BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

In the Matter of	**DOCKET NO. 000001-EI**
FUEL AND PURCHASED POWER COST RECOVERY CLAUSE AND GENERATING PERFORMANCE INCENTIVE FACTOR	

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VOLUME 1

Pages 1 through 183

PROCEEDINGS:	**HEARING**
BEFORE:	COMMISSIONER E. LEON JACOBS, JR. COMMISSIONER LILA A. JABER COMMISSIONER BRAULIO L. BAEZ
DATE:	Monday, November 20, 2000
TIME:	Commenced at 9:30 a.m. Concluded at 12:00 noon
REPORTED BY:	JANE FAUROT, RPR FPSC Division of Records & Reporting Chief, Bureau of Reporting

APPEARANCES:

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

JEFFREY A. STONE, Beggs & Lane, 700 Blount Building, 3 West Garden Street, Post Office Box 12950, Pensacola, Florida 32576-2950, appearing on behalf of Gulf Power Company.

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

VICKI GORDON KAUFMAN, McWhirter, Reeves, McGlothlin, Davidson, Decker, Kaufman, Arnold & Rief Steen, P.A, 117 South Gadsden Street, Tallahassee, Florida 32301, appearing on behalf of Florida Industrial Power Users Group (FIPUG).

MATTHEW M. CHILDS and CHARLES A. GUYTON, Steel, Hector & Davis, 215 South Monroe Street, Suite 601, Tallahassee, Florida 32301, appearing on behalf of Florida Power & Light Company (FPL).

STEPHEN C. BURGESS, Deputy Public Counsel, Office of Public Counsel, 111 West Madison Street, Room 812, Tallahassee, Florida 32399-1400, appearing on behalf of the Citizens of the State of Florida.

WILLIAM COCHRAN KEATING, IV, Florida Public Service Commission, Division of Legal Services, 2540 Shumard Oak Boulevard, Tallahassee, Florida 32399-0870, appearing on behalf of the Commission Staff.

I N D E X

WITNESSES

EXHIBITS

NUMBER:		ID.	ADMTD.
1	TECO's Revised Positions on Issues 9 and 10	11	25
2	FIPUG's Positions on Issues 9 and 10	12	25
3	KWH-1 and 2	50	77
4	JES-1 and 2	81	81
5	RJM-1 and 2	81	81
6	GY-1	81	81
7	KMD-1, 2, 3, 4, 5 and 6	81	81
8	RS-1 and 2	81	81
9	GMB-1 and 2	81	81
10	MFO-1 and 2	81	81
11	TAD-1, 2 and 3	81	81
12	JRD-1 and 2	81	81
13	MWH-1	81	81
14	JDJ-1, 2, 3 and 4	81	81
15	BSB-1 and 2	81	81
16	RB-1	81	81
17	FPSC Staff's Composite Exhibit	81	81

P R O C E E D I N G S

COMMISSIONER JACOBS: Let's go on the record. Counsel, read the notice.

MR. KEATING: Pursuant to notice issued September 29th, 2000, and amended October 6th, 2000, this time and place have been set for a hearing in Docket Number 000001-EI, fuel and purchased power cost recovery clause and generating performance incentive factor; Docket Number 000002-EG, energy conservation cost recovery clause; Docket Number 000003-GU, purchased gas adjustment true-up; and Docket Number 000007-EI, environmental cost recovery clause.

COMMISSIONER JACOBS: Very well. Let's take appearances. Mr. McGee.

MR. McGEE: James McGee, Post Office Box 14042, St. Petersburg, 33733, appearing on behalf of Florida Power Corporation in the 01 and 02 dockets.

MR. BEASLEY: I'm James D. Beasley with the law firm of Ausley and McMullen, P.O. Box 391, Tallahassee, Florida, 32302. I am representing Tampa Electric Company in the fuel and purchased power, conservation, and environmental cost recovery dockets.

MR. STONE: I'm Jeffrey A. Stone of the law firm Beggs and Lane, Pensacola, Florida, P.O. Box 12950, and I am representing Gulf Power Company in the 01, 02, and 07 dockets.

COMMISSIONER JACOBS: Very well.

MR. CHILDS: Matthew Childs with the firm of Steel, Hector and Davis appearing on behalf of Florida Power and Light Company in the fuel and purchased power docket, designated 01.

MR. GUYTON: Charles A. Guyton with the law firm of Steel, Hector and Davis appearing on behalf of Florida Power and Light Company.

MR. PALECKI: Michael Palecki, 3539 Apalachee Parkway, Tallahassee, Florida, 32311, appearing on behalf of City Gas Company of Florida on the 02 and 03 dockets.

MR. SCHIEFELBEIN: Wayne Schiefelbein appearing on behalf of Chesapeake Utilities Corporation in the 02 and 03 dockets.

MS. KAUFMAN: Vicki Gordon Kaufman of the McWhirter Reeves law firm, 117 South Gadsden Street, Tallahassee, Florida, 323301. I'm appearing on behalf of the Florida Industrial Power Users Group in the 01, 02, and 07 dockets.

MR. ELIAS: Bob Elias representing the Commission staff in the 02 and 07 dockets.

MR. KEATING: Cochran Keating representing Commission staff in the 01 and 03 dockets.

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COMMISSIONER JACOBS: Next we have a motion in 01, is that correct?

MR. KEATING: Yes, there are a few preliminary matters to go through in 01, and I would recommend we go through a few of those before we get to the motion.

COMMISSIONER JACOBS: All right.

MR. KEATING: First, I would like to point out that Issues 13E through 13G that are listed on Pages 23 and 24 of the prehearing order --

COMMISSIONER JACOBS: Yes.

MR. KEATING: -- no longer need to be decided. Tampa Electric Company withdrew its proposal for an experimental pilot program for seasonal fuel factors. Those issues address or were intended to address that program. So there is nothing to decide there now.

COMMISSIONER JABER: Mr. Keating, which issues are those?

MR. KEATING: Those were Issues 13E through 13G.

COMMISSIONER JACOBS: That program came up, as I recall, as a result of our discussions with -- and the workshops that we had. I assume that is a reflection of positive developments in those relationships, I hope.

MR. BEASLEY: Yes, sir, I think it is. And there is not the extent of interest in those experimental rates as there was previously. So we have withdrawn them and we concur that those three issues are rendered moot for purposes of this proceeding.

COMMISSIONER JACOBS: Very well. Show those -- that Issues 13A through G are withdrawn.

MR. KEATING: Another issue that I believe can be removed is Issue 11C on Page 20 of the prehearing order. That issue addresses the appropriate regulatory treatment for the $222.5 million settlement payment in the FPL/Okeelanta case. The Commission's proposed agency action order in that case has been protested. Therefore, there is not a settlement amount to approve any particular cost-recovery mechanism for at this time. So I don't believe that issue needs to be decided today, either.

COMMISSIONER JACOBS: Okay. Without objection, show -- Commissioners, any questions? Okay. Then show Issue 11C withdrawn, as well.

MR. KEATING: And I apologize, but I'm working backwards through the prehearing order. The next issues that I would like to get to is Issue 9 and Issue 10 on Pages 17 and 18 of the prehearing order. Issue 9 and 10 are not shown as stipulated issues. The parties have agreed to a manner in which they can agree to move forward on these issues.

Issue 9 asks how the Commission should implement its order in the shareholder incentive docket that was issued earlier this year. The parties have agreed that that issue can be decided along with -- as part of FIPUG's protest of the PAA portion of that order with the understanding that the decision would be effective -- the decision regarding the implementation methodology would be effective January 1st, 2001, and understanding that FIPUG's protest would not be resolved until after that date.

MR. BEASLEY: Commissioners, we agree with the deferral. And we had some degree of difficulty in coming to a way of stating that this matter would be deferred. And so what I have done for Tampa Electric is to prepare revised positions on Issues 9 and 10 which would have the effect of deferring Issue 9 and allowing the company to go forward with the estimated benchmark that it has calculated for Issue 10. And if I could distribute this perhaps and have it marked as an exhibit, it can stand as our position in stipulating on these two issues.

COMMISSIONER JACOBS: Very well.

MR. CHILDS: And, Commissioners, for Florida Power and Light Company, we would adopt the position as stated by Tampa Electric with the necessary revision to substitute Florida Power & Light Company's name for Tampa Electric.

COMMISSIONER JACOBS: Very well.

MR. BURGESS: Commissioners, the Citizens agree with Mr. Keating's characterization of the agreement that we have reached. And as he stated it, that can be presented as our position, and the position that we have in the prehearing order can then be deleted.

COMMISSIONER JACOBS: Ms. Kaufman.

MS. KAUFMAN: Chairman Jacobs, as Mr. Beasley said, we have agreed on the deferral of 9 and 10. But, unfortunately, we are not able to agree on language as to how that would be presented. So we have these dualing positions on that. And I have the position of FIPUG to be incorporated, as well.

COMMISSIONER JACOBS: Okay.

MR. BEASLEY: Could I request that the document I handed out be marked for identification, please.

COMMISSIONER JACOBS: Okay. We can mark it as Exhibit 1.

(Whereupon, Exhibit No. 1 was marked for identification.)

MR. STONE: Commissioner, while Ms. Kaufman is handing out her position, I would like on behalf of Gulf Power Company to indicate that we would adopt the language contained in TECO's position on Issues 9 and 10 as reflected in Exhibit 1 as the position of Gulf Power Company on those issues, except that we would adopt Gulf

Power's number under Issue 10.

MR. McGEE: And that would be the case for Florida Power Corporation, as well. We adopt TECO's position on Issue Number 11. And on Issue Number 10 with the exception of the dollar amount, which should read 11,061,127. Excuse me, Issue 9, Florida Power adopts TECO's position, the dollar amount that I just read pertains to Issue 10.

COMMISSIONER JACOBS: Okay. Very well.

MS. KAUFMAN: And, Chairman Jacobs, I suppose we need a number for FIPUG's position as well as an exhibit.

COMMISSIONER JACOBS: Okay. We'll mark that as Exhibit 2.

(Whereupon, Exhibit No. 2 marked for identification.)

MS. KAUFMAN: Thank you.

COMMISSIONER JABER: What was the change Mr. McGee made, Mr. Chairman?

COMMISSIONER JACOBS: He only changed the number in Issue 10, is that correct?

MR. McGEE: We adopted TECO's Exhibit Number 1, but that reflected TECO's dollar amount for Issue 10, so I just substituted the correct amount for Florida Power.

COMMISSIONER JABER: Which is the amount reflected in the current prehearing order?

MR. McGEE: That's correct.

COMMISSIONER JACOBS: Very well. Anything else?

MR. KEATING: FIPUG had filed a motion for oral argument and a motion to strike related to Issues 9 and 10. I believe that that no longer needs to be decided, but --

COMMISSIONER JACOBS: Yes, it sounds like we have resolved --

MS. KAUFMAN: I think that is right, Commissioner. There was another part to that motion, though, that deals with the Florida Power and Light issue, Issue 11A.

MR. KEATING: And that, I believe, is the remaining preliminary matter.

MS. KAUFMAN: But as to 9 and 10, you are correct, those parts of the motion are now moot.

COMMISSIONER JACOBS: Very well. Here it is. So then we are on the motion of FIPUG with regard to their motion to amend their prehearing position on Issue 11A.

Commissioners, we have a motion for oral argument on this.

COMMISSIONER JABER: I can move to grant oral argument with respect to the motion on Issue 11A.

COMMISSIONER BAEZ: Second.

COMMISSIONER JACOBS: Very well. Show the motion is granted.

Is there a need for each party to argue? Can we just do it ten minutes per side?

MS. KAUFMAN: Commissioner, I think this is going to be very short, and I think it is only FPL and FIPUG that are concerned with this issue.

COMMISSIONER JACOBS: Very well. Proceed.

MS. KAUFMAN: And, again, it is going to be very brief. FIPUG just requests permission to amend its position on FPL Issue 11A, which has to do with how they are going to recover the quite large underrecovery that they now have.

At the prehearing conference it is correct that we did agree to stipulate to the two-year recovery that they have proposed. However, after the conference and after I consulted with my client, I discovered that I should not have made that stipulation and that was an error.

It is FIPUG's position that the recovery for Florida Power and Light should occur over a three-year period, not a two-year period. And I advised the staff, I advised Mr. Childs. There is no prejudice to Florida Power and Light. They have their witness here. They have had plenty of notice that the stipulation was in error and that we intended to change our position to three years.

And so we would ask that the Commission exercise its discretion and permit us to do so. Thank you.

COMMISSIONER JACOBS: Mr. Childs.

MR. CHILDS: Commissioners, we would object to the request by FIPUG to change their position. I don't believe that they have alleged or stated today any true good cause to change that position. I find myself personally in a position of being reluctant to make the point, but I think it is necessary for us to object.

They originally started in response to the procedural order in this docket which required all parties to state their position in their prehearing statement. And they stated that had they had no position at this time. And then they amended that at the prehearing conference to agree with staff, which essentially agreed to the two-year period requested by FPL.

Subsequent to that, they sought to amend that issue which, in effect, says now that that one issue is subject to a potential decision different than the position stipulated by the parties. In essence, it puts it at issue. We object to that.

We also object to the fact that Issue 11B, which has to do with the -- in essence, the agreement by FPL to waive interest on this unrecovered amount. It is now sort of left there that we would continue to waive interest on that, but we would have a three-year period for recovery. They have not asked to amend their position on that, and our belief is that we have adequately and appropriately responded to the significance of that charge and asked to recover it over two years. That while I am sympathetic to the counsel's position for FIPUG, I don't believe it is appropriate at this late date to change their position and put a stipulated issue at issue now. So we object.

COMMISSIONER JABER: I have a question, Mr. Chairman.

COMMISSIONER JACOBS: Go ahead.

COMMISSIONER JABER: Mr. Childs, can we force a party to stipulate?

MR. CHILDS: Can you force them?

COMMISSIONER JABER: Uh-huh.

MR. CHILDS: I don't think you can force them, but I would note that they not only stipulated, they agreed with the position. So the reason the issue was stipulated is because the position that they took at the prehearing was the same as staff, which is the two-year period of recovery. And I think you can force them to take a position on an issue if they don't have an adequate reason for not doing so, which is what the procedural order says that they have to have a reason. The prehearing officer has to make a ruling that they have an adequate reason for not having a position at that time. And none of that was discussed.

COMMISSIONER JABER: Isn't this really FIPUG changing its positions and -- that is the first question. And the second is if that is the case, if we accept that, then this issue just remains an issue at hearing, correct?

MR. CHILDS: I think that is correct.

COMMISSIONER JACOBS: And there is no real -- the prohibition that you would argue only has to do with what is in the prehearing order's guidelines, is that correct?

MR. CHILDS: Beg your pardon?

COMMISSIONER JACOBS: The only guidelines that would apply would be in the prehearing order, is that correct? There is no real prohibition on a party amending its position.

MR. CHILDS: I'm not aware of any other prohibition other than if someone wanted to attempt to find independently precedent in the Commission. But the prehearing order, I think, addressed the procedures to be followed.

COMMISSIONER JACOBS: Staff.

COMMISSIONER BAEZ: I just have one last question, Mr. Childs.

MR. CHILDS: I'm sorry.

COMMISSIONER BAEZ: When you were commenting on the waiver of interest for that last year, that is not the only alternative that we have to decide ultimately on what the treatment is going to be. You still maintain -- you could still maintain your position of holding or waiving interest for the two years that you offered up originally?

MR. CHILDS: Well, we could. And I misspoke. If I can go back, I think I said the procedure in the prehearing order. I meant the procedural order, not the prehearing order. Sorry. The waiver of interest is not the only position that Florida Power and Light could have taken. But my point is that as presented by our witness and presented in this case, we presented those together. And they wish to change one issue and leave the other one alone.

COMMISSIONER BAEZ: Well, and I guess what I'm trying to get at is that even allowing the amended position wouldn't put the company in a position, strictly speaking, that any waiver of interest or any position that you took prior would extend to that third year in question.

MR. CHILDS: Well, I mean, I guess -- I hope I understand.

COMMISSIONER BAEZ: Arguing for the moment that we can allow this amendment to take place, it is not -- it wouldn't prejudice the company in terms that we would be deciding on whether to have you waive interest for a third year, that is not your position and you wouldn't support that?

MR. CHILDS: No. But we may ask you to permit us to waive the issue on two years is what I'm saying.

COMMISSIONER BAEZ: I mean, we are not changing what would ultimately be your position, then.

MR. CHILDS: Okay.

MS. KAUFMAN: Chairman Jacobs, can I just respond before you turn to staff? I would just say that Mr. Childs is in no different position than if I had said at the prehearing conference we think the recovery period should be three years. And I think Commissioner Jaber's point, you cannot force a party to agree with another party's position on something.

It was an error, and I take responsibility for that, but I don't think that because it occurred after the prehearing conference -- now, if Florida Power and Light could demonstrate some prejudice, that would be one thing, but they can't. Ms. Dubin's testimony was in. There is no opportunity for any additional testimony. So they are in the same place they would have been if I had said at the prehearing conference our position would be three years. So I would suggest to you that you should go ahead and allow the amendment.

COMMISSIONER JABER: Are you also in the same place if a Commissioner rejected the stipulated issue? Let's set aside FIPUG making the mistake. If we didn't want to approve a stipulated issue, isn't the effect of that that the issue was litigated and you go forward with the hearing on that issue?

MR. CHILDS: It is. But I think that the distinction that I make as to -- I mean, I think as a practical matter the Commission closely monitors the development of these issues as we go along anyway. But I think there is a distinction between saying that you can change your position and have the Commission decide. And you can change your position and then put the utility to proof on the issue.

I mean, that is one of the distinctions is that now the issue is in play as to all aspects of your decision-making process. And I take exception to their comment that, well, there is no prejudice because you are here anyway. I think there is. I mean, it was a stipulated issue before and now it is not, or might not be.

COMMISSIONER JACOBS: Staff.

MR. KEATING: Staff recommends that you grant FIPUG's motion to amend its position. And the way that I have looked at it is that you have got really two competing interests; you have got FIPUG's interest in having its position accurately stated, and you have Florida Power and Light's interest in being able to know after the prehearing what is in store for the hearing and being able to adequately prepare for the hearing.

I think because FIPUG notified staff and FPL, the prehearing was a Friday, the following Monday, two weeks before this hearing of the error, I'm not sure that there is a -- I don't think that there is much prejudice to Florida Power and Light in terms of their ability to prepare for hearing with the new position taken by FIPUG.

And I would point out in the procedural order it does speak to parties taking positions at certain times. In pertinent part it states unless a matter is not at issue for that party, each party shall diligently endeavor in good faith to take a position on each issue prior to issuance of the prehearing order.

And FIPUG indeed took a position prior to issuance of the prehearing order. And obviously we prefer that parties state their positions at the prehearing so they can be reflected in the prehearing order and that they are on the record, but with FIPUG's motion and its timely notification of the error, we would recommend that you approve their motion.

COMMISSIONER JABER: Mr. Chairman, I don't think we have a choice. It is not a stipulated issue if parties don't stipulate the issue. And regardless of the fact that we have had the prehearing conference or not, I think this is awkward to say to FIPUG you have to stick with the position. Because it is a stipulated issue, it would be one thing if there were numerous positions and FIPUG was changing its mind, I could probably stomach that. But their changing the position has the effect of removing the proposed stipulation.

So I would move to grant staff's recommendation, which is to grant FIPUG's motion with respect to allowing them to change the position. But to the degree there is any perception or unfairness to Florida Power and Light, perhaps the witness that would be appropriate to testify on this issue could have an additional two or three minutes to comment as to why, you know, a three-year recovery period might not be appropriate on that. I think there is a way to balance those interests.

COMMISSIONER BAEZ: Well, and I guess just so that I can be clear, there hasn't been any testimony filed on this particular issue?

MR. CHILDS: We have filed testimony on this issue.

COMMISSIONER BAEZ: That addresses it?

MR. CHILDS: It addresses the two-year recovery, yes.

COMMISSIONER JABER: The two-year recovery, but not the three year.

COMMISSIONER BAEZ: But not what is going to become an issue here. But your witness is here?

MR. CHILDS: Oh, yes.

COMMISSIONER BAEZ: I will second it.

COMMISSIONER JACOBS: Very well. Show that -- and I would add that I find -- I would find it difficult to prohibit a party from changing their position. I am concerned about the idea that there could be surprise, but I think given that the issue of the two-year period had already been an issue and that the extra year is in line with that, I don't think there is any significant prejudice to allow that position. And so show that the motion is granted.

Are there any other preliminary matters, counsel?

MR. KEATING: I would just bring up one other point as a preliminary matter. On Issues 4 and 7, Issue 4 is on Page 9, it begins on Page 9. Issue 7 begins on Page 12. You will notice that there are some very small differences between the numbers in Florida Power Corporation's position and in staff's position, and it is my understanding that Florida Power Corporation agrees with the staff numbers.

MR. McGEE: That is correct.

MR. KEATING: I would also point out that on Issues 4 and 7, with that understanding, there is agreement on all the numbers. And, let's see, I believe those are not shown as stipulated at this time, there is a notation in the prehearing order under each of those issues that notes that the resolution of Issue 10 may have a fallout effect on the factors set forth in those issues. And it is our understanding that it is not in considering that Issue 10 has been agreed to now as earlier discussed, it definitely does not have an affect on the factors in Issue 4 and 7.

So those can be shown as stipulated issues with the exception of Florida Power and Light simply because if FIPUG were to prevail with its position on Issue 11A that would have a fallout effect on Issues 4 and 7, the factors in Issues 4 and 7 for Florida Power and Light. It would also have an affect on the amount in Issue 3 for Florida Power and Light.

COMMISSIONER JACOBS: So we need to -- if it is going to be stipulated, I guess we need to hear from Florida Power and Light as to whether or not they are going to accept the fallouts in these issues pending the resolution of Issue 11.

What say you, Mr. Childs?

MR. CHILDS: I believe that the resolution of Issue 11, depending upon your ruling, would be a mathematical computation and we are able to accommodate that.

COMMISSIONER JACOBS: Okay. Very well. So we will show Issues 4 and 7 as stipulated pending the resolution of Issue 10.

MR. KEATING: That would be 11A.

COMMISSIONER JACOBS: I'm sorry, 11A. Is that it?

MR. KEATING: Unless the parties have any other preliminary matters to bring up, that is all that I am aware of.

COMMISSIONER JACOBS: Okay. Very well.

MS. KAUFMAN: Commissioner, I guess I should move Exhibit 2 into the record.

COMMISSIONER JACOBS: Right.

MR. BEASLEY: We move Exhibit 1, sir.

COMMISSIONER JACOBS: Show Exhibit 1 and 2 admitted without objection.

(Exhibits 1 and 2 admitted into the record.)

COMMISSIONER JACOBS: Very well. So that leaves --

MR. KEATING: I believe that just leaves Issue 11A outstanding. And we have discussed that it would have a fallout effect on the other issues. But 11A is really the one that remains for decision or remains for hearing.

MR. CHILDS: We are prepared to call our witness when it is appropriate.

COMMISSIONER JACOBS: Very well. Very well. Then let's proceed.

MR. CHILDS: We call Ms. Dubin.

COMMISSIONER JABER: Mr. Chairman, when do the other witnesses' testimony get moved into the record? Is that done at the end?

COMMISSIONER JACOBS: Why don't we go ahead and do that at the end.

MR. KEATING: Yes. I would suggest we take up any witnesses that need to be heard. I understand that Commissioner Jacobs may have some questions for certain witnesses that otherwise may have been excused. So perhaps we ought to go through all the witnesses that we do need.

COMMISSIONER JACOBS: Right. And on that note, why don't we swear all the witnesses that will testify.

(Witnesses sworn.)

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KOREL M. DUBIN

was called as a witness on behalf of Florida Power and Light Company and, having been duly sworn, testified as follows:

DIRECT EXAMINATION

BY MR. CHILDS:

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

A My name is Korel M. Dubin. 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 and Light Company as Manager of Regulatory Issues in the Regulatory Affairs Department.

Q Do you have before you a document entitled testimony of Korel M. Dubin, Docket Number 000001-EI, September 21, 2000?

A Yes, I do.

Q Was that prepared by you as your direct testimony in this proceeding?

A Yes, it is.

Q Is the testimony commencing on Page 3, Line 21, through Page 4, the sentence ending on Line 6 intended by you to address what has now been identified as Issue 11A in this proceeding?

A Yes.

Q And there the company takes the position that the underrecovery should be supported over a two-year period?

A Yes.

MR. CHILDS: Commissioners, with your indulgence I am simply going to ask the witness at this time to follow up on the point that the Commissioner made as to whether she would comment as to why the two-year period was proposed and what is the company's position as to a recovery over a three-year period. I'm not sure if it is three years or longer or three years.

BY MR. CHILDS:

Q But can do you that, Ms. Dubin?

A Sure. When Florida Power and Light -- well, certainly everyone is in the situation with fuel prices increasing. We took a look at the large underrecovery that we had and tried to see how we could mitigate its impact on customers' bills. And in that we took a look at it and said, okay, let's balance this between how to mitigate the impact on customer bills, but also at the same time keeping in balance the uncertainty in the fuel market that we have ahead of us.

And we felt that the two-year period was a good way to reduce the impact on customer bills as well as, of course, waiving the interest, also, which amounts to, I believe, $33 million over the two-year period. Three years, we believe, is just a bit too long. There is an awful lot of uncertainty in the fuel market, and we don't think it is reasonable to extend it out further than that.

MR. CHILDS: Okay. We will tender the witness. As I note, I have not asked that this testimony that I just specifically identified be inserted in the record, because I assume all her testimony is going in the record and I will just keep it as part of that.

COMMISSIONER JACOBS: That is sufficient. Ms. Kaufman.

MS. KAUFMAN: Thank you.

CROSS EXAMINATION

BY MS. KAUFMAN:

Q Ms. Dubin, I just have a few questions for you on 11A, and I appreciate the Commission's indulgence in letting us change our position.

Ms. Dubin, can I assume that you are generally familiar with FIPUG and the fact that they are a group of large industrial customers?

A Yes.

Q And that they take service from FPL generally on your rate Schedules E and F?

A Yes.

Q Now, you had an underrecovery of about $518 million, is that correct?

A Yes, that is correct.

Q What would be your typical practice, how would you -- over what time frame would you recovery an underrecovery in the typical scenario?

A We would typically recover a true-up amount over a one-year period and we would include interest with that.

Q And as I understood your comments in your summary, the reason that you wanted to go to a two-year recovery of this underrecovery was at least in part to mitigate the impact on your customers, is that right?

A That is exactly what it is. We wanted to mitigate the impact on customer bills, yes.

Q Because if you had recovered it in one year they would have seen a -- let's just say a much greater increase than they are going to see under the two-year recovery, correct?

A Yes.

Q Wouldn't it also be true that if you spread the recovery over three years you would further mitigate this rather large underrecovery?

A You would mitigate it. Of course, in the first year you would have a lower bill in 2001, but with the uncertainty out in the future, the bill then, say, in 2002, 2003 particularly, the bill could be much higher because you are including an additional $173 million in 2003.

Q But when you say it could be much higher, you are adding in whatever your fuel prices are going to reflect in 2003?

A Yes.

Q But in terms of spreading the $518 million, it is going to have a lower impact the more time you spread it over?

A True. You divide it by three versus dividing it by two, yes. But, again, the interest calculation is also then much higher. It goes from 33 million to 50 million.

Q Right. But you are not proposing to collect any interest as to the two-year recovery period?

A That's correct.

Q Would you agree with me, and you might have to take this perhaps subject to check, that some of the industrial customers that are in your service territory also take service from Florida Power Corporation?

A Yes.

Q And I want to take a look at your schedule, it is E1E, and that is where you have set out the fuel factors that we are going to be discussing, is that right?

A Yes.

Q And I'm going to be looking particularly at rate

Schedule E, which is the one that most of our FPL industrial customers take service off of. Are you with me? Okay.

A Schedule E1E?

Q Yes. E1E, and it is numbered Page 9 behind Appendix 2, E schedules. And I am also going to be looking at the -- for the most part the off-peak, because that is usually where our clients try to focus their consumption.

Would you agree with me, looking at that schedule, that the off-peak rate you are proposing there is 2.680?

A Yes.

Q Do you have a copy of Florida Power Corporation's E1E schedule?

A No, I do not.

MS. KAUFMAN: Commissioners, I'm going to just be having Ms. Dubin compare those, and this is the same schedule in Florida Power Corporation's testimony, I believe, with Mr. Wieland's testimony. It does not have a number on the bottom of it, however.

COMMISSIONER JACOBS: You're indicating that it is attached to Mr. Wieland's testimony, though?

MS. KAUFMAN: I think it is. I had made a copy for Ms. Dubin, let me just be sure. Yes, it is. But it is about halfway back in Mr. Wieland's testimony.

COMMISSIONER JACOBS: Very well.

MS. KAUFMAN: And at the top it is called Florida Power Corporation, calculation of final fuel cost factors.

BY MS. KAUFMAN:

Q And, Ms. Dubin, if you can look at the Florida Power Corp schedule I gave you, and I want you to look at Line 3, which I understand to be the rate that corresponds to your Florida Power and Light rate that we have been discussing. And would you agree that their off-peak rate is 2.064?

A Yes.

Q Okay. So would you also agree with me that that is a significant difference between those two rates, especially for a large customer that consumes a lot of power?

A It is, Ms. Kaufman, but I think you also need to look in terms of the total bill. And, for example, a customer who was on a CILC rate, their total bill, and I'm talking about a customer who may be a large manufacturer, that type of a customer, that on a total bill basis, if you take a look at the usage, and we usually look at -- the usage there is 10,000 kW with an 80 percent load factor, and using 5,840,000-kilowatt hours a month, that our total bill is less than Florida Power Corp's.

Q Okay. And I appreciate the distinction that you are trying to make. But I want to just focus on trying to compare the two rates.

A Well, that is what I'm trying to do, but it's on a total bill basis, and what the customer is actually paying altogether.

Q I understand. But if we look at the two rates, the two what I will just call the industrial rates, you are going to see a large difference in the rate between Florida Power Corp's proposed rate for the coming year and Florida Power and Light's, correct?

A In their fuel charge, yes.

Q Right, in their fuel charge. And we would see a significant reduction in your fuel charge if your underrecovery was spread over three years, correct?

A Yes. I was going to say I might add that on a total bill basis, the Florida Power and Light rate is 4.08 cents per kwh and the Florida Power Corp charge is 4.14 cents per kwh, which is also a significant difference.

Q Have you recalculated the fuel factor on Schedule E using the three-year period?

A Yes.

Q What is it?

A I have the average factor.

Q You didn't do the off-peak/on-peak?

A I don't think I have it in that format. The average factor would change from 2.925 to 2.826.

Q Okay. But you have not done the calculation, the changes you would have to make on E1E to change the off-peak to 2.680, you don't know what that number would be if we did a three-year recovery?

A I have a total bill, which is a reduction of about 2 percent.

MR. CHILDS: Excuse me. You used a 2.680, is that what you said?

MS. KAUFMAN: Yes. I thought that's what we were discussing.

MR. CHILDS: Where is that?

MS. KAUFMAN: Schedule E1E, Group E, off-peak.

MR. CHILDS: Thank you.

MS. KAUFMAN: Thank you. That's all I have.

COMMISSIONER JACOBS: Any other cross? Staff. Commissioners.

COMMISSIONER JABER: Yes. Ms. Dubin, I wasn't clear on something you said. In the two-year recovery period, you are not proposing to collect interest?

THE WITNESS: No, Commissioner. We would propose to waive the recovery of interest for the two-year recovery period, which is about $33 million.

COMMISSIONER JABER: Okay. So then the only concern you have with the three-year recovery period is one of the -- it is your fear about what the future bills would look like compiled with the recovery for the underrecovery for this year?

THE WITNESS: It is a long time to be carrying -- another $173 million is what we would be carrying in that third year. And as everyone can see in the media and everything, that the fuel prices are kind of all over the place. And there is so much uncertainty that we wouldn't want to extend it that far.

COMMISSIONER JACOBS: Staff.

MR. KEATING: Staff has no questions.

COMMISSIONER JACOBS: Very well. Other questions? Very well. I guess we will do the testimony and exhibits in order with the other witnesses. So if there is no other --

MR. CHILDS: Could I ask a couple of questions on redirect?

COMMISSIONER JACOBS: I'm sorry. You are correct, go ahead.

REDIRECT EXAMINATION

BY MR. CHILDS:

Q Ms. Dubin, you were asked a series of questions comparing the fuel adjustment charges of Florida Power and

Light Company to those for Florida Power Corporation?

A Yes.

Q Are there other differences that would affect the off-peak fuel charge, other billing determinants that would affect that charge in addition to the cost of fuel?

A All the other clause adjustment charges and their base charge.

Q Sure. Okay. Now, as to the level of the charge in terms of determining the impact of the level of the fuel adjustment charge, does Florida Power and Light Company look to other factors, as well, other factors on the bill or the level of the bill in making a recommendation as to the period of recovery?

A Yes. Every time we go about filing our clause adjustments we take a look at the impact of the different items on the bill and take a look at where our bill falls. And, I might add that Florida Power and Light certainly over the last several years, our charges continue to be among the lowest in Florida and well below the national average.

Q Are there other announced changes or possible changes that you are aware of that can effect the level of the bill in the near future?

A Yes. As part of Florida Power and Light's three year sharing, revenue sharing program, in June customers will be seeing an additional refund amount, it is a one-time refund in June. And right now our estimates are that that will be a refund of somewhere between 75 and $100 million. That same large manufacturing customer that I mentioned earlier, they should be receiving somewhere in the neighborhood of about a $70,000 refund in the month of June.

MR. CHILDS: Commissioners, that's all I have.

COMMISSIONER JACOBS: Very well. No other cross then. Ms. Dubin, you are excused.

THE WITNESS: Thank you.

COMMISSIONER JACOBS: I had asked to inquire into the issue having to do with fuel purchases and specifically management of fuel costs through market proceedings and hedging. And I understand that Mr. Yupp was available to testify on that for Florida Power and Light?

MR. CHILDS: He is here.

COMMISSIONER JACOBS: Okay. Commissioners, this I don't intend will take, will take very long. And, of course, if other parties have questions then they would be free, but we would then ask Mr. Yupp to come forward.

MR. BURGESS: Mr. Chairman, while he is coming forward, I might ask -- I was not present when appearances were taken. Might I make an appearance in the 1, 2, and 7 dockets?

COMMISSIONER JACOBS: Very well. Show Mr. Burgess has appeared in Dockets 01, 02 and 07.

MR. BURGESS: Thank you very much.

MR. CHILDS: We are ready to proceed.

COMMISSIONER JACOBS: Very well.

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GERARD YUPP

was called as a witness on behalf of Florida Power and Light Company and, having been duly sworn, testified as follows:

DIRECT EXAMINATION

BY MR. CHILDS:

Q Would you state your name and address?

A My name is Gerard Yupp. My business address is 11770 U.S. Highway 1, North Palm Beach, Florida 33408.

Q By whom are you employed and in what capacity?

A I am employed by Florida Power and Light, and I am Manager of Regulated Wholesale Power Trading.

MR. CHILDS: Commissioner Jacobs, this witness does not have prefiled testimony on that issue. But I am prepared to ask him to summarize that as a predicate for questions you might have, to summarize what the company does. Is that okay?

COMMISSIONER JACOBS: Very well.

BY MR. CHILDS:

Q Mr. Yupp, I think you are aware that there has been some interest in the efforts of Florida Power and Light and others concerning their efforts on hedging. And I would ask if you could summarize generally what the company is doing and what its objectives are?

A Okay. Commissioners, our objective in my group is to procure fuel at below market costs. In pursuing that objective we take a portfolio approach to fuel procurement. We try to divide up what we feel our needs are under long-term, mid-term, and then short-term, and by short-term I mean monthly and daily purchasing, to balance our portfolio and to, again, procure the cheapest fuel that we can.

Currently we do have a couple of long-term deals on our gas side that go for ten years and five years respectively, that locks in a base load volume for us at market price. Most of what we are doing is on a monthly and daily short-term basis as we head into a month. We are monitoring the fuel market where we think it could go during the month, and we are hedging ourselves by adjusting the quantity of fuel that we need for that month by purchasing it either on a monthly basis, or if we see prices declining during the month, we may hold back and do some daily purchasing in order to take advantage of falling prices.

Again, our whole approach is to procure it at below market cost to minimize the cost to our customers.

That is a basic summary.

COMMISSIONER JACOBS: Very well. If I understand it, you have approximately 30 to 40 percent of your fuel needs that you take care of through long-term contracts?

THE WITNESS: Yes, that is correct.

COMMISSIONER JACOBS: Okay. Now, let's go specifically to the gas contracts that you just mentioned, five or ten years. About what percentage of your gas needs is taken up by those contracts?

THE WITNESS: Again, it is roughly 30 to 40 percent. That will vary, of course, as seasons change. If fuel prices were right, that gas was our fuel of choice, then it may be lower. But on average we are about 30 to 40 percent under long-term contracts to meet our needs.

COMMISSIONER JACOBS: Okay. And then so the remaining 65 percent would be that portion that you would go and look at the month ahead market and determine whether or not you were going to do those purchases?

THE WITNESS: That is correct.

COMMISSIONER JACOBS: Okay. Now, I noticed in your analysis of your tables, you have a dispatched cost versus a -- I'm sorry, I had it in front of me a moment ago -- the purchased cost, is that correct?

THE WITNESS: I'm not sure which table you --

COMMISSIONER JACOBS: Let me get the proper terminology here. It doesn't say if it is a purchased cost. And I'm looking at the tables that are attached to Ms. Dubin's testimony but were sponsored by you. And I guess you have them in your testimony, as well, but that is the first place I saw them. And these are fuel cost-recovery forecast assumptions, are you familiar with those tables?

THE WITNESS: Right.

COMMISSIONER JACOBS: Okay. And there is a base case, there is a low case and a high case. What I am specifically just focusing on right now is the base case. And in that regard, there is the table which shows a -- and, again, let's focus on gas for the moment -- that has basically a price for gas and then it has a weighted average dispatch price for gas. Are you with me?

THE WITNESS: Yes.

COMMISSIONER JACOBS: Oh, there is a page number. This is page --

THE WITNESS: I believe it is Page 6 of Appendix 1.

COMMISSIONER JACOBS: Yes, I overlooked it. And my question simply goes to the weighted average dispatch price. Help me understanding what that means.

THE WITNESS: Weighted average dispatch price would be the weighted average price that -- including what we have under long-term, what we see the forecast to be in the upcoming year. So it would take our long-term contracts, and, of course, that would be at market price, where we see market, and then what we plan on doing in a daily, or monthly, or even longer term market. So it would include all of that and just weight it per type of procurement.

COMMISSIONER JACOBS: Okay. Now, that weighing process, would that -- would you essentially exhaust your long-term contracts and then mix in the other shorter term contracts, is that how that process would work?

THE WITNESS: Yes.

COMMISSIONER JACOBS: Okay. And let me just step back for a moment, because really I am interested in some general overall advice here more so than just specific testimony. The concern would be, of course, and you are much more familiar than I, the trends in the -- and, again, let's keep our discussion on the natural gas market.

And I don't have the official citations to this, but the reports all indicate that versus one year ago the price of delivered gas to large customers is about 40 to 50 percent ahead of what it was a year or so ago. And that trend is not anticipated to diminish significantly, although it may not continue at the same pace. So the thought occurs to me, I would be interested in how companies are managing those costs.

And let me state I don't know that hedging is the best or worst of methods of managing those costs. But the concern would be, particularly when we look at the fuel clause docket, that companies are managing those costs when they see that market trend in front of them. And so it sounds to me like what will be happening here is that companies would be looking to figure out what the long-term contracts are and taking advantage of those.

Now, can you expand the volume on those long-term contracts at all, or do you have options, in essence, under those long-term contracts, or essentially it is only for the capacity that you committed to at the beginning?

THE WITNESS: Right. We are locked into a specific volume which does increase on a monthly basis given our needs. And that is seasonal, of course. But, no, whatever is laid out in the contract, those are the volumes that we take.

COMMISSIONER JACOBS: And I understand that there is some indexing that occurs there.

THE WITNESS: Yes.

COMMISSIONER JACOBS: How does that work?

THE WITNESS: The way the fuel is priced, it is based on a first-of-month index, an inside FERC publication. So the base load volume that is in those contracts has various delivery points. And we take the -- it is priced off the first of the month index for inside FERC for those delivery points. And it becomes a weighted -- essentially would be a weighted average then of three different zones that we do take fuel delivery at.

COMMISSIONER JACOBS: So these long-term contracts are going to have some, essentially some kind of factors that may push that contract price up according to what the present day spot markets are showing?

THE WITNESS: That is correct. So it will be priced at what the market is. And, again, our objective now is to procure fuel below market. We feel that it is essential to have a certain base load volume, and in this case gas, locked in under long-term that guarantees us supply and guarantees us a price at the current market.

Where we can make up the difference is in our, let's say, short-term strategies of buying monthly and buying daily where we can capture the down side of a market or where we can stay out of a market that is rising and switch over, in this case let's say to fuel oil. So we are constantly evaluating that.

And, again, I think that a lot of what we do is in the shorter term basis, but it gives us greater flexibility to capitalize on where the market is moving. We are a little bit more sure or lot more sure in some cases on a shorter term basis of where the market can move. And so we can have a little bit better plan than once -- and, again, that's why I think we focus a lot on short-term planning. Going out into the future, of course, becomes more uncertain the longer you look out and a little bit more risky. So we tend to try to take advantage of the market in the short-term.

COMMISSIONER JACOBS: Now, it sounds that under the long-term contracts you can opt -- your option is to choose not to purchase gas under that, and you can go to another fuel source or some other -- if the market is dropping you could go to a shorter term purchasing option.

THE WITNESS: Under our -- excuse me, I didn't mean to interrupt.

COMMISSIONER JACOBS: But within that long-term contract, do you have any option of capping that escalation that would occur through the indexing?

THE WITNESS: No, we do not. And in our

long-term contracts, they are must-take volumes. So we must take that volume of gas. Again, that is not -- it may only be 30 percent of what we believe that we are going to need on a per month basis. But we do have the flexibility, we do not have to take that gas into our system then. If markets develop where we can sell off some of that gas, we could do that and burn oil instead. But this isn't a great enough quantity to where we are, you know, going to need this gas for our base load unit. So in that scenario we must take this gas.

COMMISSIONER JACOBS: Uh-huh. So in the event we are -- when we see the markets moving -- well, let's not speculate. In the event that -- let's say a year ago if I could have projected that we would be in the position that we are today, you know, probably 30, 40, 50 percent above what the market was last year, for your base load gas needs, it doesn't sound like there was a way to basically manage around that.

THE WITNESS: No, there isn't on that. Our base load needs would have -- we would have received that fuel at market prices. You know, in light of what has happened we -- in light of what has happened where we could take advantage of -- if that had been seen that fuel prices were going to move so greatly, you know, that would be more in the mid-term and monthly and daily type buying.

But, again, as fuel prices did move up, we are not -- we are generally fairly conservative in our approach, again, with monthly and daily to look out a year and go lock up a piece of fuel for our needs. That price puts our customers at risk if prices move the other way on us.

So that is why we tend to be a little bit conservative. Our goal is to procure below market and the risk in some longer term -- and maybe mid-term type procurement is great, and we don't feel that is the best thing for our customers.

COMMISSIONER JACOBS: Okay. Commissioners, do you have any questions? Thank you. I think that is about what I have for Mr. Yupp. Thank you very much. Florida Power, do you have --

MR. McGEE: Florida Power would call Mr. Wieland.

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KARL H. WIELAND

was called as a witness on behalf of Florida Power Corporation and, having been duly sworn, testified as follows:

DIRECT EXAMINATION

BY MR. McGEE:

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

A My name is Karl H. Wieland. My business address is Post Office Box 14042, St. Petersburg, Florida 33733.

Q And would you state your capacity with Florida Power Corporation, please?

A I am the Manager of Financial Analysis at Florida Power.

Q Mr. Wieland, do you have a document before you entitled direct testimony of Karl H. Wieland, levelized fuel and capacity cost-recovery factors for January through December, 2000?

A Yes, I do.

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

A Yes, it was.

Q If were asked the questions that are contained in that testimony would your answers be the same today?

A Yes, they would.

MR. McGEE: Mr. Chairman, we would ask that Mr. Wieland's prepared testimony be inserted into the record as though read.

COMMISSIONER JACOBS: Right. We will go ahead and admit his. We will eventually do the others, but upon your request, we will admit Mr. Wieland's testimony into the record as though read.

MR. McGEE: Right. And Mr. Wieland has two exhibits, KHW-1 and 2 attached to his prepared testimony. Could we have that marked for identification.

COMMISSIONER JACOBS: All right. We will mark those as Exhibit 3.

MR. McGEE: It would be Exhibit 3, I believe.

COMMISSIONER JACOBS: Yes.

(Whereupon, Exhibit No. 3 marked for identification.)

FLORIDA POWER CORPORATION

DOCKET NO. 000001-EI

Estimated/Actual Fuel and Capacity Cost Recovery True-Up Amounts for January through December 2000

DIRECT TESTIMONY OF KARL H. WIELAND

Q. Please state your name and business address.

A. My name is Karl H. Wieland. 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 Manager of Financial Analysis.

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

A. Yes.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present for Commission approval the Company's estimated/actual fuel and capacity cost recovery true-up amounts for the period of January through December 2000.

Q. Do you have an exhibit to your testimony?

A. Yes. I have prepared an exhibit attached to my prepared testimony consisting of Parts A through D and Commission Schedules E1 through E9, which contains the calculation of the Company's true-up balances and the supporting data. Parts A through C contain the assumptions which support the Company's reprojection of fuel costs for the months of August through December 2000. Part D contains the Company's reprojected capacity cost recovery true-up balance and supporting data.

FUEL COST RECOVERY

Q. How was the estimated true-up under-recovery of $55,217,807 shown on Schedule E1-B, Sheet 1, line 20, developed?

A. The estimated true-up calculation begins with the actual balance of $(46,926,023), taken from Schedule A2, page 3 of 4, for the month of July. This balance was projected to the end of December, 2000, including interest estimated at the July ending rate of 0.545% per month. The development of the actual/estimated true-up amount for the period ending December 2000 is shown on Schedule E1-B.

Q. What are the primary reasons for the projected December-ending 2000 under-recovery of $55.2 million?

A. At the time Florida Power prepared the projections used in its May 1, 2000 mid-course correction filing, oil and natural gas prices, which had risen sharply compared to the original projection, had begun to decline steadily from their peak in early March. Prices were expected to follow their normal pattern of declining further during the summer months, then rising again by winter. Shortly after the mid-course correction was approved by the Commission on May 15, 2000, however, these prices began to rise again. Oil and gas prices have since increased sharply and are projected to remain higher than the projection used for the mid-course correction. These price increases have resulted in higher fuel costs than forecasted in the mid-course correction filing, which is the primary reason for the projected year-end under-recovery.

Q. How does the current fuel price projection compare with the projection used for the mid-course correction?

A. Forecasted prices for residual fuel oil increased an average of $5.00 per barrel, or 25%, from $20 to $25 per barrel. Distillate oil increased $4 per barrel, or 13%, from approximately $31 to $35 per barrel. The natural gas forecast rose more than $1 per MMBTU or 40%, from $3 to over $4 per MMBTU. These price changes alone increased system fuel cost by more than $60 million. Rising natural gas and oil prices also led to higher projected purchased power costs, but were offset by increases in the fuel cost of wholesale sales that are credited to the fuel clause.

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

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

CAPACITY COST RECOVERY

Q. How was the estimated true-up under-recovery of $143,205 shown on Part D, Line 29, developed?

A. The estimated true-up calculation begins with the actual balance of $5,635,281, for the month of July. This balance was projected to the end of December, 2000, including interest estimated at the July ending rate of 0.545% per month.

Q. What are the major changes between the original projection for the year 2000 and the actual/estimated reprojection?

A. Capacity payments in the reprojection increased because expected cost savings from an agreement with El Paso Power Services Company to restructure three QF contracts did not materialize due to the inability of El Paso to satisfy a condition precedent to closing the transaction. The loss of these originally projected savings was largely offset by higher revenues from sales, resulting in a period-ending actual/estimated true-up under-recovery of only $143,205.

Q. Does this conclude your testimony?

A. Yes.

FLORIDA POWER CORPORATION

DOCKET No. 000001-EI

Levelized Fuel and Capacity Cost Recovery Factors
January through December 2001

DIRECT TESTIMONY OF
KARL H. WIELAND

Q. Please state your name and business address.

A. My name is Karl H. Wieland. 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 Manager of Financial Analysis.

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

A. Yes.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present for Commission approval the Company's levelized fuel and capacity cost factors for the period of January through December 2001.

Q. Do you have an exhibit to your testimony?

A. Yes. I have prepared an exhibit attached to my prepared testimony consisting of Parts A through D and the Commission's minimum filing requirements for these proceedings, Schedules E1 through E10 and H1, which contain the Company's levelized fuel cost factors and the supporting data. Parts A through C contain the assumptions which support the Company's cost projections, Part D contains the Company's capacity cost recovery factors and supporting data.

FUEL COST RECOVERY

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

A. Schedule E1, page 1 of the "E" Schedules in my exhibit, shows the calculation of the Company's basic fuel cost factor of 2.521 ¢/kWh (before line loss adjustment). The basic factor consists of a fuel cost for the projection period of 2.43648 ¢/kWh (adjusted for jurisdictional losses), a GPIF reward of 0.00712 ¢/kWh, and an estimated prior period true-up of 0.07564 ¢/kWh.

Utilizing this basic factor, Schedule E1-D shows the calculation and supporting data for the Company's levelized fuel cost factors for secondary, primary, and transmission metering tariffs. To accomplish this calculation, effective jurisdictional sales at the secondary level are calculated by applying 1% and 2% metering reduction factors to primary and transmission sales (forecasted at meter level). This is consistent with the methodology being used in the development of the capacity cost recovery factors.

Schedule E1-E develops the TOU factors 1.369 On-peak and 0.834 Off-peak. The levelized fuel cost factors (by metering voltage) are then multiplied by the TOU factors, which results in the final fuel factors to be applied to customer bills during the projection period. The final fuel cost factor for residential service is 2.525 ¢/kWh.

Q. What is the change in the fuel factor from the current June - December mid-course correction period to the 2001 projection period?

A. The average fuel factor increases from 2.307¢/kWh to 2.521 ¢/kWh, an increase of 9.3%.

Q. Please explain the reasons for the increase.

A. The increase is due to the large increases in oil and natural gas prices during 1999 to 2000. After dipping below $10 per barrel in the spring of 1999, average residual oil prices exceeded $20 per barrel at year-end, and kept rising during 2000 to their present level of $25 per barrel. Natural gas prices followed a similar pattern, rising from less than $2/MCF to well over $4/MCF during a one-year period. Prices for distillate oil and purchased power increased as well. Rising consumption and the scheduled nuclear refueling outage in 2001 further increase consumption of the high-cost fuels and exacerbates the problem.

Q. What steps has Florida Power taken to limit the increase in the fuel factor?

A. Florida Power is proposing to recover the 2000 under-recovery of $55.2 million over a two-year period in order to limit the increase in the fuel factor in January. Florida Power's proposed factor of 2.521 cents per kWh is based on recovering $27.6 million during the January-December 2001 period, and the balance in 2002. Recovery of the full $55.2 million during 2001, as is the normal practice, would increase the fuel factor to 2.597 cents per kWh, an increase over the current factor of 12.6%. Although this action adds cost to the following year, Florida Power forecasts its total fuel cost to decline in 2002, allowing a reduction in recoverable costs even when the deferred true-up amount is included. This forecast assumes that future oil and gas prices will be at or below 2001 levels.

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

A. Line 4 shows the recovery of the costs associated with conversion of combustion turbine units to burn natural gas instead of distillate oil, the annual payment to the Department of Energy for the decommissioning and decontamination of their enrichment facilities, and the expected cost of purchasing emission allowances for the year. Recovery of the conversion for the peaking units has already been approved by this Commission. The costs to be recovered in 2001 declined from the previous year because two units at the Intercession site (7 and 9) have been completely amortized, and two additional units (8 and 10) will be fully amortized by August, 2001. The cost of conversions for the remaining units included in line 4 is $2,634,000, the payment to the DOE is $1,600,000, and the emission allowance purchases are estimated to be 20,000 tons at a price of $200 per ton, or $4,000,000. The three items together total $8,234,000.

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

A. Line 6 includes energy costs for the purchase of 60 MWs from Tampa Electric Company and the purchase of 405 MWs under a Unit Power Sales (UPS) agreement with the Southern Company. The capacity payments associated with the UPS contract are based on the original contract of 400 MWs. The additional 5 MWs are the result of revised SERC ratings for the five units involved in the unit power purchase, providing a benefit to Florida Power in the form of reduced costs per kW. Both of these contracts have been in place and have been approved for cost recovery by the Commission. The capacity costs associated with these purchases are included in the capacity cost recovery factor.

Q. What is included in Schedule E1, line 8, "Energy Cost of Economy Purchases (Non-Broker)"?

A. Line 8 consists primarily of economy purchases from within or outside the state which are not made through the Florida Energy Broker Network (EBN). Line 8 also includes energy costs for purchases from

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

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

A. Florida Power estimates the total gain on non-separated sales during 2001 to be $12,319,498, which exceeds the three-year rolling average for such sales of $11,061,127 by $1,258,371. The sharing mechanism recently approved by the Commission in Docket No. 991779-EI allocates 80% of this difference ($1,006,697) to customers, for a total customer benefit of $12,067,824, and 20% of the difference ($251,674) to shareholders, which amounts to 2% of the total gain.

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

A. The three-year rolling average of $11,061,127 is based on calendar years 1998-2000, and was calculated in a manner agreed to by the parties at an implementation meeting conducted by Staff on September 13, 2000. Actual gains for 1998 and 1999 were based on information supplied to the Commission in Docket No. 991779-EI. Non-broker economy sales for 1998-99 were taken from the late-filed exhibit entitled "Shareholder Incentive on Non-Broker Sales" to my deposition, while Broker sales for the same period were taken from Florida Power's response to Staff Interrogatory No. 7. The estimated gain for 2000 was supplied to the Commission in Florida Power's Estimated/Actual True-up filing, submitted August 21, 2000, on Schedule E1-B, Sheet 2, Lines 14a and 15a.

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

A. Florida Power has several wholesale contracts with Seminole, some of which represent Seminole's own firm resources, and others that provide for the sale of supplemental energy to supply the portion of their load in excess of Seminole's own resources, 1327 MW in 2001. The fuel costs charged to Seminole for supplemental sales are calculated on a "stratified" basis, in a manner which recovers the higher cost of intermediate/peaking generation used to provide the energy. New contracts for fixed amounts of intermediate and peaking capacity began in January of 1999. While those sales are not necessarily priced at average cost, Florida Power is crediting average fuel cost for the appropriate stratification (intermediate or peaking) in accordance with Order No. PSC-97-0262-FOF-EI. The fuel costs of wholesale sales are normally included in the total cost of fuel and net power transactions used to calculate the average system cost per kWh for fuel adjustment purposes. However, since the fuel costs of the stratified sales are not recovered on an average system cost basis, an adjustment has been made to remove these costs and the related kWh sales from the fuel adjustment calculation in the same manner that interchange sales are removed from the calculation. This adjustment is necessary to avoid an over-recovery by the Company which would result from the treatment of these fuel costs on an average system cost basis in this proceeding, while actually recovering the costs from these customers on a higher, stratified cost basis.

Line 17 also includes the fuel cost of sales made to the City of Tallahassee in accordance with Order No. PSC-99-1741-PAA-EI. The stratified sales shown on Schedule E6 include 100,140 MWh, of which 93% is priced at average nuclear fuel cost, the balance at an estimated incremental cost of $25 per MWH. A third type of stratified sale is the sale of 50 MW of capacity beginning April 1, 2001. Florida Power is making this sale in order to comply with the FERC market power requirements.

Q. Why is the sale of 50 MW treated as a stratified sale rather than as an average sale as required by Order No. PSC-97-0262-FOF-EI for separated sales?

A. Florida Power has made a commitment to hold existing customers harmless from the effect of the merger. This sale is a requirement of the merger. Assigning average system fuel cost to this sale would increase the fuel factor because the incremental cost of the sale is expected to be higher than the average cost. Florida Power's estimate for the incremental cost of this sale is 3.525 cents/kWh (Schedule E-6), as opposed to the average cost of 2.413 cents/kWh (Schedule E-1, Line 25). By crediting the higher incremental cost to the fuel clause, customers are unaffected by this sale.

Q. Has Florida Power confirmed the validity of using the "short-cut" method of determining the equity component of EFC's capital structure for calendar year 1999?

A. Yes. Florida Power's Audit Services department has reviewed the analysis performed by Electric Fuels Corporation (EFC). The revenue requirements under a full utility-type regulatory treatment methodology using the actual average cost of debt and equity required to support Florida Power business was compared to revenues billed using equity based on 55% of net long-term assets (short cut method). The analysis showed that for 1999, the short cut method resulted in revenue requirements which were $92,160 or .035% lower than revenue requirements under the full utility-type regulatory treatment methodology. Florida Power continues to believe that this analysis confirms the appropriateness of the short cut method.

Q. Has Florida Power properly calculated the 1999 price for waterborne transportation services provided by Electric Fuels Corporation?

A. Yes. The 1999 waterborne transportation calculation has been reviewed by Staff and Public Counsel and deemed properly calculated.

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

A. The cost per million BTU of the nuclear fuel which will be in the reactor during the projection period (primarily Cycle 12) was developed from the unamortized investment cost of the fuel in the reactor. Cycle 12 consists of several "batches," of fuel assemblies which are separately accounted for throughout their life in several fuel cycles. The cost for each batch is determined from the actual cost incurred by the Company, which is audited and reviewed by the Commission's field auditors. The expected available energy from each batch over its life is developed from an evaluation of various fuel management schemes and estimated fuel cycle lengths. From this information, a cost per unit of energy (cents per million BTU) is calculated for each batch. However, since the rate of energy consumption is not uniform among the individual fuel assemblies and batches within the reactor core, an estimate of consumption within each batch must be made to properly weigh the batch unit costs in calculating a composite unit cost for the overall fuel cycle. The cost per million BTU for cycle 12 was also used for Cycle 13 which will be in effect following the fall 2001 refueling outage.

Q. How was the rate of energy consumption for each batch within Cycle 12 estimated for the upcoming projection period?

A. The consumption rate of each batch has been estimated by utilizing a core physics computer program which simulates reactor operations over the projection period. When this consumption pattern is applied to the individual batch costs, the resultant composite Cycle 12 is $0.33 per million BTU.

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

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

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

A. The system sales forecast is made by the forecasting section of the Integrated Resource Planning Department using the most recent data available. The forecast used for this projection period was prepared in June 2000.

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

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

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

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

CAPACITY COST RECOVERY

Q. How was the Capacity Cost Recovery factor developed?

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

Sheet 1: Projected Capacity Payments. This schedule contains system capacity payments for UPS, TECO and QF purchases. The retail portion of the capacity payments are calculated using separation factors from the Company's most recent Jurisdictional Separation Study.

Sheet 2: Estimated/Actual True-Up. This schedule presents the actual ending true-up balance as of July, 2000 and re-forecasts the over/(under) recovery balances for the next five months to obtain an ending balance for the current period. This estimated/actual balance of $(143,205) is then carried forward to Sheet 1, to be collected during the January through December, 2001 period.

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

Sheet 4: Calculation of 12 CP and Annual Average Demand. The calculation of average 12 CP and annual average demand is based on 1999 load research data and the delivery efficiencies on Sheet 3.

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

Q. Please discuss the increase in the CCR factor compared to the prior period.

A. The average retail CCR factor of 0.89218 is 9.3% higher than the previous year's factor of 0.81641. The increase is primarily due to the fact that capacity costs for 2000 included an over-recovery credit of $33.3 million, whereas the 2001 costs include a $0.1 million under-recovery. Absent true-ups, the capacity cost increase from 2000 to 2001 is less than 0.1%. Increases in capacity payments are almost completely offset by growth in kWh sales.

Q. Does this conclude your testimony?

A. Yes.

MR. McGEE: And with that we will tender Mr. Wieland for questioning by the Commission, by Commissioner Jacobs in particular.

COMMISSIONER JACOBS: Okay. Good morning, Mr. Wieland.

THE WITNESS: Good morning, Commissioner.

COMMISSIONER JACOBS: I don't wish to be repetitive, so what I would simply ask if you could just explain how -- if any ways your process would differ from -- you heard the testimony of Mr. Yupp?

THE WITNESS: Yes, sir.

COMMISSIONER JACOBS: How your process would be in any way differentiated from the process that they adhere to in the overall procurement and the ability to deal with market fluctuations.

THE WITNESS: I would be glad to, Commissioner. I assume that your interest is primarily in natural gas as opposed to some other fuels?

COMMISSIONER JACOBS: Well, I kept it simple, but, yes, one of my primary interests is gas, but the overall idea, I think, would apply to the other fuels, because I think we have seen a significant escalation in oil, as well. And in coal perhaps it is not as, but my concern has to do with -- in terms of looking at the costs, fuel costs expenditures in this docket, and I will just give you a bit of how I came to this.

The idea that markets fluctuate is, of course, not anything new, we expect that. My concern has been that as we see these fluctuating marketplaces, I know that these companies are very -- your company and others are very astute and they are taking advantage of means. And my goal is to understand how that translates into the costs that we actually see coming into the clause to see and insure that the companies are, what I think are legitimate efforts to manage their costs and how those translate to what we see in the clause.

And more so to understand more carefully, but also to see if there are things that we can do to help the companies manage these costs more effectively. Because, you know, no one can predict, I agree with that. I wouldn't expect the companies to be able to predict these fluctuations that we have seen heretofore. But just to see how you would approach it from a strategic standpoint is my goal.

THE WITNESS: I understand. Well, let me just talk about coal very briefly. Coal obviously has been very stable in recent years. But typically the way we procure coal, and, of course, in our case it is being done through Electric Fuels Corporation, but the way they procure coal is they typically have a mix of contract and spot coal. Spot coal being both the quantities and the prices at the market on a monthly basis. And it varies, but it is typically -- it is certainly less than half of the volumes are done on a spot basis.

The long-term contracts, which is typically half to perhaps 80 percent of the total, typically has specified volumes, some with minimum takes, some not. And they have prices that tend to be fixed, but very short periods of time. Most if not all of them have what are called market reopeners to where, let's say, you have a long-term contract that every one or two or three years the price is subject to change based on the market. And so in a sense long-term you are still paying market prices, even though you may in the short-term get away from them.

When it comes to oil, we have contracts with suppliers, but like FPL, the prices for oil are basically at the market. They change literally on a weekly basis driven by index indices. We do not have any long-term oil contracts that I am aware of where the prices are fixed for any length of time.

Now, turning to gas, gas is a little bit of a mix. And I guess to look at prices, I mean, first of all, I think you need to put aside the transportation of gas, which is fairly substantial, but those tend to be under long-term contracts, the escalation of the transportation through pipelines. The commodity itself, for the most part our procurement practices are very much like FPL's. We buy subject to certain indices where they are delivered at the market. And those prices, I think, change at least weekly, if not daily.

We do have long-term contracts in the sense that we have contracts with suppliers to supply certain quantities. In some instances the quantities are minimum takes, you know, we have to take at least so much per month. In other cases we have a quantity but we can take less than that without a penalty. So, typically, in any given month anywhere from less than 50 to 100 percent of our volumes are on a long-term contract basis.

The prices, as I said, for the most part change, as Mr. Yupp talked about, with the market. Now, there are two exceptions that I might mention. One is we do have a long-term gas contract that is not at market but where the prices are actually fixed and agreed to over a long time period.

That particular contract is with the Tiger Bay facility where we purchased a QF facility, if you will recall some years ago. And with the purchase of that facility we essentially inherited that as part of the deal. That particular contract, and perhaps that goes to show you how uncertain the future is. When we first got it that was substantially more expensive than any of the other gas we bought. It was substantially above market. We had talked about spending some serious money to buy our way out of it. Today it is the cheapest gas we have got. Tomorrow, who knows.

But that tells you that long term, unless you have very, very clear vision of where prices are headed in the future, signing in or locking in prices long term may not be a good idea. And we typically have stayed away from that.

COMMISSIONER JABER: Can I ask you a question to follow up with respect to the transportation expense. You said that the gas transportation is a significant amount of the cost. Are those contracts negotiated separately and are they long-term?

THE WITNESS: Yes, they are; and, yes, they are long-term. There are -- you can buy transportation on an interruptible basis, but you really need to lock in at least a certain minimum on a contractual basis. Otherwise, when the transportation is tight and everybody is using gas, you are not going to get any delivered even if you have some that you could put in the end of the pipe.

COMMISSIONER JABER: Is the price also -- do you get a better price for the more you transport, the more that is transported to you?

THE WITNESS: I would say typically not. The pipelines have tariffs that are approved by, I think, somebody I think in Washington. I'm not sure who. Now that is not to say that if you are a very large purchaser you may not have a little bit more leverage to negotiate something better than a very small one might. But generally, I think, the pipelines are required to have at least reasonably fair tariffs for all of their users.

And in terms of percentage -- and, of course, with the commodity prices going up, pipeline transportation charges are not as big a percentage as they were, but they are typically less than one dollar per million BTU, just to kind of give you a rough number, usually 70 or 80 cents. Whereas the gas was at one time as low as a dollar per million BTU, now it is five. So today gas transportation is probably less than 20 percent of the total cost.

Perhaps just to wrap up on other things that we do to hedge, now while we buy most of our gas on a market basis, for this upcoming winter we did go to some of the suppliers and purchase gas at a locked-in price for the winter. Not all of it, but we got with several of our suppliers, and at the time felt, our fuel procurement people felt that the price they could get on a fixed basis for the period was attractive.

Recognizing that the prices could go down as well as they could go up, so we did lock in prices that were in the $3.80 to $3.85 area for this winter period starting in November and going through February. Obviously those months aren't here yet, but at least if you were to look at prices today they are significantly above that number. So, in essence, I guess you could say we took a bit of a chance, locked in some prices at what turned out to be attractive rates. And we think they are going to stay attractive through the winter.

We have done a little bit of that, and I guess I would characterize that as being a hedge. But, again, I would caution you to understand that long-term it could -- we could as well have locked in on $4 prices and watched them zoom down to 3. So, I mean, in a sense unless a company thinks they are smart enough to outguess the market every time, that kind of hedge is not something that is necessarily going to reduce your cost, it just makes your cost a little bit more predictable. So we have done a little bit of that and it just turns out it has worked well for us. At least so far it is working well for us.

COMMISSIONER JACOBS: Do you have a sense of how companies in similar circumstances as yourself approach this issue? Did they look at the more short-term kind of normalization approach more so than long-term kind of contract?

THE WITNESS: Yes. As I said, when I was listening to what Mr. Yupp was saying, I think our approach in general is very much like theirs. A preference not to lock in prices for a very long period of time, but to perhaps do something on a short-term.

COMMISSIONER JACOBS: Very well. Commissioners, any other questions? Very well. Thank you, Mr. Wieland.

Why don't we take a break. Let's do this over the break. If the other companies' witnesses wouldn't have anything much more significant to offer, then you can represent that when we come back and we won't take the time to go through a long testimony with other companies. I will be happy to accept the fact that they would essentially agree with the testimony that has been presented already. Let's take a ten minute break and we will come back.

(Recess.)

COMMISSIONER JACOBS: We will go back on the record.

MR. McGEE: Could we have Mr. Wieland's exhibit, I believe that would be Composite Exhibit 3, admitted into evidence?

COMMISSIONER JACOBS: Without objection, show Exhibit 3, composite, admitted.

MR. McGEE: Thank you.

(Composite Exhibit 3 admitted into the record.)

COMMISSIONER JACOBS: Mr. Beasley.

MR. BEASLEY: Commissioners, we have, of course, listened this morning. I don't think we have substantially a lot to add. We have met with your staff on numerous occasions, most recently in early October, discussing with them and explaining all the efforts that the utilities take in order to keep their overall cost of fuel and purchased power as low as possible. We will continue to do that and we will be happy to respond to any future questions you may have. But we don't have anything substantial to add to what was presented to you earlier today.

COMMISSIONER JACOBS: Very well, thank you. Mr. Stone.

MR. STONE: Commissioner, on behalf of Gulf, our comments would be essentially the same as Mr. Beasley's on behalf of TECO. We did meet with staff in October and continue to meet with staff as needed. Just for the record, Gulf's historical fuel purchases are very heavily tilted towards coal. Natural gas made up only 4.3 percent of our fuel procurement in 1999. Oil doesn't even make its way into the percentages it is so small. And we are very heavily fueled by coal. And of our coal, 35 percent of it is on the spot market.

COMMISSIONER JACOBS: Very well. With that, we will move to resolving Docket 01.

MR. KEATING: Commissioners, I would recommend that we go ahead now and move the testimony, the prefiled testimony of all witnesses into the record as though read, and I believe that is listed on Pages 5 and 6 of the prehearing order.

COMMISSIONER JACOBS: Very well. Without objection, show the direct testimony of Witness Scardino. We have already had Mr. Wieland. Mr. Scardino, Ms. McClintock, Mr. Yupp, Wade, Dubin, Silva, Bachman, Oaks, Davis, Douglas, Howell, Jordan, Buckley, Brown, and Burkhardt entered into the record as though read.

MR. KEATING: I would also recommend that the exhibits listed on Pages 29 through 32 of the prehearing order be marked for identification. And I am leaving out what is identified on Page 32 as the Staff-1 exhibit, that related to Issue 9, which the parties have agreed to address at a later time. The exhibit identified as Staff-2, has been -- what is included in the exhibit is slightly different from what is described there, so we have prepared a separate composite exhibit that has been handed out.

COMMISSIONER JACOBS: Okay.

MR. KEATING: We will identify that once we have identified the exhibits listed.

COMMISSIONER JACOBS: Very well. Let's mark exhibits of Witness Scardino, JES-1 and 2, as Exhibit 4. Mark exhibits of Witness McClintock, RJM-1 and 2, as Exhibit 5, composite. We will mark exhibit of Witness Yupp, GY-1, as Exhibit 6. Mark the exhibits of Witness Dubin, KMD-1, 2, 3, 4, 5, and 6 as Exhibit 7, composite. Mark the exhibits of Witness Silva, RS-1 and 2, as Exhibit 8. Mark the exhibits of Witness Bachman, GMB-1 and 2, as Exhibit 9, composite. Mark the exhibits of Witness Oaks, MFO-1 and 2, as Exhibit 10, composite. Mark the exhibits of Witness Davis, TAD-1, 2, and 3 as Exhibit 11, composite. Exhibits of Witness Douglas, JRD-1 and 2, are Exhibit 12. Exhibit for Witness Howell, MHW-1, Exhibit 13. Exhibits of Witness Jordan, JDJ-2. Now, there is two JDJ-3s, is that one?

MR. KEATING: Yes. That may be an error in the numbering. The first exhibit sponsored by Ms. Jordan should probably be JDJ-1, and the second JDJ-2.

COMMISSIONER JACOBS: Okay. Show that as amended. So then we will have JDJ-1, 2, 3, and 4 marked as Exhibit 14. Show exhibits of Witness Buckley, BSB-1 and 2, as Exhibit 15. And the exhibit of Witness Burkhardt, RB-1, as Exhibit 16.

And, staff, you have one additional exhibit?

MR. KEATING: Correct. Staff has prepared a composite exhibit. I believe everybody should have a copy of it now. It consisted of --

COMMISSIONER JACOBS: And this is the package that you distributed, is that correct?

MR. KEATING: That's correct. It consists of Florida Power Corporation's response to Document Request Number 3 from staff, Florida Power and Light's response to Document Request Number 2 from staff, Gulf's response to Document Request Number 2 from staff, Tampa Electric's response to Document Request Number 3 from staff, and the deposition transcript of Witness Yupp. I believe we also handed out a one-page addition that needs to be made to that exhibit, and that is the late-filed deposition exhibit that goes with the deposition of Mr. Yupp.

COMMISSIONER JACOBS: Very well.

MR. KEATING: And if we could have that included with the composite exhibit, I believe that would be Number 17.

COMMISSIONER JACOBS: So that will be amended into the Composite Exhibit 17. We will call that -- that is Staff's Composite Exhibit. Very well. That takes care of all the exhibits?

MR. KEATING: Yes.

(Whereupon, Exhibit Nos. 4 through 17 marked for identification and received into evidence.).

Florida Power Corporation
Docket No. 000001-EI

Fuel and Capacity Cost Recovery Final True-up Amounts for January through December 1999

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

A. Yes.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to describe the Company's Fuel Cost Recovery and Capacity Cost Recovery final true-up amounts for the period of January through December 1999.

Q. Have you prepared exhibits to your testimony?

A. Yes, I have prepared a three-page fuel adjustment true-up variance analysis for the January through December 1999 period which examines the difference between the estimated true-up and the actual period-end true-up. This variance analysis is attached to my prepared testimony and designated Exhibit No. ___ (JS-1). Also attached to my prepared testimony and designated Exhibit No. ___ (JS-2) are the Capacity Cost Recovery Clause true-up calculations for the January through December 1999 period. My third exhibit will present the revenues and expenses associated with the purchase of the Tiger Bay facility approved in Docket No. 970096-EQ and the corresponding amortization. This presentation is also attached to my prepared testimony and designated Exhibit No. ___ (JS-3). Also, I will sponsor the applicable Schedules A1 through A9 (period to date) for December 1999, 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. _____ (JS-4).

Q. What is the source of the data that 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 December 31, 1999 for fuel cost recovery?

A. The actual ending balance as of December 31, 1999 for true-up purposes is an under-recovery of $903,442.

Q. How does this amount compare to the estimated 1999 ending balance included in the Company's projections for calendar year 2000?

A. An estimated year-end under-recovery of $7,346,176 was included in the 2000 projections and is being collected from customers through FPC's currently effective fuel cost recovery factor. When this amount is compared to the actual year-end under-recovery balance of $903,442, the final net true-up attributable to the twelve-month period ended December 31, 1999 is an over-recovery of $6,442,734

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 under-recovery of$0.9 million as shown on your Exhibit No. ____ (JS-1)?

A. The factors contributing to the over-recovery are summarized on Sheet 1 of 3. The actual jurisdictional kWh sales were higher than the original estimate by 454,635,229 kWh. This increase in kWh sales, attributable to increased customer growth and economic growth, resulted in higher jurisdictional fuel revenues of $17.7 million. When revenues are adjusted for the estimated prior period true-up provision, the resulting current period net revenues are $15.4 million. The $17.2 million unfavorable variance in jurisdictional fuel and purchased power expense was primarily attributable to the increased use of higher cost peaking units to help meet demand.

When the differences in jurisdictional revenues and jurisdictional fuel expenses are combined, the net result is an under-recovery of $1.8 million related to the January through December 1999 period. Other factors not directly related to the period include a$0.9 million recovery of interest. This results in the actual ending under-recovery balance of $0.9 million, as of December 31, 1999.

Q. Please explain the components shown on Exhibit No. ____ (JS-1), Sheet 2 of 3, which produced the $22.7 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 <u>amount</u> (MWH's) of energy required; (2) changes in the <u>heat rate</u>, or efficiency, of generated energy (BTU's per KWH); and (3) changes in the <u>unit price</u> 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 decrease of $9.0 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) reflected an unfavorable variance of $31.6 million. This variance was primarily the result of greater peaking unit operation than estimated.

A cost increase of $0.1 million resulted from the price variance (column D), which was caused by a number of sources detailed on lines 1 through 19 of Sheet 2 of 3, of Exhibit (JS-1).

Q. What were the major contributors to the $9.0 million cost decrease associated with the variance in MWH requirements?

A. The primary reason for the favorable variance in MWH requirements was that power sales were greater than estimated. Also, purchases from qualifying facilities decreased, which allowed the shortfall to be replaced by more economical FPC generation. The favorable variance from these two sources was offset by the higher costs associated with changes in the estimated generation mix.

Q. Does the period-ending true-up balance include any noteworthy adjustments to fuel expense?

A. Yes. Schedule A2, page 1 of 4, contained in my Exhibit No. _____ (JS-4), shows other jurisdictional adjustments to fuel expense in the footnote to line 6b. Noteworthy adjustments include the previously approved recovery of the costs associated with the following natural gas conversion projects: Intercession City P7 - P10, Debary P7 - P9, Bartow P2 and P4, and Suwannee P1 an P3.

Q. Did ratepayers benefit from the investment in these natural gas conversion projects?

A. Yes, for the true-up period the estimated system fuel savings related to the gas conversion projects was $13,504,015. The total system depreciation and return was $3,648,365, resulting in a net system benefit to ratepayers of $9,855,650. My Exhibit No. ___ (JS - 1), sheet 3 of 3, contains a schedule showing the development of these savings for each conversion project.

Q. Are any other noteworthy adjustments to fuel expense shown in the footnote to line 6b?

A. Yes. For the period, the Company has excluded $0.8 million of fuel costs associated with the testing of Hines Unit I that were capitalized to the unit's work order. The fair value of the remaining fuel burned at Hines Unit I is reflected in the A Schedules as part of recoverable fuel expense and offset by a corresponding amount of fuel revenue, in accordance with Commission Order No. PSC-94-1160-FOF-EI.

Q. Has the Company passed any sulfur dioxide emission allowance transactions through the current or prior true-up periods?

A. Yes. In prior true-up periods, the Company has passed through $1,140,595 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 1998. Additionally, the Company has incurred $951,350 of expense for the purchase of 10,900 SO_2 allowances. Under the provisions of the Clean Air Act Amendments of 1990, a percentage of FPC's allowances are withheld each year to populate a pool of allowances which EPA offers for sale at auction. Although anyone can purchase, the real intent of the allowance pool was to ensure that allowances would be available for new units or new entrants to the energy market. Once these allowances are sold, proceeds are returned to the company that provided the allowances.

During the current true-up period, the Company received proceeds of $309,689 from the EPA auction and has applied those proceeds as a credit to fuel expense. The Company also purchased 7,300 allowances during this period at a cost of $1,359,350, which has applied as a debit to fuel expense.

Q. Were there any other unusual adjustments included in the current true-up period?

A. Yes. On July 1, 1997, the Commission approved an agreement between FPC and Tiger Bay Limited Partnership for the purchase of the Tiger Bay cogeneration facility and terminate the five related purchase power agreements (PPAs) as part of a stipulation between FPC and the other parties in Docket No. 980096-EQ. The purchase agreement was consummated on July 15, 1997, at which time the Tiger Bay facility became one of FPC's generating facilities.

Pursuant with the terms of the stipulation, FPC placed approximately $75 million of the purchase price into rate base, with the remaining amount set up as a regulatory asset for the retail jurisdiction, according to FPC's jurisdictional separation at that time. The stipulation allows FPC to continue collecting revenues from its ratepayer's as if the five terminated PPAs were still in effect. These revenues are then to be used to offset all fuel expenses relating to the Tiger Bay facility and interest applicable to the unamortized balance of the retail portion of the Tiger Bay regulatory asset, with any remaining revenues used to amortize the regulatory asset.

Following this methodology, a $37.2 million adjustment was made to remove the cost of fuel consumed by the Tiger Bay facility during the true-up period, since these costs were recovered from the PPA revenues. Exhibit No. ___ (JS-3) shows a year-end retail balance for the Tiger Bay regulatory asset of $287,817,871, computed in accordance with the approved stipulation. This balance reflects an additional reduction of $10.2 million in accelerated amortization.

CAPACITY COST RECOVERY

Q. What is the Company's jurisdictional ending balance as of December 31, 1999 for capacity cost recovery?

A. The actual ending balance as of December 31, 1999 for true-up purposes is an over-recovery of $28,834,883.

Q. How does this amount compare to the estimated 1999 ending balance included in the Company's projections for calendar year 2000?

A. When the estimated year-end over-recovery of $33,314,649 to be collected during 2000 is compared to the $28,834,883 actual over-recovery, the final net true-up attributable to the twelve-month period ended December 1999 is an under-recovery of $4,479,766.

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

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

Q. What factors contributed to the actual period-ending over-recovery of $28.8 million?

A. Exhibit No. _____ (JS-2), sheet 1 of 3, entitled "Capacity Cost Recovery Clause Summary of Actual True-Up Amount," compares actual results to the original forecast for the period. As can be seen from sheet 1, actual jurisdictional revenues were \$6.6 million higher than forecasted revenues due to increased customer usage. Net capacity costs were \$21.7 million lower, due to a reduction in purchases from qualifying facilities. The over-recovery also produced an additional interest credit of \$0.5 million.

Q. Does this conclude your testimony?

A. Yes, it does.

FLORIDA POWER CORPORATION

Docket No. 000001-EI

Re: GPIF Reward/Penalty Amount for January through December 1998

DIRECT TESTIMONY OF REBECCA J. McCLINTOCK

Q. Please state your name and business address.

A. My name is Rebecca J. McClintock. 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 Resource Planning, Financial Services.

Q. What are your responsibilities as Principal Engineer?

A. As a Principal Engineer, I am responsible for compiling and reporting various operational statistics regarding the Company's generating system. In particular, my duties include the preparation of the information and material required by the Commission's GPIF mechanism.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to describe the calculation of the Company's Generation Performance Incentive Factor (GPIF) reward/penalty amount for the period of January through December 1999. This was developed by comparing the actual performance of the Company's seven GPIF generating units to the approved targets set for these units prior to the period.

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

A. Yes, under my direction an exhibit (RJM-1) has been prepared consisting of the numbered sheets which are attached to my prepared testimony. The exhibit contains the schedules required by the GPIF Implementation Manual, which support the development of the incentive amount. I have also included other data forms to supplement the required schedules.

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

A. I have calculated the Company's GPIF incentive amount to be a reward of **$2,183,063**. This amount was developed in a manner consistent with the GPIF Implementation Manual. Sheet 1 of my exhibit shows the calculation of system GPIF points and the corresponding reward. The summary of weighted incentive points earned by each individual unit can be found on Sheet 3.

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

A. The calculation of incentive points is made by comparing the adjusted actual performance data for equivalent availability and heat rate to the target performance indicators for each unit. This comparison is shown on the Generating Performance Incentive Points Table found on Sheets 8 through 14 of my exhibit.

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

A. Adjustments to the actual equivalent availability and heat rate data are necessary to allow their comparison with the "target" Point Tables exactly as approved by the Commission prior to the period. These adjustments are described in the Implementation Manual and are further explained by a Staff memorandum, dated October 23, 1981, directed to the GPIF utilities. The adjustments to actual equivalent availability concern primarily the differences between target and actual planned outage hours, and are shown on Sheet 6 of my exhibit. The heat rate adjustments concern the differences between the target and actual Net Output Factor (NOF), and are shown on Sheet 7. The methodology for both the equivalent availability and heat rate adjustments are explained in the Staff memorandum.

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

A. Yes. Sheet 22 of my exhibit summarizes the planned outages experienced by the Company's GPIF units during the period. Sheet 23 presents an as-worked schedule for each individual planned outage.

Q. Does this conclude your testimony?

A. Yes.

FLORIDA POWER CORPORATION

DOCKET NO. 000001-EI

GPIF Targets and Ranges for January through December 2001

DIRECT TESTIMONY OF REBECCA J. McCLINTOCK

Q. Please state your name and business address.

A. My name is Rebecca J. McClintock. 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 Resource Planning, Financial 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 January through December, 2001. These GPIF targets and ranges have been developed from individual unit equivalent availability and average net operating heat rate targets and improvement/degradation ranges for each of Florida Power's GPIF generating units in accordance with the Commission's Generating Performance Incentive Implementation Manual. The presentation of GPIF targets and ranges on an annual, calendar-year basis is in accordance with Commission Order No. PSC-98-0691-FOF-PU.

Q. Do you have an exhibit to your testimony?

A. Yes, I will sponsor an exhibit containing 89 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, all of which are attached to my prepared testimony.

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

A. I have included the same units as were included for the current period, namely, Crystal River Units 1 through 5, Anclote Units 1 and 2, Bartow Unit 3 and Tiger Bay. Florida Power's new Hines Unit 1 was not included for this projection period because its current performance history is not yet sufficient to provide a representative data base for setting targets and ranges.

Q. Have you determined the equivalent availability targets and improvement/degradation ranges for Florida Power'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 last section of my exhibit entitled "Unplanned Outage Rate Tables and Graphs."

Q. What is the target equivalent availability factor for Crystal River 3?

A. The EAF target for Crystal River 3 is 85.48%. The unit's EUOR and EUOF targets are 3.40% and 3.01%, respectively. Crystal River 3's six-week refueling outage scheduled for the Fall of 2001 results in a POF of 11.51%.

The availability targets for Crystal River 3 were developed after removing from the historical data all forced outage hours associated with the unit's shutdown from September 1996 to February 1998 to address certain design issues related to backup safety systems.

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 Florida Power'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 years, 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 simulations were made using the PROSYM computer model. In these simulations 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 simulation performed by Florida Power's corporate financial model.

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

TESTIMONY OF GERARD YUPP

DOCKET NO. 000001-EI

SEPTEMBER 21, 2000

Q. Please state your name and address.

A. My name is Gerard Yupp. My address is 11770 U. S. Highway One, North Palm Beach, Florida, 33408.

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

A. I am employed by Florida Power & Light Company (FPL) as Manager of Regulated Wholesale Power Trading in the Energy Marketing and Trading Division.

Q. Have you previously testified in this docket?

A. No.

Q. Please summarize your educational background and professional experience.

A. I graduated from Drexel University with a Bachelor of Science Degree in Electrical Engineering in 1989. I joined the Protection and Control

Department of FPL in 1989 as a Field Engineer and worked in the area of relay engineering. While employed by FPL, I earned a Masters of Business Administration degree from Florida Atlantic University in 1994. In May of 1995, I joined Cytec Industries as a plant electrical engineer where I worked until October 1996. At that time, I rejoined FPL as a real-time power trader in the Energy Marketing and Trading Division. I progressed from real-time trading to short-term power trading and assumed my current position in February 1999.

Q. Please describe your duties and responsibilities in that position as they relate to this docket.

A. I am responsible for supervising the daily operations of wholesale power trading as well as developing longer term power and fuel strategies. Daily operations include: fuel allocation and fuel burn management for FPL's oil and/or gas burning plants, coordination of plant outages with wholesale power needs, coordination of UPS/R scheduling with power market conditions, real-time power trading, short term power trading, transmission procurement and scheduling. Longer term initiatives include monthly fuel planning and evaluating opportunities within the wholesale power markets based on forward market conditions, FPL's outage schedule, fuel prices and transmission availability.

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 petroleum coke, 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 the POWRSYM model used to calculate the fuel costs to be included in the proposed fuel cost recovery factors for the period January through December, 2001.

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 Appendix I, pages 1 through 14 of this filing.

Q. In addition to the "Base Case" fuel price forecast, have you prepared alternative fuel price forecasts?

A. Yes. In addition to the "Base Case" fuel price forecast, we have prepared, for fuel oil and natural gas supply, two alternate forecasts, a "Low" and a "High" price forecast.

Q. Why did you prepare these "Low" and "High" forecasts for fuel oil

and gas supply?

A. The conditions that affect the prices of fuel oil and natural gas can change significantly between the time the forecast is developed and the date of the filing in September. While we do revise our short-term fuel price forecast each month, and more often if needed, in order to support fuel purchase decisions, it is not possible to wait until we have our early September fuel price forecast update to rerun our POWRSYM system simulation, in order to reflect the latest changes in fuel market conditions, and still meet our September 21, 2000 filing date. Furthermore, while FPL has, in the past, rerun its projections and re-filed its fuel cost recovery factor after its initial filing to reflect late changes in fuel market conditions, this approach does not provide the same flexibility to react to those changes that use of a banded forecast provides. Trying to incorporate such "last minute" changes puts us at risk of not having adequate time to produce new computer simulations and all of the associated documentation required for filing.

Therefore, in addition to the "Base Case" forecast of future fuel prices, FPL prepared "Low" and "High" fuel price forecasts to define a reasonable range of fuel oil and natural gas prices. We then used these alternate forecasts as inputs to the POWRSYM model to determine what the Fuel Factor would be if it were based on fuel prices at either end of the range. This gives us the flexibility to propose the Fuel Factor that most appropriately reflects our view of future fuel oil and natural gas prices at the time of the projection filing.

Q. **Why did you prepare alternate forecasts for fuel oil and gas supply only?**

A. Because coal and petroleum coke prices have been and are expected to continue to be steady, and gas transportation costs are well defined.

Q. **How is your testimony organized?**

A. My testimony first describes the basis for the "Base Case" fuel price forecast for oil, coal and petroleum coke, and natural gas, as well as, the projection for natural gas availability. Then it describes the "Low" and "High" price forecasts for fuel oil and natural gas supply. Then my testimony addresses plant heat rates, outage factors, planned outages, and changes in generation capacity. Lastly, my testimony addresses projected interchange and purchased power transactions.

BASE CASE FUEL PRICE FORECAST

Q. **What are the key factors that could affect FPL's price for heavy fuel oil during the January through December, 2001 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 the Base Case, world demand for crude oil and petroleum products is projected to be somewhat stronger in 2001 than in 2000 due to improved world economic conditions, especially in Asia, and continued strong petroleum product demand in the United States and Europe. Although crude oil production capacity will be more than adequate to meet the projected strong crude oil and petroleum product demand, general adherence by OPEC members to its most recent production accord, and the continued alliance of Mexico and Norway with OPEC, will prevent significant overproduction and keep the supply of crude oil and petroleum products tight during most of 2001.

Q. **What is the projected relationship between heavy fuel oil and crude oil prices during the January through December, 2001 period?**

A. The price of heavy fuel oil on the U. S. Gulf Coast (1.0% sulfur) is projected to be approximately 84% of the price of West Texas Intermediate (WTI) crude oil during this period.

Q. **Please provide FPL's projection for the dispatch cost of heavy fuel oil for the January through December, 2001 period.**

A. FPL's Base Case projection for the system average dispatch cost of heavy fuel oil, by sulfur grade, by month, is provided in Appendix I on page 3, 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 January through December, 2001.**

A. FPL's Base Case projection for the system average dispatch cost of light oil, by sulfur grade, by month, is shown in Appendix I on page 4, in dollars per barrel.

Q. **What is the basis for FPL's projections of the dispatch cost for St. Johns' River Power Park (SJRPP) and Scherer Plant?**

A. FPL's projected dispatch cost for SJRPP is based on FPL's price projection for spot coal and petroleum coke delivered to SJRPP. The dispatch cost for Scherer is based on FPL's price projection for spot coal delivered to Scherer Plant.

For 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.

In the case of SJRPP, FPL will continue to blend petroleum coke with the coal in order to reduce fuel costs. It is anticipated that petroleum coke will represent 17.5% of the fuel blend at SJRPP during 2001. The lower price of petroleum coke is reflected in the projected dispatch cost for SJRPP, which is based on this projected fuel blend.

Q. **Please provide FPL's projection for the dispatch cost for SJRPP and Scherer Plant for the January through December, 2001 period.**

A. FPL's projected system weighted average dispatch cost of "solid fuel" (coal and petroleum coke) for this period, by month, in dollars per million BTU, delivered to plant, is shown in Appendix I on page 5.

Q. **What are the factors that can affect FPL's natural gas prices during the January through December, 2001 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. The dominant factors influencing the projected price of natural gas in 2001 are: (1) projected natural gas demand in North America will continue to grow moderately in 2001, primarily in the electric generation sector, and (2) natural gas deliverability increases from the U.S. Gulf Coast to the market and imports from Canada will be available to meet these projected increases in demand.

Q. What are the factors that affect the availability of natural gas to FPL during the January through December, 2001 period?

A. The key factors are (1) the existing capacity of natural gas transportation facilities into Florida, (2) the Phase IV expansion of the Florida Gas Transmission Pipeline System, (3) the portion of that capacity that is contractually allocated to FPL on a firm, "guaranteed" basis each month, and (4) 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. The Phase IV expansion of the Florida Gas Transmission Pipeline System is assumed to be complete by May 1, 2001 increasing the capacity of the natural gas transportation facility into the State of Florida by 272,000 million BTU per day to 1,727,000 million BTU per day (including FPL's firm allocation of 505,000 to 750,000 million BTU per day, 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 35,000 and 220,000 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 505,000 to 750,000 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 January through December, 2001 period.**

A. FPL's Base Case projections of the system average dispatch cost in dollars per million BTU and availability of natural gas in thousand, million BTU's per day, by month, are provided in Appendix I on page 6.

"LOW" and "HIGH" PRICE FORECASTS FOR FUEL OIL AND GAS SUPPLY

Q. **What is the basis for the "Low" forecast for fuel oil and gas**

supply?

A. The "Low" forecast prices for fuel oil and gas supply were set such that based on the consensus among FPL's fuel buyers and energy analysts, there is less than a 5% likelihood that the actual monthly average price of each fuel for each month in the January through December, 2001 period will be below the "Low" price forecast.

Q. Please provide the "Low" price forecasts for fuel oil and gas supply.

A. FPL's projection for the average dispatch cost of heavy fuel oil, by sulfur grade, by month, based on the "Low" price forecast is provided in Appendix I on page 7, in dollars per barrel. FPL's projection for the average dispatch cost of light fuel oil based on the "Low" price forecast, by sulfur grade, by month, is shown in Appendix I on page 8, in dollars per barrel. FPL's projections of the system average dispatch cost of natural gas based on the "Low" price forecast are provided in Appendix I on page 9, in dollars per million BTU.

Q. What is the basis for the "High" forecast for fuel oil and gas supply?

A. The "High" forecast prices for fuel oil and gas supply were set such that based on the consensus among FPL's fuel buyers and energy analysts, there is less than a 5% likelihood that the actual average monthly price of each fuel for each month in the January through December, 2001 period will be above the "High" price forecast.

Q. **Please provide the "High" price forecasts for fuel oil and gas supply.**

A. FPL's projection for the average dispatch cost of heavy fuel oil, by sulfur grade, by month, based on the "High" price forecast is provided in Appendix I on page 10, in dollars per barrel. FPL's projection for the average dispatch cost of light fuel oil based on the "High" price forecast, by sulfur grade, by month, is shown in Appendix I on page 11, in dollars per barrel. FPL's projections of the system average dispatch cost of natural gas based on the "High" price forecast are provided in Appendix I on page 12, in dollars per million BTU.

Q. **Based on FPL's current (September, 2000) view of the fuel oil and natural gas markets, at what level do you now project prices will be during the January through December, 2001 period?**

A. Based on current market conditions, and consistent with our September, 2000 forecast update, FPL now projects that actual fuel oil and gas prices during the January through December, 2001 period will be the closest to those projected in the "Base Case" price forecast, than the "Low" or "High" price forecast. Therefore, the projected fuel costs calculated by POWRSYM using the "Base Case" oil and gas price forecast are the most appropriate projected costs for the January through December, 2000 period. As stated in the testimony of Korel M. Dubin, the "Base Case" oil and gas price forecast was used to calculate the proposed Fuel Factor for the period January through December, 2001.

PLANT HEAT RATES, OUTAGE FACTORS, PLANNED OUTAGES, and CHANGES IN GENERATING CAPACITY

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

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 January through December, 2001?

A. Yes. This data is shown in Appendix I on page 13.

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 January through December, 2001 period.

Q. Please describe significant planned outages for the January through December, 2001 period.

A. Planned outages at our nuclear units are the most significant in relation to Fuel Cost Recovery. St. Lucie Unit No.1 will be out of service for refueling from March 26, 2001 until April 25, 2001, or thirty days during the projected period. Turkey Point Unit No. 3 is scheduled to be out of service for refueling from October 1, 2001, until October 31, 2001, or thirty days during the projected period. St. Lucie Unit No. 2 will be out of service for refueling from November 19, 2001, until December 19, 2001, or thirty days during the projected period. There are no other significant planned outages during the projected period.

Q. Please list any changes to FPL's "<u>continuous</u>" generation capacity,

actual, or projected to take place during the period ending December 2001, that were not reflected in FPL's Fuel Cost Recovery filing of October 1, 1999.

A. The Fort Myers repowering project and the addition of simple cycle combustion turbines at the Martin site will increase both the Net Winter Continuous Capability (NWCC) and the Net Summer Continuous Capability (NSCC). This data is shown in Appendix I on page14.

INTERCHANGE and PURCHASED POWER TRANSACTIONS

Q. Are you providing the projected interchange and purchased power transactions forecasted for January through December, 2001?

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

Q. What fuel price forecast for fuel oil and gas supply was used to project interchange and purchased power transactions?

A. The interchange and purchased power transactions presented below, and shown in Appendix II on Schedules E6, E7, E8 and E9, were developed using the "Base Case" fuel price forecast for fuel oil and gas supply.

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; and UPS Replacement Energy - Schedule R.

For services provided by FPL to other utilities, FPL has developed amended Interchange Service Schedules, including AF/AS (Emergency), BF/BS (Scheduled Maintenance), CF (Economy), DF/DS (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. 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 January through December, 2001 period.

A. Under the UPS agreement FPL's capacity entitlement during the projected period is 931 MW from January through December, 2001. 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 an input to POWRSYM, is based on data provided by the Southern Companies. For the period, FPL projects the purchase of 5,896,577 MWH of UPS Energy at a cost of $92,458,690. In addition, we project the purchase of 276,239 MWH of UPS Replacement energy (Schedule R) at a cost of $6,640,670. The total UPS Energy plus Schedule R projections are presented in Appendix II on Schedule E7.

Energy purchases from the JEA-owned portion of the St. Johns River Power Park generation are projected to be 3,096,772 MWH for the period at an energy cost of $38,288,980. 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 460,048 MWH at a cost of $2,011,657. These projections are shown in Appendix II on Schedule E7.

In addition, as shown in Appendix II on Schedule E8, we project that purchases from Qualifying Facilities for the period will provide 7,163,233 MWH at a cost to FPL of $148,060,870.

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. Please describe the method used to forecast the Off-System Sales and Economy Purchases.

A. The quantity of Off-System sale and Economy Purchase transactions are projected based upon estimated generation costs and expected market conditions.

Q. What are the forecasted amounts and costs of Off-System sales?

A. We have projected 1,775,000 MWH of Off-System sales for the period. The projected fuel cost related to these sales is $70,533,750. The projected transaction revenue from the sales is $104,410,000. The gain for Off-System sales is $26,137,870 and is credited to our customers.

Q. In what document are the fuel costs of Off-System sales transactions reported?

A. Appendix II, on Schedule E6, provides the total MWH of energy, total dollars for fuel adjustment, total cost, and total gain for Off-System sales.

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 436,977 MWH of energy at a cost of $2,218,829. These projections are shown in Appendix II on Schedule E6.

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

purchases for the January to December, 2001 period?

A. The costs of these purchases are shown in Appendix II on Schedule E9 of. For the period FPL projects it will purchase a total of 1,599,726 MWH at a cost of $52,401,269. If generated, we estimate that this energy would cost $60,978,017. Therefore, these purchases are projected to result in savings of $8,576,748.

SUMMARY

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 January through December, 2001, including FPL's "Base Case," and "Low" and "High" price forecasts for fuel oil and gas supply. I have explained why the projected fuel costs developed using the "Base Case" price forecast are the most appropriate for the January through December, 2001 period. 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 they were used as inputs to the POWRSYM model in developing the projected Fuel Cost Recovery Factors for the January through December, 2001 period.

Q. Does this conclude your testimony?

A. Yes, it does.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

TESTIMONY OF R. L. WADE

DOCKET NO. 000001-EI

September 21, 2000

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 POWERSYM used to calculate the costs to be included in the proposed fuel cost recovery factors for the period January 2001 through December 2001.

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

A. FPL's nuclear fuel cost projections are developed using energy production at our nuclear units and their operating schedules, for the period January 2001 through December 2001.

Q. Please provide FPL's projection for nuclear fuel unit costs and energy for the period January 2001 through December 2001.

A. FPL projects the nuclear units will produce 241,302,766 MMBTU of energy at a cost of $0.2951 per MMBTU, excluding spent fuel disposal costs for the period January 2001 through December 2001. Projections by nuclear unit and by month are in Appendix II, on Schedule E-4, starting on page 16.

Q. Please provide FPL's projections for spent nuclear fuel disposal costs for the period January 2001 through December 2001 and explain the basis for FPL's projections.

A. FPL's projections for spent nuclear fuel disposal costs of approximately $22.0 million are provided in Appendix II, on Schedule E-2, starting on page 10. These projections are based on FPL's contract with the U.S. Department of Energy (DOE), which sets the spent fuel disposal fee at 0.9259 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 January 2001 through December 2001 explain the basis for FPL's projection.

A. FPL's projection of $6.1 million for D&D costs is based on the amount to be paid during the Period January 2001 through December 2001 and is included in Appendix II, on Schedule E-2 starting on page 10.

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.

1. <u>Spent Fuel Disposal Dispute</u>. 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, states, and state regulatory agencies filed suit against DOE over DOE's denial of its obligation to accept spent nuclear fuel beginning in 1998. On July 23, 1996, the U.S. Court of Appeals for the District of Columbia Circuit (D.C. Circuit) held that DOE is required by the Nuclear Waste Policy Act (NWPA) to take title and dispose of spent nuclear fuel from nuclear power plants beginning on January 31, 1998. DOE declined to seek further review of the decision, which was remanded to DOE for further proceedings. On December 17, 1996, DOE advised the electric utilities that it would not begin to dispose of spent nuclear fuel by the unconditional deadline.

In response to DOE's letter, FPL, other electric utilities, states, and state utility commissions petitioned the D.C. Circuit for an order authorizing the suspension of payments into the Nuclear Waste Fund (NWF) without prejudice to the utilities' contract rights until DOE performs on its unconditional obligation to take title to and dispose of spent nuclear fuel. The petitioners also requested an order requiring DOE to begin disposing of spent nuclear fuel by January 31, 1998 or in the alternative, directing DOE to develop a program that would enable the agency to begin disposing of spent nuclear fuel by January 31, 1998. (Northern States Power Co. v. DOE).

While the petition was pending, and before oral argument, DOE issued a letter on June 3, 1997 to all electric utilities with nuclear plants that have contracts with DOE for spent fuel disposal asserting its preliminary position that the delay in disposal of spent nuclear fuel was "unavoidable." Based on this conclusion, DOE asserted that it was not responsible for delays in disposal of spent nuclear fuel.

On November 14, 1997, a panel of the D.C. Circuit granted the mandamus petition in part, finding that DOE did not abide by the Court's earlier ruling that the NWPA imposes an unconditional obligation on DOE to begin disposal of spent fuel by January 31, 1998. The writ of mandamus precludes DOE from excusing its own delay on the grounds that it has not yet prepared a permanent repository or interim storage facility. The Court did not grant the other requests for relief. The Court stated in its decision that the utility contract holders should pursue remedies against DOE in the appropriate forum.

On May 5, 1998, the D.C. Circuit denied petitions for rehearing filed by DOE and Yankee Atomic Electric Company. The Court also denied requests by all other petitioners in the Northern States Power case for an order requiring DOE to begin spent fuel disposal. On November 30, 1998, the

U.S. Supreme Court denied petitions for a writ of certiorari filed by the states and state utility commissions, and by DOE.

On June 8, 1998, FPL filed a lawsuit against DOE in the U.S. Court of Federal Claims, claiming in excess of $300,000,000 in damages arising out of DOE's failure to begin spent fuel disposal on January 31, 1998. On April 6, 1999, the Court of Federal Claims granted DOE's motion to dismiss a companion lawsuit brought by Northern States Power Company (NSP) on grounds that NSP failed to exhaust its administrative remedies prior to filing the lawsuit and should have first filed a claim with DOE's Contracting Officer. On August 31, 2000, the U.S. Court of Appeals for the Federal Circuit reversed the decision of the Court of Federal Claims, holding that NSP could proceed with its spent fuel damages lawsuit against DOE in court without proceeding first before DOE's Contracting Officer.

It is possible that the decision of the Federal Circuit on the jurisdictional issue could be reviewed by the full panel of the Federal Circuit, and then by the U.S. Supreme Court. FPL's lawsuit has been stayed pending the outcome of the NSP case. If the Federal Circuit decision stands, FPL would move the Court of Claims for summary judgement on liability and then proceed toward a trial to determine the amount of damages owed by DOE.

2(a). Uranium Enrichment Pricing Disputes - FY 1993 Overcharges. FPL is currently seeking to resolve a pricing dispute concerning uranium enrichment services purchased from the United States (U.S.) Government, prior to July 1, 1993. FPL's 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 Year 1993. FPL has been making such payments. Therefore, D&D should not have been included in the price charged by DOE for deliveries during Fiscal Year 1993, and the price should have been reduced accordingly. FPL filed a claim with the DOE 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. On October 11, 1996, FPL, along with five other U.S. utilities and one foreign entity, appealed DOE's rejection of the Fiscal Year 1993 overcharge claim with the U.S. Court of Federal Claims (FPL v. DOE).

On August 12, 1998, the Court of Federal Claims dismissed FPL's complaint. On August 25, 1999, the Federal Circuit reversed the decision of the Court of Federal Claims, and remanded the issue for trial. FPL expects DOE to file a motion for summary judgment before trial. Assuming the motion is resolved in FPL's favor, FPL expects that trial will take place in the second quarter of 2001. If the Court grants DOE's motion, FPL has the right to appeal the Court's decision to the Federal Circuit.

2(b). Uranium Enrichment Pricing Disputes - Challenge to D&D Assessment. In a related case, Yankee Atomic Electric Company had challenged the authority of the United States to impose the D&D fees. On May 6, 1997, a panel of the U.S. Court of Appeals for the Federal Circuit held that the D&D special assessment was lawful under the Energy Policy Act. United States v. Yankee Atomic Electric Co. A lower court had ruled that the D&D special assessment was unlawful. On August 15, 1997, the full panel of the Federal Circuit denied Yankee's request for rehearing. On June 26, 1998, the U.S. Supreme Court denied Yankee's petition for a writ of certiorari.

FPL has joined a complaint filed by 21 U.S. utilities in the U.S. District Court for the Southern District of New York challenging the D&D

assessment as a violation of the due process clause of the Fifth Amendment to the U.S. Constitution. (Consolidated Edison Co. v. United States). The Southern District of New York trial judge granted the Government's motion for a stay of discovery in the Consolidated Edison case pending the Government's appeal of the Southern District's denial of the Government's request to transfer the case to the Court of Federal Claims. The Government's appeal to the Federal Circuit has been briefed and argued. A decision is expected before the end of 2000.

As a protective measure, on July 27, 1998, FPL filed a claim before DOE's Contracting Officer and on July 29, 1998, a complaint with the U.S. Court of Federal Claims challenging the D&D assessment on grounds that the D&D assessment is an impermissible retroactive adjustment to previous fixed price uranium enrichment service contracts. FPL's lawsuit in the Court of Federal Claims has been stayed pending resolution of the proceedings in the Southern District of New York. Similar protective complaints filed by four other utilities have been dismissed by the Court of Federal Claims. All four utilities have appealed the dismissal of their claims; three of those cases have been briefed and argued. A decision in those cases is expected before the end of 2000.

Q. **Please explain the project to expand the spent fuel storage capacity at the St. Lucie Plant.**

A. **As stated in my prior testimony, the** U.S. Court of Appeals for the District of Columbia Circuit (D.C. Circuit) has affirmed that the Nuclear Waste Policy Act (NWPA) imposes an obligation on the DOE to take title and dispose of spent nuclear fuel from nuclear power plants beginning on January 31, 1998. **The DOE did not begin accepting spent nuclear fuel in 1998. The earliest date projected by the DOE for Yucca Mountain (the designated geologic repository) to be fully operational is 2010. For planning purposes, FPL assumes that the DOE will not begin accepting spent fuel until 2015. Under this assumption, FPL spent fuel would start being removed from the plant sites in 2016.**

In the meantime, the two spent fuel pools at the St. Lucie Plant are approaching their current licensed capacity. FPL projects that it will lose the ability to remove the entire core and place that fuel in the spent fuel pools for Unit 1 in 2005 and for Unit 2 in 2007. If FPL does not implement the St. Lucie Spent Fuel Storage Project, it will eventually reach the point when there will be no place to store discharged fuel. If FPL is unable to discharge spent fuel from the reactor core, FPL will be unable to load new fuel in the reactor core. The inability to load new fuel effectively results in the shut down of the unit.

Q. What previous steps have been taken by FPL to ensure adequate storage capacity for spent fuel at the St. Lucie Plant?

A. FPL has taken the following steps to ensure adequate storage of spent fuel at the St. Lucie Plant.

1) High-density storage racks were installed in the spent fuel pool of St. Lucie Unit 1.

2) FPL requested and received a license amendment from the NRC in 1999 that increased the

licensed capacity of the spent fuel pool of St. Lucie Unit 2 by two hundred and eighty-four fuel assemblies.

3) FPL has participated in industry lawsuits against the DOE. The intent of these lawsuits has been to affirm DOE's legal obligation to accept spent fuel, to maintain pressure on DOE to make progress towards acceptance of spent fuel, to affirm that DOE's delayed performance has adversely affected the owners and customers of utilities that generate power with nuclear power plants, and ultimately to recover damages caused by DOE's delay in performance of its spent nuclear fuel disposal obligations.

4) Through industry organizations, FPL has supported legislation that would set the government's high level waste program back on course and require DOE to meet its obligations. In 2000, the U.S. Senate and House passed the Nuclear Waste Policy Act Amendments bill. President Clinton vetoed the bill. Neither the Senate nor the House had a sufficient margin to override the veto.

5) Since 1992 FPL has been monitoring and evaluating the status of various spent fuel

storage alternatives. The intent of this effort was to ensure that FPL considered all feasible alternatives and to ensure that FPL began implementation of storage alternatives in time to prevent shut down of either unit.

Q. What is the status of spent fuel storage at the Turkey Point Plant?

A. FPL projects that Turkey Point will lose the ability to remove the entire core and place that fuel in the spent fuel pools for Unit 3 in 2010 and for Unit 4 in 2011.

Q. Briefly describe the scope of the St. Lucie Spent Fuel Storage Project.

A. The project is pursuing two methods to expand the spent fuel storage capacity at St. Lucie. First, FPL is studying the feasibility of installing new high-density storage racks in the Unit 2 spent fuel pool and licensing the capability of installing storage racks in a portion of the spent fuel pools intended for use in transferring fuel into storage canisters or casks (cask pits). Second, FPL will develop the capability to store spent fuel outside of the spent fuel pool in dry storage containers licensed by the Nuclear Regulatory Commission (NRC) under 10 CFR Part 72. Before transfer to the DOE facility, these containers would be located at either the St. Lucie Plant or at a facility operated by Private Fuel Storage, LLC (PFS) in Tooele County, Utah. Dry storage facilities are usually referred to as an independent spent fuel storage installation (ISFSI).

Q. Are the two storage methods mutually exclusive?

A. No. If installing new high-density storage racks for St. Lucie Unit 2, and cask pit racks are feasible, this additional capacity merely defers the need for developing the capability to transfer spent fuel to dry storage.

Q. How will FPL make the decision on which alternative to pursue?

A. FPL will choose an alternative that minimizes the life-cycle cost of spent fuel storage while maximizing FPL's ability to be flexible in response to uncertainty surrounding the issue of spent fuel storage and disposal. Selection of a least cost alternative implies the ability to forecast the future with some degree of certainty. For spent fuel storage, the following uncertainties and risks exist:

1) For options that increase the capacity of the existing spent fuel pools, there is the risk of intervention when FPL requests an amendment to the operating licenses of the units. Dry storage technologies licensed under the general license provisions of 10 CFR Part 72 may be implemented without an amendment to the operating licenses and without the risk and uncertainty of intervention before the NRC. An amendment to the operating license would be required for issues related to fuel handling.

2) There is uncertainty when DOE will begin accepting spent fuel and at what rates.

3) FPL's ultimate accumulation of spent fuel assemblies is uncertain. If FPL receives license renewals and utilizes the right to operate the nuclear units over an additional twenty-year term, the accumulation and disposition of spent fuel will

be different than under the term of the existing operating licenses.

4) There is uncertainty regarding the ability of vendors of dry storage systems to deliver storage equipment and services on a just-in-time basis.

5) There is uncertainty if the PFS facility will be successfully licensed and begin accepting spent fuel.

Q. **What is PFS?**

A. FPL purchased an interest in PFS in May 2000. PFS is a consortium of eight utilities seeking to license, construct, and operate an independent spent fuel storage installation in Tooele County, Utah, on the reservation of the Skull Valley Band of the Goshute Indian tribe. PFS has filed a license application with the NRC. Hearings on the safety aspects of the application began in June 2000. A second round of hearings on safety is scheduled to be held in 2001. PFS expects a license decision from the NRC by the end of 2001. Based on an affirmative decision, operations could begin by the end of 2003. If operation of the PFS facility proceeds as expected, FPL may be able to reduce the costs for a dry storage installation over what would be required absent offsite storage capability.

Q. **What sorts of costs will be incurred as part of the St. Lucie Spent Fuel Storage Project?**

A. For high-density storage racks for Unit 2 or additional cask pit racks, these costs would include:

1) Design and engineering;
2) Procurement and installation of the storage racks; and
3) Disposal of the old storage racks as low level radioactive waste and packaging and processing of items currently stored in the cask pits.

For the development and implementation of dry storage capability, these costs would include:

1) Design and engineering for an independent spent fuel storage installation (ISFSI) and for fuel handling equipment;
2) Construction of an ISFSI;

3) Upgrade of cranes in the fuel handling buildings;

4) Procurement of storage canisters and protective overpacks;

5) Procurement of transportation equipment; and

6) Site infrastructure modifications (i.e., heavy haul roads) necessary to permit movement of spent fuel from the spent fuel pool to the ISFSI.

If the PFS initiative is successful, FPL's costs would include PFS-construction, PFS-supplied equipment and services, and annual storage fees for spent fuel stored at the PFS facility.

Q. **What is FPL's estimate of costs for the St. Lucie Spent Fuel Storage Project?**

A. Preliminary estimates of costs for storage options range from $4 million to $51 million for the period of 2001 through 2005. Additional costs would be incurred beyond 2005, however the magnitude is subject to the uncertainty previously described.

Q. **Why is there such a range in the project estimates for 2001 through 2005?**

A. The $51 million estimate is based on utilization of PFS and development of an ISFSI during the five-year period. The $4 million estimate reflects an incremental approach whereby additional storage capacity would be added in increments and deferred as long as possible. FPL would be able to defer development of an ISFSI at the St. Lucie Plant.

Q. Is FPL requesting that the St. Lucie Spent Fuel Storage Project be recovered through the Fuel Cost Recovery Clause?

A. FPL is not requesting recovery through the Fuel Cost Recovery Clause at this time, although FPL will be incurring costs beginning in 2001 necessary for the St. Lucie Spent Fuel Storage Project. However, FPL would like to be able to request recovery of appropriate costs associated with this project at some future date, including costs incurred in 2001, once FPL makes a decision on which alternative or alternatives to use.

Q. Does this conclude your testimony?

A. Yes, it does.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

TESTIMONY OF KOREL M. DUBIN

DOCKET NO. 000001-EI

August 23, 2000

Q. Please state your name and address.

A. My name is Korel M. Dubin 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 Manager, Regulatory Issues in the Regulatory Affairs Department.

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 calculation of the Estimated/Actual True-up amounts for the Fuel Cost Recovery Clause (FCR) and the Capacity Cost Recovery Clause (CCR) for the period January 2000 through December 2000.

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 Appendices I and II. Appendix I contains the FCR related schedules and Appendix II contains the CCR related schedules.

FCR Schedules A-1 through A-9 for January 2000 through July 2000 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 that 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. Please explain the calculation of the FCR Estimated/Actual True-up amount you are requesting this Commission to approve.

A. Appendix I, pages 2 and 3, show the calculation of the FCR Estimated/Actual True-up amount. The calculation of the estimated/actual true-up amount for the period January 2000 through December 2000 is an underrecovery, including interest, of $518,005,376 (Appendix I, page 3, Column13, lines C7 plus C8).

Appendix I, pages 2 and 3 also provide 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 Provision for this period (lines C4 through C10), and the End of Period True-up amount (line C11).

The data for January 2000 through July 2000, columns (1) through (7) reflects the actual results of operations and the data for August 2000 through December 2000, columns (8) through (12), are based on updated estimates.

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. In Order No. 13694, Docket No. 840001-EI, dated 9/20/84, the Commission established a procedure by which utilities would notify the Commission when their collection of projected fuel costs were going to be either over or under by 10%. Does this $518 million estimated/actual true up amount exceed the

Commission's 10 % guideline?

A. Yes. Pursuant to Order No. 13694, we are providing notification of these circumstances. FPL is currently evaluating various alternatives to lessen the impact of this underrecovery on customer bills and will include a proposed recovery plan for Commission review and approval with the September 21, 2000 filing for the period January through December 2001.

Q. **Please summarize FPL's midcourse correction that became effective on June 15, 2000.**

A. On May 1, 2000, FPL filed a midcourse correction for $234.7 million. Of this amount $96.4 million was for the Final True up for the period ending December 1999. Additionally the midcourse correction included 60% of the $230.7 million projected underrecovery for 2000 or $138.3 million. The midcourse correction was approved on June 5, 2000 per Order No. PSC-00-1081-PCO-EI.

Q. **What is the status of the $96.4 million Final True-up amount for the period ending December 1999 and the $138 million "in-period" True-up amount for 2000?**

A. The Final True-up underrecovery of $96,356,314 deferred from the period January 1999 through December 1999 and, presented in my Final True-up testimony filed on April 1, 2000, has already been included in customer charges from June 15, 2000 through December

2000 as a result of the midcourse correction filed on May 1, 2000. See (Appendix I, page 3, Column 13, line C10b)

The "in-period" True-up amount of $138 million has also been included in customer charges from June 15, 2000 through December 2000 and is reflected in the Jurisdictional Fuel Revenues on Appendix I, page 3, Line C3.

Q. Please summarize the variance schedule provided as page 4 of Appendix I.

A. *The variance calculation of the* Estimated/Actual *data* compared to the original projections for the January 2000 through December 2000 period is provided in Appendix I, Page 4.

FPL's FCR filing dated December 15, 1999 projected Total Fuel and Net Power Transactions to be $1.606 billion for January through December 2000 (See Appendix I, page 4, Column 2, Line D6). The estimated/actual projected Jurisdictional Total Fuel Cost and Net power Transactions is now projected to be $2.268 billion for the period January through December 2000 (Actual data for January through July 2000 and Revised Estimates for August through December 2000) (See Appendix I, page 4, Column 1, Line D6) which results in a difference of $662.7 million.

This $662.7 million difference less the variance in Jurisdictional Fuel Revenues for 2000 of $161.7 million, results in a difference of $501 million. This $501 million plus interest of $17 million results in the $518 million underrecovery.

Q. Please explain the variances causing the $518 million underrecovery.

A. As shown on Appendix I, page 4, line A5, the variance in Total Fuel Costs and Net Power Transactions is $664.9 million or a 40.8% increase from the original projections. This variance is mainly due to a $676.2 million or 50.7% increase in the Fuel Cost of System Net Generation due primarily to the higher than projected costs of heavy oil and natural gas. The variance also includes a $13 million increase in Energy Payments to Qualifying Facilities, $27.1 million increase in the Energy Cost of Economy Purchases. These amounts are slightly offset by a $26.1 million decrease in Purchased Power due to less purchases from Southern, a $24.5 million variance in Power Sold and a $1.7 million variance in Revenues from Off System Sales.

The $676.2 million increase in the cost of System Generation is due primarily to higher than originally projected oil and gas costs. Heavy oil costs are projected to be $311.3 million higher than the projected oil cost included in the original filing. The projected unit cost of heavy oil included in the original filing was $2.48 per MMBTU. The estimated/actual unit cost of heavy oil is $3.98 per MMBTU, an increase of $1.50 or 60%. Natural gas costs are projected to be $325.9 million higher than the projected natural gas cost included in the original filing. The projected unit cost of natural gas included in the original filing was $3.31 per MMBTU. The estimated/actual unit cost of natural gas is $4.19 per MMBTU, an increase of $.88 or 27%. Additionally, FPL plans to burn 43,168,139 MMBTU or 26% more natural gas than was included in the original filing.

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

A. Yes, they were.

CAPACITY PAYMENT RECOVERY CLAUSE

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

A. The Estimated/Actual True-up for the period January 2000 through December 2000 is an overrecovery, including interest, of $42,411,275 (Appendix II, page 3, lines 17 plus 18). Appendix II, pages 2-3 shows the calculation supporting the CCR Estimated/Actual True-up amount.

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.

Q. **Please explain the calculation of the Interest Provision.**

A. The calculation of the interest provision and follows the same methodology used in calculating the interest provision for the other cost recovery clauses, as previously approved by this Commission.

The interest provision is the result of multiplying the monthly average true-up amount (line 4) times the monthly average interest rate (line 9). The average interest rate for the months reflecting actual data is developed using the 30 day commercial paper rate as published in the Wall Street Journal on the first business day of the current and subsequent months. The average interest rate for the projected months is the actual rate as of the first business day in August 2000.

Q. **Have you provided a schedule showing the variances between the Estimated/Actuals and the Original Projections?**

A. Yes. Appendix II, page 4, shows the Estimated/Actual capacity charges and applicable revenues compared to the original projections for the January 2000 through December 2000 period.

Q. What is the variance related to capacity charges?

A. As shown in Appendix II, page 4, line 7, the variance related to capacity charges is an $8 million decrease. The primary reasons for the variance is a $3 million decrease in payments to non-cogenerators due to a decrease in capacity rates for UPS purchases, plus a $7 million decrease in payments to cogenerators due to lower than projected capacity factors for Cedar Bay, Florida Crushed Stone and Royster. These amounts were somewhat offset by a $2 million variance in transmission revenues.

Q. What is the variance in Capacity Cost Recovery revenues?

A. As shown on line 12, Capacity Cost Recovery revenues, net of revenue taxes, are $30 million higher than originally projected.

Q. Does this conclude your testimony.

A. Yes, it does.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

TESTIMONY OF KOREL M. DUBIN

DOCKET NO. 000001-EI

September 21, 2000

Q. Please state your name and address.

A. My name is Korel M. Dubin 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 Manager of Regulatory Issues in the Regulatory Affairs Department.

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 cost recovery factors (FCR) and the capacity cost recovery factors (CCR) for the Company's rate schedules for the period January 2001 through December 2001. The calculation of the fuel factors is based on projected fuel cost, using the "base case" forecast as described in the testimony of FPL Witness Gerry Yupp, 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. I am also providing projections of avoided energy costs for purchases from small power producers and cogenerators and an updated ten year projection of Florida Power & Light Company's annual generation mix and fuel prices.

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 Appendices II and III. Appendix II contains the FCR related schedules and Appendix III contains the CCR related schedules.

FCR Schedules A-1 through A-9 for January 2000 through August 2000 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 that 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. 2.925¢ per kWh. Schedule El, Page 3 of Appendix II shows the calculation of this twelve-month levelized fuel factor. Schedule E2, Pages 10 and 11 of Appendix II indicates the monthly fuel factors for January 2001 through December 2001 and also the twelve-month levelized fuel factor for the period.

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

A. Yes. Schedule E1-D, Page 8 of Appendix II, provides a twelve-month levelized fuel factor of 3.213¢ per kWh on-peak and 2.798¢ 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 is the true-up amount that FPL is requesting to be included in the fuel factor for the January 2001 through December 2001 period?

A. On August 23, 2000, FPL filed its Estimated/Actual True-up, an underrecovery of $518, 005,376, for the period January 2000 through December 2000. In order to mitigate the impact of this large underrecovery on customer bills, FPL is proposing to spread this estimated/actual true-up underrecovery of $518,005,376 over a two-year period. This results in a Residential 1,000 kWh bill for 2001 that is $2.99 lower than if recovered over a one year period. FPL has included one-half of this estimated/actual true-up underrecovery of $518,005,376, or $259,002,688, in the calculation of the twelve-month levelized fuel factor for the January 2001 through December 2001 period. The remainder of the estimated/actual true-up underrecovery will be included for recovery in the fuel factor for the January 2002 through December 2002 period. FPL proposes to treat the unrecovered portion of the $518,005,376 as a base rate regulatory asset in 2001 and 2002, rather than the current practice of recovering the commercial paper rate of return through the fuel clause.

Q. What adjustments are included in the calculation of the twelve-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, one-half of the estimated/actual fuel cost underrecovery for the January 2000 through December 2000 period amounts to $259,002,688. This amount divided by the projected retail sales of 89,259,918 MWH for January 2001 through December 2001 results in an increase of

0.2902¢ per kWh before applicable revenue taxes. In his testimony for the Generating Performance Incentive Factor, FPL Witness Rene Silva calculated a reward of $6,973,751 for the period ending December 1999 which is being applied to the January 2001 through December 2001 period. This $6,973,751 divided by the projected retail sales of 89,259,918 MWH during the projected period results in an increase of 0.0078¢ per kWh, as shown on line 33 of Schedule E1, Page 3 of Appendix II.

Q. Is FPL presenting any other issues to be addressed in the Fuel Cost Recovery Clause?

A. Yes. FPL's petition in Docket No. 000982-EI for approval of the Okeelanta/Osceola Settlement and recovery of the cost of the Settlement through the Fuel and Capacity Cost Recovery Clauses is pending approval (scheduled to go before the Commission on September 26, 2000). If approved, FPL will include the cost associated with the Okeelanta/Osceola settlement agreement in its Fuel and Capacity Cost Recovery calculations. The total amount of the settlement payment expected to be made in November 2000 is $222.5 million. If recovered in one year, the impact on the Residential 1,000 kWh bill in 2001 would be $2.75. If recovered over five years, the impact on the Residential 1,000 kWh bill in 2001 would be $0.85. In order to mitigate the impact on customers' bills in 2001, FPL proposes to reflect the payment as a regulatory asset, delay recovery for one year, and recover the settlement payment over a five-year period starting January 1, 2002. From the date of payment through December 2001, FPL proposes to treat the payment as a base rate asset. Afterwards, FPL is proposing to move the amount to the clauses as a regulatory asset and earn the applicable commercial paper rate of return on the unrecovered balance rather than the overall return, which is current practice. This will also serve to reduce fuel factors charged to our customers in the future from what would otherwise be charged.

When the Okeelanta/Osceola Settlement is included in the clauses in 2002, FPL proposes that 21 percent of the settlement payments should be recovered through the Fuel Cost Recovery Clause and 79 percent should be recovered through the Capacity Cost Recovery Clause. The proposed ratio for recovery is the same manner that payments under these contracts would have been recovered through the Fuel and Capacity Cost Recovery Clauses.

Q. What is the status of implementing the decision on incentives for off system sales?

A. On August 15, 2000, the Commission voted to allow the utilities to split (80% to customers and 20% to shareholders) any gains on off system sales that exceed a threshold based on a three year average of gains. A meeting was held on September 12, 2000 with the parties in the docket to discuss the implementation of this incentive. At the meeting, Staff proposed that each utility file an initial forecast threshold with their projection filings on September 21, 2000 and the final revised threshold with their true up filings in April 2001. As I understand Staff's proposal, the first two and one half years used in the calculation of the average would be the actual gains for those years and the final six months would be estimated. Later, the threshold of gains on off system sales is to be updated with actual gains for the balance of the third year and filed as part of the true up testimony. We also thought, however, that Staff proposed to include as much actual data as was available for the third year threshold component. Therefore, in the filing, FPL has included seven months of actual data and five months of forecast data in the third year threshold component. For the forecast year 2001, the three year average threshold consists of actual gains for 1998, 1999 and January through July 2000, and estimates for August through December 2000 (see below). Gains on sales in 2001 are to be measured against this three year average threshold, after it has been adjusted with the true up filing to include all actual data for the year 2000. FPL believes this approach is appropriate.

1998	$62,276,203
1999	$59,183,161
2000	$20,673,259
Average threshold	$47,377,541

CAPACITY PAYMENT RECOVERY CLAUSE

Q. Please describe Page 3 of Appendix III.

A. Page 3 of Appendix III provides a summary of the requested capacity payments for the projected period of January 2001 through December 2001. Total recoverable capacity payments amount to $427,597,309 (line 12) and include payments of $193,297,344 to non-cogenerators (line1), payments of $348,687,456 to cogenerators (line 2), $3,467,177 of Mission Settlement payments (line 3) and $4,377,300 relating to the St. John's River Power Park (SJRPP) Energy Suspension Accrual (line 4a). This amount is offset by transmission revenues from capacity sales of $5,738,050 (line 4), $2,034,552 of return requirements on Energy Suspension payments (line 4b) and $56,945,592 of jurisdictional capacity related payments included in base rates (line 8) less a net overrecovery of $58,869,559 (line 9). The net overrecovery of $58,869,559 includes the final overrecovery of $16,458,284 for the January 1999 through December 1999 period plus the estimated/actual overrecovery of $42,411,275 for the January 2000 through December 2000 period, which was filed with the Commission on August 23, 2000.

Q. Please describe Page 4 of Appendix III.

A. Page 4 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 describe Page 5 of Appendix III.

A. Page 5 of Appendix III presents the calculation of the proposed Capacity Payment Recovery Clause (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 bills for January 2001 through December 2001. This will provide for 12 months of billing on the FCR and CCR factors for all our customers.

Q. What will be the charge for a Residential customer using 1,000 kWh effective January 2001?

A. The total residential bill, excluding taxes and franchise fees, for 1,000 kWh will be $80.55. The base bill for 1,000 residential kWh is $43.26, the fuel cost recovery charge from Schedule E1-E, Page 9 of Appendix II for a residential customer is $29.31, the Conservation charge is $1.81, the Capacity Cost Recovery charge is $5.27, the Environmental Cost Recovery charge is $.08 and the Gross Receipts

Tax is $.82. A Residential Bill Comparison (1,000 kWh) is presented in Schedule E10, Page 65 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 KOREL M. DUBIN

DOCKET NO. 000001-EI

April 3, 2000

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

A. My name is Korel M. Dubin, and my business address is 9250 West Flagler Street, Miami, Florida, 33174. I am employed by Florida Power & Light Company (FPL) as the Manager of Regulatory Issues in the Rates and Tariffs Department.

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) and Capacity Cost Recovery Clause (CCR) Net True-Up amounts for the period January 1999 through December 1999. The Net True-Up for the FCR is an underrecovery, including interest, of $96,356,314. The Net True-Up for the CCR is an overrecovery, including interest, of $16,458,284. I am requesting

Commission approval to include these true-up amounts in the calculation of the FCR and CCR factors respectively, for the period January 2001 through December 2001.

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 two appendices. Appendix I contains the FCR related schedules and Appendix II contains the CCR related schedules. FCR Schedules A-1 through A-9 for the January 1999 through December 1999 period have been filed monthly with the Commission and served on all parties. These schedules 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 (FCR)

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 period January 1999 through December 1999, an underrecovery of $96,356,314 which I am requesting be included in the calculation of the FCR factor for the period January 2001 through December 2001. 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 period January 1999 through December 1999 of $87,509,829 is shown on line 1. The estimated/actual End-of-Period overrecovery for the same period of $8,846,485 is shown on line 2. This was included in the calculation of the FCR factor for the period January 2000 through December 2000. Line 1 less line 2 results in the Net True-Up for the period January 1999 through December 1999 shown on line 3, an underrecovery of $96,356,314.

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 January 1999 through December 1999.

Q. What was the variance in fuel costs?

A. As shown on Appendix I, page 4, line A5, total fuel costs and net power transactions were $98.4 million or 6.4% higher than the estimated/actual projection. This variance is primarily due to a $100.2 million increase in the Fuel Cost of System Net Generation, a $6.3 million increase in Energy Payments to Qualifying Facilities, and a $2.1 million increase in the Energy Cost of Economy Purchases. These amounts are offset by a $6.4 million decrease in the Fuel Cost of Purchased Power a $3.8 million variance in the Fuel Cost of Power Sold.

The $100.2 million increase in the Fuel Cost of System Net Generation is primarily due to a $33 million oil variance and a $65 million gas variance. Driven by higher than projected market prices, oil was $0.51 per mmbtu or 21% higher than projected resulting in a $31 million variance. Due to higher than projected load, FPL burned 1.35% more oil causing an additional $2 million variance. Gas was $0.31 per mmbtu or 10% higher than projected resulting in a $23 million variance. And, due to higher than projected load, 23% more gas was burned than projected causing a $42 million variance.

The $6.3 million increase in Energy Payments to Qualifying Facilities is primarily due to higher than originally projected purchases from QF's. The

$2.1 million increase in the Energy Cost of Economy Purchases is due to higher than originally projected cost of economy purchases. The $6.4 million decrease in the Fuel Cost of Purchased Power is due to less than originally projected purchases from Southern and SJRPP. The $3.8 million variance in the Fuel Cost of Power Sold is due to higher than originally projected sales.

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

A. As shown on Appendix 1, page 4, line D1, actual jurisdictional Fuel Cost Recovery revenues, net of revenue taxes, were $1.0 million or 0.1% higher than the estimated/actual projection. This increase was due to higher than projected jurisdictional sales, which were 36,334,953 kWh 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.

CAPACITY COST RECOVERY CLAUSE (CCR)

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

A. Appendix II, page 3, entitled "Summary of Net True-Up Amount" shows the calculation of the Net True-Up for the period January 1999 through December 1999, an overrecovery of $16,458,284, which I am requesting to be included in the calculation of the CCR factors for the January 2001 through December 2001 period.

The actual End-of-Period overrecovery for the period January 1999 through December 1999 of $95,522,335 (shown on line 1) less the estimated/actual End-of-Period overrecovery for the same period of $79,064,052, (shown on line 2) results in the Net True-Up overrecovery for the period January 1999 through December 1999 (shown on line 3) of $16,458,284.

Q. Have you provided a schedule showing the calculation of the End-of-Period true-up?

A. Yes. Appendix II, pages 5 through 8, entitled "Calculation of Final True-up Amount", shows the calculation of the CCR End-of period true-up for the period January 1999 through December 1999. The End of-Period true-up shown on page 6, line 17 plus line 18 is an overrecovery of $95,522,335.

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 A-2 "Calculation of True-Up and Interest Provision" for the Fuel Cost Recovery Clause.

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

A. Yes. Appendix II, page 4, entitled "Calculation of Final True-up Variances", shows the actual capacity charges and applicable revenues compared to the estimated/actuals for the period January 1999 through December 1999.

Q. What was the variance in net capacity charges?

A. As shown on line 7, actual net capacity charges on a Total Company basis were $14 million lower than the estimated/actual projection. This variance was primarily due to $10 million lower than expected Payments to Non-Cogenerators caused by lower payments to Southern Company due to a decrease in capacity rates for UPS purchases. Additionally, as a result of reduced capacity factors, payments to Cogenerators (Cedar Bay, Florida Crushed Stone, and Broward North) were $3 million lower than projected. And, Revenues from Capacity Sales were $1 million higher due to higher than projected sales.

Q. What was the variance in Capacity Cost Recovery revenues?

A. As shown on line 12, actual Capacity Cost Recovery revenues, net of revenue taxes, were $2.2 million or 0.5% higher than the estimated/actual projection. This increase was due to higher than projected jurisdictional sales, which were 36,334,953 kWh higher than the estimated/actual projection.

Q. Does this conclude your testimony?

A. Yes, it does.

BEFORE THE PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

TESTIMONY OF R. SILVA

DOCKET NO. 000001-EI

APRIL 3, 2000

Q. Please state your name and business address.

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

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

A. I am Manager of Economic Analysis, Planning, and Regulatory Response, in the Power Generation Division of FPL.

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

A. Yes, I have.

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

A. The purpose of my testimony is to report the actual performance for the Equivalent Availability Factor (EAF) and Average Net Operating Heat Rate (ANOHR) for the seventeen (17) generating units used to determine the Generating Performance Incentive Factor (GPIF). I have compared the actual performance of each unit to the targets that were approved in Commission Order No. PSC-98-1715-FOF-EI issued December 18, 1998, for the period January through December, 1999, and have performed the calculations prescribed by the GPIF Rule based on this comparison. My testimony presents the result of my calculations, which is an incentive reward for the period.

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

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

Q. **What is the incentive amount you have calculated for the period JANUARY THROUGH DECEMBER, 1999?**

A. I have calculated a GPIF incentive reward of $ 6,973,751.

Q. **Please explain how the reward amount is calculated?**

A. The steps involved in making this calculation are provided in Document No. 1. Page 2 of Document No. 1 provides the GPIF Reward/Penalty Table (Actual) which shows an overall GPIF performance point value of +3.53 corresponding to a GPIF reward of $6,973,751. Page 3 provides the calculation of the maximum allowed incentive dollars. The calculation of the system actual GPIF performance points is shown on page 4. This page lists each unit, the unit's performance indicators (ANOHR and EAF), the weighting factors and the associated GPIF points.

Page 5 is the actual EAF and adjustments summary. This page lists each of the seventeen (17) units, the actual outage factors and the actual EAF, in columns 1 through 5. Column 6 is the adjustment for planned outage variation. Column 7 is the adjusted actual EAF, which is calculated on page 6, and Column 8 is the target EAF. Column 9 contains the Generating Performance Incentive Points for availability as determined from the tables submitted to, and approved by, the Commission prior to the start of the period. These tables are shown on pages 8 through 24.

Page 7 shows the adjustments to ANOHR. For each of the seventeen (17) units, it shows the target heat rate formula, the actual Net Output Factor (NOF) and the actual ANOHR in columns 1 through 4. Since heat rate varies with NOF, it is necessary to determine both the target and actual heat rates at the same NOF. This adjustment is to provide a common basis for comparison purposes and is shown numerically for each GPIF unit in columns 5 through 8. Column 9 contains the Generating Performance Incentive Points that have been determined from the table submitted for each unit and approved by the Commission prior to the beginning of the period. These tables are also shown on pages 8 through 24.

Q. Are there any changes to the targets approved through Commission Order No. PSC-98-1715-FOF-EI?

A. No, the approved targets have not changed.

Q. Please explain the primary reason or reasons why FPL will be rewarded under the GPIF for the January through December, 1999 period?

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

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

A. Turkey Point Unit 3 operated at an adjusted actual EAF of 99.1%, compared to its target of 93.6%. This results in a +10.00 point reward, which corresponds to a GPIF reward of $1,875,491.

Turkey Point Unit 4 operated at an adjusted actual EAF of 90.1%, compared to its target of 84.3%. This results in a +10.00 point reward, which corresponds to a GPIF reward of $1,692,061.

St. Lucie Unit 1 operated at an adjusted actual EAF of 86.4%, compared to its target of 83.6%. This results in a +9.10 point reward, which corresponds to a GPIF reward of $1,807,613.

St. Lucie Unit 2 operated at an adjusted actual EAF of 96.6%, compared to its target of 93.6%. This results in a +10.00 point reward, which corresponds to a GPIF reward of $1,871,951.

The total GPIF reward due to the nuclear units' actual availability performance is $7,247,116.

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

A. Turkey Point Unit 3 operated with an adjusted actual ANOHR of 11,064 BTU/KWH. This ANOHR is within the ± 75 BTU/KWH deadband around the projected target, therefore there is no GPIF reward or penalty.

Turkey Point Unit 4 operated with an adjusted actual ANOHR of 11,076 BTU/KWH which was better than projected by 90 BTU/KWH. This will result in a +0.82 point reward, which corresponds to a GPIF reward of $92,591.

St. Lucie Unit 1 operated with an adjusted actual ANOHR of 10,804 BTU/KWH. This ANOHR is within the ± 75 BTU/KWH deadband around the projected target, therefore there is no GPIF reward or penalty.

St. Lucie Unit 2 operated with an adjusted actual ANOHR of 10,812 BTU/KWH, which was better than projected by 83 BTU/KWH. This will result in a +0.99 point reward, which corresponds to a GPIF reward of $45,169.

In total, the nuclear units' heat rate performance results in a GPIF reward of $137,760.

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

A. $7,384,877.

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

A. Yes, nine (9) of the thirteen (13) fossil generating units performed better than their availability targets, while the remaining unit performed worse than its target. The combined fossil unit availability performance results in a GPIF reward of $427,283.

Three (3) of the thirteen (13) fossil units operated with ANOHR's that were better than their projected targets and five (5) units operated with ANOHR's that were worse than their projected targets. The remaining five (5) units operated with ANOHR's that were within the ± 75 BTU/KWH deadband around the projected targets and they will receive no incentive reward or penalty. In total, the combined fossil units heat rate performance results in a GPIF penalty of $838,409.

In total, the GPIF penalty for FPL's fossil units for the period of January through December, 1999 is $411,126

Q. Does this conclude your testimony?

A. Yes, it does.

BEFORE THE PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

TESTIMONY OF R. SILVA

DOCKET NO. 000001-EI

SEPTEMBER 21, 2000

Q. Please state your name and business address.

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

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

A. I am the Manager of Planning, Forecasting and Regulatory Response in the Power Generation Business Unit of FPL.

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

A. Yes, I have.

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

A. The purpose of my testimony is to present the target unit average net operating heat rates and target unit equivalent availability for the period of January through December, 2001, for use in determining the Generating Performance Incentive Factor (GPIF).

Q. Mr. Silva, please summarize what the FPL system targets are for Equivalent Availability Factor (EAF) and Average Net Operating Heat Rate (ANOHR).

A. For the period of January through December, 2001, FPL projects a weighted system equivalent planned outage factor of 6.1 % and a weighted system equivalent unplanned outage factor of 5.7 %, which yield a weighted system equivalent availability target of 88.2 %. The targets for this period reflect planned refueling outages for three nuclear units. FPL also projects weighted system average net operating heat rate target of 9841 BTU/KWH for the period January through December, 2001. As discussed later in this testimony, these targets represent fair and reasonable values when compared to historical data. FPL therefore requests that the targets for these performance indicators be approved by the Commission.

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

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

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

A. Yes, I have. In my Document No.1, pages 6 and 7, contain the information summarizing the targets and ranges for unit equivalent availability and average net operating heat rates for the eighteen (18) generating units which FPL proposes to have considered as GPIF units for the period of January through December, 2001. The Sheets presented in these pages were prepared in accordance with the latest revisions of the GPIF Manual. All of these targets have been derived utilizing methodologies as adopted in Section 4, Subsection 2.3 of the GPIF Manual.

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

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

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

A. Yes.

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

A. The eighteen (18) units which FPL proposes to use for the period of January through December, 2001, represent the top 81.3% of the total forecasted system net generation for this period. These units were selected in accordance with the GPIF Manual Section 3.1, using the estimated net generation for each unit taken from the production costing simulation program, POWRSYM, which forms the basis for the projected levelized fuel cost recovery factor for the period.

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

A. Yes. These targets are reasonable and in some cases very challenging.

Q. Does this conclude your testimony?

A. Yes, it does.

(Transcript continues in sequence in Volume 2.)

STATE OF FLORIDA)

: CERTIFICATE OF REPORTER

COUNTY OF LEON)

I, JANE FAUROT, RPR, Chief, FPSC Bureau of Reporting Official Commission Reporter, do hereby certify that the Hearing in Docket No. 000001-EI was heard by the Florida Public Service Commission at the time and place herein stated.

It is further certified that I stenographically reported the said proceedings; that the same has been transcribed under my direct supervision; and that this transcript, consisting of 182 pages, Volume 1 constitutes a true transcription of my notes of said proceedings and the insertion of the prescribed prefiled testimony of the witnesses.

I FURTHER CERTIFY that I am not a relative, employee, attorney or counsel of any of the parties, nor am I a relative or employee of any of the parties' attorneys or counsel connected with the action, nor am I financially interested in the action.

DATED THIS 30TH DAY OF NOVEMBER, 2000.

Jane Faurot

JANE FAUROT, RPR
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Chief, Bureau of Reporting
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