BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

In the Matter of	DOCKET NO. 970001-EU
Fuel and purchased power cost recovery clause and generating performance incentive factor.	

VOLUME 1

Pages 1 through 200

PROCEEDINGS: **HEARING**

BEFORE: CHAIRMAN JULIA L. JOHNSON
COMMISSIONER TERRY DEASON
COMMISSIONER DIANE K. KIESLING

DATE: **Wednesday, February 19, 1997**

TIME: Commenced at 9:30 a.m.

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

REPORTED BY: JOY KELLY CSR, RPR
Chief, Bureau of Reporting
H. RUTHE POTAMI, CSR, RPR
ROWENA NASH
Official Commission Reporter

APPEARANCES:

JAMES A. McGEE, Post Office Box 14042, 3201 34th Street South, St. Petersburg, Florida 33733-4042, appearing on behalf of **Florida Power Corporation.**

JAMES D. BEASLEY, Ausley & McMullen, Post Office Box 391, Tallahassee, Florida 32302, appearing on behalf of **Tampa Electric Company.**

VICKI GORDON KAUFMAN, McWhirter, Reeves, McGlothlin, Davidson, Rief and Bakas, 315 South Gadsden Street, Tallahassee, Florida 32301, appearing on behalf of **Florida Industrial Power Users Group.**

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

VICKI D. JOHNSON and **ROBERT ELIAS**, Florida Public Service Commission, Division of Legal Services, 2540 Shumard Oak Boulevard, Tallahassee, Florida 32399-0870, appearing on behalf of the **Commission Staff.**

ALSO PRESENT:

ROBERTA BASS, DAVE WHEELER and **SID MATLOCK**, FPSC Division of Electric & Gas

WITNESSES-VOLUME 1

EXHIBITS VOLUME 1

NUMBER		ID.	ADMTD.
1	(Scardino) JS-1	20	200
2	(Scardino) JS-2	20	200
3	(Wieland) KHW-1	20	
4	(Wieland) KHW-4	20	
5	(Zuloaga) DBZ-1	20	
6	(Zuloaga) DBZ-2	20	
7	(Morley) RM-1	20	20
8	(Morley) RM-2	20	20
9	(Morley) RM-3	20	20
10	(Silva) RS-1	20	20
11	(Bachman) GMB-1	20	20
12	(Cranmer) SDC-1)	20	20
13	(Cranmer) SDC-2	20	20
14	(Fontaine) GDF-1	20	20
15	(Fontaine) GDF-2	20	20
16	(MFO-1)	20	20
17	(Oaks) MFO-2	20	20
18	(Branick) KAB-1	20	20
19	(Branick) KAB-2	20	20
20	(Brankick) KAB-3	20	20
21	(Branick) KAB-4	20	20
22	(Keselowsky) GAK-1	20	20
23	(Keselowsky) GAK-2	20	20
24	(Keselowsky) GAK-3	20	20

PROCEEDINGS

CHAIRMAN JOHNSON: I'm going to call the hearing to order. Could you please read the notice?

MR. KEATING: Pursuant to notice issued January 13, 1997, this time and place has been set for hearing in Dockets No. 970001-EI, fuel and purchased power cost recovery clause and generating performance incentive factor; 970002-EG, conservation cost recovery clause; 977003-GU, purchased gas adjustment and 970007-EI, environmental cost recovery clause.

CHAIRMAN JOHNSON: Take appearances.

MR. BEASLEY: James D. Beasley with the law firm of Ausley & McMullen, Post Office Box 391, Tallahassee, Florida 32302, representing Tampa Electric Company in the 970001, 2 and 7 dockets.

MR. McGEE: James McGee, P. O. Box 14042, St. Petersburg 33733, on behalf of Florida Power in the 01 and 02 dockets.

MR. HOWE: I'm Roger Howe with the Office of Public Counsel. With me is the Public Counsel, Mr. Jack Shreve, representing the Citizens of the State of Florida, in the 01, 03, 07 dockets.

MS. KAUFMAN: Vicki Gordon Kaufman, McWhirter, Reeves, McGlothlin, Davidson, Rief and Bakas, 117 South Gadsden, Tallahassee 32301. I'm appearing on behalf of the Florida Industrial Power Users Group in 01, 02 and 07 dockets.

MS. JOHNSON: Vicki Johnson, appearing for the Commission Staff 01 and 07 dockets.

MR. KEATING: Cochran Keating appearing on behalf of Commission Staff in the 03 docket.

MS. WAGNER: Lorna Wagner appearing on behalf of Commission Staff in the 02 docket.

CHAIRMAN JOHNSON: Are there any preliminary matters? Have we established an order that we will process the different dockets?

MR. KEATING: Yes. We'd like to start with the 02, and then move on to the 03, 07 and then the 01 docket.

CHAIRMAN JOHNSON: Very well.

* * * * *

MS. JOHNSCN: We're proceeding into the 01 docket. There are several preliminary matters in that docket.

The Prehearing Order that was issued in this docket indicated that the witness, Scardino, his testimony was stipulated into the record. It's my understanding this morning that Florida Power Corp intends to call that witness this morning at the hearing. I want to make that correction. It's also my understanding that Mr. Scardino will address Issue 14D.

COMMISSIONER DEASON: Let me ask a question concerning Witness Scardino. Was it simply an error that his testimony was indicated as stipulated, or was it stipulated and there was a change of mind as to whether that witness should appear?

MS. JOHNSON: My recollection was that the Issue 14D was an issue that Public Counsel raised. And I think in our discussion at the prehearing conference it was my understanding, or I was operating under the assumption that Witness Wieland would be addressing that issue. Therefore, when the Prehearing Order was drafted he was noted for that issue; Wieland was noted for that issue, therefore, Wieland was correctly identified as not being stipulated into the record but I subsequently learned that Mr. Scardino, in fact, addresses that issue.

COMMISSIONER DEASON: It's more of an error as opposed to a change in mind.

MS. JOHNSON: That's correct.

MR. McGEE: If I might, Commissioner --

CHAIRMAN JOHNSON: On the Prehearing Order Wieland isn't scheduled to testify to 14D -- I have no idea how to pronounce --

MR. McGEE: That's an error. That's an error.

In the draft Prehearing Order an issue relating -- excuse me, a position relating to an unrelated GPIF issue inadvertently was put under Florida Power's position for 14D. The witness whose name is unpronounceble, I think, is the witness for the GPIF. Mr. Wieland has always been the witness for 14D, and in our prehearing statement it was stated that way.

CHAIRMAN JOHNSON: Not Mr. Wieland, you mean Mr. Scardino.

MR. McGEE: That was the point that I wanted to clarify.

On Issue 1, which relates t_ the true-up amount for the April-September 1996 period, that is the subject of Mr. Scardino's testimony.

As the Prehearing Order indicates that's stipulated to all parties except for Florida Power. And the reason for that -- Mr. Howe you can state differently if I say this wrong -- Public Counsel raised Issue 14D, which had to do with an extended outage at the Crystal River nuclear plant, and questioned whether any replacement fuel cost related to that outage should be recovered. So that's why

Mr. Scardino's testimony hasn't been stipulated and why we need to put him on.

CHAIRMAN JOHNSON: So Mr. Scardino is going to testify as to 14D, but Mr. Wieland is not?

MR. McGEE: Mr. Scardino will testify to 14D as it relates to fuel cost through the end of September. Mr. Wieland picks up then with the estimated true-up period as well as the projections.

CHAIRMAN JOHNSON: So the Prehearing Order should show both of them identified as testifying to elements of 14D.

MR. McGEE: Yes. That is correct.

CHAIRMAN JOHNSON: Okay. Any questions OPC on that? Then we'll reflect that, because neither were identified in the Prehearing Order as addressing 14D. But we will clarify that.

Any other preliminary matters?

MS. JOHNSON: Yes. With respect to Issues 14D, 14E, and 18B which address the recovery of costs associated with the outage at Florida Power's Crystal River Unit 3, at the prehearing conference the Prehearing Officer, Commissioner Deason, permitted oral argument on those issues, and oral argument is to be limited to 15 minutes to each party. I just want to bring that to your attention.

I would also add that as a preliminary item -- and I'll apologize for any confusion that my drafting of the Prehearing Order may have created but it's been somewhat confusing.

With respect to 16B the parties have not addressed this issue. However, this issue was related to the Commission's vote at an agenda conference that was held yesterday, and with that I would assume that the parties are all in agreement. And I would just ask at this time, before we proceed, to confirm if that is, in fact, correct; that that issue can be shown as a stipulated issue.

MR. BEASLEY: It would be stipulated that there should be no affect on this hearing.

MR. HOWE: I guess I can agree that as a result of the Commission's vote there will be no effect on this hearing.

MS. KAUFMAN: I can stipulate to the same.

CHAIRMAN JOHNSON: Okay.

MS. JOHNSON: I think that the position that is shown for Staff reflects what the parties have just stipulated to, so that will be reflected, or that will be shown as the stipulated position.

CHAIRMAN JOHNSON: Staff's position on 16B will be the stipulated position.

MS. JOHNSON: That's correct.

COMMISSIONER DEASON: With that stipulation what are the remaining issues? Are they strictly Florida Power issues?

MS. JOHNSON: That's correct.

COMMISSIONER DEASON: Could you enumerate those, please?

MS. JOHNSON: Yes. Those issues are generic issues 1 through 4, 7 and 18A for Florida Power Corp; and Florida Power Corp company-specific issues 14B, 14C, 14D, 14E, 18B, 24A and 24B.

COMMISSIONER KIESLING: That's for which utility, Florida Power Corp?

MS. JOHNSON: Florida Power Corp.

CHAIRMAN JOHNSON: What were the first -- you said 1 through 4?

MS. JOHNSON: 1 through 4 and 7, which are generic issues, as they relate to Florida Power Corp.

COMMISSIONER KIESLING: What about 18A.

MS. JOHNSON: Yes, that's correct.

CHAIRMAN JOHNSON: Public Counsel, did you have a comment?

MR. HOWE: Chairman Johnson, I wanted to tell you our position, to clarify on Issue 16B. We took the position that if the Commission were to reach a decision yesterday at the agenda conference, they could have an immediate effect that it should be implemented.

We agree that the Commission's decision does not offer anything for immediate implementation but we don't see any way to really stipulate the way the issue is worded. We're just agreeing that the effect of the Commission's vote yesterday did not offer anything for us to implement in this proceeding.

CHAIRMAN JOHNSON: Do you understand that, counsel?

MS. JOHNSON: Yes. I'd just add what is shown as a Staff position for that issue we are in agreement with that portion.

Our position really sets forth that the Commission's vote on yesterday will be considered in a docket which will consider the treatment of two new contracts for TECO, and that any adjustments that might be required for those two contracts as a result of the Commission's vote on yesterday will be reflected in the August 1997 fuel hearing.

COMMISSIONER KIESLING: But what I'm hearing from the parties is that that's not their stipulation. Their stipulation that this issue, I guess, is a moot issue in the sense that there is no effect on this proceeding and that's all they want to say.

MS. KAUFMAN: Chairman Johnson, on FIPUG's behalf I think I would agree with Commissioner Kiesling's discussion. Our position is that issue 16B is moot now.

MR. HOWE: And I just wanted to clarified, Commissioners, that we disagreed with the Staff. In other words, they were all along were saying defer to August no matter what your vote was yesterday. And our position was if we had anything that would be favorable to the customers out of yesterday's vote, it should be implemented immediately. The effect is in the nature of -- from our perspective that it's moot. I can't state that it's a stipulation.

MS. JOHNSON: Staff is in agreement that no adjustment should be made in this hearing to reflect the Commission's vote on yesterday. So we can reflect that as our position.

I guess what we were intending to do with our position on this issue was just to bring to your attention that your vote on yesterday will impact the treatment of those two contracts, which will be considered at a later docket. But we can agree with the stipulated position that both FIPUG and OPC referred to.

CHAIRMAN JOHNSON: That issue is moot.

COMMISSIONER KIESLING: That's it's moot is what they will say.

MS. JOHNSON: Yes.

CHAIRMAN JOHNSON: Any other preliminary matters?

MS. JOHNSON: May we have a moment to confer? (Pause)

MS. JOHNSON: Yes. Staff agrees that no adjustment is required in this fuel hearing. I guess the discussion that -- my statements with respect to the FMPA and Lakeland contracts, if any adjustments are necessary, those will be made in August and we can raise that issue in the August fuel hearing.

COMMISSIONER KIESLING: So it's moot.

MS. JOHNSON: Yes.

COMMISSIONER KIESLING: Thank you.

CHAIRMAN JOHNSON: Any other preliminary matters?

MR. BEASLEY: Get the exhibits in.

MS. JOHNSON: There is one other preliminary matter.

Public Counsel filed a motion for an order precluding Florida Power Corp from supplementing its prefiled direct testimony addressing the fuel cost effects of the extended outage at the Crystal River No. 3 nuclear unit. At the time of the prehearing conference that motion was not ripe for resolution. It is now. You may wish to resolve that prior to proceeding.

CHAIRMAN JOHNSON: Since there was no supplemental testimony filed, is this motion then withdrawn?

MR. HOWE: No, it is not. I have no idea what Florida Power's witnesses are going to say when they take the stand. I should characterize that I've talked to Mr. McGee, but I've not yet heard their testimony.

As such I do not know if there will be references to the extended outage at CR-3. Rather than viewing it as moot, given that the Company has not filed a response, I think the appropriate treatment would be to consider it unopposed.

COMMISSIONER KIESLING: Consider it what?

MR. HOWE: Unopposed.

CHAIRMAN JOHNSON: As I look at this, you wanted to preclude them from trying to supplement any prefiled testimony in a motion. To the extent that they try to on the stand, I will recognize the appropriate objections as such. You'll have to make the objection because I won't be able to say, "Oh, that's supplemental." We can just proceed in that manner. And I understand your concern, that to the extent that -- you've put everyone on notice, to the extent they try to supplement, that the objection will be made and at this point in time I'll rule on it.

MR. HOWE: Thank you.

MS. JOHNSON: With that, Staff would move the prefiled testimony of the witnesses which are shown on Page 5 whose testimony has been stipulated into the record and I can read those names. Those would be Florida Power Corp's witness with the unpronounceable name Dario Z-U-L-O-A-G-A.

MR. HOWE: Excuse me. Chairman Johnson, on that witness I guess would it be Zuloaga.

MR. McGEE: That's as close as I've heard.

MR. HOWE: Mr. Zuloaga filed two pieces of testimony; his original testimony and his revised testimony.

At the prehearing conference I opposed introduction of his revised testimony. His original testimony shows Crystal River Unit 3 up and running in the April through September 1997 projection period for purposes of setting GPIF targets and ranges. That is consistent with the prefiled testimony of Mr. Wieland which also shows Crystal River 3 on line throughout the upcoming projection period.

Mr. Zuloaga's revised testimony shows Crystal River 3 off-line throughout the projection period. I opposed that revised testimony and believe the Company should be bound by their originally filed testimony. They did not ask for leave to file revised testimony; they did not offer any justification for revising his testimony. Under the circumstances we believe Mr. Zuloaga's originally filed testimony, which was filed on January 13th, 1997, should be his testimony in the record of this proceeding.

MS. KAUFMAN: Chairman Johnson, FIPUG agrees with that. And I was going to call to your attention -- this relates to issue 18A on Page 24, and FIPUG's position is reflected there as "no position" but our position should be that we agree with Public Counsel on this issue.

MR. McGEE: Madam Chairman.

CHAIRMAN JOHNSON: Hold on one second.

MR. McGEE: Excuse me. We'll let the record reflect the position of FIPUG on Issue 18A as in agreement with Public Counsel.

MS. KAUFMAN: That's right, Chairman.

CHAIRMAN JOHNSON: Now, back to the witness.

MR. McGEE: This issue was addressed during the prehearing conference. And it was agreed that it would be included in the oral argument. But that the decision as to whether or not the original testimony or the amended testimony would be inserted into the record in this proceeding would be subject to the oral argument and would not require the testimony of the witness, and so he was, therefore, excused.

The determination as to whether the original or the amended should be used is based on a matter of policy and we'll address that at the oral argument.

CHAIRMAN JOHNSON: So it would not be appropriate to stipulate at this point in time?

MR. McGEE: That's correct.

CHAIRMAN JOHNSON: Would you agree?

MR. HOWE: Yes, Chairman Johnson. I just raised it when I did when Ms. Johnson said that it was going to be introduced, and I wanted to bring to your attention, before you voted to introduce this testimony, that there's two pieces.

CHAIRMAN JOHNSON: That will be noted. Ms. Johnson.

MS. JOHNSON: Yes. I just wanted to note that I was aware that there was disagreement as to which version of his testimony. And as reflected in the Prehearing Order on Page 33 they indicated that an original and revised version were filed and the determination of which version would be dependent upon your resolution of Issues 18A and B. So thank you for that correction.

The other -- the stipulated witnesses then whose testimony should be inserted into the record would start with Florida Power and Light's witness Silva, Wade, Morely, Bachman for FPUC, Oaks for Gulf, Cranmer, Fontaine and Howell for Gulf; Witness Branick and Keselowsky for TECO.

CHAIRMAN JOHNSON: Are there any objections to those being inserted into the record as though read? Seeing none they will be so inserted. Are there exhibits?

MS. JOHNSON: Yes. Staff would ask that the exhibits be marked for identification. At this time Staff would request that all of the exhibits be marked for identification but we'll only move into the record those exhibits for the witnesses that have been stipulated.

CHAIRMAN JOHNSON: Okay. Very well.

MS. JOHNSON: Turning to Page 30 the first exhibit is JS-1 which should be marked 1. JS-2 Exhibit 2; KHW-1 should be Exhibit 3. KHW-2 should be

Exhibit 4. DBZ-1 Exhibit 5, DBZ-2 should be Exhibit 6. RM-1 should be Exhibit 7. And what is shown as RS-2 for Witness Morely should be RM-2 and that will be Exhibit 8. RM-3 is Exhibit 9. RS-1 is Exhibit 10; GMB-1 is Exhibit 11. SDC-1 is Exhibit 12. SDC-2 is Exhibit 13. GDF-1 is Exhibit 14. GDF-2 is 15. Turning to Page 32, MFO-1 is 16. MFO-2 is 17. KAB-1, 18; KAB-2, 19; KAB-3 is 20; KAB-4 is 21; GAK-1 is 22; GAK-2 is 23 and GAK-3 is 24.

CHAIRMAN JOHNSON: They will be marked as stated.

(Exhibits 1 through 24 marked for identification.)

MS. JOHNSON: Staff would then move exhibits 7 through 24 into the record at this time.

CHAIRMAN JOHNSON: They will be moved into the record without objection. 7 through 24?

MS. JOHNSON: That's correct.

(Exhibits 7 through 24 received in evidence.)

FLORIDA POWER CORPORATION

DOCKET NO. 970001-EI

GPIF Targets and Ranges for
April through September 1997

REVISED
DIRECT TESTIMONY OF
DARIO B. ZULOAGA

Q. Please state your name and business address.

A. My name is Dario B. Zuloaga. 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 Florida Power Corporation as a Principal Engineer in Energy Supply, Performance Services.

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

A. Yes, they have.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present the development of the Company's Generating Performance Incentive Factor (GPIF) targets and ranges for the period of April through September, 1997. This development includes the targets and improvement/degradation ranges for unit equivalent availability and unit average net operating heat rate in accordance with the Commission's Generating Performance Incentive Implementation Manual. The revision to my testimony explains the reason that the Crystal River 3 nuclear unit has been excluded from the GPIF for the upcoming April - September period and recalculates the GPIF to reflect the exclusion.

Q. Do you have an exhibit to your testimony?

A. Yes, I will sponsor an exhibit containing 75 pages, which consists of the GPIF standard form schedules prescribed in the 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. I have also included a table after the standard form schedules which demonstrates that, with the exclusion of Crystal River 3 from the GPIF, the Company's remaining GPIF units continue to generate more than 80% of total system generation.

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

A. We have included Crystal River Units 1, 2, 4 and 5 and Anclote Units 1 and 2. The Crystal River 3 nuclear unit will likely be unavailable for the entire April - September 1997 period. Florida Power voluntarily shutdown the unit on September 2, 1996 to address several design issues related to backup safety systems, including an emergency diesel generator. Even with the nuclear unit unavailable for the period, the remaining units are projected to provide 82.3% of Florida Power's total system generation, as shown on Table 1 at the end of my exhibit.

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

A. Yes, I have. This information is included in the Target and Range Summary on page 3 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 Implementation Manual. This method describes 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 a POF of 10% results in an EAF of 75%.

The supporting graphs and a summary table of all target and range rates are contained in the section of my exhibit entitled "Unplanned Outage Rate Tables and Graphs".

Q. **Please describe the method utilized in the development of the improvement/degradation ranges for each GPIF unit's availability targets.**

A. In general, the methodology described in the 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 terms 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, I have. This information is included in the Target and Range Summary on Page 3 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 comparable GPIF periods, as described in the Implementation Manual. A "least squares" computer program was used to curve-fit the heat rate data within ranges having a 90% confidence level of including all data. The computer analyses and data plots used to develop the heat rate targets and ranges for each of the GPIF units are contained in the section of my exhibit 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 the incentive points. The maximum savings (loss) dollars are the same as those used in the calculation of weighting factors.

Q. How were the GPIF weighting factors determined?

A. To determine the weighting factors for availability, a series of PROMOD 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. Does this conclude your testimony?

A. Yes.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

TESTIMONY OF R. L. WADE

DOCKET NO. 970001-EI

January 16, 1997

Q. Please state your name and address.

A. My name is Robert L. Wade. 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 Director, Business 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 and costs of disposal of spent nuclear fuel. Both of these costs were input values to POWRSYM for the calculation of the proposed fuel cost recovery factor for the period April 1997 through September 1997.

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, consistent with those assumed in POWRSYM, for the period April 1997 through September 1997.

Q. Please provide FPL's projection for nuclear fuel unit costs and energy for the period April 1997 through September 1997.

A. We estimate the nuclear units will produce 119,888,359 MBTU of energy at a cost of $0.341 per MMBTU, excluding spent fuel disposal costs for the period April 1997 through September 1997. Projections by nuclear unit and by month are provided on Schedule E-4 of Appendix II.

Q. Please provide FPL's projections for nuclear spent fuel disposal costs for the period April 1997 through September 1997 and what is the basis for FPL's projections.

A. FPL's projections for nuclear spent fuel disposal costs are provided on Schedule E-2 of Appendix II. These projections are based on FPL's contract with the Department of Energy (DOE), which sets the spent fuel disposal fee at 1 mill per net Kwh generated minus transmission and distribution line losses.

Q. Please provide FPL's projection for Decontamination and Decommissioning (D&D) costs to be paid in the period April 1997 through September 1997 and what is the basis for FPL's projection.

A. Deposits into the D&D fund are scheduled to be paid annually on the last day of October, therefore, FPL is not projecting payment of D&D costs during this fuel cost recovery period.

Q. Are there any other fuel-related costs which FPL is including in the calculation of the proposed Fuel Cost Recovery Factor?

A. Yes. As a result of the docket proceedings on August 29, 1996, FPL was awarded recovery of costs relating to the increase of thermal power of FPL's Turkey Point Nuclear Units 3 and 4. Each nuclear unit has currently increased the thermal power from 2200 megawatts thermal to 2300 megawatts thermal, increasing the output of each unit by approximately 31 megawatts electric. FPL will recover approximately $10M in costs associated with the thermal power uprate over a two year period, starting January 1, 1997. Therefore, FPL is including $2.5M in recovery costs during the period April 1997 through September 1997.

Q. Are there currently any unresolved disputes under FPL's nuclear fuel contracts?

A. Yes. As reported in prior testimonies, there are two unresolved disputes.

The first dispute is under FPL's contract with the Department of Energy (DOE) for final disposal of spent nuclear fuel. FPL, along with a number of electric utilities, has filed suit against the DOE over DOE's denial of its obligation to accept spent nuclear fuel beginning in 1998. A July 23, 1996, ruling by the U.S. Court of Appeals for the D.C. Circuit said that DOE is required by the Nuclear Waste Policy Act to take title and dispose of spent nuclear fuel from nuclear power plants beginning on January 31, 1998. DOE currently has declined to seek Supreme Court review of this decision and the case is now remanded to DOE for further proceedings. FPL will continue to closely follow these proceedings and may consider, at an appropriate time, additional legal action against DOE to enforce the obligation to take title to and dispose of FPL's spent nuclear fuel starting January 31, 1998.

Secondly, FPL is currently seeking to resolve a price dispute for uranium enrichment services purchased from the United States (U.S.) Government, prior to July 1, 1993.

Our contract for enrichment services with the U.S. Government calls for pricing to be calculated in accordance with "Established DOE Pricing Policy". Such policy had always been one of cost recovery, which included costs related to the Decontamination and Decommissioning (D&D) of the DOE's enrichment facilities. However, the Energy Policy Act of 1992 (The Act) requires utilities to make separate payments to the U.S. Treasury for D&D, starting in Fiscal 1993, as FPL has been doing. Therefore, D&D should not have been included in the price charged by DOE for deliveries during Fiscal 1993, and the price should have been reduced accordingly. FPL had filed a claim with the Contracting Officer, on July 14, 1995, for a refund for such deliveries. On October 13, 1995, the DOE Contracting Officer officially rejected FPL's claim. FPL had until October 13, 1996 to file an appeal. FPL has filed an appeal with the U.S. Court of Federal Claims.

Meanwhile, in a related case, the U.S. Court of Federal Claims ruled that the D&D special assessment itself was unlawful. The Court found that in this specific instance, the special assessment was essentially a retroactive price increase on a contract which had already been performed, and was therefore illegal. The DOE has appealed this decision to the U.S. Court of Appeals for the Federal Circuit. Oral arguments were held October 11, 1996 before the appeals court. The court may take anywhere from two to six months before issuing a final decision on this case. FPL will continue to follow this case and will take actions, as appropriate, consistent with the outcome of the appeal.

Q. In prior testimony, activities and costs associated in implementing 24 month fuel cycle operation were discussed. Can you provide an update on the implementation of 24 month fuel cycle operation for the nuclear units at St. Lucie?

A. Yes. FPL re-evaluated the cost benefit for 24 month fuel cycle operation. We factored into our evaluation the recent repeated success at Turkey Point in achieving less than 40 days of refueling outages and the goal to replicate this at St. Lucie and to improve upon it at both sites. The result of our evaluation with the shorter outages shows no net benefit. Therefore, the 24 month fuel cycle operation project has been cancelled.

Q. Does this conclude your testimony?

A. Yes, it does.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

SUPPLEMENTAL TESTIMONY OF ROSEMARY MORLEY

DOCKET NO. 960001-EI

August 20, 1996

Q. Please state your name and address.

A. My name is Rosemary Morley and my business address is 9250 West Flagler Street, Miami, Florida 33174.

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

A. I am employed by Florida Power & Light Company (FPL) as the acting Manager of Rates and Tariff Administration, taking the place of Barry T. Birkett who has left FPL.

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 revise the estimated/actual true-up amount for April 1996 through September 1996 by including actual data for June and July 1996. I have provided revised fuel factors for the Company's rate schedules for the period October 1996 through September 1997. These revised factors are to replace those filed by Barry T. Birkett on June 24, 1996 and adopted by me on July 30, 1996.

Q. Have you prepared any schedules that reflect these revisions?

A. Yes. Attachment I contains the Fuel Cost Recovery schedules that reflect these revisions and Attachment II contains Commission A-Schedules for June and July 1996.

Q. Please explain the reasons for these revisions.

A. The variance for June 1996 is $23 million. This variance is due primarily to a $14.8 million increase in Jurisdictional Fuel Costs and a $8.1 million decrease in Jurisdictional Fuel Revenues (see Attachment I, Page 3). The increase in Total Jurisdictional Fuel Costs is primarily due to higher than projected use of heavy oil. Heavy oil generation was 81.4% higher than projected. This increase was caused by lower than projected generation from nuclear (33.1%), natural gas (5%) and coal (7%) (see Schedule A3 for the month of June 1996 provided in Attachment II). The decrease in Jurisdictional Fuel Revenues is due to an error in the calculation of estimated revenues for June. The mid-course correction factor for July 1996 was inadvertently used in this calculation.

The variance for July 1996 is $37 million. This variance is primarily due to a 4.3% higher than projected Net Energy For Load causing more heavy oil to be burned ($20.9 million), more purchased power to be utilized ($6.8 million) and less power sold ($6.7 million) (see Attachment I, Page 4). The unit cost of heavy oil was $.27 per barrel lower than projected which slightly offset the heavy oil variance. Gas prices were $.50 per MCF higher than projected resulting in a $10.6 million variance that was offset by $1.1 million because less gas than projected was used (see Schedule A3 for the month of July 1996 provided in Attachment II).

Q. What is the total underrecovery included in the fuel factors for the period October 1996 through September 1997?

A. In the June 24, 1996 filing, FPL included a final true-up amount of $17,175,052 for the period October 1995 through March 1996 and an estimated/actual true-up amount of $88,480,000 for the period April 1996 through September 1996. This $88,480,000 estimated/actual true-up amount was based on two months of actual data for April and May 1996 and four months of revised estimates for June through September 1996.

FPL now proposes to revise this estimated/actual true-up amount to include an additional $60,555,547 underrecovery to reflect actual data for June and July 1996, therefore using four months of actual data for April through July 1996 and two months of estimated data for August and September 1996. This results in an estimated/actual true-up amount, including interest of $149,035,547. This estimated/actual underrecovery of $149,035,547 for the April through September 1996 plus the final true-up underrecovery of $17,157,052 for the October 1995 through September 1996 period results in a total underrecovery of $166,192,598 to be recovered in the October 1996 through September 1997 period (Attachment I, Pages 7 and 8).

Q. What is the proposed revised levelized fuel factor for which the Company requests approval?

A. The proposed six-month levelized fuel factor is 2.204 ¢ per kWh, as shown on Schedule E1 (Attachment I, Page 5). Time of Use factors are provided on Schedule E1-D (Attachment I, Page 9) and Fuel Factors by Rate Class are provided on Schedule E1-E (Attachment I, Page 10).

Q. What will be the charge for a Residential customer using 1,000 kWh effective October 1996?

A. The total residential bill, excluding taxes and franchise fees, for 1,000 kWh will be $78.82. The base bill for 1,000 kWh is $47,46, the Fuel Cost Recovery charge from Schedule E1-E (Attachment I, Page 10) for a residential customer is $22.09, the Conservation charge is $2.09, the Capacity Cost Recovery charge is $6.21, the

Environmental Cost Recovery charge is $.17 and the Gross Receipts Tax is $.80. A Residential Bill Comparison (1,000 kWh) is presented in Schedule E10 (Attachment I, Page 11).

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

A. Yes, it does.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

TESTIMONY OF R. MORLEY

DOCKET NO. 960001-EI

November 13, 1996

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

A. My name is Rosemary Morley, and my business address is 9250 West Flagler Street, Miami, Florida, 33174. I am employed by Florida Power & Light Company (FPL) as Manager of Rates and Tariff Administration.

Q. Have you previously testified in this docket?

A. Yes, I have.

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

A. The purpose of my testimony is to present the schedules necessary to support the actual Fuel Cost Recovery Clause (FCR) Net True-Up amount for the period April 1996 through September 1996. The Net True-Up for FCR is an underrecovery, including interest, of

$13,513,839. I am requesting Commission approval to include this true-up amount in the calculation of the FCR factor for the period April 1997 through September 1997.

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

A. Yes, I have. It consists of Appendix I which contains the FCR related schedules. FCR Schedules A-1 through A-13 for the April 1996 through September 1996 period have been filed monthly with the Commission, are served on all parties and are incorporated herein by reference.

Q. What is the source of the data which you will present by way of testimony or exhibits in this proceeding?

A. Unless otherwise indicated, the actual data is taken from the books and records of FPL. The books and records are kept in the regular course of our business in accordance with generally accepted accounting principles and practices, and provisions of the Uniform System of Accounts as prescribed by this Commission.

Q. Please explain the calculation of the Net True-up Amount.

A. Appendix I, page 3, entitled "Summary of Net True-Up", shows the calculation of the Net True-Up for the six-month period April 1996 through September 1996, an underrecovery of $13,513,839, which

I am requesting be included in the calculation of the Fuel Cost Recovery Factor for the period April 1997 through September 1997. The calculation of the true-up amount for the period follows the procedures established by this Commission as set forth on Commission Schedule A-2 "Calculation of True-Up and Interest Provision".

The actual End-of-Period underrecovery for the six-month period April 1996 through September 1996 of $162,549,386 shown on line 1, less the estimated/actual End-of-Period underrecovery for the same period of $149,035,547 shown on line 2 that was included in the calculation of the Fuel Cost Recovery Factor for the period October 1996 through March 1997, results in the Net True-Up for the six-month period April 1996 through September 1996 shown on line 3, an underrecovery of $13,513,839.

Q. Have you provided a schedule showing the variances between actuals and estimated/actuals?

A. Yes. Appendix I, page 4, entitled "Calculation of Final True-up Variances", shows the actual fuel costs and revenues compared to the estimated/actuals for the period April 1996 through September 1996.

Q. What was the variance in fuel costs?

A. As shown on Appendix I, page 4, line A7, actual fuel costs on a Total Company basis were $16.8 million higher than the estimated/actual projection. This variance is primarily due to a $12.0 million increase in the Fuel Cost of System Net Generation, a $3.7 million increase in the Fuel Cost of Purchased Power and a $5.6 million increase in Energy Payments to Qualifying Facilities, offset by a $2.9 million decrease in the Fuel Cost of Power Sold and a $5.7 million decrease in the Energy Cost of Economy Purchases.

The increase in the Fuel Cost of System Net Generation was primarily due to an 6.1% increase in natural gas usage to meet higher than projected sales. The increase in the Fuel Cost of Purchased Power was primarily due to higher than projected Unit Power Sales (UPS) purchases from Southern Company due to the unavailability of low cost economy energy due to hot weather throughout the Southeast. The increase in Energy Payments to Qualifying Facilities (QF's) was primarily due to higher than anticipated deliveries from the Indiantown Cogeneration Limited (ICL) and Cedar Bay contracts. The decrease in the Energy Cost of Economy Purchases was primarily due to the unavailability of low cost economy energy due to hot weather throughout the Southeast.

Q. What was the variance in retail (jurisdictional) Fuel Cost Recovery revenues?

A. As shown on line D1, actual jurisdictional Fuel Cost Recovery revenues, net of revenue taxes, were $2.3 million higher than the estimated/actual projection. This increase was due to higher jurisdictional kWh sales. Jurisdictional sales were 633,438,727 kWh (1.6%) higher than the estimated/actual projection.

Q. How is Real Time Pricing (RTP) reflected in the calculation of the Net True-up Amount?

A. In the determination of Jurisdictional kWh sales, only kWh sales associated with RTP baseline load are included, consistent with projections (Appendix I, page 4, Line C3). In the determination of Jurisdictional Fuel Costs, revenues associated with RTP incremental kWh sales are included as 100% Retail (Appendix I, page 4, Line D4c) in order to offset incremental fuel used to generate these kWh sales.

Q. Does this conclude your testimony?

A. Yes, it does.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

TESTIMONY OF ROSEMARY MORLEY

DOCKET NO. 970001-EI

January 16, 1997

Q. **Please state your name and address.**

A. My name is Rosemary Morley and my business address is 9250 West Flagler Street, Miami, Florida 33174.

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

A. I am employed by Florida Power & Light Company (FPL) as the Manager of Rates and Tariff Administration.

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 for Commission review and approval the fuel factors for the Company's rate schedules for the period April 1997 through September 1997. The calculation of the fuel factors is based on projected fuel cost and operational data as set forth in Commission Schedules E1 through E10, H1 and other exhibits filed in this proceeding and data previously approved by the

Commission.

My testimony presents the schedules necessary to support the calculation of the Estimated/Actual True-up amounts for the Fuel Cost Recovery Clause (FCR) for the period October 1996 through March 1997.

In addition, my testimony requests a midcourse correction to the currently approved Capacity Cost Recovery Clause factors for the period of April through September 1997.

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

A. Yes, I have. It consists of various schedules included in Appendix II and Appendix III.

FCR Schedules A-1 through A-13 for October 1996 and November 1996 have been filed monthly with the Commission, are served on all parties and are incorporated herein by reference.

Q. **What is the source of the data which you will present by way of testimony or exhibits in this proceeding?**

A. Unless otherwise indicated, the actual data is taken from the books and records of FPL. The books and records are kept in the regular course of our business in accordance with generally accepted accounting principles and practices and provisions of the Uniform System of Accounts as prescribed by this Commission.

FUEL COST RECOVERY CLAUSE

Q. **What is the proposed levelized fuel factor for which the Company requests approval?**

A. 2.192¢ per kWh. Schedule EI, Page 3 of Appendix II shows the calculation of this six-month levelized fuel factor. Schedule E2, Page 10 of Appendix II indicates the monthly fuel factors for April 1997 through September 1997 and also the six-month levelized fuel factor for the period.

Q. **Has the Company developed a six-month levelized fuel for its Time of Use rates?**

A. Yes. Schedule E1-D, Page 8 of Appendix II provides a six-month levelized fuel factor of 2.418¢ per kWh on-peak and 2.081¢ per kWh off-peak for our Time of Use rate schedules.

Q. **Were these calculations made in accordance with the procedures previously approved in this Docket?**

A. Yes, they were.

Q. What adjustments are included in the calculation of the six-month levelized fuel factor shown on Schedule E1, Page 3 of Appendix II?

A. As shown on line 29 of Schedule E1, Page 3, of Appendix II the estimated/actual fuel cost underrecovery for the October 1996 through March 1997 period amounts to $63,591,152. This estimated/actual underrecovery for the October 1996 through March 1997 period plus the final underrecovery of $13,513,839 for the April 1996 through September 1996 period results in a total underrecovery of $77,104,991. This amount, divided by the projected retail sales of 42,644,754 MWH for April 1997 through September 1997 results in an increase of .1808¢ per kWh before applicable revenue taxes.

Q. Please explain the calculation of the FCR Estimated/Actual True-up amount you are requesting this Commission to approve.

A. Schedule E1-B, Page 5 of Appendix II shows the calculation of the FCR Estimated/Actual True-up amount. The calculation of the estimated/actual true-up amount for the period October 1996 through March 1997 is an underrecovery, including interest, of $63,591,152 (Column 7, lines C7 plus C8). This amount, when combined with the Final True-up underrecovery of $13,513,839 (Column 7, line C9a) deferred from the period April 1996 through September 1996, presented in my Final True-up testimony filed on November 19, 1996, results in the End of Period underrecovery of $77,104,991 (Column 7, line C11).

This schedule also provides a summary of the Fuel and Net Power Transactions (lines A1 through A7), kWh Sales (lines B1 through B3), Jurisdictional Fuel Revenues (line C1 through C3), the True-up and Interest calculation (lines C4 through C10) for this period, and the End of Period True-up amount (line C11).

The data for October through December 1996, columns (1) through (3) reflects the actual results of operations and the data for January through March 1997, columns (4) through (6), are based on updated estimates.

The variance calculation of the Estimated/Actual data compared to the original projections for the October 1996 through March 1997 period is provided in Schedule E1-B-1, Page 6 of Appendix II.

As shown on line A5, the variance in Total Fuel Costs and Net Power Transactions is $57.9 million or a 9.0% increase. This variance is primarily due to a $46.1 million increase in Fuel Cost of System Net Generation, a $12.7 million increase in Fuel Cost of Purchased Power, a $11.8 million increase in Energy Payments to Qualifying Facilities and a $7.9 million increase in Energy Cost of Economy Purchases offset by a $21.0 million increase in Fuel Cost of Power Sold.

The increase in Fuel Cost of System Net Generation is primarily due to increases in natural gas prices reflecting the impact of the continuation of historically low natural gas storage levels and a colder than normal November and December 1996. The increase in Fuel Cost of Purchased Power is primarily due to higher than projected UPS purchases from Southern Companies. The increase in Energy Payments to Qualifying Facilities is primarily due to corrections made to projections relating to deliveries from Indiantown Cogeneration Limited (ICL) and Cedar Bay. The increase in Energy Cost of Economy Purchases is primarily due to a slightly lower projected transaction price for the period based on the most current data available. The increase in Fuel Cost of Power Sold is primarily due to higher than expected power sold during the months of October through December and revised estimates for January through March were adjusted to reflect the most current sales data available.

The true-up calculations follow the procedures established by this Commission as set forth on Commission Schedule A2 "Calculation of True-Up and Interest Provision" filed monthly with the Commission.

Q. **Is FPL requesting that any other costs be recovered through the Fuel Cost Recovery Clause?**

A. Yes. FPL is requesting that costs associated with two projects be recovered through the Fuel Cost Recovery Clause.

Q. **Please explain the first project that FPL is requesting to be recovered through the Fuel Recovery Clause.**

A. FPL is requesting recovery of the depreciation expense and return on investment for rail cars recently purchased to deliver coal to Scherer Plant.

As discussed in the direct testimony of Rene Silva, FPL has recently purchased 63 rail cars with an initial value of $3.6 million which will be used to deliver coal to Scherer Plant. These rail cars are required to enable FPL to deliver the projected annual tonnage of coal required to operate its share of Scherer Unit No. 4. Since any coal delivery shortfall would require FPL to use more expensive oil generation to meet load requirements, purchasing the required rail cars benefits FPL's customers.

Q. **What is the basis for requesting recovery of these costs through the Fuel Cost Recovery Clause?**

A. The recovery of these costs is consistent with the recovery treatment of other transportation costs such as the purchase of SJRPP rail cars, approved in Order No. 18136, Docket No. 87000-EI, issued on September 10, 1987 and the previous purchase of 462 Scherer rail cars, approved in Order No. PSC-95-1089-FOF-EI, Docket No.

950001-EI, issued on September 5, 1995. In this order, the Commission states that "When economically beneficial to a utility's ratepayers, the cost of purchasing or leasing rail cars is considered to be a fuel-related expense that should be recovered through the fuel clause". For these reasons, FPL believes that it is appropriate to bring this issue forward for Commission consideration and approval.

Q. Please explain the second project that FPL is requesting to be recovered through the Fuel Recovery Clause.

A. FPL is including the cost of implementing certain equipment modifications at some of its generating plants and fuel storage facilities. As discussed in the direct testimony of Rene Silva, these modifications will enable FPL to operate these plants using a heavier, more economic grade of residual fuel oil called "low gravity" fuel oil. This type of fuel contains more energy, or BTU's, per barrel than the standard residual fuel oil.

As Mr. Silva testifies, these costs include a one-time expenditure of approximately $2,087,000 for new equipment and related modifications. From 1997 through 1999 fuel savings are projected to be approximately $19.94 million. From April through September 1997 the fuel savings are projected to be approximately $2.87 million.

Q. What is the basis for requesting recovery of these costs through

the Fuel Cost Recovery Clause?

A. In Order No. 950001-EI, Docket No. PSC-95-0450-FOF-EI, issued on April 6, 1995, the Commission approved the recovery of approximately $2.8 million for modifications to various plants which enabled the units to operate using a more economic grade of residual fuel oil. In this order, the Commission stated that they "have allowed such costs to be recovered through the fuel clause in the past when those expenditures resulted in significant savings to the utility's ratepayers". In addition they state "that FPL's cost for modifications fits within the policy....established in Order No. 14546" which allows fuel-related expenditures that are not being recovered through a utility's base rates to be recovered through the fuel clause.

CAPACITY PAYMENT RECOVERY CLAUSE

Q. Is FPL proposing any changes to the Capacity Cost Recovery Clause?

A. FPL is requesting that the Commission approve a midcourse correction to decrease its currently authorized Capacity Cost Recovery Factors, effective with customer billings on cycle day 3 of April 1997.

Q. Please explain why FPL is proposing this change.

A. In Order No. PSC-96-1172-FOF-EI, the Commission approved FPL's currently authorized Capacity Cost Recovery Factors (CCR) for the period October 1996 through September 1997. FPL has experienced a $28.8 million overrecovery due primarily to lower than expected capacity payments to QF's during the period June 1996 through December 1996. The original projections for June 1996 through December 1996 assumed $24.5 million in capacity payments for the Osceola and Okeelanta QF's which did not occur.

In the last proceeding, FPL requested to file the CCR on an annual basis. FPL believes that the clause should remain on an annual basis but that infrequently a midcourse correction may be appropriate. FPL believes that the magnitude of this overrecovery warrants this change.

Q. Have you prepared any exhibits that reflect these changes?

A. Yes. I have provided pages 1 through 7 of Appendix III.

Q. Please explain page 3 of Appendix III.

A. Page 3 of Appendix III provides a summary of the capacity costs previously approved for recovery during the twelve month period from October 1996 through September 1997. This amount has been adjusted by the additional net overrecovery of $28,817,281 which is reflected on line 9a.

The net overrecovery of $28,817,281 reflected on line 9a includes the final overrecovery of $15,078,256 for the period of April through September 1996 (see pages 4a-4c of Appendix III) plus the actual overrecovery of $13,739,025 for the months of October through December 1996 (see pages 5a-5b of Appendix III).

On page 5a of Appendix III, the calculation of the CCR Net True-Up overrecovery which has been included in the CCR factor for the period April through September 1997 is shown. The final overrecovery of $15,078,256 for the period April through September 1996 is shown on page 5a, line 17 of Appendix III. The actual overrecovery of $13,739,025 is provided on page 5a, line 14 plus line 15 of Appendix III.

Q. Is this true-up calculation consistent with the true-up methodology used for the other cost recovery clauses?

A Yes, it is. The calculation of the true-up amount follows the procedures established by this Commission as set forth on Commission Schedule A2 "Calculation of True-Up and Interest Provision" for the Fuel Cost Recovery Clause. The interest calculations are provided as pages 4c and 5b of Appendix III.

Q. Please explain page 6 of Appendix III.

A. Page 6 of Appendix III calculates the allocation factors for demand and energy at generation. The demand allocation factors are calculated by determining the percentage each rate class contributes to the monthly system peaks. The energy allocators are calculated by determining the percentage each rate contributes to total kWh sales, as adjusted for losses, for each rate class.

Q. Please explain page 7 of Appendix III.

A. Page 7 of Appendix III presents the calculation of the proposed CCR factors by rate class.

Q. What effective date is the Company requesting for the new factors?

A. The Company is requesting that the new FCR and CCR factors become effective with customer billings on cycle day 3 of April 1997 and continue through cycle day 2 of September 1997. This will provide for 6 months of billing on these factors for all our customers.

Q. What will be the charge for a Residential customer using 1,000 kWh effective April 1997?

A. The total residential bill, excluding taxes and franchise fees, for 1,000 kWh will be $78.03. The base bill for 1,000 residential kWh is $47.46, the fuel cost recovery charge from Schedule E1-E, Page 9 of Appendix II for a residential customer is $21.96, the Conservation charge is $2.62, the Capacity Cost Recovery charge is $5.03, the Environmental Cost Recovery charge is $.17 and the Gross Receipts

Tax is $.79. A Residential Bill Comparison (1,000 kWh) is presented in Schedule E10, Page 39 of Appendix II.

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

A. Yes, it does.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

TESTIMONY OF RENE SILVA

DOCKET NO. 970001-EI

January 16, 1997

Q **Please state your name and address.**

A. My name is Rene Silva. My business address is 9250 W. Flagler Street, Miami, Florida 33174.

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

A. I am employed by Florida Power & Light Company (FPL) as Manager of Forecasting and Regulatory Response in the Power Generation Business Unit.

Q. **Have you previously testified in this docket?**

A. Yes.

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

A. The purpose of my testimony is to present and explain FPL's projections for (1) dispatch costs of heavy fuel oil, light fuel oil, coal and natural gas,

(2) availability of natural gas to FPL, (3) generating unit heat rates and availabilities, and (4) quantities and costs of interchange and other power transactions. These projected values were used as input values to POWRSYM in the calculation of the proposed fuel cost recovery factor for the period April through September, 1997. In addition, my testimony presents and explains costs, included (in part) in the projected Fuel Cost Recovery Factor, associated with (a) railcars purchased by FPL to deliver coal to the Scherer coal plant, and (b) fuel-related equipment modifications and new equipment to be purchased by FPL, necessary to enable FPL to use a more economic grade of residual fuel oil. These costs are related to the delivery and/or use of fuel in a more economic manner, for the purpose of reducing fuel costs to our customers.

Q. **Have you prepared or caused to be prepared under your supervision, direction and control an Exhibit in this proceeding?**

A. Yes, I have. It consists of pages 1 through 9 of Appendix I of this filing.

Q. **What are the key factors that could affect FPL's price for heavy fuel oil during the April through September, 1997 period?**

A. The key factors are (1) demand for crude oil and petroleum products (including heavy fuel oil), (2) non-OPEC crude oil production, (3) the extent to which OPEC production matches actual demand for OPEC crude oil, (4) the price relationship between heavy fuel oil and crude oil, and (5) the terms of FPL's heavy fuel oil supply and transportation contracts.

In general, world demand for crude oil and petroleum products is projected to continue to increase at a moderate rate through 1997 as a result of continued economic growth in the Pacific Rim countries.

On the supply side, total non-OPEC crude oil production is projected to rise slightly through 1997 due to increases in the North Sea and Latin America. The balance of the projected increase in crude oil demand is projected to be adequately met by a slight increase in OPEC production.

Based on these factors crude oil prices, and consequently heavy fuel oil prices, for the April through September, 1997 period will be somewhat lower than at present.

Q. **What is the projected relationship between heavy fuel oil and crude oil prices during the April through September, 1997 period?**

A. The price of heavy fuel oil on the U. S. Gulf Coast (1.0% sulfur) is projected to be approximately 76% of the price of West Texas Intermediate (WTI) crude oil.

Q. Please provide FPL's projection for the dispatch cost of heavy fuel oil for the April through September, 1997 period.

A. FPL's projection for the system average dispatch cost of heavy fuel oil, by sulfur grade, by month, is provided on page 3 of Appendix I in dollars per barrel.

Q. What are the key factors that could affect the price of light fuel oil?

A. The key factors that affect the price of light fuel oil are similar to those described above for heavy fuel oil.

Q. Please provide FPL's projection for the dispatch cost of light fuel oil for the period from April through September, 1997.

A. FPL's projection for the average dispatch cost of light oil, by sulfur grade, by month, is shown on page 4 of Appendix I.

Q. What is the basis for FPL's projections of the dispatch cost of coal?

A. FPL's projected dispatch cost of coal is based on FPL's price projection of spot coal delivered to its coal plants.

For St. Johns River Power Park (SJRPP), annual coal volumes delivered under long-term contracts are fixed on October 1st of the previous year. For Scherer Plant, the annual volume of coal delivered under long-term contracts is set by the terms of the contracts. Therefore, the price of coal delivered under long-term contracts does not affect the daily dispatch decision. The dispatch price of coal for each coal plant is based on the variable component of the coal cost, the projected spot coal price.

In the case of SJRPP, FPL plans to blend petroleum coke with the coal in order to reduce fuel costs, beginning in early 1997. It is anticipated that petroleum coke will represent 16% of the fuel blend at SJRPP. The lower price of petroleum coke is reflected in the weighted average price of fuel delivered to SJRPP.

Q. **Please provide FPL's projection for the dispatch cost of coal for the April through September, 1997 period.**

A. FPL's projected system average dispatch cost of coal, shown on page 5 of Appendix I, is about $1.52 per million BTU, delivered to plant.

Q. **What are the factors that can affect FPL's natural gas prices during**

the April through September, 1997 period?

A. In general, the key factors are (1) domestic natural gas demand and supply, (2) natural gas imports, (3) heavy fuel oil prices and (4) the terms of FPL's gas supply and transportation contracts. For the projected period, the dominant factor influencing the price of gas will be strong gas demand caused by the current low level of gas inventory.

Every year, between the months of April and October, natural gas market inventories are built up as a reserve in preparation for peak winter gas demand. However, the quantity of natural gas in inventory in November, 1996 - the end of the gas "injection" season - was much lower than it has been in previous years.

It is projected that this situation will keep demand for natural gas very strong beyond the winter of 1996-1997. Consequently, gas prices are projected to remain firm through September, 1997, although slightly lower than prices in 1996.

Q. What are the factors that affect the availability of natural gas to FPL during the April through September, 1997 period?

A. The key factors are (1) the existing capacity of natural gas transportation facilities into Florida, (2) the portion of that capacity that is contractually allocated to FPL on a firm, "guaranteed" basis each month and (3) the natural gas demand in the State of Florida.

The current capacity of natural gas transportation facilities into the State of Florida is 1,455,000 million BTU per day (including FPL's firm allocation of 480,000 to 630,000 million BTU per day during this period, depending on the month). Total demand for natural gas in the State during the period (including FPL's firm allocation) is projected to be between 100,000 and 255,000 million BTU per day below the pipeline's total capacity. This projected available pipeline capacity could enable FPL to acquire and deliver additional natural gas, beyond FPL's 480,000 to 630,000 million BTU per day of firm, "guaranteed" allocation, should it be economically attractive, relative to other energy choices.

Q. **Please provide FPL's projections for the dispatch cost and availability (to FPL) of natural gas for the April through September, 1997 period.**

A. FPL's projections of the system average dispatch cost and availability of natural gas are provided on page 6 of Appendix I.

Q. Are the projected dispatch prices for natural gas for the April through September, 1997 period provided in page 6 of Appendix I significantly different from those (actual and projected) for December, 1996 through March 1997?

A. Yes. Prices for natural gas have risen very sharply since early December. For example, the actual dispatch price of natural gas (delivered under firm transportation) for January, 1997 is $4.25 per million Btu, compared to $2.58 per million Btu in November, 1996. We anticipate that natural gas prices will remain high through March, 1997. These high prices for December, 1996 through March, 1997 are reflected in FPL's calculation of the "estimated-actual" component of the proposed fuel factor for the projected (April through September, 1997) period.

Conversely, our projected natural gas dispatch prices for the April through September, 1997 period, presented in Appendix I, reflect our view that when heating demand for natural gas ends, prices will decrease significantly, as they did in 1996. For example, the projected dispatch price of natural gas (delivered under firm transportation) for April, 1997 is $1.79 per million Btu, much lower than the current price.

Q. Why have natural gas prices risen in December and January?

A. Natural gas prices have risen primarily as a result of very high demand caused by colder than normal weather throughout the country. Another contributor to the current high price of natural gas has been the fact that the total volume of natural gas placed in storage throughout the country in preparation for the 1996-1997 heating season was lower than in previous years.

In other words, the high market prices of natural gas are a reaction to the current weather-driven high demand for natural gas, as well as uncertainty regarding both the level of demand during the rest of the winter and the adequacy of natural gas inventory volumes to meet that demand. This uncertainty will also contribute to increased volatility in natural gas prices during the next few months.

Q. How do you plan to address this high level of uncertainty?

A. We will continue to monitor developments in natural gas supply and demand conditions, as well as movements in the market price of natural gas. If, prior to the time of the February fuel hearings before the Commission, it becomes likely that market forces will keep the prices of natural gas higher than we have projected for the April through September, 1997 period, we will present supplemental testimony reflecting our revised projections.

Q. **Please describe how you have developed the projected unit Average Net Operating Heat Rates shown on Schedule E4 of Appendix II.**

A. The projected Average Net Operating Heat Rates were calculated by the POWRSYM model. The current heat rate equations and efficiency factors for FPL's generating units, which present heat rate as a function of unit power level, were used as inputs to POWRSYM for this calculation. The heat rate equations and efficiency factors are updated as appropriate, based on historical unit performance and projected changes due to plant upgrades, fuel grade changes, or results of performance tests.

Q. **Are you providing the outage factors projected for the period April through September, 1997?**

A. Yes. This data is shown on page 7 of Appendix I.

Q. **How were the outage factors for this period developed?**

A. The unplanned outage factors were developed using the actual historical full and partial outage event data for each of the units. The historical unplanned outage factor of each generating unit was adjusted, as necessary, to eliminate non-recurring events and recognize the effect of planned outages to arrive at the projected factor for the April through

September, 1997 period.

Q. Please describe significant planned outages for the April through September, 1997 period.

A. Planned outages at our nuclear units are the most significant in relation to Fuel Cost Recovery. Turkey Point Unit No.3 is scheduled to be out of service for refueling beginning on March 3, 1997 and until April 12, 1997, or twelve days during the projected period. Turkey Point Unit No.4 is scheduled to be out of service for refueling beginning on September 8, 1997 and until October 12, 1997, or twenty three days during the projected period. St. Lucie Unit No.2 will be out of service for refueling beginning on April 14, 1997 and until June 1, 1997, or forty-nine days during the projected period. There are no other significant planned outages during the projected period.

Q. Are any changes to FPL's generation capacity planned during the April through September, 1997 period?

A. Yes. Net Summer Continuous Capability (NSCC) at Pt. Everglades Unit No.4 will increase by 18 MW, from 385 MW to 403 MW, while its Summer Peaking Capability (SPC) will increase by 15 MW, from 395 MW to 410 MW. Similarly, NSCC at Martin Unit No.2 will increase by

16 MW, from 798 MW to 814 MW, while its SPC will increase by 11 MW, from 808 MW to 819 MW, and SPC at Martin Units No.3 and 4 will increase by 27 MW at each Unit, from 430 MW to 457 MW.

Q. Are you providing the projected interchange and purchased power transactions forecasted for April through September, 1997?

A. Yes. This data is shown on Schedules E6, E7, E8, and E9 of Appendix II of this filing.

Q. In what types of interchange transactions does FPL engage?

A. FPL purchases interchange power from others under several types of interchange transactions which have been previously described in this docket: Emergency - Schedule A; Short Term Firm - Schedule B; Economy - Schedule C; Extended Economy - Schedule X; Opportunity Sales - Schedule OS; UPS Replacement Energy - Schedule R and Economic Energy Participation - Schedule EP.

For services provided by FPL to other utilities, FPL has developed amended Interchange Service Schedules, including AF (Emergency), BF (Scheduled Maintenance), CF (Economy), DF (Outage), and XF (Extended Economy). These amended schedules replace and supersede existing Interchange Service Schedules A, B, C, D, and X for services provided by FPL.

Q. Does FPL have arrangements other than interchange agreements for the purchase of electric power and energy which are included in your projections?

A. Yes. FPL purchases coal-by-wire electrical energy under the 1988 Unit Power Sales Agreement (UPS) with the Southern Companies. FPL has contracts to purchase nuclear energy under the St. Lucie Plant Nuclear Reliability Exchange Agreements with Orlando Utilities Commission (OUC) and Florida Municipal Power Agency (FMPA). FPL also purchases energy from JEA's portion of the SJRPP Units, as stated above. Additionally, FPL purchases energy and capacity from Qualifying Facilities under existing tariffs and contracts.

Q. Please provide the projected energy costs to be recovered through the Fuel Cost Recovery Clause for the power purchases referred to above during the April through September, 1997 period.

A. Under the UPS agreement FPL's capacity entitlement during the projected period is 913 MW from April through September, 1997. Based upon the alternate and supplemental energy provisions of UPS, an availability factor of 100% is applied to these capacity entitlements to project energy purchases. The projected UPS energy (unit) cost for this period, used as input to POWRSYM, is based on data provided by the Southern Companies. For the period, FPL projects the purchase of 1,886,961 MWH of UPS Energy at a cost of $35,625,380. In addition, we project the purchase of 767,139 MWH of UPS Replacement energy (Schedule R) at a cost of $13,003,560. The total UPS Energy plus Schedule R projections are presented on Schedule E7 of Appendix II.

Energy purchases from the JEA-owned portion of the St. Johns River Power Park generation are projected to be 1,526,623 MWH for the period at an energy cost of $23,236,710. FPL's cost for energy purchases under the St. Lucie Plant Reliability Exchange Agreements is a function of the operation of St. Lucie Unit 2 and the fuel costs to the owners. For the period, we project purchases of 192,523 MWH at a cost of $730,700. These projections are shown on Schedule E7 of Appendix II.

In addition, as shown on Schedule E8 of Appendix II, we project that purchases from Qualifying Facilities for the period will provide 4,254,160 MWH at a cost to FPL of $81,519,989.

Q. How were energy costs related to purchases from Qualifying Facilities developed?

A. For those contracts that entitle FPL to purchase "as-available" energy we used FPL's fuel price forecasts as inputs to the POWRSYM model to project FPL's avoided energy cost that is used to set the price of these energy purchases each month. For those contracts that enable FPL to purchase firm capacity and energy, the applicable Unit Energy Cost mechanism prescribed in the contract is used to project monthly energy costs.

Q. Have you projected Schedule A/AF - Emergency Interchange Transactions?

A. No purchases or sales under Schedule A/AF have been projected since it is not practical to estimate emergency transactions.

Q. Have you projected Schedule B/BF - Short-Term Firm Interchange Transactions?

A. No commitment for such transactions had been made when projections were developed. Therefore, we have estimated that no Schedule BF sales or Schedule B purchases would be made in the projected period.

Q. Please describe the method used to forecast the Economy Transactions.

A. The quantity of economy sales and purchase transactions are projected based upon historic transaction levels, adjusted to remove non-recurring factors.

Q. What are the forecasted amounts and costs of Economy energy sales?

A. We have projected 386,220 MWH of Economy energy sales for the period. The projected fuel cost related to these sales is $10,021,597. The projected transaction revenue from the sales is $12,990,840. Eighty percent of the gain for Schedule C is $2,375,393 and is credited to our customers.

Q. In what document are the fuel costs of economy energy sales transactions reported?

A. Schedule E6 of Appendix II provides the total MWH of energy and total dollars for fuel adjustment. The 80% of gain is also provided on Schedule E6 of Appendix II.

Q. What are the forecasted amounts and costs of Economy energy

purchases for the April to September, 1997 period?

A. The costs of these purchases are shown on Schedule E9 of Appendix II. For the period FPL projects it will purchase a total of 2,677,497 MWH at a cost of $53,242,230. If generated, we estimate that this energy would cost $60,946,338. Therefore, these purchases are projected to result in savings of $7,704,108.

Q. What are the forecasted amounts and cost of energy being sold under the St. Lucie Plant Reliability Exchange Agreement?

A. We project the sale of 262,195 MWH of energy at a cost of $1,095,050. These projections are shown on Schedule E6 of Appendix II.

Q. Does FPL's proposed fuel factor reflect a return on, and depreciation of, railcars recently purchased by FPL to deliver coal to Scherer Plant?

A. Yes. FPL recently placed an order for 63 railcars, with an initial value of $3,618,121.27. These railcars will be used to deliver coal to Scherer Plant. Like other railcars already owned by FPL, which are used to deliver coal to SJRPP and Scherer Plant, and which have been previously approved for cost recovery purposes, a return on, and depreciation of, these 63 Scherer railcars is reflected in FPL's fuel factor. The cost recovery treatment of these railcars is discussed in the testimony of FPL Witness Rosemary Morley

Q. When will FPL place in service these 63 railcars for Scherer coal deliveries?

A. The 63 railcars, which have been ordered from Thrall Car Manufacturing Co., of Chicago Heights, Illinois, will be placed in service in March, 1997.

Q. Why did FPL purchase 63 additional railcars for Scherer coal deliveries?

A. Seven of these railcars are replacements for seven cars destroyed as a result of a derailment. The other 56 railcars are required to enable FPL to deliver the projected annual tonnage of coal required to operate its share of Scherer Unit 4, between 2.2 and 2.3 million tons per year.

As indicated in prior testimony filed with the FPSC (Testimony of Rene Silva, June 20, 1995, pages 14 and 15), FPL estimated that it would need 4.6 unit trains of 110 railcars each, plus spares, to meet its projected need (approximately 518 railcars). At the time FPL decided to purchase only 4 unit-trains (plus 22 spares), or 56 railcars short of meeting its estimated need. Any actual shortfall would be met by using railcars owned by other Plant Scherer co-owners.

FPL's projection of railcar requirements has not changed; there is still a need for 56 additional railcars. However, the Scherer Plant co-owners have a net shortage of railcars, so FPL cannot assume that it will be able to meet its railcar shortfall by using co-owners' railcars in the future. Since any coal delivery shortfall would require FPL to use more expensive oil generation to meet load requirements, purchasing the required railcars benefits FPL's customers.

Q. Why was Thrall Car Manufacturing Co. selected to provide FPL's railcars?

A. Thrall was selected as a result of a competitive bid evaluation process conducted by Southern Company Services acting as agent for the Scherer Plant co-owners, which include FPL. Thrall's total cost was the lowest bid received from the two companies qualified to manufacture this type of railcars. FPL reviewed the bids and the evaluation process, verified that Thrall's was the lowest cost bid, and concurred with the selection of Thrall Car Manufacturing Co.

Q. Did FPL compare the lease option to the purchase decision?

A. Yes. FPL compared five different lease alternatives to its purchase decision. The purchase decision is about $37,000 lower in cost than the best of the lease options. Therefore the purchase decision is the correct choice.

Q. Does FPL's proposed fuel factor reflect recovery of costs FPL is incurring in order to allow FPL to use a more economic grade of residual fuel oil at a number of its generating units?

A. Yes. FPL is including in the proposed fuel cost recovery factor the costs of implementing certain equipment modifications and additions at some of its generating plants and fuel storage facilities to enable FPL to operate these plants using a heavier, more economic grade of residual fuel oil, "low gravity" fuel oil. The cost recovery treatment of these equipment modifications and additions is discussed in the testimony of FPL Witness Rosemary Morley.

Q. What is "low gravity" fuel oil?

A. Low gravity residual fuel oil, specifically 6.0 Degrees API Gravity residual fuel oil, differs from standard gravity residual fuel oil (10.1 Degrees API Gravity) only in that it is heavier, and as a result it contains more energy (Btu's) per barrel. Otherwise, it has the same characteristics as standard gravity residual fuel oil.

Q. What is the magnitude of the costs related to the use of low gravity oil at these generating units?

A. Approximately $2.087 million.

Q. What is the magnitude of the fuel savings?

A. Fuel savings are projected to be about $4.78 million in 1997, $7.52 million in 1998 and $7.64 million in 1999, or about $19.94 million over three years, a 9-to-1 savings-to-cost ratio. We have not projected fuel savings beyond 1999 due to uncertainty regarding environmental requirements after 1999.

Q. What fuel costs savings are projected for the April through September, 1997 period?

A. Based on current projections of fuel oil burn at the targeted generating units, and on the schedule for completion of the necessary equipment additions and modifications, fuel savings are projected to be about $2.87 million during the April through September, 1997 period.

Q. What do the costs consist of?

A. The one-time cost includes about $2.054 million for required modifications to oil-water separation systems at a number of FPL's plants and fuel storage facilities to effectively remove this heavier type of fuel oil from waste streams. These changes are necessary for FPL to use this fuel oil.

The one-time cost also includes about $33,000 in new "sleeves" and "aprons" for oil transfer hoses required to prevent oil spills, and "deep-skirted" booms required to contain the spread of a spill of the low gravity fuel oil, should one occur. The U.S. Coast Guard has indicated that FPL will be allowed to transport this type of fuel oil, provided it implements a number of measures of which the addition of the spill prevention and containment equipment referred to above is a part. A detailed breakdown of the "one-time" costs related to the use of this more economic fuel oil, by location, is provided on Page 8 of Appendix I.

These equipment changes and additions are required because the low gravity fuel oil is heavier than water. FPL would not make these changes and additions if it were not proposing a change to this more economic type of fuel oil.

Q. **What is the basis for the projected fuel savings?**

A. FPL intends to use the low gravity fuel oil at a number of its oil generating units. As a result, FPL's suppliers have offered to charge from \$0.10 to \$0.25 per barrel less for the oil used at these generating units. In addition, the heavier (6.0 Degrees API Gravity) fuel oil contains 0.10 MMBtu's per barrel more than standard gravity fuel oil. These price discounts and energy content advantages are applied to the quantity of fuel oil projected to be burned during 1997 through 1999 to project fuel savings. The calculation of the fuel savings projection is provided on Page 9(a-d) of Appendix I.

Q. Is FPL currently permitted to use low gravity fuel oil at its generating units?

A. Yes. In fact, FPL has used a "lower-than-standard" or "intermediate" gravity residual fuel oil (8.0 Degrees API Gravity) at a number of its plants. Full use of this "intermediate" gravity fuel oil would reduce fuel costs to FPL's customers by about \$10.19 million during 1997 through 1999. However, FPL's plan is to use the lower (6.0 Degrees API Gravity) gravity fuel oil and thereby achieve an additional \$9.75 million fuel cost savings. The equipment additions and modifications referred to above are required to ensure that we meet all environmental requirements while using "intermediate" and "low" gravity residual fuel oil for the purpose of reducing fuel costs.

Q. Will FPL incur any other incremental cost as a result of its use of low gravity fuel oil?

A. Yes. FPL will incur an incremental barging cost of about $215,00 per year to deliver the low gravity fuel oil to its Turkey Pt. and Ft. Myers generating units. However, FPL does not seek recovery of that incremental barging cost through the Fuel Cost Recovery Clause.

Q. Would you please summarize your testimony?

A. Yes. In my testimony I have presented FPL's fuel price projections for the fuel cost recovery period of April through September, 1997. In addition, I have presented FPL's projections for generating unit heat rates and availabilities, and the quantities and costs of interchange and other power transactions for the same period. These projections were based on the best information available to FPL, and were used as inputs to POWRSYM in developing the projected Fuel Cost Recovery Factor for the April through September, 1997 period. My testimony also explains FPL's decision to purchase 63 additional railcars to deliver coal to its Scherer Unit No.4, the lowest cost alternative available to FPL. In addition, my testimony presents and explains costs, included in the projected fuel cost recovery factor, that FPL will incur in order to utilize a more economic "low gravity" fuel oil, as well as the fuel savings to be derived from the use of the "low gravity" fuel oil.

Q. Does this conclude your testimony?

A. Yes, it does.

BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 970001-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 April 1997 - September 1997 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 October 1996 - March 1997 and to establish a "true-up" amount to be collected or refunded during April 1997 - September 1997

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, E1-B, E1B-1, E2, E7, E8 and E10 for Marianna and Fernandina Beach. They are included in Composite Prehearing Identification Number GMB-3.

These schedules support the calculation of the levelized fuel adjustment factor for April 1997 - September 1997. Schedule E1-B shows the Calculation of Purchased Power Costs and Calculation of True-Up and Interest Provision for the period October 1996 - March 1997 based on 2 Months Actual and 4 Months Estimated data.

Q. In derivation of the projected cost factor for the April 1997 - September 1997 period, did you follow the same procedures that were used in the prior period filings?

A. Yes.

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

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

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 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 April 1997 - September 1997 period.

A. We have determined that at the end of March 1997 based on two months actual and four months estimated, we will have over-recovered $491,914 in purchased power costs in our Marianna division. Based on estimated sales for the period April 1997 - September 1997, it will be necessary to subtract .33106¢ per KWH to refund this over-recovery.

In Fernandina Beach we will have over-recovered $191,913 in purchased power costs. This amount will be refunded at .14153¢ per KWH during the April 1997 - September 1997 period. Page 3 and 12 of Composite Prehearing Identification Number GMB-3 provides a detail of the calculation of the true-up amounts.

Q. Looking back upon the April 1996 - September 1996 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 over-recovery of $8,729 and Fernandina Beach Division under-recovered $307,510. 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 April 1996 through September 1996 for both divisions?

A. In Marianna the final remaining true-up amount was an over-recovery of $459,638. The final remaining true-up amount for Fernandina Beach was an under-recovery of $56,002.

Q. What are the estimated true-up amounts for the period of October 1996 through March 1997?

A. In Marianna, there is an estimated over-recovery of $32,276. Fernandina Beach has an estimated over-recovery of $247,915.

Q. What will the total fuel adjustment factor, excluding demand cost recovery, be for both divisions for the period April 1997 - September 1997?

A. In Marianna the total fuel adjustment factor as shown on Line 33, Schedule E1, is 2.179¢ per KWH. In Fernandina Beach the total fuel adjustment factor for "other classes", as shown on Line 43, Schedule E1, amounts to 2.859¢ per KWH.

Q. Please advise what a residential customer using 1,000 KWH will pay for the period April 1997 - September 1997 including base rates (which include revised 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 $64.70, a decrease of $7.38 from the previous period. In Fernandina Beach a customer will pay $65.35, an decrease of $6.28 from the previous period.

Q. Does this conclude your testimony?

A. Yes.

Disk Fuel 1/97 Doc 970001-ei

970001-ei-test-gb

GULF POWER COMPANY

Before the Florida Public Service Commission
Prepared Direct Testimony of
Susan D. Cranmer
Docket No. 960001-EI
Fuel and Purchased Power Energy Cost Recovery
Date of Filing: November 19, 1996

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

A. My name is Susan Cranmer. My business address is 500 Bayfront Parkway, Pensacola, Florida 32501. I hold the position of Assistant Secretary and Assistant Treasurer of Gulf Power Company. In this position, I am responsible for supervising the Rates and Regulatory Matters Department.

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

A. I graduated from Wake Forest University in Winston-Salem, North Carolina in 1981 with a Bachelor of Science Degree in Business and from the University of West Florida in 1982 with a Bachelor of Arts Degree in Accounting. I am also a Certified Public Accountant licensed in the State of Florida. I joined Gulf Power Company in 1983 as a Financial Analyst. Prior to being selected for my current position, I have held various positions with Gulf including Computer Modeling Analyst, Senior Financial Analyst, and Supervisor of Rate Services.

My responsibilities include supervision of: tariff administration, cost of service activites, calculation of cost recovery factors, the regulatory filing function in the Rates and Regulatory Matters Department, and also treasury activities.

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 Ms. Cranmer's Exhibit consisting of one schedule be marked as Exhibit No. 12 (SDC-1).

Q. Are you familiar with the Fuel and Purchased Power (Energy) True-up Calculation for the period of April 1996 through September 1996 set forth in your exhibit?

A. Yes. This document was prepared under my supervision.

Q. Have you verified that to the best of your knowledge and belief, the information contained in this document is correct?

A. Yes, I have.

Q. What is the amount to be refunded or collected through the fuel cost recovery factor in the period April 1997 through September 1997?

A. An amount to be refunded of $3,892,089 was calculated as shown in Schedule 1 of my exhibit.

Q. How was this amount calculated?

A. The $3,892,089 was calculated by taking the difference in the estimated April 1996 through September 1996 under-recovery of $2,727,188 as approved in Order No. PSC-96-1172-FOF-EI, dated September 19, 1996 and the actual over-recovery of $1,164,901 which is the sum of lines 7 and 8 shown on Schedule A-2, page 2 of 3, Period-to-date of the monthly filing for September 1996.

Q. Ms. Cranmer, does this complete your testimony?

A. Yes, it does.

GULF POWER COMPANY

Before the Florida Public Service Commission
Prepared Direct Testimony of
Susan D. Cranmer
Docket No. 970001-EI
Fuel and Purchased Power Cost Recovery
Date of Filing: January 13, 1997

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

A. My name is Susan Cranmer. My business address is 500 Bayfront Parkway, Pensacola, Florida 32501. I hold the position of Assistant Secretary and Assistant Treasurer for Gulf Power Company.

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

A. I graduated from Wake Forest University in Winston-Salem, North Carolina in 1981 with a Bachelor of Science Degree in Business and from the University of West Florida in 1982 with a Bachelor of Arts Degree in Accounting. I am also a Certified Public Accountant licensed in the State of Florida. I joined Gulf Power Company in 1983 as a Financial Analyst. Prior to assuming my current position, I have held various positions with Gulf including Computer Modeling Analyst, Senior Financial Analyst, and Supervisor of Rate Services.

My responsibilities include supervision of: tariff administration, cost of service activities, calculation of cost recovery factors, the regulatory filing function of the Rates and Regulatory Matters Department, and various treasury activities.

Q. Have you previously filed testimony before this Commission in Docket No. 970001-EI?
A. Yes, I have.

Q. What is the purpose of your testimony?
A. The purpose of my testimony is to discuss the calculation of Gulf Power's fuel cost recovery factors for the period April 1997 through September 1997.

Q. Are you familiar with the Fuel Cost Recovery Clause Calculation for the period of April 1997 through September 1997?
A. Yes, these documents were prepared under my supervision.

Q. Have you verified that to the best of your knowledge and belief, the information contained in these documents is correct?
A. Yes, I have.

Counsel: We ask that Ms. Cranmer's Exhibit

consisting of thirteen schedules,
along with Schedules A1 through A9
previously filed with the Commission for
the months of June, July, August,
September, October, and November 1996,
be marked as Exhibit No. 13 (SDC-2).

Q. Ms. Cranmer, what has Gulf calculated as the true-up to be applied in the period April 1997 through September 1997?

A. The true-up for this period is a decrease of .0244¢/kwh. This includes a final true-up over-recovery of $3,892,089. As shown on Schedule E-1A, it also includes an estimated true-up under-recovery of $2,698,394 for the current period. The resulting over-recovery is $1,193,695.

Q. What has been included in this filing to reflect the GPIF reward/penalty for the period of April 1996 through September 1996?

A. This is shown on Line 32b of Schedule E-1 as an increase of .0017¢/kwh, thereby rewarding Gulf by $82,198.

Q. Ms. Cranmer, what is the levelized projected fuel factor for the period April 1997 through September 1997?

A. Gulf has proposed a levelized fuel factor of 2.154¢/kwh. It includes projected fuel and purchased power energy expenses for April 1997 through September 1997 and projected kwh sales for the same period, as well as the true-up and GPIF amount. The proposed levelized fuel factor also includes the special recovery amount associated with the Air Products contract. The calculation of the special recovery amount is presented on Schedule E-12 of my exhibit. The levelized fuel factor has not been adjusted for line losses.

Q. Ms. Cranmer, how were the line loss multipliers used on Schedule E-1E calculated?

A. They were calculated in accordance with procedures approved in prior filings and were based on Gulf's latest mwh Load Flow Allocators.

Q. Ms. Cranmer, what fuel factor does Gulf propose for its largest group of customers (Group A), those on Rate Schedules RS, GS, GSD, OSIII, and OSIV?

A. Gulf proposes a standard fuel factor, adjusted for line losses, of 2.180¢/kwh for Group A. Fuel factors for Groups A, B, C, and D are shown on Schedule E-1F. These factors have also been adjusted for line losses.

Q. Ms. Cranmer, how were the time-of-use fuel factors calculated?

A. These were calculated based on projected loads and system lambdas for the period April 1997 through September 1997. These factors included the GPIF, true-up, and special contract recovery cost amounts and were adjusted for line losses. These time-of-use fuel factors are also shown on Schedule E-1E.

Q. How does the proposed fuel factor for Rate Schedule RS compare with the factor applicable to March and how will the change affect the cost of 1000 kwh on Gulf's residential rate RS?

A. The current fuel factor for Rate Schedule RS applicable to March 1997 is 2.345¢/kwh compared with the proposed factor of 2.180¢/kwh. For a residential customer who uses 1000 kwh in April 1997, the fuel portion of the bill will decrease from $23.45 to $21.80.

Q. Ms. Cranmer, has Gulf updated its estimates of the as-available avoided energy costs to be shown on COG1 as required by Order No. 13247 issued May 1, 1984, in Docket No. 830377-EI and Order No. 19548 issued June 21, 1988, in Docket No. 880001-EI?

A. Yes. A tabulation of these costs is set forth in Schedule E-11 of my Exhibit SDC-1. These costs represent the estimated averages for the period from April 1997 through March 1999.

Q. When does Gulf propose to collect these new fuel charges?
A. The fuel factors will apply to April 1997 through September 1997 billings beginning with Cycle 1 meter readings scheduled on April 2, 1997 and ending with meter readings scheduled on September 30, 1997.

Q. Ms. Cranmer, does this complete your testimony?
A. Yes, it does.

GULF POWER COMPANY
Before the Florida Public Service Commission
Direct Testimony of
G. D. Fontaine
Docket No. 960001-EI
Date of Filing November 19, 1996

Q. Please state your name, address and occupation.

A. My name is George D. Fontaine, my business address is Post Office Box 1151, Pensacola, Florida 32520, and my position is Performance Test Specialist for Gulf Power Company.

Q. Please describe your educational and business background.

A. I received my Bachelor of Mechanical Engineering Degree from Auburn University in 1980. Following graduation, I joined Gulf Power Company as an Associate Engineer at the Scholz Electric Generating Plant, and as I previously stated, my current position is Performance Test Specialist. I am also a registered Professional Engineer in the State of Florida.

Q. Mr. Fontaine, have you previously testified in this Docket?

A. Yes, sir.

Q. Mr. Fontaine, 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 April 1, 1996, through September 30, 1996.

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

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

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

A. Yes, it was.

Counsel: We ask that Mr. Fontaine's exhibit be marked for identification as exhibit 14 (GDF-1).

Q. Mr. Fontaine, before reviewing the GPIF Results for Gulf's units, is there any information which has been supplied to the Commission pertaining to this GPIF period which requires amendment?

A. Yes, some corrections need to be made to the actual unit performance data which was submitted monthly to the Commission during this period. These corrections are based on discoveries made during our final review to determine the accuracy of this information prior to this proceeding. The Actual Unit Performance Data tables on pages 14 to 19 of Schedule 5 incorporate these changes. The data contained on these tables is the data upon which the GPIF calculation was made.

Q. Mr. Fontaine, 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 13 of Schedule 5. Pages 3 through 8 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-96-0353-FOF-EI is on page 9 of Schedule 2. The results are: Crist 6, +10.00 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. Mr. Fontaine, what were the heat rate results for the period?

A. The detailed calculation of the actual average net operating heat rates for the Company's GPIF units is on pages 2 through 7 of Schedule 3. These heat rate figures have not at this point been adjusted in accordance with GPIF procedures for load and other factors to the bases of their targets.

As was done for the prior GPIF periods, and as indicated on pages 8 through 13 of Schedule 3, the target setting equations were used to adjust actual results to the target bases. These equations, submitted in January 1996, are shown on page 15 of Schedule 3.

As calculated on page 16 of Schedule 3, the adjusted actual average net operating heat rates correspond to GPIF unit heat rate points of: +10.00 for Crist 6, +10.00 for Crist 7; 0.00 for Smith 1, 0.00 for Smith 2; -6.13 for Daniel 1; and -10.00 for Daniel 2.

Q. Mr. Fontaine, what number of Company points were 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 Company points would be +0.95 as indicated on page 2 of Schedule 4. This calculated to a reward in the amount of $82,198.

Q. Mr. Fontaine, would you please summarize your testimony?

A. Yes, Sir. In view of the adjusted actual equivalent availabilities, as shown on page 9 of Schedule 2, and the adjusted actual average net operating heat rates achieved, as shown on page 16 of Schedule 3, evidencing the Company's performance for the period, Gulf calculates a reward in the amount of $82,198 as provided for by the GPIF plan.

Q. Mr. Fontaine, does this conclude your testimony?

A. Yes, Sir.

GULF POWER COMPANY
Before the Florida Public Service Commission
Direct Testimony of
G. D. Fontaine
Docket No. 970001-EI
Date of Filing January 13, 1997

Q. Please state your name, address and occupation.

A. My name is George D. Fontaine, my business address is Post Office Box 1151, Pensacola, Florida 32520, and my position is Performance Test Specialist for Gulf Power Company.

Q. Please describe your educational and business background.

A. I received my Bachelor of Mechanical Engineering Degree from Auburn University in 1980. Following graduation, I joined Gulf Power Company as an Associate Engineer at the Scholz Electric Generating Plant, and as I previously stated, my current position is Performance Test Specialist. I am also a registered Professional Engineer in the State of Florida.

Q. Have you previously testified in this Docket?

A. Yes. I have presented testimony regarding the Generating Performance Incentive Factor (GPIF) periodically for the past several years.

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

A. The purpose of my testimony today is to present GPIF targets for Gulf Power Company for the period of April 1, 1997 through September 30, 1997.

Q. 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 three schedules.

Q. Was this exhibit prepared by you or under your direction and supervision?

A. Yes, it was.

Counsel: We ask that Mr. Fontaine's exhibit be marked for identification as exhibit 15 (GDF-2).

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

A. We propose that Crist Units 6 and 7, Smith Units 1 and 2, and Daniel Units 1 and 2 continue to be the Company's GPIF units.

Q. What are the target heat rates Gulf proposes to use in the GPIF for these units for the performance period April 1, 1997 through September 30, 1997?

A. I would like to refer you to Page 32 of Schedule 1 of my exhibit where these targets are listed.

Q. How were these proposed target heat rates determined?

A. In every case they were determined according to the GPIF implementation manual procedures for Gulf.

Page 2 of Schedule 1 shows the target average net operating heat rate equations for the proposed GPIF units, and pages 4 through 29 of Schedule 1 contain the weekly historical data used for the statistical development of these equations.

Plant Daniel is now scheduled to burn Powder River Basin(PRB) fuel throughout the target summer period. In the past, Plant Daniel has burned PRB primarily during off-peak times of the year and high BTU western fuel during the peak summer periods. The statistical development of the Plant Daniel target net operating heat rate equations was performed with weekly data for the past three years. Weekly PRB-only data from the same period was not utilized as it did not result in a significant difference in the target equations.

Pages 30 and 31 of Schedule 1 present the calculations which 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 32 of Schedule 1, 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 equivalent availabilities and their ranges are listed on page 4 of Schedule 2.

Q. How are these 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.

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, were determined per GPIF manual procedures for Gulf.

Q. Mr. Fontaine, has Gulf completed the GPIF minimum filing requirements data package?
A. Yes, we have completed the required data. Schedule 3 of my exhibit contains this information.

Q. Mr. Fontaine, would you please summarize your testimony?
A. Yes. Gulf asks that the Commission accept:

1. Crist Units 6 and 7, Smith Units 1 and 2 and Daniel Units 1 and 2, for inclusion under the GPIF for the period of April 1, 1997 through September 30, 1997.

2. The target, maximum attainable, and minimum attainable average net operating heat rates, as proposed by the Company and as shown on page 32 of Schedule 1 and also page 5 of Schedule 3 of my exhibit.

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.

4. The weekly average net operating heat rate least squares regression equations, shown on page 2 of Schedule 1 and also pages 18 through 23 of Schedule 3 of my exhibit, for use in adjusting the six-month actual unit heat rates to target conditions.

Q. Mr. Fontaine, does this conclude your testimony?

A. Yes, Sir.

GULF POWER COMPANY

Before the Florida Public Service Commission
Prepared Direct Testimony of
Michael F. Oaks
Docket No. 960001-EI
Date of Filing: November 19, 1996

Q. Please state your name and business address.
A. My name is Michael F. Oaks and my business address is 500 Bayfront Parkway, Post Office Box 1151, Pensacola, Florida 32520-0328.

Q. By whom are you employed and in what capacity?
A. I am the Compliance and Fuel Supply Supervisor at Gulf Power Company.

Q. Mr. Oaks, will you please describe your education and experience?
A. I graduated from Belhaven College in Jackson, Mississippi, in 1977 with a Bachelor of Science Degree in Chemistry. I joined Gulf Power Company in 1977 as a Chemist. Since then, I have held various positions with the Company, including Water Chemistry Specialist, Water Quality Specialist, Environmental Affairs Specialist, Environmental Audit Administrator, and Compliance Administrator. I was promoted to my present position in May 1996.

Q. What are your duties as Fuel Supply Supervisor?
A. I supervise and administer the Company's fuel procurement, transportation, budgeting, contract administration, and quality control to

ensure the generating plants are provided an adequate low cost fuel supply with minimal operational problems.

Q. Mr. Oaks, have you previously testified before this Commission?
A. Yes. I have presented testimony to this Commission.

Q. Mr. Oaks, 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 April 1996 through September 1996. Also, it is my intent to be available to answer any 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 prepared an exhibit consisting of one schedule.

Counsel: We ask that Mr. Oak's exhibit consisting of one schedule be marked as Exhibit No. 16 (MFO-1).

Q. During the period April 1, 1996, through September 30, 1996, how did Gulf's actual fuel expenses compare with the budget or projected expenses?
A. Gulf's actual fuel expense was $110,872,521 as compared with the projected amount of $114,725,542, or under our estimate by 3.36%.

Gulf's total net system generation was 5,645,598 MWH compared to the projected generation of 5,622,394 MWH or 0.41% more than predicted. The resulting total fuel cost per KWH generated was 1.9639¢/KWH or 3.75% under the projected amount of 2.0405¢/KWH.

Q. How much spot coal did Gulf Power Company purchase during the period ending September 30, 1996?

A. Gulf purchased 629,871 tons or 32% of its supply from the spot coal market. My Schedule 1 of Exhibit No. 16 (MFO-1) consists of a list of contract and spot coal suppliers for the period ending September 30, 1996.

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

A. For the period, Gulf's average unit cost of coal purchased was 7.30% lower than projected.

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

A. Yes. Gulf's coal purchases were either from coal vendors with long term contracts subject to cost escalations or from a competitively bid spot purchase order. These coal vendors were selected by procedures designed to provide an assured quantity of coal of a known quality for a specific term at the lowest available delivered cost. Gulf has administered the provisions of these contracts and purchase orders appropriately. All of Gulf's oil purchases were from oil vendors selected by open bids to ensure the most economical price of oil.

Q. Mr. Oaks, does this conclude your testimony?
A. Yes.

GULF POWER COMPANY

Before the Florida Public Service Commission
Prepared Direct Testimony of
Michael F. Oaks
Docket No. 970001-EI
Date of Filing: January 13, 1997

Q. Please state your name and business address.

A. My name is Michael F. Oaks and my business address is 500 Bayfront Parkway, Post Office Box 1151, Pensacola, Florida 32520-0328.

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

A. I am the Compliance and Fuel Supply Supervisor at Gulf Power Company.

Q. Mr. Oaks, will you please describe your education and experience?

A. I graduated from Belhaven College in Jackson, Mississippi, in 1977 with a Bachelor of Science Degree in Chemistry. I joined Gulf Power Company in 1977 as a Chemist. Since then, I have held various positions with the Company, including Water Chemistry Specialist, Water Quality Specialist, Environmental Affairs Specialist, Environmental Audit Administrator, and Compliance Administrator. I was promoted to my present position in May 1996.

Q. What are your duties as Fuel Supply Supervisor?

A. I supervise and administer the Company's fuel procurement, transportation, budgeting, contract administration, and quality control to ensure the generating plants are provided an adequate low cost fuel supply with minimal operational problems.

Q. Are you the same Michael F. Oaks who has previously submitted testimony in this proceeding?

A. Yes.

Q. Mr. Oaks, 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 April 1, 1997, to September 30, 1997 and to be available to answer any questions that may occur concerning the Company's fuel procurement procedures.

Q. 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 one schedule. Schedule 1 of my exhibit is a tabulation of projected and actual fuel cost for the past ten years. The purpose of this schedule is to illustrate the accuracy of our short term projections of fuel expenses.

COUNSEL: We ask that Mr. Oaks' exhibit, consisting of one schedule, be marked as Exhibit No. 17 (MFO-2).

Q. Has Gulf Power Company made any changes to its projection methods for this period?
A. No.

Q. Will there be any major changes in Gulf's fuel purchasing program during this period?
A. Yes. The seasonal fuel program that has been in effect for Plant Daniel is being changed. Significant cost savings can be realized by switching to year-round use of Powder River Basin (PRB) coal rather than the seasonal mix of high Btu Western coal during peak times and PRB for the remainder of the year. Effective January 1, 1997, we are switching to a year-round PRB program. We expect to save over a half million dollars per year (Gulf's portion) for the 1997-1999 period.

Q. How much spot market coal does Gulf Power project it will purchase during the April 1997 through September 1997 period?
A. We are projecting the purchase of approximately 564,880 tons on the spot market. This represents approximately 16% of our projected purchase requirements.

Q. Mr. Oaks, does this conclude your testimony?
A. Yes.

GULF POWER COMPANY

Before the Florida Public Service Commission
Direct Testimony of
M. W. Howell
Docket No. 960001-EI
Date of Filing: November 19, 1996

Q. Please state your name, business address and occupation.
A. My name is M. W. Howell, and my business address is 500 Bayfront Parkway, Pensacola, Florida 32501. I am Transmission and System Control Manager for Gulf Power Company.

Q. Have you previously testified before this Commission?
A. Yes. I have testified in various rate case, cogeneration, territorial dispute, planning hearing, fuel clause adjustment, and purchased power capacity cost recovery dockets.

Q. Please summarize your educational and professional background.
A. I graduated from the University of Florida in 1966 with a Bachelor of Science Degree in Electrical Engineering. I received my Masters Degree in Electrical Engineering from the University of Florida in 1967, and then joined Gulf Power Company as a Distribution Engineer. I have since served as Relay Engineer, Manager of Transmission,

Manager of System Planning, Manager of Fuel and System Planning, and Transmission and System Control Manager. My experience with the Company has included all areas of distribution operation, maintenance, and construction; transmission operation, maintenance, and construction; relaying and protection of the generation, transmission, and distribution systems; planning the generation, transmission, and distribution system additions in the future; bulk power interchange administration; overall management of fuel planning and procurement; and operation of the system dispatch center.

I have served as a member of the Engineering Committee and the Operating Committee of the Southeastern Electric Reliability Council, chairman of the Generation Subcommittee and member of the Edison Electric Institute System Planning Committee, and chairman or member of a number of various technical committees and task forces within the Southern electric system and the Florida Electric Power Coordinating Group, regarding a variety of technical issues including system operations, bulk power contracts, generation expansion, transmission expansion, transmission interconnection requirements, central dispatch, transmission system operation, transient stability, underfrequency operation, generator underfrequency protection, system production costing, computer modeling, and others.

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

A. I will summarize Gulf Power Company's purchased power recoverable costs for energy purchases and sales that were incurred during the April 1, 1996 through September 30, 1996 recovery period. I will then compare these actual costs to their projected levels for the period and discuss the primary reasons for the differences.

Q. During the period April 1, 1996 through September 30, 1996, 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 Schedule A-1, was $13,485,745 as compared to the projected amount of $11,237,118. This resulted in a variance above budget of $2,248,627, or 20%. The actual cost per KWH purchased was 2.1838 ¢/KWH as compared to the projected 1.7782 ¢/KWH, or 23% above the projection.

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

A. During the recovery period, Gulf Power purchased 617,546,322 KWH, shown on line 12 of Schedule A-1, as compared to the estimate of 631,930,000 KWH, or only 2% fewer KWH. However, both Southern territorial loads and off-system energy sales were greater than budget. This, quite naturally, caused higher cost generating units to dispatch, thus raising the unit price of energy purchased from the pool.

Q. During the period April 1, 1996 through September 30, 1996, what was Gulf's actual purchased power fuel cost for energy sales and how did it compare with the projected amount?

A. Gulf's pool and off-system sales, shown on line 18, were 960,933,220 KWH, or only 3% over the projection for the period. The actual fuel cost per KWH sold was 1.9048 ¢/KWH as compared to 2.0461 ¢/KWH, or 7% below the projection. The resulting actual total purchased power fuel cost for energy sales, as shown on line 18 of Schedule A-1, was $18,303,630 as compared to the projected amount of $19,181,800, or 5% below budget.

Q. How are Gulf's net purchased power fuel costs affected by Southern electric system energy sales?

A. As a member of the Southern electric system power pool, Gulf Power participates in these sales. Gulf's generating units are economically dispatched to meet the needs of its territorial customers, the system, and off-system customers.

Therefore, Southern system energy sales provide a market for Gulf's surplus energy and generally improve unit load factors. The cost of fuel used to make these sales is credited against, and therefore reduces, Gulf's fuel and purchased power costs.

Q. Does this conclude your testimony?

A. Yes.

GULF POWER COMPANY

Before the Florida Public Service Commission
Direct Testimony of
M. W. Howell
Docket No. 970001-EI
Date of Filing: January 13, 1997

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

A. My name is M. W. Howell, and my business address is 500 Bayfront Parkway, Pensacola, Florida 32501. I am Transmission and System Control Manager for Gulf Power Company.

Q. Have you previously testified before this Commission?

A. Yes. I have testified in various rate case, cogeneration, territorial dispute, planning hearing, fuel clause adjustment, and purchased power capacity cost recovery dockets.

Q. Please summarize your educational and professional background.

A. I graduated from the University of Florida in 1966 with a Bachelor of Science Degree in Electrical Engineering. I received my Masters Degree in Electrical Engineering from the University of Florida in 1967, and then joined Gulf Power Company as a Distribution Engineer. I have since served as Relay Engineer, Manager of Transmission, Manager of System Planning, Manager of Fuel and System Planning, and Transmission and System Control Manager. My experience with the Company has included all areas of distribution operation, maintenance, and construction; transmission operation, maintenance, and construction; relaying and protection of the generation, transmission, and distribution systems; planning the generation, transmission, and distribution system additions; bulk power interchange administration; overall management of fuel planning and procurement; and operation of the system dispatch center.

I have served as a member of the Engineering Committee and the Operating Committee of the Southeastern Electric Reliability Council, chairman of the Generation Subcommittee and member of the Edison Electric Institute System Planning Committee, and chairman or member of a number of various technical committees and task forces within the Southern electric system and the Florida Electric Power Coordinating Group, regarding a variety of technical issues including system operations, bulk power contracts, generation expansion, transmission expansion, transmission interconnection requirements, central dispatch, transmission system operation, transient stability, underfrequency operation, generator underfrequency protection, system production costing, computer modeling, and others.

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

A. The purpose of my testimony is to support Gulf Power Company's projection of purchased power recoverable costs for energy purchases and sales for the period April, 1997 - September, 1997.

Q. What is Gulf's projected purchased power recoverable cost for energy purchases for the April, 1997 - September, 1997 recovery period?

A. Gulf's projected recoverable cost for energy purchases, shown on line 12 of Schedule E-1 of the fuel filing, is $10,622,241. These purchases result from Gulf's participation in the coordinated operation of the Southern electric system power pool. This amount is used by Gulf's witness Susan Cranmer 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 April, 1997 - September, 1997 recovery period?

A. The projected fuel cost for energy sales, shown on line 18 of Schedule E-1, is $17,664,800. These sales also result from Gulf's participation in the coordinated operation of the Southern electric system power pool. This amount is used by Gulf's witness Susan Cranmer as an input in the calculation of the fuel and purchased power cost adjustment factor.

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

KAREN A. BRANICK

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

A. My name is Karen A. Branick. My business address is 702 North Franklin Street, Tampa, Florida 33602. My position is Manager - Energy Issues in the Regulatory and Business Strategy Department of Tampa Electric Company.

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

A. I received a Bachelor of Science Degree in Chemical Engineering and Chemistry from the University of Pittsburgh, Pittsburgh, Pennsylvania in 1986. In 1987 I was employed as a chemist for Florida Power & Light Company (FPL). In 1990, I became a performance engineer; in 1991 a lab supervisor; and in 1992 an operations supervisor for FPL. My career at Tampa Electric Company began in 1992 in the Production Department. My responsibilities included insurance of proper boiler chemistry and chemical engineering support during normal operations and maintenance outages. I led projects related to alternate fuel test burns and waste water management. In 1994, I transferred to the Bulk Power & Market Development Department where I managed the customer accounts of approximately 30 of Tampa Electric's large industrial customers. I also participated in developing proposals for long term off system sales of wholesale power. In October of 1996, I was promoted to Manager-Energy Issues in the Regulatory and Business Strategy Department. My present responsibilities include the areas of fuel adjustment filings, capacity cost recovery filings and rate design.

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

A. The purpose of my testimony is to present the net true-up amounts for the April 1996 through September 1996 period for both the Fuel Cost Recovery and the Capacity Cost Recovery Clauses.

FUEL COST RECOVERY CLAUSE

Q. What is the net true-up amount for the fuel cost recovery clause for the period April 1996 through September 1996?

A. An over/(under) - recovery of ($3,401,136). The actual fuel cost over/(under) - recovery, including interest, is ($2,243,966) for the period April 1996 through September 1996 (Schedule A2, page 2 of 3, of September 1996 monthly filing, in Document No. 4, reflects an end of period total net true-up of ($7,920,243). Subtracting the beginning of period deferred true-up of ($5,676,277) yields the ($2,243,966). This ($2,243,966) amount, less the actual/estimated over/(under) - recovery approved in the August 1996 fuel hearings of $1,157,170 results in a final over/(under) - recovery for the period of ($3,401,136). This over/(under) - recovery amount of ($3,401,136) will be carried over and applied in the calculation of the fuel recovery factor for the period April 1997 through September 1997.

Q. How much effect will this ($3,401,136) over/(under) - recovery in the April 1996 through September 1996 period, have on the April 1997 through September 1997 period?

A. The ($3,401,136) over/(under) - recovery will cause a 1,000 KWH residential bill to be approximately $0.42 higher.

Q. Have you prepared an Exhibit in this proceeding?

A. Yes. Exhibit No. (KAB-1, Fuel Cost Recovery and Capacity

Cost Recovery) which contains four documents. Document No. 3 is used to explain the capacity cost recovery clause which is discussed later in my testimony. Document No. 4 contains Commission Schedules A-1 through A-9 for the months of April 1996 through September 1996. Included with the September 1996 monthly filing is a six months summary for each of Commission Schedules A6, A7, A8, and A9 for the period April 1996 through September 1996.

Q. Please explain Document No. 1.

A. Document No. 1, entitled "Tampa Electric Company Final Fuel Over/(Under) - Recovery for the period April 1996 through September 1996" shows the calculation of the final fuel over/(under) - recovery for the period of ($3,401,136) which will be applied to jurisdictional sales during the period April 1997 through September 1997.

Line 1 shows the total company fuel costs of $188,432,722 for the period April 1996 through September 1996. The jurisdictional amount of total fuel costs is $189,884,563 as shown on line 2. This amount is compared to the jurisdictional fuel revenues applicable to the period on line 3 to obtain the actual over/(under) - recovered fuel costs for the period, shown on line 4. The resulting

($2,077,061) over/(under) - recovered fuel costs for the period, combined with ($166,905) of interest shown on line 5, constitute the actual over/(under) - recovery of ($2,243,966) shown on line 6. The ($2,243,966) less the actual/estimated over/(under) - recovery of $1,157,170 shown on line 7, which was approved in the August 1996 fuel hearings, results in the final over/(under) - recovery of ($3,401,136) shown on line 8.

Q. What does Document No. 2 show?

A. Document No. 2, entitled "Tampa Electric Company Calculation of True-Up Amount Actual vs. Original Estimates for the period April 1996 through September 1996," shows the calculation of the actual over/(under) - recovery as compared to the original estimate for the same period.

Q. What was the variance in jurisdictional fuel revenues for the period April 1996 through September 1996?

A. As shown on line C1 of my Document No. 2, the company collected $502,795 or 0.3% more jurisdictional fuel revenues than originally estimated.

Q. What was the total fuel and net power transaction cost variance for the period April 1996 through September 1996?

A. As shown on line A7 of Document No. 2, the fuel and net power transactions cost variance is $2,262,154 or 1.2%.

Q. What are the reasons for the total fuel and net power transactions cost being higher by $2,262,154 or 1.2%?

A. The primary reason for the 1.2% increase is due to Net Energy for Load being up 43,305 MWH or 0.5%. This 0.5% combined with the ¢/KWH for Total Fuel and Net Power Transaction being greater than estimated by 0.7%, accounts for the 1.2% increase.

CAPACITY COST RECOVERY CLAUSE

Q. What is the net true-up amount for the capacity cost recovery clause for the period April 1996 through September 1996?

A. An over/(under) - recovery of $12,560. The actual capacity cost over/(under) - recovery, including interest, is $1,115,914 for the period April 1996 through September 1996 (Document No. 3, pages 2 and 3 of 5). This amount, less the actual/estimated over/(under) - recovery approved in the August 1996 fuel hearings of $1,103,354 results in a final over/(under) - recovery for the period of $12,560 (Document No. 3, page 5 of 5). This over/(under) - recovery amount of $12,560 will be carried over and applied in the calculation of the capacity cost recovery factor for the period April 1997 through September 1997.

Q. How much effect will this $12,560 over/(under) - recovery in the April 1996 through September 1996 period, have on the April 1997 through September 1997 period?

A. The $12,560 over/(under) - recovery will have no effect on a 1,000 KWH residential bill.

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

Karen A. Branick

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

A. My name is Karen A. Branick. My business address is 702 North Franklin Street, Tampa, Florida 33602. My position is Manager - Energy Issues in the Regulatory and Business Strategy Department of Tampa Electric Company.

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

A. I received a Bachelor of Science Degree in Chemical Engineering and Chemistry from the University of Pittsburgh, Pittsburgh, Pennsylvania in 1986. In 1987 I was employed as a chemist for Florida Power & Light Company (FPL). In 1990, I became a performance engineer; in 1991 a lab supervisor; and in 1992 an operations supervisor for FPL. My career at Tampa Electric Company began in 1992 in the Production Department. My responsibilities included insurance of proper boiler chemistry and chemical engineering support during normal operations and maintenance outages. I led projects related to alternate fuel test burns and waste water management. In 1994, I transferred to the Bulk Power & Market Development Department where I managed the customer accounts of approximately 30 of Tampa Electric's large industrial customers. I also participated in developing proposals for long term off-system sales of wholesale power. In October of 1996, I was promoted to Manager-Energy Issues in the Regulatory and Business Strategy Department. My present responsibilities include the areas of fuel adjustment, capacity cost recovery, environmental filings and rate design.

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

A. The purpose of my testimony is to present to the Commission the proposed Total Fuel and Purchased Power Cost Recovery factors, the proposed Capacity Cost Recovery factors and the billing refund credit factors for the period of April 1997 - September 1997.

Fuel and Purchased Power Cost Recovery Factors / Capacity Cost Recovery Clause

Q. Did you review the projected data necessary to calculate the Total Fuel and Purchased Power Cost Recovery factors for the period April 1997 - September 1997?

A. Yes I have.

Q. Do you wish to sponsor an exhibit consisting of Schedules H-1 (April - September, 1994 through 1997) and Schedules E-1 through E-10 (April 1997 - September 1997)?

A. Yes. Also contained in this exhibit are Schedules E-2, E-3, E-5, E-6, E-7, E-8 and E-9 for the prior period October 1996 - March 1997. These schedules are furnished as back-up for the projected true-up for this period and consist of two actual months and four projected months.

(Have identified as Exhibit No. 19 (KAB-2), Fuel Projection.)

Q. Does Schedule E-1 of Exhibit No. 19 (KAB-2), Fuel Projection, show the proper value for the Total Fuel and Purchased Power Cost Recovery Clause as projected for the period April 1997 - September 1997?

A. Yes.

Q. What is the proper value of the fuel adjustment factor for the new period?

A. The proper value for the new period is 2.415 cents per kwh before the application of the factors that adjust for variations in line losses.

Q. Please describe the information provided on Schedule E-1C.

A. The GPIF and True-up factors are provided on Schedule E-1C. We propose that a GPIF penalty of ($298,369) be included in the projection period. The True-up amount for the October 1996 - March 1997 period is an overrecovery of $1,590,623. This overrecovery is comprised of a final True-up underrecovery amount of ($3,401,136) for the April 1996 - September 1996 period and an estimated overrecovery in the amount of $4,991,759 for the October 1996 - March 1997 period.

Q. Please describe the information provided on Schedule E-1D.

A. Schedule E-1D presents the company's on-peak and off-peak fuel charge factors for the April 1997 - September 1997 period.

Q. What is the purpose of Schedule E-1E?

A. The purpose of Schedule E-1E is to present the standard, on-peak and off-peak fuel charge factors after adjusting for variations in line losses.

Q. Has Tampa Electric included in the fuel projection any long-term off-system sales which were not included in the last projected fuel filing?

A. Yes, two new sales are included. On November 4, 1996, Tampa Electric began service for a sale of peaking power to the City of Lakeland. On December 16, 1996, service began for a multi-unit power sale to the Florida Municipal Power Agency.

Q. How has Tampa Electric treated the fuel revenues from these sales?

A. The company has credited the actual contract fuel revenues from these two sales to the fuel clause on Schedule E6.

Q. How are the non-fuel revenues from these two sales treated in the fuel clause?

A. Tampa Electric entered into Letters of Commitment with the City of Lakeland ("Lakeland") dated August 19, 1996 and the Florida Municipal Power Agency ("FMPA") dated October 2, 1996 to provide long term capacity and energy under service schedule D. These two power sales are different from previous long-term Big Bend Sales ("Big Bend Sales") for two primary reasons. First, the sales are from different resources than the Big Bend Sales that were separated at the time of Tampa Electric's rate case. Second, each sale contains a provision for supplemental service, which is a means for the customer to obtain additional capacity and energy for short periods of time during the period of the Letter of Commitment. These differences from the previously separated sales provide the opportunity for the application of a different regulatory treatment than was required for the Big Bend sales in the last rate case and subsequent regulatory agreements.

Q. Does the fuel projection include cost recovery for SO_2 emission allowances?

A. Yes, cost recovery of SO_2 emission allowances is included in the Fuel and Purchased Power Cost Recovery Clause for the two month actual/four month re-projected period October 1996 through March 1997. These costs are already included in the fuel factor in effect for this period. Beginning with the projection for April 1997 through September 1997, recovery of the costs of SO_2 emission allowances have been moved to the Environmental Cost Recovery Clause. This recovery mechanism is consistent with Order No. PSC-96-1048-FOF-EI issued August 14, 1996 which established Tampa Electric's Environmental Cost Recovery Clause.

Q. Please recap the proposed Fuel and Purchased Power Cost Recovery factors for the April 1997 - September 1997 period.

A.

Rate Schedule	Fuel Charge Factor (cents per kwh)
Average Factor	2.415
RS, GS and TS	2.432
RST and GST	2.941 (on-peak)
	2.190 (off-peak)
SL-2, OL-1 and OL-3	2.303
GSD, GSLD, and SBF	2.418
GSDT, GSLDT, EV-X and SBFT	2.924 (on-peak)
	2.177 (off-peak)
IS-1, IS-3, SBI-1, SBI-3	2.339
IST-1, IST-3, SBIT-1, SBIT-3	2.829 (on-peak)
	2.106 (off-peak)

Q. How does Tampa Electric Company's proposed average fuel charge factor of 2.415 cents per kwh compare to the average fuel charge factor for the October 1996 - March 1997 period?

A. The proposed fuel charge factor is 0.014 cents per kwh (or 14 cents per 1000 kwh) higher than the average fuel charge factor of 2.401 cents per kwh for the October 1996 - March 1997 period.

Q. Are you also requesting Commission approval of the projected Capacity Cost Recovery factors for the Company's various rate schedules?

A. Yes.

Q. Have you prepared or caused to be prepared under your direction or supervision an exhibit which supports this request?

A. Yes. It consists of five pages identified as Exhibit No. 20 KAB-3, Capacity Cost Recovery.

Q. What payments are included in Tampa Electric's capacity cost recovery factor?

A. Tampa Electric is requesting recovery, through the capacity cost recovery factor, of capacity payments made pursuant to cogeneration, small power production and purchased power agreements to which we are a party.

Q. Please re-cap the proposed Capacity Cost Recovery Clause factors for the April 1997 - September 1997 period.

A.

Rate Schedule	Capacity Cost Recovery Factor (cents per kwh)
RS	0.179
GS and TS	0.173
GSD, EV-X	0.132
GSLD and SBF	0.118
IS-1, IS-3, SBI-1, SBI-3	0.010
SL-2, OL-1 and OL-3	0.021

These factors can be seen in Exhibit No. 20 (KAB-3), page 3 of 5.

Stipulation Refund

Q. Is Tampa Electric requesting to modify the Revenue Credit Refund Factor for the period April 1997 through September

1997?

A. Yes. In Tampa Electric's Fuel Projection for the period October 1996 through March 1997, Tampa Electric requested approval of Revenue Credit Refund Factors for that period. The Credit Refund is for $25 million dollars, plus interest, over the twelve-month period October 1996 through September 1997 per the stipulation approved in Docket 950379-EI, Order No. PSC-96-0670-S-1. The FPSC approved the factors in Order No. PSC -96-0670-EI .

The factor was based on projected twelve month retail energy sales. Exhibit No. 21 (KAB -4) shows the new factors by rate class based on the outstanding refund balance as of 12/31/96, re-projected retail energy sales for the period January 1997 through September 1997 and a projected commercial paper rate of six percent. Based on these changes, the new factors adjusted for line losses are

Rate Class	Credit Factor cents/KWH
Average Factor	0.168
RS, RST, GS, GST, TS	0.169
GSD, GSDT, GSLD, GSLDT	
EV-X, SBF, SBFT	0.169
IS-1, IST-1, IS-3, IST-3, SBI-1,	

SBIT-1, SBI-3, SBIT-3	0.168
SL, OL	0.163

Q. What is the composite effect of the above changes on a 1,000 kwh residential Customer?

A. A residential bill for 1,000 kwh will decrease $0.07 beginning April 1997. See table below.

Type of Charge	Oct. 96 Thru Mar. 97	Apr. 97 thru Sept. 97
Customer	$ 8.50	$ 8.50
Energy	43.42	43.42
Conservation	1.62	1.63
Environmental	0.41	0.33
Fuel	24.18	24.32
Capacity	1.98	1.79
Deferred Revenue Plan Refund	(1.74)	(1.69)
FGR Tax	2.01	2.01
Total	$ 80.38	$ 80.31

Q. When should the new charges and refund go into effect?

A. They should go into effect commensurate with the first billing cycle in April 1997.

Q. Does this conclude your testimony?

A. Yes it does.

TAMPA ELECTRIC COMPANY
DOCKET NO. 960001-EI
SUBMITTED FOR FILING 11/19/96
(TRUE UP)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

GEORGE A. KESELOWSKY

Q. Will you please state your name, business address, and employer?

A. My name is George A. Keselowsky and my business address is Post Office Box 111, Tampa, Florida 33601. I am employed by Tampa Electric Company.

Q. Please furnish us with a brief outline of your educational background and business experience.

A. I graduated in 1972 from the University of South Florida with a Bachelor of Science Degree in Mechanical Engineering. I have been employed by Tampa Electric Company in various engineering positions since that time. My current position is that of Senior Consulting Engineer -Production Engineering.

Q. What are your current responsibilities?

A. I am responsible for testing and reporting unit performance, and the compilation and reporting of generation statistics.

Q. What is the purpose of your testimony?

A. My testimony presents the actual performance results from unit equivalent availability and station heat rate used to determine the Generating Performance Incentive Factor (GPIF) for the period April 1996 through September 1996. I will also compare these results to the targets established prior to the beginning of the period.

Q. Have you prepared an exhibit with the results for this six month period?

A. Yes. Under my direction and supervision an exhibit has been prepared entitled, "Tampa Electric Company, April 1996 - September 1996, Generating Performance Incentive Factor Results" consisting of 28 pages that was filed with this testimony (Have identified as Exhibit GAK-1).

Q. Have you calculated the results of Tampa Electric Company for its performance under the GPIF during this period?

A. Yes I have. This is shown on page 4 of my exhibit. Based upon - 1.355 GPIF points, the result is a penalty amount of $298,369 for the period.

Q. Please proceed with your review of the actual results for the April 1996 - September 1996 period.

A. On page 3 of my exhibit, the actual average common equity for the period is shown on line 8 as $1,090,873,671. This produces the maximum penalty or reward figure of $2,201,985 as shown on line 15, page 3, and also page 2 of my exhibit.

Q. Would you please explain how you arrived at the actual equivalent availability results for the six units included within the GPIF?

A. Yes I will. Operating data on each of our operating 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 six months provides the basis for the GPIF.

Q. Are the equivalent availability results shown on page 6, 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 page 6 of my exhibit. 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:

Gannon Unit No. 5

On this unit, no planned outage hours were originally scheduled to fall within the Summer 1996 period. Due to a revision of the outage schedule 206.6 planned outage hours were accomplished within the Summer 1996 period. Consequently, the actual equivalent availability of 83.1% is adjusted to 87.2%, as shown on page 7 of my exhibit.

Gannon Unit No. 6

On this unit, 1,199 planned outage hours were originally scheduled to fall within the Summer 1996 period. The outage schedule was revised such that the entire outage fell within the period and actual planned outage activities required 1319.5 hours. Consequently, the actual equivalent availability of 64.8% is adjusted to 67.3%, as shown on page 8 of my exhibit.

Big Bend Unit No. 1

This unit was not scheduled to have a planned outage during the Summer 1996 period and did not in fact have one. Consequently, the actual equivalent availability of 84.8% requires no adjustment as shown on page 9 of my exhibit.

Big Bend Unit No. 2

This unit was not scheduled to have a planned outage during the Summer 1996 period and did not in fact have one. Consequently, the actual equivalent availability of 87.2% required no adjustment as shown on page 10 of my exhibit.

Big Bend Unit No. 3

On this unit no planned outage hours were originally scheduled to fall within the Summer 1996 period. Due to a revision of the outage schedule, an outage was moved such that the last 28.8 planned outage hours fell within the period. Consequently, the actual equivalent availability of 83.7% is adjusted to 84.2% as shown on page 11 of my exhibit.

Big Bend Unit No. 4

This unit was not scheduled to have a planned outage during the Summer 1996 period and did not in fact have one. Consequently, the actual equivalent availability of 92.7% requires no adjustment as shown on page 12 of my exhibit.

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 page 6, column 4, of my exhibit. This number is entered into the respective Generating Performance Incentive Point (GPIP) Table for each particular unit on pages 21 through 26. Page 4 of my exhibit summarizes the equivalent availability points to be awarded or penalized.

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

A. The actual heat rate and adjusted actual heat rate for Gannon and Big Bend Station are shown on page 6 of my exhibit. The adjustment was developed based on the guidelines of section 4.3.6 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 my exhibit. This heat rate number is entered into the respective GPIP table for the particular unit, shown on pages 21 through 26. Page 4 of my exhibit summarizes the weighted heat rate and equivalent availability points to be awarded.

Q. Were any additional adjustments to heat rate required?

A. In order to assure compatability of data, Big Bend Unit 3 heat rates have been calculated in the standard fashion, without scrubber power. This methodology has been reviewed and approved by the PSC staff, to be employed until there is sufficient operational history with the scrubber to meet target preparation guidelines.

Q. Does this assure that the Big Bend 3 heat rate for the period is appropriate for comparison to its target and meets GPIF criteria?

A. Yes.

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

A. This is shown on page 28 of my exhibit. Essentially, the weighting factors shown on page 4, column 3, plus the equivalent availability points and the heat rate points shown on page 4, column 4, are substituted within the equation. This resultant value, -1.355, is then entered into the GPIF table on page 2. Using linear interpolation, a penalty amount of $298,369 is calculated.

Q. Does this conclude your testimony?

A. Yes, it does.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

GEORGE A. KESELOWSKY

Q. Will you please state your name, business address, and employer?

A. My name is George A. Keselowsky and my business address is Post Office Box 111, Tampa, Florida 33601. I am employed by Tampa Electric Company.

Q. Please furnish us with a brief outline of your educational background and business experience.

A. I graduated in 1972 from the University of South Florida with a Bachelor of Science Degree in Mechanical Engineering. I have been employed by Tampa Electric Company in various engineering positions since that time. My current position is that of Senior Consulting Engineer - Energy Supply Engineering.

Q. What are your current responsibilities?

A. I am responsible for testing and reporting unit performance, and the compilation and reporting of generation statistics.

Q. What is the purpose of your testimony?

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

Q. Have you prepared an exhibit showing the various elements of the derivation of Tampa Electric Company's GPIF formula?

A. Yes, I have prepared, under my direction and supervision, an exhibit entitled "Tampa Electric Company, Generating Performance Incentive Factor" April 1997 - September 1997, consisting of 35 pages filed with the Commission on January 16, 1997. (Have identified as Exhibit GAK-2). The data prepared within this exhibit is consistent with the GPIF Implementation Manual previously approved by this Commission.

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

A. Six of our coal-fired units are included. These are: Gannon Station Units 5 and 6; and Big Bend Station Units 1, 2, 3, and 4.

Q. Will you describe how Tampa Electric Company evolved the various factors associated with the GPIF as ordered by this Commission?

A. Yes. First, the two factors to be used, as set forth by the Commission Staff, are unit availability and station heat rate.

Q. Please continue.

A. A target was established for equivalent availability for each unit considered for this period. Heat rate targets were also established for each unit. A range of potential improvement and degradation was determined for each of these parameters.

Q. Would you describe how the target values for unit availability were determined?

A. Yes I will. The Planned Outage Factor (POF) and the Equivalent Unplanned Outage Factor (EUOF) were subtracted from 100% to determine the target equivalent availability. The factors for each of the 6 units included within the GPIF are shown on page 5 of my exhibit. For example, the projected EUOF for Big Bend Unit Four is 8.5%. The Planned Outage Factor for this same unit during this period is 0%. Therefore, the target equivalent availability for this unit equals:

$$100\% - [(8.5\% + 0\%)] = 91.5\%$$

This is shown on page 4, column 3 of my exhibit.

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

A. Maximum equivalent availability is arrived at using the following formula.

Equivalent Availability Maximum

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

The factors included in the above equations are the same factors that determine target equivalent availability. To attain the maximum incentive points, a 20% reduction in Forced Outage and Maintenance Outage Factors (EUOF), plus a 5% reduction in the Planned Outage Factor (POF) will be necessary. Continuing with our example on Big Bend Unit Four:

$EAF_{MAX} = 100\% - [0.8\ (8.5\%) + 0.95\ (0\%)] = 93.2\%$

This is shown on page 4, column 4 of my exhibit.

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

A. The potential for unit availability degradation is significantly greater than is the potential for unit availability improvement. This concept was discussed extensively and approved in earlier hearings before this Commission. Tampa Electric Company's approach to incorporating this skewed effect into the unit availability tables is to use a potential degradation range equal to twice the potential improvement. Consequently, minimum equivalent availability is arrived at via the following formula:

Equivalent Availability Minimum

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

Again, continuing with our example of Big Bend Unit Four,

$EAF_{MIN} = 100\% - [1.4\ (8.5\%) + 1.1\ (0\%)] = 88.1\%$

Equivalent availability MAX and MIN for the other five units is computed in a similar manner.

Q. How do you arrive at the Planned Outage, Maintenance Outage and Forced Outage Factors?

A. Our planned outages for this period are shown on page 19 of my exhibit. A Critical Path Method (C.P.M.) for each major planned outage which affects GPIF is included in my exhibit. For example, Big Bend Unit 1 is scheduled for an annual maintenance outage March 17 toMay 11, 1997. There are 983 planned outage hours scheduled for the summer 1997 period, and a total of 4391 hours during this 6 month period. Consequently, the Planned Outage Factor for Unit 1 at Big Bend is 983/4391 x 100% or 22.4%. This factor is shown on pages 5 and 15 of my exhibit. Big Bend Units 2, 3 and 4 have planned outage factors of zero, as does Gannon Unit 5. Gannon Unit 6 has a planned outage factor of 3.8%.

Q. How did you arrive at the Forced Outage and Maintenance Outage Factors on each unit?

A. Graphs of both of these factors (adjusted for planned outages) vs. time are prepared. Both monthly data and 12 month moving average data are recorded. For each unit the most current, September 1996, 12 month ending value was used as a basis for the projection. This value was adjusted up or down 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 a EUOF of 10.0% for Gannon Unit Five. The Equivalent Unplanned Outage Factor (EUOF) for Gannon Unit Five is verified by the data shown on page 13, lines 3, 5, 10 and 11 of my exhibit and calculated using the formula:

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

or

$$EUOF = \frac{(354 + 87)}{4391} \times 100 = 10.0\%$$

Relative to Gannon Unit Five, the EUOF of 10.0% forms the basis of our Equivalent Availability target development as shown on sheets 4 and 5 of my exhibit.

Q. Please continue with your review of the remaining units.

Big Bend Unit One

A. The projected EUOF for this unit is 9.8% during this period. This unit will have a planned outage this period and the Planned Outage Factor is 22.4%. This results in a target equivalent availability of 67.8% for the period.

Big Bend Unit Two

The projected EUOF for this unit is 15.1%. This unit will not have a planned outage during this period and the Planned Outage Factor is 0%. Therefore, the target equivalent availability for this unit is 84.9%.

Big Bend Unit Three

The projected EUOF for this unit is 15.7%. This unit will not have a planned outage this period and the Planned Outage Factor is 0%. Therefore, the target equivalent availability for this unit is 84.3%.

Big Bend Unit Four

The projected EUOF for this unit is 8.5%. This unit will not have a planned outage during this period and the Planned Outage Factor is 0%. This results in a target equivalent availability of 91.5% for the period.

Gannon Unit Five

The projected EUOF for this unit is 10.0%. This unit will not have a planned outage during this period and the Planned Outage Factor is 0%. Therefore, the target equivalent availability for this unit is 90.0%.

Gannon Unit Six

The projected EUOF for this unit is 9.9%. This unit will have a planned outage during this period and the Planned Outage Factor is 3.8%. Therefore, the target equivalent availability for this unit is 86.3%.

Q. Would you summarize your testimony regarding Equivalent Availability Factor (EAF), Equivalent Unplanned Outage Factor (EUOF) and Equivalent Unplanned Outage Rate (EUOR)?

A. Yes I will. Please note on page 5 that the GPIF system weighted Equivalent Availability Factor (EAF) equals 83.0%. This target compares very favorably to previous GPIF periods. It is in fact better than four of the five previous periods, as well as the five period average EAF. These targets represent an outstanding level of performance for our system.

Q. As you graph and monitor Forced and Maintenance Outage Factors, why are they adjusted for planned outage hours?

A. This adjustment makes these 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 our units are usually base loaded, reserve shutdown is generally not a factor. To demonstrate the effects of a planned outage, note the EUOR and EUOF for Gannon Unit Six on page 15. During the months of April and June through September, EUOF and EUOR are equal. This is due to the fact that no planned outages are scheduled during these months. During the month of May, EUOR exceeds EUOF. The reason for this difference is the scheduling of a planned outage. The adjusted factors apply to the period hours after planned outage hours have been extracted.

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

A. Yes it does. Rates provide a proper and accurate method of arriving at the unit parameters. These are then converted to factors since they are directly additive. That is, the Forced Outage Factor + Maintenance Outage Factor + Planned Outage Factor + Equivalent Availability = 100%. Since factors are additive, they are easier to work with and to understand.

Q. You previously stated that you had developed a CPM for your unit outages. How do you use the CPM in conjunction with your planned outages?

A. The CPM's included in this exhibit are preliminary and include only the major work activities we expect to accomplish during the planned outage. Planned outages are very complex and are anticipated months in advance. The actual CPM's utilized in the execution of the planned outage are detailed for all major and minor work activities.

Since it is important to the company and beneficial to our Customers to control outage length, we have implemented a computerized outage management system. Essentially, this tool enables management to monitor outage progress, measure activity results against previously established milestones, and verify timely execution of all critical path events. This results in the shortest outage time possible and the maximum utilization of all resources. Any reduction in planned outage length directly improves unit equivalent availability.

Q. Has Tampa Electric Company prepared the necessary heat rate data required for the determination of the Generating Performance Incentive Factor?

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

Q. On what basis were the heat rate targets determined?

A. Average net operating heat rates are determined and reported on a unit basis. Therefore, all heat rate data pertaining to the GPIF is calculated on this basis.

Q. How were these targets determined?

A. Net heat rate data for the three most recent summer periods, along with the PROMOD III program, formed the basis of our target development. Projections of unit performance were made with the aid of PROMOD III. 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 Unit 3 requires an additional amount of station service power. How do you plan to address the associated effect to net heat rate for GPIF purposes?

A. The change in heat rate for this unit resulting from increased utilization of the Unit 4 scrubber can be quantified, but the operational history is short of GPIF guidelines. The target for Big Bend 3 has, therefore, been developed in the standard fashion using data without scrubber power. In order to assure compatability with this target, scrubber power will be removed prior to calculating Unit 3 heat rate for the subsequent True-Up process. This method has been reviewed and approved by the PSC

Staff to be employed until there is sufficient history to meet target preparation guidelines. Successful implementation of this innovation to maximize the potential of existing plant equipment, represents a major cost savings and a significant benefit for our customers.

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 vs. net output factor curves have been developed for each unit. This information is shown on pages 27 through 32 of my exhibit.

Q. Would you elaborate on the analysis used in the determination of the ranges?

A. The net heat rate vs. net output factor curves are the results 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. Can you summarize your heat rate projection for the summer 1997 period?

A. Yes. The heat rate target for Big Bend Unit 1 is 9,968 Btu/Net kwh. The range about this value, to allow for potential improvement or degradation, is ±286 Btu/Net kwh. The heat rate target for Big Bend Unit 2 is 10,079 Btu/Net kwh with a range of ±263 Btu/Net kwh. The heat rate target for Big Bend Unit 3 is 9,969 Btu/Net kwh, with a range of ±210 Btu/Net kwh. The heat rate target for Big Bend Unit 4 is 9,992 Btu/Net kwh with a range of ±167 Btu/Net kwh. The heat rate target for Gannon Unit 5 is 10,448 Btu/Net kwh with a range of ±405 Btu/Net kwh. The heat rate target for Gannon Unit 6 is 10,471 Btu/Net kwh with a range of ±294 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 12 of my exhibit.

Q. Do you feel that the heat rate targets and ranges in your projection meet the criteria of the GPIF and the philosophy of this Commission?

A. Yes I do.

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 12. Our PROMOD III cost simulation model was used 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 $149,288,000 is shown on page 6 column 2.

The PROMOD III output was then used 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. After all the individual savings are calculated, column 4 is totaled: $5,650,900 reflects the savings if all 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 Two, the weighting factor for equivalent availability is 10.53% as shown in the right hand column on page 6. Pages 7 thru 12 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 Two, page 10, if the unit operates at 87.9% equivalent availability, fuel savings would equal $595,000 and 10 equivalent availability points would be awarded.

The Generating Performance Incentive Factor Reward/Penalty Table on page 2 is a summary of the tables on pages 7 through 12. The left hand column of this document shows the Tampa Electric Company's incentive points. The center column shows the total fuel savings and is the same amount as shown on page 6, column 4, $5,650,900. 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 my exhibit on page 3, line 8, the estimated average common equity for the period April 1997 - September 1997 is shown to be $1,178,497,286. This produces the maximum allowed jurisdictional incentive dollars of $2,377,692 shown on line 15.

Q. Is there any other constraint set forth by this Commission regarding the magnitude of incentive dollars?

A. Yes. Incentive dollars are not to exceed fifty percent of fuel savings. Page 2 of my exhibit demonstrates that this constraint is met.

Q. Do you wish to summarize your testimony on the GPIF?

A. Yes. To the best of my knowledge and understanding, Tampa Electric Company has fully complied with the Commission's directions, philosophy, and methodology in our determination of Generating Performance Incentive Factor. The GPIF for Tampa Electric Company is expressed by the following formula for calculating Generating Performance Incentive Points (GPIP):

$$GPIP = (0.0439\ EAP_{GN5} + 0.0523\ EAP_{GN6} + 0.0961\ EAP_{BB1} + 0.1053\ EAP_{BB2} + 0.1545\ EAP_{BB3} + 0.0730\ EAP_{BB4} + 0.0772\ HRP_{GN5} + 0.0861\ HRP_{GN6} + 0.0818\ HRP_{BB1} + 0.0936\ HRP_{BB2} + 0.0707\ HRP_{BB3} + 0.0655\ HRP_{BB4})$$

Where:

GPIP = Generating performance incentive points.

EAP = Equivalent availability points awarded/deducted for Units 5 and 6 at Gannon and Units 1, 2, 3 and 4 at Big Bend.

HRP = Average net heat rate points awarded/deducted for Units 5 and 6 at Gannon and Units 1, 2, 3 and 4 at Big Bend.

Q. Have you prepared a document summarizing the GPIF targets for the April 1997 - September 1997 period?

A. Yes. The availability and heat rate targets for each unit are listed on attachment "A" to this testimony entitled "Tampa Electric Company GPIF Targets, April 1, 1997 - September 30, 1997".

Q. Do you wish to sponsor an exhibit consisting of estimated unit performance data supporting the fuel adjustment?

A. Yes I do. (Have identified as Exhibit GAK-3).

Q. Briefly describe this exhibit.

A. This exhibit consists of 23 pages. This data is Tampa Electric Company's estimate of the Unit Performance Data and Unit Outage Data for the April 1997 - September 1997 period.

Q. Does this conclude your testimony?

A. Yes.

CHAIRMAN JOHNSON: Okay. Counsel are there any other preliminary matters?

MR. BEASLEY: We ask on behalf of Tampa Electric that we be excused from the hearing.

CHAIRMAN JOHNSON: Yes.

MS. JOHNSON: Staff is not aware of any.

CHAIRMAN JOHNSON: Very well. How should we proceed then, with the oral arguments?

MS. JOHNSON: I'd just like to note before we get started that there are primarily, of the remaining issues, two categories of issues. The first category relates to the Crystal River 3 outage and those are issues 14D, 14E, 18A and 18B. The second category of issues relates to the recovery of settlement payments for two cogen settlement agreements that Florida Power Corp has entered into; those being Lake Cogen and Pasco Cogen. And those issues are 14B, 14C, 24A and 24B.

And we're ready to proceed at your pleasure.

CHAIRMAN JOHNSON: Are we going to hear oral arguments on all of the issues that you just stated?

MS. JOHNSON: Not on the cogen settlement payments, that's not my understanding. The witness will appear for those issues.

MR. McGEE: Those will be addressed by the testimony of Mr. Wieland.

CHAIRMAN JOHNSON: And the oral argument then will relate to 14D, 14E, 14A and B?

MR. McGEE: That's correct.

CHAIRMAN JOHNSON: Which issue is relating to -- is it GPIF?

MR. McGEE: 18A and 18B.

CHAIRMAN JOHNSON: 18A and B. You're prepared to make oral argument on that?

MR. HOWE: Yes, ma'am, but I would suggest that it would probably be best to have oral argument after the witnesses have taken the stand, because the oral argument will address, from our perspective, the reasonableness of the Company's position being offered through testimony.

COMMISSIONER KIESLING: Could I get a clarification?

CHAIRMAN JOHNSON: Sure.

COMMISSIONER KIESLING: What pleading or whatever is this oral argument going to be based on? I mean I don't understand. I'm trying to find something to look at to see what the issues are that you're going to be arguing about and I don't know what that is.

MR. HOWE: In this particular case it is a bit confusing.

The oral argument is to give the party -- as I understand it is to give the parties an opportunity to represent their legal positions to the Commission on whether Florida Power Corporation, given the evidence presented in this proceeding, should be allowed to recover the replacement fuel cost associated with the ongoing extended outage at the Crystal River No. 3 nuclear unit.

The Company is offering evidence. Our position is that evidence is not of sufficient quality for the Commission to make a decision in their favor.

At the prehearing conference it was agreed that the best way to address this legal argument would be by offering the parties 15 minutes each to argue their position.

COMMISSIONER DEASON: What we need to keep in mind here today is that we're probably going to be asked to make a decision on these matters to actually be -- enable Staff and the parties to calculate precise fuel adjustment recovery factors. We don't have the luxury of having an evidentiary hearing, having legal briefs, legal issues identified and then having parties come in some month or six weeks later file pleadings on those legal issues and having oral argument on those legal issues. We're in a very time constrained situation here. So I thought it would be appropriate as far as policy/legal aspects of the technical issues that we would go ahead and specify there's going to be oral argument so we'd have the benefit of that before we're actually asked to make a decision.

COMMISSIONER KIESLING: Yeah. And I wasn't questioning the wisdom of that, but I had somehow failed to comprehend that we were going to make a ruling today. So that's where my confusion came in. And now I understand. It's crystal clear to me. I just needed that one fact.

CHAIRMAN JOHNSON: I'm still a little confused on one thing, as it relates to the GPIF. What are we going to hear? The revised or -- I thought you need to argue that beforehand so we could make a determination, "Oh, that witness is not here anyway."

MR. McGEE: That was the issue where we agreed that the policy considerations could control which version was used.

CHAIRMAN JOHNSON: Whichever we ruled upon, we just insert that. That would be --

MR. HOWE: Yes, ma'am.

CHAIRMAN JOHNSON: Okay. Very well. Then we can proceed with our witnesses.

MR. McGEE: Florida Power will call Mr. Scardino.

\- - - - -

JOHN SCARDINO, JR.

appeared as a witness and testified as follows:

DIRECT STATEMENT

BY MR. McGEE:

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

A My name is John Scardino, Jr. My business address is P. O. Box 14042, St. Petersburg, Florida 33733.

Q What is your capacity with Florida Power?

A I'm the vice president and comptroller.

Q Mr. Scardino, do you have before you a document entitled "Direct Testimony of John Scardino, Jr." consisting of 11 pages and attached exhibits?

A Yes, I do.

Q And was that prepared by you under your direct supervision as your testimony under this proceeding today?

A Yes, it was.

Q Do you have any additions or corrections that you'd like to make to the testimony?

A Yes, I do.

Q Would you explain them, please?

A Page 4, Line 17 and 20, I have a revision to the numbers that are presented. They were presented in error. So this is just a correction of an error.

Line 17, the replacement number should be $46,846,686. Line 20 the replacement number is $12,203,216. If I could ask you to turn to my Exhibit 1, JS-1, Lines 38 and 41 need to be revised consistent with Page 4, Line 38 the replacement number is an underrecovery of $46,846,686. That number would appear in brackets just as the previous number had. And then Line 41 the replacement number is $12,203,216 also in brackets.

To the best of my knowledge those are the only revisions that I have to my prefiled testimony.

Q With those revisions, if you were asked the questions contained in your prepared testimony would your answers be the same today?

A Yes, they would.

MR. McGEE: Madam Chairman, we'd ask Mr. Scardino's prepared testimony be inserted into the record as though read.

CHAIRMAN JOHNSON: It will be so inserted.

MR. McGEE: And his exhibits have been identified.

FLORIDA POWER CORPORATION

DOCKET NO. 960001-EI

Re: Fuel and Capacity Cost Recovery
Final True-up Amounts for
April through September 1996

DIRECT TESTIMONY OF
JOHN SCARDINO, JR.

Q. Please state your name and business address.

A. My name is John Scardino, Jr. My business address is P. O. Box 14042, St. Petersburg, Florida 33733.

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

A. I am employed by Florida Power Corporation (FPC) in the capacity of Vice President and Controller. In addition, I also hold the position of Vice President and Controller of Florida Progress Corporation, the holding company of Florida Power Corporation.

Q. Would you please describe your educational background and work experience?

A. I graduated from the University of South Florida in 1972 with a Bachelor's Degree in Business Administration, majoring in Accounting. I began my employment with Florida Power in 1970. Since then, I have held the following accounting positions within the Controller's Department: Manager of Accounting Research and Analysis, Manager of General Accounting, Director of General Accounting and Budgets, and Assistant

Controller. My responsibilities prior to becoming Assistant Controller included maintenance of the general records of the Company, fuel accounting, customer accounting, financial and regulatory reporting, coordinating the preparation of all accounting schedules required in the Company's base rate proceedings before the Federal Energy Regulatory Commission (FERC) and the Florida Public Service Commission (FPSC), and corporate budgeting process. As Assistant Controller, my supervisory responsibilities expanded to include the following departments: Accounts Payable and Disbursements Accounting, Plant and Depreciation Accounting, Systems and Procedures, Payroll, Tax, and Regulatory Accounting and Financial Reporting. I was elected to the position of Vice President and Controller at Florida Power Corporation in April, 1991. In addition to my work experience, I have completed the 1994 Stanford Executive Program and the Edison Electric Institute Executive Management Program. I also have attended a variety of courses on management and finance sponsored by the Company, the Southeastern Electric Exchange, Edison Electric Institute and others. In addition, I currently serve on the Chief Accounting Officer Committee of the Edison Electric Institute, am a member of the EEI-FERC Accounting Liaison Committee and am a member of the Institute of Management Accountants.

Q. What are the responsibilities of your present position as they relate to Florida Power Corporation?

A. As Chief Accounting Officer, I am responsible for the Company's accounting policies and procedures, and its general books and related accounting records, including the preparation of monthly financial statements, quarterly and annual reporting to the Securities and Exchange Commission (10Q and 10K), FERC Annual Form 1 Report, and the Company's monthly Rate of Return report required by the FPSC under its continuing surveillance authority. I have testified before the FPSC in various accounting related matters.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to describe the Company's Fuel Cost Recovery Clause final true-up amount for the period of April 1996 through September 1996, and the Company's Capacity Cost Recovery Clause final true-up amount for the same period.

Q. Have you prepared exhibits to your testimony?

A. Yes, I have prepared a three-page true-up variance analysis which examines the difference between the estimated fuel true-up and the actual period-end fuel true-up. This variance analysis is attached to my prepared testimony and designated Exhibit No. 1 (JS-1). Also attached to my prepared testimony and designated Exhibit No. 1 (JS-2) are the Capacity Cost Recovery Clause true-up calculations for the April 1996 through September 1996 period. Also, I will sponsor the applicable Schedules A1 through A9 for the period to date through September 1996, which have been previously filed with the Commission and are also attached to my prepared testimony for ease of reference and designated as Exhibit No. 2 (JS-3).

Q. What is the source of the data which you will present by way of testimony or exhibits in this proceeding?

A. Unless otherwise indicated, the actual data is taken from the books and records of the Company. The books and records are kept in the regular course of business in accordance with generally accepted accounting principles and practices, and provisions of the Uniform System of Accounts as prescribed by this Commission.

FUEL COST RECOVERY

Q. What is the Company's jurisdictional ending balance as of September 30, 1996 for fuel cost recovery?

A. The actual ending balance as of September 30, 1996 for true-up purposes is an underrecovery of $59,049,902.

Q. How does this amount compare to the Company's estimated ending balance to be included in the October 1996 through March 1997 period?

A. When the estimated underrecovery of $46,846,686 ~~$42,808,659~~ to be collected during the period of October 1996 through March 1997 is taken into account, the final true-up ending balance attributable to the six-month period ended September 30, 1996 is an underrecovery of $12,203,216 ~~$40,741,243.~~

Q. How was the final true-up ending balance determined?

A. The amount was determined in the manner set forth on Schedule A2 of the Commission's standard forms previously submitted by the Company on a monthly basis.

Q. What factors contributed to the period-ending jurisdictional underrecovery of $59 million as shown on your Exhibit No. __/__ (JS-1)?

A. The factors contributing to the underrecovery are summarized on Sheet 1 of 3. The actual jurisdictional kwh sales were higher than the original estimate by 322,166,010 KWH. This increase in KWH sales, attributable to abnormally warm weather, resulted in higher jurisdictional fuel revenues of $27.6 million and also accounted for much of the $59.7 million unfavorable variance in jurisdictional fuel and purchased power expense.

When these differences in jurisdictional revenues and jurisdictional fuel expenses are combined, the net result is an underrecovery of $33.5 million related to the April 1996 through September 1996 time period. Other variances not directly related to the period, result in the actual ending balance underrecovery of $59. million, as of September 30, 1996.

Q. Please explain the components shown on Exhibit No. __/__ (JS-1), Sheet 2 of 3 which produced the $64.7 million unfavorable system variance from the projected cost of fuel and net purchased power transactions.

A. Sheet 2 of 3 shows an analysis of the system variance for each energy source in terms of three interrelated components: (1) changes in the amount (MWH's) of energy required; (2) changes in the heat rate, or efficiency, of generated energy (BTU's per KWH); and (3) changes in the unit price of either fuel consumed for generation ($ per million BTU) or energy purchases and sales (cents per KWH).

Q. What effect did these components have on the system fuel and net power variance for the true-up period?

A. As can be seen from Sheet 2 of 3, variances in the amount of MWH requirements from each energy source (column B) combined to produce a cost increase of $38.8 million. I will discuss this component of the variance analysis in greater detail below.

The heat rate variance for each source of generated energy (column C) produced a net cost increase of $4.3 million. On the Company's Schedule A3, exhibit (JS-3), all BTU's for light oil are included in the light oil heat rate computation. However since no KWH generation is associated with light oil consumed at steam plants, the resulting heat rate shown on A3 is distorted. In order to compute the true heat rate variance, light oil consumed at steam units is shown separately on line 23 of Sheet 2 of 3 of exhibit (JS-1).

A cost increase of $21.5 million resulted from the price variance (column D), which was caused by a number of factors detailed on lines 1 through 25 of Sheet 2 of 3, of exhibit(JS-1). The most significant factors contributing to the unfavorable variance were increased oil prices and an increase in the price of QF payments.

Q. Please explain the analysis shown on Sheet 3 of 3 of your Exhibit No. __/__ (JS-1).

A. The analysis on Sheet 3 of 3 attempts to identify the effect that generation mix has on total net system fuel and purchased power cost. Although this interrelationship is generally understood to exist, it is not readily apparent from the individual variances contained in the FPSC "A" Schedules or in the analysis presented on Sheet 2 of 3. For example, a decrease in the MWH requirements of nuclear generation shows up on Schedule A3 and on Sheet 2 of my exhibit as a cost decrease of $4.8 million. While this may be correct in isolation, the true effect of decreased nuclear generation is obviously a corresponding increase in the MWH requirements of a number of other more costly energy sources, primarily heavy and light oil. The result is a higher net system cost of $33.3 million even if total system MWH requirements remain unchanged.

In addition to the effect of variances in generation mix, this analysis also attempts to identify the independent effect of the <u>net</u> variance in total system MWH requirements from all energy sources combined (internal and external). In this true-up period, for example, total system requirements were higher than the original forecast by 73,206 MWH. This would have led to higher net costs of $2.1 million even if the mix of generation had not changed, since the higher system load increases oil generation at a cost above the system average.

Q. Please explain how this analysis was performed.

A. The analysis on Sheet 3 of 3 is made in two steps. The first, captioned "MWH RECONCILIATION," allocates the MWH variances for the individual energy sources shown in column B among the primary causal variances in columns C through H. Since the causal variances identified in this analysis are not all inclusive, the amount of any residual over- or under-allocation is shown in column I, "Unallocated Variances." The second step, captioned "COST RECONCILIATION," assigns a dollar value to the MWH variances identified in step 1. This is done by allocating the cost variances identified in column B of Sheet 2 for each energy source (and shown again in column B of Sheet 3) among the causal variances based on the MWH's allocated to each in step 1. As mentioned above, the allocation of individual MWH and cost variances to the various causes of those variances is not intended to be all inclusive or precise. It is intended to be a representative approximation of the exceedingly complex cause and effect relationship existing among the individual and total MWH variances and their related cost variances.

Q. What were the major contributors to the $38.8 million cost increase associated with the variance in MWH requirements?

A. Higher than expected system requirements during the period accounted for $2.1 million of the unfavorable variance. The remaining $36.7 million unfavorable increase is caused by the use of higher cost generation and purchased power primarily to replace nuclear generation.

Q. Does this six-month period's ending balance include any noteworthy adjustments to fuel expense as shown on exhibit (JS-3), Schedule A2, page 1 of 4, footnote to line 6b ?

A. Yes, Exhibit No. 2 (JS-3) shows other jurisdictional adjustments to fuel expense. Noteworthy adjustments include recovery of the Company's Intercession City Gas Conversion Projects, a final oil refund credit administered by the Department of Energy, and the pass through of Emission Allowance Credit transactions.

Q. Did ratepayers benefit from the investment in the Intercession City Gas Conversion projects previously approved by the FPSC ?

A. Yes, for this period, the estimated system fuel savings related to the conversion of Units 7 & 9 are $1,452,722. The total system depreciation and return was $327,419 resulting in a net system benefit to ratepayers of $1,125,303. The estimated system fuel savings related to the conversion of Units 8 & 10 are $1,148,099. The system depreciation and return was $73,033 resulting in a net system benefit to ratepayers at $1,075,066.

Q. Did the Company pass through to ratepayers the refund received from the DOE?

A. Yes, on May 31, 1996 the DOE made the final Crude Oil Supplemental Refund Distribution in Case No. RB272-0007. The $4.4 million refund which reduced fuel costs to ratepayers during this period concludes the investigation into crude oil overcharges.

Q. Has the Company passed any sulfur dioxide emission allowance transactions through the current or prior periods fuel adjustment clause?

A. Yes, in prior six-month fuel adjustment clause periods, the Company has passed through $627,328 of proceeds from the mandated EPA Sulfur Dioxide Emission Allowance Auction as a credit to fuel expense. This amount represents the auction proceeds for the years 1993 through 1995.

In the current six-month fuel adjustment clause period, the Company passed through $122,171 of proceeds for the 1996 EPA Sulfur Dioxide Emission Allowance Auction as a credit to fuel expense. See (JS-3) Schedule A2, Page 1 of 4, Footnote to Line 6b. The Company plans to continue to pass future emission allowance auction proceeds through the fuel adjustment clause.

CAPACITY COST RECOVERY

Q. What is the Company's jurisdictional ending balance as of September 30, 1996 for capacity cost recovery?

A. The actual ending balance as of September 30, 1996 for true-up purposes is an overrecovery of $14,454,408.

Q. How does this amount compare to the Company's estimated ending balance to be included in the October 1996 through March 1997 period?

A. When the estimated overrecovery of $10,754,129. to be refunded during the period of October through March 1997 is taken into account, the final true-up ending balance attributable to the six month period ended September 1996 period is an overrecovery of $3,700,279.

Q. Is this true-up calculation consistent with the true-up methodology used for the other cost recovery clauses?

A. Yes it is. The calculation of the final net true-up amount follows the procedures established by this Commission as set forth on FPSC Schedule A2 "Calculation of True-Up and Interest Provision" for the Fuel Cost Recovery Clause.

Q. What factors contributed to the actual period-end overrecovery of $14.5 million?

A. Exhibit No. 1 (JS-2), sheet 1 of 3, entitled "Capacity Cost Recovery/Summary of Actual True-Up Amount", compares the summary items from sheet 2 of 3 to the original forecast for the period. As can be seen from sheet 1, the actual jurisdictional capacity cost revenues were $11.1 million higher than forecast due to higher KWH sales during the period, and capacity expenses were $3.1 million lower due to several Cogenerators not meeting contractual capacity factors.

Q. Does this conclude your testimony?

A. Yes, it does.

MR. McGEE: With that I would ask Mr. Scardino to give a summary of his testimony. And I would ask that in doing so he identify any amounts in his true-up testimony that relate to Issue 14D, the issue concerning the extended outage.

WITNESS SCARDINO: The purpose of my testimony is to provide the true-up amounts for the fuel cost recovery and the capacity cost recovery clauses for the period April 1996 through September 1996.

The final jurisdictional fuel cost true-up for the period April 1996 through September 1996 is $12,203,216.

The jurisdictional balance for the fuel cost recovery clause as of September 30th, 1996, as presented in Exhibit 1, JS-1 is an underrecovery of $59,049,902.

The Company's earlier estimate of an underrecovery of $46,846,686 is already included in the fuel cost factors for the current period October 1996 through March 1997.

The increase in the underrecovery of $12,203,216 is primarily attributed to the unavailability of Crystal River Unit No. 3 in September of 1996 due to a forced outage.

The jurisdictional balance for the capacity cost recovery clause as of September 30th, 1996, as presented in Exhibit 2, JS-2, is an overrecovery of $14,454,408. The Company's earlier estimate of an overrecovery of $10,754,129 was included in the capacity cost factors for this current period October 1996 through March 1997.

The additional overrecovery of $3,700,279 is due to primarily increased kilowatt-hour sales.

With regards to Issue 14D, which is associated with the recovery of replacement fuel cost due to the extended outage of Crystal River Unit No. 3, my testimony does not address this issue because to the best of my knowledge the true-up period of April 1996 through September 1996 preceded the beginning of the extended outage.

Absent a finding by this Commission of imprudence, the Company should be allowed to recover such costs.

This concludes my testimony.

MR. McGEE: We tender the witness.

CHAIRMAN JOHNSON: Public Counsel.

MR. HOWE: I had not intended to ask Mr. Scardino any questions, but now I'm afraid I'm forced to.

CROSS EXAMINATION

BY MR. HOWE:

Q Mr. Scardino, is it your position that the forced -- I'm sorry, that the outage of Crystal River 3 began after September of 1996?

A No, Mr. Howe, I believe you used the word "forced outage."

Q I corrected myself and used the term "outage."

A Could you be more specific.

We had a forced outage that occurred beginning early September of 1996 due to an equipment failure. It had nothing to do with what we understand today to be the extended outage of Crystal River 3.

Q Oh, I see. So you're making a distinction between the reason that the unit originally came off line and the reason it is currently off line?

A That is correct.

Q Would you agree that the unit has been off-line continuously since September 2, 1996?

A Yes, I would.

Q And you used the term "forced outage." Would you agree that the unit was removed from service voluntarily by Florida Power Corporation and not under the direction of any outside entity?

A No, I would not. And the exception that I would take is that it wasn't removed from service voluntarily.

We were removed from service due to an equipment failure. An oil pipe ruptured and we were forced into a shutdown mode on September 2nd.

Q But you did not receive direction from any outside entity, any entity outside of the corporation; is that correct?

A That is correct. This is just an equipment failure which may occur from time to time.

MR. HOWE: I have no further questions.

MS. JOHNSON: Staff has no questions.

CHAIRMAN JOHNSON: I do have a question. Similar to Mr. Howe I was a little confused, too, as to the distinction that you're making.

You said that your analysis of April through September '96 -- I thought you said it was before the forced outage? Now explain to me what you meant by that and the distinction that you are making?

WITNESS SCARDINO: What I was attempting to do, Chairman Johnson, was to indicate that the extended outage follows the period ending September 30th, 1996. I did not intend to infer that the forced outage that occurred on September 2nd is outside of the period. I was trying to make the distinction that we came down for a specific reason, the equipment failure. Subsequent to that decisions were made to place the unit in an extended outage. But that decision, to the best of my knowledge, took place beyond the period September 30, 1996.

CHAIRMAN JOHNSON: And it was for reasons different than those that you're referring to as the forced outage and the forced outage you testified was the equipment failure.

WITNESS SCARDINO: That is correct.

CHAIRMAN JOHNSON: And the extended outage, you aren't testifying as to the cost or --

WITNESS SCARDINO: No, I am not testifying to the cost.

CHAIRMAN JOHNSON: Any other questions?

COMMISSIONER DEASON: How does the forced outage which occurred on September 2nd affect your true-up calculations?

WITNESS SCARDINO: Earlier I provided a comparison that indicated the Company's earlier estimate for the underrecovery as of September 30th was $46,846,686. Today our current actual numbers are $59,049,902. That increase of $12,203,216, the primary reason for that increase in the underrecovery is the forced outage that occurred on September 2nd. That 12 million would also include any other fluctuations that the Company may have experienced between the estimated rates and its actual costs, but primarily they relate to the Crystal River 3 forced outage in September.

COMMISSIONER DEASON: Thank you.

CHAIRMAN JOHNSON: Any other questions? Any redirect?

COMMISSIONER KIESLING: Staff.

CHAIRMAN JOHNSON: They said they didn't have any questions.

COMMISSIONER KIESLING: I'm sorry. I missed that.

CHAIRMAN JOHNSON: She went quickly.

COMMISSIONER KIESLING: I am missing everything today. I apologize.

CHAIRMAN JOHNSON: Any redirect?

MR. McGEE: No, ma'am.

CHAIRMAN JOHNSON: Exhibits?

MR. HOWE: Excuse me, Chairman Johnson, I realize thisi is unusual but to be honest with you I was surprised by some of Mr. Scardino's statements. If I could, I'd like to ask one additional question.

CHAIRMAN JOHNSON: I'll allow you that.

CONTINUED EXAMINATION

BY MR. HOWE:

Q Mr. Scardino, I'm going to show you a document that we obtained from the United States Nuclear Regulatory Commission, Office of Public Affairs, dated November 12, 1996, and there is the statement -- I'll be showing you the document, I only have this one copy -- it said "The Crystal River plant was voluntarily shut down in early September by FPC who identified several potential unreviewed safety questions." I'd like for you to take a look at this document and tell me if you believe it is correct or incorrect? (Hands document to witness.)

CHAIRMAN JOHNSON: While he's studying that, are you going to want that marked, and do you have additional copies, if so?

MR. HOWE: I don't have any copies right now, Chairman Johnson. I believe the phrase I read into the record and the date and so forth, unless the Company sees some need to contest it, I think will stand on its own.

CHAIRMAN JOHNSON: You may need to read it again for my benefit.

WITNESS SCARDINO: This document that Mr. Howe passed to me is the first time that I've seen this document.

I do take exception to the language. The Crystal River plant was voluntarily shut down in early September by FPC. Everything I know sitting before you today tells me that's not the case.

Q And when you say everything you know, Mr. Scardino, what is the source of your information? Is it information that has been provided to you by others?

A Yes, in part. My sources of information, you know, come in part from discussions with the cost controller at Crystal River 3 regarding that forced outage. So that is a part of the source of my information.

MR. HOWE: Thank you very much.

Chairman Johnson, so the record will be clear, it's a one-page document I provided to Mr. Scardino. It is entitled "United States Nuclear Regulatory Commission, Office of Public Affairs, Region 2," gives an address, and states "For Immediate Release." Dated Tuesday, November 12th, 1996, and the heading is "NRC Establishes Restart Panel for Crystal River Plant, Schedules Corrective Action Meeting in Atlanta." It was this one one-page document from which I read the sentence and used as the source of the question to Mr. Scardino.

I'd be more than happy to provide copies to everybody at the appropriate time.

COMMISSIONER KIESLING: In lieu of copies, I just have a question, since I haven't seen it either. Is it in the nature of like a notice of something or is it in the nature of a direct letter from the NRC to FPC or Crystal River?

MR. HOWE: It is in the nature of a general announcement by the NRC that they have established a restart panel for Crystal River 3.

COMMISSIONER KIESLING: Thank you.

CHAIRMAN JOHNSON: I don't need a copy.

Any re-redirect.

MR. McGEE: Does Public Counsel intend to introduce that letter?

CHAIRMAN JOHNSON: I don't think so.

MR. HOWE: I certainly can, Jim, if you'd like.

MR. McGEE: If that was the plan, I wanted to note for the record that we would object to that because the letter is contrary to the testimony of the witness and we have no one to cross examine concerning the accuracy --

MR. HOWE: I fully understand. And that was the reason for my question to Mr. Scardino was he had stated something -- I did not object at the time but I was kind of caught off guard because Mr. Scardino suddenly went into the reason for the outage and characterized it as a forced outage. And that was nothing that appeared in his prefiled direct testimony. And so I was kind of caught off guard.

And I think as far as the ability to recross, Mr. Scardino, I believe, has stated that he relied on information of others in making his statement and identified that individual, and I have no opportunity to cross examine them. I think in both cases we're dealing with hearsay.

CHAIRMAN JOHNSON: Certainly. And it hasn't been marked and I don't believe it will be offered as such -- the document you were referring to.

MR. McGEE: Mr. Howe, might I ask the date of that notice?

MR. HOWE: Yes. In fact, here I'll pass it to you. It's dated Tuesday, November 12th, 1996.

MR. McGEE: If I might ask the witness one follow-up question.

REDIRECT EXAMINATION

BY MR. McGEE:

Q Mr. Scardino, do you have knowledge of when

Florida Power notified the Nuclear Regulatory Commission that it was voluntarily placing Crystal River 3 in a extended outage?

A Yes. It's my understanding that took place on October 4th.

Q All right.

MR. McGEE: Then I would just note for the record that this notice is dated sufficiently after that.

CHAIRMAN JOHNSON: What was your question again? I didn't hear your question.

MR. McGEE: I had asked him if he had knowledge as to when Florida Power notified the NRC that we had elected to place the plant in an extended outage, and I think he indicated that that was in early October. And I simply wanted to point out that this letter substantially follows that. It's some two and a half months almost after the outage began. Suggesting the possibility for some confusion --

CHAIRMAN JOHNSON: That's fine.

COMMISSIONER KIESLING: A month and a week, October 4th.

MR. McGEE: The outage that Mr. Howe refers to begins September 2nd.

COMMISSIONER KIESLING: You've got me

confused. You just asked the witness when the outage referred to in that letter, when they notified NRC that they were going to stay in their shutdown status. He said October 4th. Then the letter came out on November 12th.

MR. McGEE: I'm suggesting that there is some confusion about the September 2nd date. Because subsequent to that outage date Florida Power notified the NRC --

MR. HOWE: Objection. The witness is testifying.

COMMISSIONER KIESLING: My problem is I don't know what you're talking about. You're not testifying; the witness is. Are you arguing a document that hasn't been offered?

MR. McGEE: The witness has contended that the document is in error.

COMMISSIONER KIESLING: I understand what the witness said. I'm trying to figure out what we're doing right now.

You asked the witness a question and then you proceeded to make a bunch of argument about, I guess, the weight you think that document deserves. But the document hasn't been offered.

MR. McGEE: That's correct.

COMMISSIONER KIESLING: So what is your argument relate to?

MR. McGEE: I was offering an explanation as to the source of the confusion.

COMMISSIONER KIESLING: I understand that. But you're not the witness.

MR. McGEE: I was commenting on the document the witness did and the witness's testimony, but if that's causing confusion --

CHAIRMAN JOHNSON: It's not that it's causing confusion, you're starting to testify and that's the problem. So with that I think we should end that line of questioning.

MR. McGEE: I have no further questions.

CHAIRMAN JOHNSON: Did you have any based upon --

MS. JOHNSON: Staff has no questions.

CHAIRMAN JOHNSON: Commissioners, anything else? Okay, sir. You can be excused. Thank you very much. Did we admit his exhibits? He had a couple of exhibits.

MR. McGEE: We'll move Mr. Scardino's exhibits.

CHAIRMAN JOHNSON: Show Exhibit 1 and 2 moved into the record without objection.

(Exhibits 1 and 2 received in evidence.)

(Witness Scardino excused.)

- - - - -

MR. McGEE: We would call Mr. Wieland.

- - - - -

(Transcript continues in sequence in Volume 2.)