for FY 2003 (October 1, 2002 - September 30, 2003). The amount to be recovered in FY 2003 includes $29 million appropriated for NRC activities related to homeland security. Homeland security costs were not included in the agency's fee base for FY 2002, and were appropriated from the Treasury's General Fund. The total amount to be recovered is about $47 million more than last year. $29 million or 62% of the $47 million increase is attributable to homeland security. FPL's projection for its portion of the NRC fees associated with homeland security is $1.5 million for 2004.

St. Lucie Unit 2 Steam Generator Replacement

Q. Please describe the results of the steam generator inspections during the Cycle 14 refueling outage at St. Lucie Unit 2.

A. During the scheduled refueling outage, the steam generators were inspected and more tubes had to be plugged than anticipated. The inspection results were evaluated and revised tube plugging projections were developed.

Q. What impact has this evaluation had on FPL's decision on whether to replace the St. Lucie Unit 2 steam generators?

A. As a result of this evaluation, FPL management anticipates replacing the steam generators at St. Lucie Unit 2 in 2007.

Q. What is the estimated cost to replace the steam generators at St. Lucie Unit 2?

A. The estimated cost for the steam generator replacement is approximately $224 million.

Q. How does the steam generator replacement project affect the reactor head replacement for St. Lucie Unit 2?

A. Unit 2 will have its reactor vessel head replaced during the 2007 outage. This project was previously planned for 2006, but will now be coordinated with the steam generator replacement project. The combined steam generator and reactor vessel head replacement effort will reduce total costs and the overall impact on Unit 2 operations.

<u>Reactor Pressure Vessel Head Inspection Status</u>

Q. What is the status of the reactor head inspections for the St. Lucie and Turkey Point Units since IEB 2002-02 has been issued?

A. The NRC issued IEB 2002-02 on August 9, 2002 to address concerns related to visual inspections of the reactor head. This bulletin resulted in all four FPL units being categorized as high susceptibility that will require ultrasonic testing in addition to visual inspections.

St. Lucie Unit 1 performed ultrasonic inspections during the refueling outage beginning on September 30, 2002. The total duration for the refueling outage was approximately 25 days. The inspections detected no indications and no repairs to the reactor head were necessary. The total cost of the inspections was approximately $6.15 million.

St. Lucie Unit 2 performed ultrasonic inspections during the refueling outage beginning on April 21, 2003. The total duration of the refueling outage was approximately 49 days. Indications were detected that resulted in repairs on 2 Control Element Drive Mechanism (CEDM) nozzles and additional inspections on 9 nozzles. The repairs resulted in an additional 14 days to the outage. The total cost of the inspections and repairs was approximately $11.1 million. Turkey Point Unit 3 performed ultrasonic inspections of the reactor vessel head during the refueling outage beginning on March 1, 2003. The total duration for the refueling outage was approximately 28 days. The inspections detected no indications and no repairs to the reactor head were necessary. The total cost of the inspections was approximately $5.25 million. Turkey Point Unit 4 is scheduled to perform ultrasonic inspections of the reactor head during the refueling outage scheduled in October 2003.

Litigation Status Update

Q. Are there currently any unresolved disputes under FPL's nuclear fuel contracts?

A. Yes.

1. Spent Fuel Disposal Dispute. The first dispute is under FPL's contract with the Department of Energy (DOE) for final disposal of spent nuclear fuel. In 1995, FPL along with a

number of electric utilities, states, and state regulatory agencies filed suit against DOE over DOE's denial of its obligation to accept spent nuclear fuel beginning in 1998. On July 23, 1996, the U.S. Court of Appeals for the District of Columbia Circuit (D.C. Circuit) held that DOE is required by the Nuclear Waste Policy Act (NWPA) to take title and dispose of spent nuclear fuel from nuclear power plants beginning on January 31, 1998.

On January 11, 2002, based on the Federal Circuit's ruling, the Court of Federal Claims granted FPL's motion for partial summary judgement in favor of FPL on contract liability.

All of the spent fuel damages cases are currently in discovery. There is no trial date scheduled at this time for the FPL damages claim.

2(a). Uranium Enrichment Pricing Disputes – FY 1993 Overcharges. FPL is currently seeking to resolve a pricing dispute concerning uranium enrichment services purchased from the United States (U.S.) Government, prior to July 1, 1993.

On August 20, 2001, the Court entered judgment for FPL for $6.075 million. DOE appealed the judgement to the Federal Circuit. On October 4, 2002, the Federal Circuit reversed the judgment and remanded the case back to the Court of Federal Claims for further consideration. The Federal Circuit directed the Court of Federal Claims to determine whether DOE had other appropriate, but unrecovered, costs sufficient to justify its FY 1993 SWU price. On May 28, 2003, the Court of Federal Claims granted the Government's motion for judgment on the record and dismissed FPL's claims, finding that DOE had other costs sufficient to justify its FY 1993 SWU price. FPL and the other utility plaintiffs have appealed the May 28 judgment to the Federal Circuit. That appeal is pending.

2(b). Uranium Enrichment Services Contract. DOE was required under FPL's uranium enrichment services contract with DOE to establish a price for enrichment services pursuant to DOE's established pricing policy, based on recovery of DOE's appropriate costs over a reasonable period of time. In the course of discovery in the FY1993 overcharge case discussed above, FPL and the other utility plaintiffs uncovered two other cost components that DOE improperly included in its cost recovery calculation. At trial in the

FY1993 case, FPL and the other plaintiffs asserted that these additional costs had been improperly included in DOE's cost recovery calculation for its FY1993 SWU price. The Court denied recovery on these issues, concluding that ruling on the merits of these issues would prejudice DOE in the particular chronology of the FY1993 litigation.

On October 10, 2001, FPL and 21 other U.S. and foreign utility plaintiffs filed new lawsuits in the U.S. Court of Federal Claims alleging that DOE breached the uranium enrichment services contract by inappropriately including two amounts in its cost recovery calculation in violation of the pricing provisions of the contracts: Imputed interest on the Gas Centrifuge Enrichment Project (GCEP) for FY1986 through FY1993, and costs relating to the production of high assay uranium (i.e., uranium produced primarily for military customers) (High Assay Costs) for FY1992 through FY1993.

<u>3. GCEP Claim</u>. In 1976, Congress first authorized the construction of GCEP as additional Government uranium enrichment capacity to meet the then-projected future demand. This future demand never materialized and, by 1985, DOE found itself in a plant over capacity position and the highest cost worldwide producer of enrichment

services. In 1985, DOE cancelled the GCEP and wrote-off the entire $3.6 billion from the DOE Uranium Enrichment Activity's 1986 financial statements relating to accumulated costs of plant construction, termination costs, and imputed interest associated with GCEP. DOE failed to exclude the entire $3.6 billion from its calculation in setting the uranium enrichment services price. Beginning in FY1986, DOE improperly left approximately $773 million of imputed interest in its cost recovery calculations and price determination. This amount is reflected in the calculation of the Contract's SWU price for FY1986 through FY1993. DOE determined that none of the capital costs of GCEP were used to provide enrichment services to customers. Additionally, under well-recognized economic and accounting principles, imputed interest should have been treated as inseparable from the underlying GCEP costs. Therefore, none of the capital investment in GCEP – neither the underlying principal nor the imputed interest - should have been included in the cost recovery calculation for the contract prices.

4. High Assay Costs. In 1991, DOE adjusted the financial statements of the Uranium Enrichment Activity by removing approximately $1.14 billion in accumulated losses and other costs relating to the production of High Assay uranium. DOE made this

adjustment based on its conclusion that the Uranium Enrichment Activity no longer had any responsibility for the High Assay program, which produced uranium for military purposes. Despite removing such costs from the financial statements, DOE improperly included approximately $394 million of High Assay costs in calculating the price for uranium enrichment services for FY1992 through FY1993.

FPL's lawsuit alleges that DOE breached the contract by including these costs in the uranium enrichment services price charged to FPL. FPL is claiming that it is owed a refund of $16,086,328.91 plus interest. FPL's lawsuit has been stayed by the Court of Federal Claims pending the outcome of the appeal of the judgment concerning the FY 1993 uranium enrichment claims, discussed in item 2(a) above.

Q. Does this conclude your testimony?

A. Yes, it does.

DIRECT TESTIMONY OF MICHAEL E. BUCKLEY

Q. Please state your name and business address.

A. My name is Michael E. Buckley and my business address is 2540 Shumard Oak Blvd., Tallahassee, Florida, 32399.

Q. By whom are you presently employed and in what capacity?

A. I am employed by the Florida Public Service Commission as a Professional Accountant Specialist in the Division of Auditing and Safety.

Q. How long have you been employed by the Commission?

A. I have been employed by the Florida Public Service Commission since July, 1989.

Q. Briefly review your educational and professional background.

A. I have a Bachelor of Business Administration with a major in accounting from Oklahoma University. I was hired as a Regulatory Analyst I by the Florida Public Service Commission on July 10, 1989 and was promoted to a Professional Accountant Specialist on June 1, 2000.

Q. Please describe your current responsibilities.

A. Currently, I am a Professional Accountant Specialist with the responsibilities of planning and directing the most complex investigative audits, including audits of cross-subsidization issues, anti-competitive behavior, and predatory pricing. I also am responsible for creating audit work programs to meet a specific audit purpose and integrating EDP applications into these programs. In addition, I serve as the acting supervisor in the absence of the district office supervisor.

Q. Have you presented expert testimony before this Commission or any other regulatory agency?

A. Yes. I have testified in the United Water Florida Inc. rate case, Docket No. 960451-WS.

Q. What is the purpose of your testimony today?

A. The purpose of my testimony is to sponsor two staff audit reports:

- Gulf Power Company: Base Year costs for hedging; Docket Number 030001-EI; Audit Control Number 02-340-1-1. A copy of the audit report is filed with my testimony and is identified as MEB-1.
- Gulf Power Company: Fuel Adjustment Audit; Docket No. 030001-EI; Audit Control Number 03-034-1-1. A copy of the audit report is filed with my testimony and is identified as MEB-2.

Q. Let's begin by discussing the first audit report, the Base Year audit. Did you prepare this audit report?

A. Yes, I was the audit manager in charge of the audit.

Q. Could you summarize the work you performed in this audit?

A. Yes. I obtained organization charts of Southern Company Services, Inc. to show what departments are involved in the physical and financial hedging process for the time period 1999 to 2003. I also obtained an employee count and charges and percentage allocations for these departments from 1999 to 2003 and compared actual costs for FERC Account #501 (Fuel Handling Expense) and FERC Account #547 (Other Fuel Handling Expense) to the estimated costs for the year 2002. I further compared the actual costs for FERC Account #501 (Fuel Handling Expense) and FERC Account #547 (Other Fuel Handling Expense) to the estimated costs for the first three months of 2003.

Q. Could you summarize your findings in this audit?

A. Yes, this report has one audit disclosure that summarizes our work and findings regarding the hedging costs at Gulf Power Company. Southern Company Services, Inc. (SCS), a subsidiary of Southern Company, charges its Fuel Services and Risk Management groups for financial hedging and other gas related activities. The Gas Procurement section in the SCS Fuel Services Organization procures physical gas, gas transportation, and gas storage, develops gas financial hedging strategy and executes financial hedging deals with counter parties. The Fuel Accounting group in the SCS Fuel Services Organization provides accounting services for gas procurement and gas financial hedging deals. The SCS Risk Management group confirms financial hedging deals with the counter parties, performs credit analysis on counter parties, performs overall risk analysis on financial hedging deals, and produces daily gas financial hedging reports. These charges are then allocated to affiliates. In 1999, 2000, 2001, and 2002, the methodology for allocations were determined by each affiliates' percent ownership of total installed fossil fuel fired capacity. For 2003, the methodology for allocations were determined by each affiliates' percent ownership of gas fired capacity for charges related to gas supply activities and each affiliates' percent ownership of coal fired capacity for charges related to coal supply activities. The estimated monthly administrative financial hedging charge for 2003 is $6,600. Gulf Power Company did not include any administrative financial hedging costs for the projected test year ended May 31, 2003, as filed in Docket No. 010949-EI.

Q. Now, in regard to the second audit report regarding the Gulf fuel adjustment audit, did you prepare this audit report?

A. Yes, I was involved in the preparation of ths audit report.

Q. Could you discuss the work performed in this audit?

A. Yes, the audit staff and I compiled the fuel cost of system net generation, and scanned and recomputed energy payments and fuel cost purchased power. As part of the audit, we verified prior year accounts to determine the accounting methodologies and procedures used by the company to account for incremental hedging costs and determined that the hedging program is consistent with the Company's risk management plan for 2002.

Q. Could you summarize your findings in this audit?

A. Audit Disclosure No. 1 discusses gains and losses on hedging settlements. Gulf Power Company recorded settlement costs of $38,750 to FERC Account 547-4 for November 2002. No administrative costs were charged for hedging in November or December 2002.

Q. Does this conclude your testimony?

A. Yes, it does.

DIRECT TESTIMONY OF JOCELYN Y. STEPHENS

Q. Please state your name and business address.

A. My name is Jocelyn Y. Stephens and my business address is 4950 West Kennedy Blvd., Suite 310, Tampa, Florida, 33609.

Q. By whom are you presently employed and in what capacity?

A. I am employed by the Florida Public Service Commission as a Regulatory Analyst IV in the Division of Auditing and Safety.

Q. How long have you been employed by the Commission?

A. I have been employed by the Florida Public Service Commission since January, 1977.

Q. Briefly review your educational background.

A. In 1972, I received a Bachelor of Science degree from Florida State University with a major in accounting. I am also a Certified Public Accountant licensed in the State of Florida.

Q. Please describe your current responsibilities.

A. Currently, I am a Regulatory Analyst IV with the responsibilities of planning and directing audits of regulated companies, and assisting in audits of affiliated transactions. I am also responsible for creating audit work programs to meet a specific audit purpose.

Q. Have you presented expert testimony before this Commission or any other regulatory agency?

A. Yes. I testified in the Florida Cities Water Co., (S. Ft. M.), transfer of certificate, Docket No. 910447-SU.

Q. What is the purpose of your testimony today?

A. The purpose of my testimony is to sponsor two staff audit reports:

- Tampa Electric Company (TECO): Base Year costs for security and hedging; Docket Number 030001-EI; Audit Control Number 02-340-2-1. A copy of the audit report is filed with my testimony and is identified as JYS-1.
- Tampa Electric Company: Capacity Cost Recovery Clause Audit; Docket No. 030001-EI; Audit Control Number 03-036-2-1. A copy of the audit report is filed with my testimony and is identified as JYS-2.

Q. Let's begin by discussing the first audit report, the TECO base year audit. Did you prepare or cause to be prepared under your supervision, direction, and control this audit report?

A. Yes, I was the audit manager for this audit.

Q. Could you summarize the work you performed in this audit?

A. Yes. For security costs, the audit staff and I obtained total security costs for the years 2000 through 2003 (projected) and determined that total recorded security costs (including incremental costs), for calendar years 2000, 2001 and 2002 totaled $2,731,227, $3,508,664, and $3,619,633, respectively. We determined that projected 2003 security costs totaled $3,283,370. We tested a randomly selected sample of security charges to supporting documentation. For hedging, we obtained total and incremental hedging costs for the years 2001, 2002 and for the projected year 2003 and determined the company's distinction between financial hedging and physical hedging. We also obtained the percentage of time employees devoted to hedging activities and recomputed hedging expense using the employees' annual salaries.

Q. Could you summarize your findings in this audit?

A. Yes. Disclosure No. 1 discusses security costs. We requested plant security costs by function (generation, transmission and distribution). However, the company stated that it did not track security costs by function, when incurred. However, the Company was able to provide security by function for incremental costs incurred as a result of the 9/11 event. Base year security costs per the company calculation for 2001 totals $3,108,013 and, for 2002 totals $3,225,684. We prepared schedules for the years 2001, 2002 and projected 2003, by account, by month, for security costs recorded in the general ledger. In order to determine the amount of normal and recurring security costs, we removed those costs identified by the company as incremental. The resulting amount equals actual security costs on a consistent basis. We then calculated an average security cost using 2001 and 2002 security costs. The average costs, per our calculation, totaled $3,166,848. I believe that the average amount better represents a base amount for security costs when determining incremental security costs to be used in future years.

Disclosure No. 2 discusses hedging costs. For the year ended December 31, 2001, TECO determined that it had incurred total hedging expense of $169,153. This total consisted of $159,723 of payroll and related fringe benefits, $2,500 for travel costs to the coal mine for contract negotiations, and $6,930 for training on hedging.

Effective in May 2002, the Fuels department and the Wholesale Marketing department merged to create the Wholesale Marketing and Fuels Department. In addition to physical and financial hedging activities, this department also performs daily activities, planning, and regulatory activities. The company cannot provide a breakdown between physical and financial hedging. This department currently consists of five positions that devote time to hedging (risk management): Director, Fuels Strategist, Forecast Analysis, Contract Administrator, and Manager of Natural Gas. Prior to May 2002, the procurement of natural gas for Tampa Electric's use was performed by Peoples Gas System (PGS). PGS arranged for the purchase and delivery of the gas and billed Tampa Electric its actual cost plus a small administration fee based on the time spent arranging the purchase. The total amount paid was included as cost of gas and recovered in the fuel clause.

For the calendar year 2002, TECO determined total hedging costs to be $252,939 with the incremental portion being $83,786. The percentage of time employees spent on hedging activities ranged from 30% to 80%. Any gains or losses on hedging activities are included in fuel costs and are recovered in the fuel clause.

Q. Now, in regard to the second audit report regarding the TECO capacity cost recovery clause audit, did you prepare this audit report?

A. Yes, I was involved in the preparation of this audit report.

Q. Could you discuss the work performed in this audit?

A. Yes, we compiled the capacity cost recovery clause revenue and agreed it to the filing and recomputed revenues using the approved rate factors and company KWH sales. We also recomputed the capacity costs and agreed these costs to the TECO billing statements. We identified costs by vendor and performed audit test work of payments to verify that vendors were paid according to contract terms. We also verified that incremental security costs were included.

Q. Could you summarize your findings in this audit?

A. Yes. Disclosure No. 1 discusses incremental security costs. The company recorded $794,598 in its capacity cost recovery filing for 2002. This equals incremental costs of $400,650 for 2001 and $393,948 for 2002. As discussed in the previous audit, I believe that a two-year average of net security costs is the most appropriate amount to be used in calculating a base year for incremental security costs. Using the two-year average for 2001 and 2002, the company's request for $393,948 for 2002 is reasonable.

Disclosure No. 2 discusses a capacity price adjustment. The company included an adjustment for $170,300 increasing its capacity charges from Hardee Power Partners (HPP) in December 2002. The company states that the adjustment was the net effect of several omissions to the filings occurring during 1993 and 1994. This adjustment is for activity that occurred eight and nine years ago. We did not verify whether or not these amounts had been included in any of the prior filings, but we did review the adjusting entry crediting the liability and debiting the capacity expense accounts in December 2002.

Disclosure No. 3 discusses an erroneous billing for optional provision customers. The company made refunds associated with the 1999 earnings settlement totaling $6.1 million plus interest over the period June through August 2002. During the process, the company erroneously calculated and made refunds to its optional provision customers. This error results in differences of approximately $7,500 between the revenues per the filing and the revenues on the general ledger. The company is working to resolve this error. Because of the overall immateriality of the refund amounts, I believe the company should be allowed to correct the error and we can audit the correction in a later year.

Q. Does this conclude your testimony?

A. Yes, it does.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

TESTIMONY OF GERARD YUPP

DOCKET NO. 030001-EI

APRIL 1, 2003

Q. Please state your name and address.

A. My name is Gerard Yupp. My business address is 700 Universe Blvd., North Palm Beach, Florida, 33408.

Q. By whom are you employed and what is your position?

A. I am employed by Florida Power & Light Company (FPL) as Manager of Regulated Wholesale Power Trading in the Energy Marketing and Trading Division.

Q. Have you previously testified in the predecessors to this docket?

A. Yes.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to provide a review of FPL's 2002 hedging activity, including the detail required by Item 5 of the

Resolution of Issues in Docket 011605-EI approved by the Commission per Order No. PSC-02-1484-FOF-EI, which states:

> "5. Each investor-owned utility shall provide, as part of its final true-up filing in the fuel and purchased power cost recovery docket, the following information: (1) the volumes of each fuel the utility actually hedged using a fixed price contract or instrument; (2) the types of hedging instruments the utility used, and the volume and type of fuel associated with each type of instrument; (3) the average period of each hedge; and (4) the actual total cost (e.g. fees, commissions, options premiums, futures gains and losses, swaps settlements) associated with using each type of hedging instrument".

Q. Are you sponsoring an exhibit for this proceeding?

A. Yes. It consists of the following document:

GJY-1: 2002 Hedging Activity

Q. Please describe FPL's hedging objectives and summarize FPL's 2002 hedging activity.

A. FPL's fuel procurement strategy aims to benefit FPL's customers by reducing fuel price volatility, and to the extent possible, mitigating fuel price increases, while maintaining the opportunity to take advantage of price decreases in the marketplace. During 2002, FPL primarily relied upon fixed price transactions to hedge its fuel portfolio. Financial swaps were utilized as a method of improving and/or protecting FPL's fixed price positions. FPL also engaged in option hedges to help mitigate the risk of fuel price increases. Additionally, FPL utilized natural gas storage to ensure the reliable delivery of fuel during significant storm events in the latter half of the year. FPL's 2002 hedging activities were successful in delivering greater price certainty, as well as $47 million in fuel savings for FPL's customers. This total includes $14.5 million in natural gas savings, $31.8 million in fuel oil savings and $.7 million in power option premiums. The savings and gains associated with the energy component of the power options are included in FPL's monthly filing of A-Schedules. The fixed price positions generated the largest percentage of savings due to the fact that the overall trend of the fuel markets was up after the positions were taken. FPL is pleased that its 2002 hedging activities resulted in these savings. However, it is important to recognize that generating savings is not the only objective of hedging. The primary objective of hedging is to reduce fuel price volatility. FPL engages in hedging to protect its customers from significant exposure to volatility in the fuel and power markets. FPL considers its hedging activities to be a success if they result in volatility control even if this occasionally means higher prices to customers than would have been the case without hedging.

As an additional note, FPL engaged in residual fuel oil hedging in November and December of 2002 by building fuel oil inventories to ensure adequate supply to meet the projected needs of FPL's customers, as well as, price protection given the heightening tensions in the Middle East. The results of this decision have proven to be very positive, however the data is not shown in Exhibit GJY-1 because the savings are realized in 2003. These results will be shown in FPL's 2003 filing.

Q. Does your Document GJY-1 provide the detail on FPL's 2002 hedging activities required by Item 5 of the Resolution of Issues?

A. Yes.

Q. Does this conclude your testimony?

A. Yes, it does.

STATE OF FLORIDA)

: CERTIFICATE OF REPORTER

COUNTY OF LEON)

I, JANE FAUROT, RPR, Chief, Office of Hearing Reporter Services, FPSC Division of Commission Clerk and Administrative Services, 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' attorney or counsel connected with the action, nor am I financially interested in the action.

DATED THIS 24th day of November, 2003.

JANE FAUROT, RPR
Chief, Office of Hearing Reporter Services
FPSC Division of Commission Clerk and
Administrative Services
(850) 413-6732