BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

In the Matter of	:	**DOCKET NO. 980001-EI**
Fuel and purchased power cost recovery clause and generating performance incentive factor.	:	

PROCEEDINGS: **HEARING**

BEFORE: COMMISSIONER SUSAN F. CLARK
COMMISSIONER JOE GARCIA
COMMISSIONER E. LEON JACOBS, JR.

DATE: **Wednesday, February 25, 1998**

TIME: Commenced at 9:30 a.m.
Concluded at 10:30 a.m.

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

REPORTED BY: H. RUTHE POTAMI, CSR, RPR
Official Commission Reporter

APPEARANCES:

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

MATTHEW M. CHILDS, Steel, Hector & Davis, 215 South Monroe Street, Suite 601, Tallahassee, Florida 32301, appearing on behalf of **Florida Power & Light Company.**

KENNETH A. HOFFMAN, Rutledge, Ecenia, Underwood, Purnell and Hoffman, P. O. Box 511, 215 South Monroe Street, Suite 420, Tallahassee, Florida 32302-0551, appearing on behalf of **Florida Public Utilities Company.**

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.**

APPEARANCES CONTINUED:

VICKI GORDON KAUFMAN, McWhirter, Reeves, McGlothlin, Davidson, Rief & Bakas, P.A, 117 South Gadsden Street, Tallahassee, Florida 32301, appearing on behalf of **Florida Industrial Power Users Group.**

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

LESLIE J. PAUGH, Florida Public Service Commission, Division of Legal Services, 2540 Shumard Oak Boulevard, Tallahassee, Florida 32399-0850, appearing on behalf of the **Commission Staff.**

I N D E X

MISCELLANEOUS

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P R O C E E D I N G S

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

COMMISSIONER CLARK: Let's call the hearing to order. We'll have the notice read.

MR. KEATING: Pursuant to notice issued January 13th, 1998, this time and place have been set for a hearing in Docket Nos. 980001-EI, fuel and purchased power cost recovery clause and generating performance incentive factor; Docket No. 980002-EG, conservation cost recovery clause; Docket No. 980003-GU, purchased gas adjustment true-up, and Docket No. 980007-EI, environmental cost recovery clause.

COMMISSIONER CLARK: We'll take appearances starting with you, Mr. Stone.

MR. STONE: Thank you, Commissioner. My name is Jeffrey A. Stone. I'm with the law firm Beggs & Lane, representing Gulf Power Company in Dockets 980001, 98002, and 980007.

MR. McGEE: James McGee, Post Office Box 14042, St. Petersburg 33733, on behalf of Florida Power Corporation in Docket 980001 and 0002.

MR. BEASLEY: I'm James D. Beasley with the law firm of Ausley & McMullen, P.O. Box 391, Tallahassee, Florida 32302, and I'm here on behalf of

Tampa Electric Company in Dockets 980001, 2, and 7.

MR. HOFFMAN: Commissioner Clark, my name is Kenneth A. Hoffman of the law firm of Rutledge, Ecenia, Underwood, Purnell and Hoffman. Our address is P.O. Box 551, Tallahassee Florida 32302. I'm here this morning on behalf of Florida Public Utilities Company in Docket Nos. 980001, 0002, and 0003.

MR. SCHIEFELBEIN: Good morning, Commissioners. Wayne Schiefelbein, Gatlin, Schiefelbein & Cowdery, 3301 Thomasville Road, Suite 300, Tallahassee 32312 appearing on behalf of Chesapeake Utilities Corporation in the 02 and 03 dockets.

MR. CHILDS: Commissioners, my name is Matthew Childs of the firm of Steel, Hector & Davis. I'm appearing on behalf of Florida Power & Light Company in the 01 and the 07 dockets.

MR. HOWE: Commissioners, I'm Roger Howe with the Office of Public Counsel, appearing on behalf of the citizens of the state of Florida in the 01, 02, 04 and 07 dockets.

MS. KAUFMAN: Vicki Gordon Kaufman of the law firm McWhirter, Reeves, McGlothlin, Davidson, Rief & Bakas. I'm appearing for the Florida Industrial Power Users Group in the 01, 02 and 07 dockets.

MS. PAUGH: Leslie Paugh on behalf of Commission Staff in the 01 and 07 dockets.

MR. KEATING: Cochran Keating on behalf of Commission Staff in the 02 and 03 dockets.

COMMISSIONER CLARK: I'd like to indicate for the record we yesterday had a phone call from Ansley Watson who, I believe, represents People's Gas. We indicated to him at that time that we didn't think it was necessary for him to come to Tallahassee from Tampa to attend this hearing because it appeared to us that the testimony would be stipulated in and the results stipulated. So he's been excused from this hearing.

All right. Any other preliminary matters? Ms. Paugh, do you want to sort of give us a road map as to what we're going to do?

MS. PAUGH: Dockets 02, 03 and 07 are completely stipulated with the exception of the generic issue of annualization. It might be appropriate to take those dockets first so that those parties may be released, and then take up 01 last, which has outstanding issues.

COMMISSIONER CLARK: Joe, I know you've done this before, but for Commissioner Jacobs' benefit, fortunately fuel adjustment and conservation cost recovery and environmental cost recovery, that we are usually able to work things out to the satisfaction of all parties; and what we do is stipulate the testimony into the record and then approve the stipulations that have been agreed to by all the parties.

What makes these cases different is that there has been a request to go to annual fuel adjustment proceedings. I had indicated, as prehearing officer, I thought that was an issue that should go to the full Commission.

What remains to be decided by the panel is, as I understand it, whether or not we should institute a six-month or nine-month adjustment for FP&L in anticipation of what the full Commission might do.

Have I characterized that correctly?

MS. PAUGH: That's correct. And with respect to all of the generic issues, there has been a ruling made to go to the full Commission, and a separate docket has been set up and it has been set for a workshop already.

COMMISSIONER CLARK: Okay. Well, if you would, would you walk me through the dockets you suggested? Was it 02, 03, and then 07?

MS. PAUGH: That's correct.

COMMISSIONER CLARK: All right. Let's walk through those and get the testimony into the record and approve the stipulations that were offered.

* * * * *

MS. PAUGH: With respect to the 01 docket all issues and subissues except the following have been stipulated by the parties:

Issue 4 with respect to FPL has not been stipulated. With respect to the remainder of the parties, is it has been.

Issue 7 with respect to FPL has not been stipulated. With respect to the remainder of the parties, it has been.

Issue 10C has not been stipulated, and Issue 21E has not been stipulated.

Would the Commissioner care to go through --

COMMISSIONER CLARK: 21 -- what was the last one.

MS. PAUGH: "E" as in "ergo".

COMMISSIONER CLARK: Now, just so I'm clear, 10C and 21E are not stipulated for any of the parties?

MS. PAUGH: Those are company-specific issues to FPL, and it has not been stipulated; that's correct.

COMMISSIONER CLARK: All right. Let's go through and take care of the items that are stipulated and get the evidence in the record, and then we will hear -- I think at that point it's appropriate to hear from FPL with respect to their position on those issues; and then I think it's you, Ms. Kaufman, we would hear from.

MS. KAUFMAN: That's right, Commissioner Clark.

COMMISSIONER CLARK: Anyone else? And then Staff will make a recommendation, right?

MS. PAUGH: That is correct.

COMMISSIONER CLARK: Let's show that the testimony of the witnesses listed on Page 5 and 6 of the prehearing order will be admitted in the record as though read.

Florida Power Corporation

Docket No. 970001-EI

Fuel and Capacity Cost Recovery
Final True-up Amounts for
April through September 1997

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 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 describe the Company's Fuel Cost Recovery Clause final true-up amount for the period of April through September 1997, and the Company's Capacity Cost Recovery Clause final true-up amount for the same period.

Q. Have you prepared exhibits to your testimony?

A. Yes, I have prepared a four-page true-up variance analysis which examines the difference between the estimated fuel true-up and the actual period-end fuel true-up. This variance analysis is attached to my prepared testimony and designated Exhibit No. 1 (JS-1). Also attached to my prepared testimony and designated Exhibit No. 1 (JS-2) are the Capacity Cost Recovery Clause true-up calculations for the April 1997 through September 1997 period. My third exhibit will present the revenues and expenses associated with the purchase of the Tiger Bay facility approved in Docket 970096-EQ and the corresponding amortization. This presentation is also attached to my prepared testimony and designated Exhibit No. 1 (JS-3). Also, I will sponsor the applicable Schedules A1 through A9 for the period-to-date through September 1997, which have been previously filed with the Commission, but have been revised to exclude Lake Cogen settlement payments and CR3 replacement fuel. These schedules are also attached to my prepared testimony for ease of reference and designated as Exhibit No. 2 (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 September 30, 1997 for fuel cost recovery?

A. The actual ending balance as of September 30, 1997 for true-up purposes is an underrecovery of **$8,219,498**.

Q. How does this amount compare to the Company's estimated ending balance included in the October 1997 through March 1998 period?

A. When the estimated underrecovery of $9,062,289 to be collected during the period of October 1997 through March 1998 is taken into account, the final true-up attributable to the six-month period ended September 30, 1997 is an overrecovery of **$842,791**.

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 but adjusted to remove the costs incurred by FPC associated with the recalculation of the firm energy price to Lake Cogen Limited which amounted to $1.6 million on a retail basis, subject to final Commission order in Docket No. 961477-EQ. Additionally, the schedules were adjusted to remove the CR3 replacement fuel costs plus interest in accordance with the conditions set forth and approved in Docket 970261-EI.

Q. What factors contributed to the period-ending jurisdictional underrecovery of $5.9 million shown on your exhibit JS-1?

A. The factors contributing to the underrecovery are summarized on JS-1, Sheet 1 of 4. The actual jurisdictional kWh sales were lower than the original estimate by 446,897,566 kWh. This decrease in kWh sales, attributable to abnormally mild weather, resulted in lower jurisdictional fuel revenues of $31.5 million. The $17.2 million favorable variance in jurisdictional fuel and purchased power expense was primarily attributable to lower system net generation resulting from abnormally mild weather. The replacement fuel costs associated with the CR3 outage were excluded from fuel, as presented on schedule A2 page 3 of 4 line D12b, and absorbed by Florida Power or recorded as a regulatory asset in accordance with the stipulation approved by the Commission in Docket 970261-EI.

When the differences in jurisdictional revenues and jurisdictional fuel expenses are combined, the net result is an underrecovery of $14.3 million related to the April through September 1997 period. Other factors not directly related to the period include a $10.2 million recovery of prior period costs and $1.8 million in interest. This results in the actual ending underrecovery balance of $5.9 million, as of September 30, 1997.

Q. Please explain the components shown on exhibit JS-1, Sheet 2 of 4 which produced the $51.7 million unfavorable system variance from the projected cost of fuel and net purchased power transactions.

A. Sheet 2 of 4 shows an analysis of the system variance for each energy source in terms of three interrelated components: (1) changes in the amount (MWH's) of energy required; (2) changes in the heat rate, or efficiency, of generated energy (BTU's per KWH); and (3) changes in the unit price of either fuel consumed for generation ($ per million BTU) or energy purchases and sales (cents per KWH).

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

A. As can be seen from Sheet 2 of 4, variances in the amount of MWH requirements from each energy source (column B) combined to produce a cost increase of $62.9 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 $4.6 million. This variance was the direct result of having to use less efficient fuel sources due to the nuclear unit's unavailability for dispatch.

A cost decrease of $15.8 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 4, of exhibit(JS-1). The most significant factor contributing to the favorable variance was the larger than expected decrease in summer heavy oil prices of $9.2 million. The favorable variance of $2.8 million resulted from Crystal River No. 3 being off-line and not having to remit a nuclear disposal payment during the true-up period.

Q. What were the major contributors to the $62.9 million cost increase associated with the variance in MWH requirements?

A. The effect of the Crystal River Unit 3 outage on the costs associated with changes in generation mix is the primary reason for the unfavorable variance in MWH requirements. Although this interrelationship is generally understood to exist, it is not readily apparent from the individual variances contained in the "A" Schedules or in the analysis presented on Sheet 2 of 4. For example, a decrease in the MWH requirements of nuclear generation shows up on Schedule A3 and on Sheet 2 of my exhibit as a cost decrease of $10.4 million. While this may be correct in isolation, the true effect of decreased nuclear generation is obviously a corresponding increase in the MWH requirements of a number of other more costly energy sources. As seen on Sheet 3 of 4, Columns C through G, the result is a higher MWH use of more costly energy sources. Sheet 3 of 4, Column B, also identifies the higher net system cost of $68.6 million which results from the change in generation mix, even if total system MWH requirements remain unchanged.

Q. Please explain the analysis shown on Sheet 3 of 4 of JS-1.

A. This analysis quantifies the replacement fuel cost of CR3, computed using the production cost program PROMOD. Actual data for load, fuel and purchased power prices, and unit availabilities were used in the calculations. PROMOD computes the difference in system costs with and without the nuclear unit. Crystal River 3 was assumed to operate at the originally projected GPIF targets. The procedure used to compute replacement cost is the same as has been used in previous replacement cost determinations before this Commission.

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

A. Yes, my exhibit JS-4 shows other jurisdictional adjustments to fuel expense. Noteworthy adjustments include recovery of the cost of the Company's natural gas conversion projects for Intercession City P7-10, Debary P7 and P9, Bartow P2 and P4, and Suwannee P1.

Q. Did ratepayers benefit from the investment in the Gas Conversion projects approved by the Commission?

A. Yes. For the true-up period, the estimated system fuel savings related to the gas conversion projects was $12,559,885. The total system depreciation and return was $996,637, resulting in a net system benefit to ratepayers of $11,563,248. A schedule of depreciation and return by gas conversion unit relating to these system totals is included on JS - 1, Sheet 4 of 4.

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

A. Yes, in prior six-month fuel adjustment periods, the Company has passed through $749,499 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 1996. Additionally, the company has incurred $743,750 of expense for the purchase of 8,500 SO_2 allowances. Under the provisions of the Clean Air Act Amendments of 1990 a percentage of Florida Power's allowances are withheld each year to populate a pool of allowances which EPA offers for sale at auction. Anyone can purchase but 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 which provided the allowances.

During the current true-up period, the Company incurred $207,600 of expense for the purchase of 2,400 EPA Sulfur Dioxide Emission Allowances. The expense was almost entirely offset from the $207,305 of proceeds received from the sale of 1,952 EPA SO_2

allowances for 1997. Florida Power looked ahead to the post-2000 time period when the Company will need to hold sufficient allowances to cover expected emissions. Projecting a deficit, Florida Power entered the SO_2 market and purchased allowances at a price considerably below the cost of other compliance options. Since the purchase was funded by the proceeds from the sale of withheld allowances, only the difference of $295 was included in recoverable fuel costs. In the future Florida Power may purchase additional allowances depending on market conditions and the Company's SO_2 compliance status.

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

A. Yes. On January 20, 1997, Florida Power entered into an agreement with Tiger Bay Limited Partnership to purchase the Tiger Bay cogeneration facility and terminate five related purchase power agreements (PPAs). The purchase, approved pursuant to a stipulation in Docket No. 970096-EQ, was closed on July 15, 1997, at which time Tiger Bay became one of Florida Power's generating facilities. Under the terms of the stipulation, Florida Power will continue to collect revenues from its ratepayer's as if the five related PPAs were still in effect. The revenues collected would then 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 recovery used to amortize the principle of the regulatory asset. Approximately $75 million of the purchase price was included in the rate base. The remaining amount was set up as a regulatory asset for both the wholesale and retail jurisdictions, according to Florida Power's jurisdictional separation at that time.

The method for amortizing the Tiger Bay regulatory asset approved in the stipulation, using PPA revenues minus fuel expense and interest, results in the retail regulatory asset being fully amortized by January 2008. As of the period ending September 30, 1997, the Tiger Bay retail regulatory asset balance, computed in accordance with the approved stipulation, and presented on JS-3, Sheet 1 of 1, stands at $350,676,037.

CAPACITY COST RECOVERY

Q. What is the Company's jurisdictional ending balance as of September 30, 1997 for capacity cost recovery?

A. The actual ending balance as of September 30, 1997 for true-up purposes is an underrecovery of $6,593,565.

Q. How does this amount compare to the Company's estimated ending balance included in the October 1997 through March 1998 period?

A. When the estimated underrecovery of $8,361,941 to be collected during the period of October 1997 through March 1998 is taken into account the final true-up attributable to the six month period ended September 1997 period is an overrecovery of $1,768,376.

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, but was adjusted to remove the costs incurred by Florida Power relating to the change in capacity rates and the buyout payments to Lake Cogen Limited that amounted to $3.3 million. Also excluded were the costs incurred by Florida Power for buyout payments to Orlando Cogen that amounted to $6.4 million and are subject to approval in Docket 961184-EQ.

Q. What factors contributed to the actual period-end underrecovery of $6.6 million?

A. My exhibit JS-2, Sheet 1 of 3, entitled "Capacity Cost Recovery Clause Summary of Actual True-Up Amount," compares the summary items from Sheet 2 of 3 to the original forecast for the period. As can be seen from Sheet 1, the actual jurisdictional capacity cost revenues were $7,286,672 lower than forecasted due to lower kWh usage resulting from milder than anticipated weather. Net capacity expenses were $1.0 million lower due to several cogenerators not meeting their contractual capacity factors.

Q. Does this conclude your testimony?

A. Yes, it does.

FLORIDA POWER CORPORATION

DOCKET NO. 980001-EI

Levelized Fuel and Capacity Cost Factors
April through September 1998

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 Director of Business Planning.

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 April through September 1998. My testimony also presents a set of contingent fuel cost factors that contain three months of replacement fuel costs associated with the extended outage of the Crystal River 3 nuclear plant (CR3) which, in accordance with the stipulation approved by the Commission in Docket No. 970261-EI, Florida Power is entitled to recover over a 12-month period after CR3 has returned to service. Florida Power asks that these contingent fuel cost factors be approved for the April - September 1998 period subject to confirmation that CR3 has returned to service before the beginning of the period.

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 G and the Commission's minimum filing requirements for these proceedings, Schedules E1 through E10 and H1, which contain the Company's levelized fuel cost factors and the supporting data. Parts A through C contain the assumptions which support the Company's cost projections, Part D contains the Company's capacity cost recovery factors and supporting data. Part E contains a calculation of costs the Company proposes to recover during the period for the conversion of an additional combustion turbine to natural gas firing. Part F recomputes the Company's true-up balances through November 1997 to exclude replacement power costs and related interest associated with the extended outage of CR3, as well as any costs associated with the Lake Cogen settlement recently disapproved by the Commission in Docket No. 961477-EQ. Part G calculates contingent fuel cost factors which include the stipulated replacement fuel costs that Florida Power will be entitled to recover if CR3 returns to service before the projection period.

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 2.015 ¢/kWh (before line loss adjustment). The basic factor consists of a fuel cost for the projection period of 2.0179 ¢/kWh (adjusted for jurisdictional losses), a GPIF reward of .00683 ¢/kWh, and an estimated true-up credit of 0.0117 ¢/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 1.291 On-peak and 0.842 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 2.018 ¢/kWh.

Q. What is the change in the fuel factor from the current to the projected period?

A. The average fuel factor increases from 1.821 to 2.015 cents per kWh, an increase of 10.7%.

Q. Please explain the reasons for the increase.

A. The primary reason for the increase in the fuel factor is that the summer period is typically a higher cost period than the winter period because of significantly higher consumption. System requirements (Schedule E-1, line 20) are 3,840 GWh or 24% higher during upcoming April - September summer period than they were during the prior October through March winter period. Since the least expensive sources of generation, nuclear and coal, are fully utilized during both periods, the additional generation required during the summer period is supplied by more expensive oil and gas fired units and by purchases. The change in fuel mix increases the cost of generation 8.6% from 1.6 to 1.74 cents/kWh. The prices for oil and coal in this projection are actually lower than prices forecast for the October through March period.

A more subtle but significant seasonal factor is the change in Unbilled Sales (line 21) between the summer and winter periods. Unbilled Sales change 1,164 GWh from the current winter period to the projected summer period. This change alone increases the fuel factor in the summer period by 0.14 cents/kWh or 8%.

There are no other unusual assumptions or events included in this projection that contribute to the increase in the fuel factor.

Q. In accordance with the stipulation approved by the Commission in Docket No. 970261-EI, Florida Power is entitled to recover $32.3 million (retail portion excluding interest) in replacement fuel costs over a 12-month period after CR3 returns to service and operates for 14 days. How has that recovery amount been treated in this filing?

A. Florida Power expects that CR3 will be fully operational, as defined in the stipulation, before the April - September 1998 projection period. However, since CR3's operational status cannot be known with certainty at the time of this filing, Florida Power has not included the stipulated recovery amount in the calculation of its fuel cost factors shown in the "E" Schedules of my exhibit. Instead, I have presented the calculation of contingent fuel cost factors that include the stipulated recovery amount in Part G of my exhibit.

Florida Power asks that these contingent fuel cost factors be approved in the event CR3 is fully operational at the time of the February hearings. In the event CR3's operational status cannot be confirmed at the time of the hearing, Florida Power asks that the contingent fuel cost factors be approved conditionally. Under this conditional approval, the contingent fuel cost factors would become effective for the April - September 1998 period only if Florida Power files a notice with the Commission by March 27, 1998 (the first day of

April cycle billings) certifying that CR3 has satisfied the operational requirements of the stipulation.

Q. What portion of the stipulated replacement fuel costs would be recovered through the contingent fuel cost factors during the April - September 1998 period?

A. Part G of my exhibit shows that $18,371,207, or 0.10705 cents per kWh (Schedule E1, line 28b), of the stipulated recovery amount would be recovered in the April - September 1998 period. This amount was calculated by taking the retail amount of stipulated replacement fuel costs ($32.3 million), adding interest ($2.28 million), then dividing the total by projected jurisdictional sales for the 12-month period from April 1998 through March 1999. The resulting factor of 0.10705 cents per kWh is then multiplied by projected sales for the upcoming April - September 1998 period to arrive at the $18.4 million six-month recovery amount.

Q. What will be the effect on residential rates of including the stipulated replacement fuel amount in the fuel cost factors for the April - September 1998 period?

A. Adding the stipulated replacement fuel amount will increase the fuel cost factors by 0.107 cents per kWh. The typical residential bill for 1,000 kWh would be $85.72, resulting in a $0.89 (1%) increase from current rates, instead of a $0.21 decrease without the replacement fuel amount, or a change or $1.10.

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 nine combustion turbine units to burn natural gas instead of distillate oil. Recovery of the conversion of Intercession City units 7 through 10, Debary units 7 & 9, Bartow units 2 & 4 and Suwannee unit 1 have already been approved by this Commission. In this filing the Company is requesting approval to add the conversion costs of an additional unit located at Suwannee beginning in June, 1998

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

A. Line 6 includes energy costs for the purchase of 50 MWs from Tampa Electric Company and the purchase of 405 MWs under a Unit Power Sales (UPS) agreement with the Southern Company. Beginning January 1998, the SERC ratings of the units supporting this purchase will be revised to 405 MW. The capacity payments associated with the UPS contract are based on the original contract of 400 MW. The additional 5 MW are the result of revised SERC ratings for the five units involved in the unit power purchase, providing a benefit to Florida Power Corporation 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. Capacity costs for 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 includes energy costs for purchases from Seminole Electric Cooperative (SECI) for load following, off-peak hydroelectric purchases from the Southeast Electric Power Agency (SEPA), and miscellaneous economy purchases from within or outside the state which are not made through the Florida Broker System. 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 factor. Such non-fuel charges, if any, are reported on line 10.

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

A. The Company has a wholesale contract with Seminole for the sale of supplemental energy to supply the portion of their load in excess of 703 MW. The fuel costs charged to Seminole for these 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. The Company also has wholesale contracts with the municipal utilities of Kissimmee and St. Cloud and with Georgia Power Company under which fuel costs are charged in a similar manner. 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 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 cost basis in this proceeding, while actually recovering the costs from these customers on a higher, stratified cost basis. The development of this adjustment is shown on Schedule E6.

Q. How was the estimated true-up shown on line 28 of Schedule E1 developed?

A. The estimated true-up calculation implements the provision of the CR3 stipulation requiring the exclusion of all CR3 replacement fuel costs until after the unit has returned to normal operations. In order to calculate a proper true up amount for the April through September 1998 period, replacement fuel costs and associated interest, along with costs associated with the Lake Cogen settlement which had previously been included in fuel underrecovery balances reported in the Company's "A" Schedules, were removed. Part F of my exhibit shows the development of this adjustment. This results in a restated November 1997 balance of $9,053,198. The balance was projected to the end of March 1998, including interest estimated at the November ending rate of 0.462% per month. The development of the estimated true-up amount for the current October 1997 through March 1998 period is shown on Schedule E1B, Sheet 1 and summarized on Schedule E1A. The current period estimated over-recovery of $10,226,809 was combined with the prior period ending balance of $(8,219,498) for a total over-recovery of $2,007,311 at the end of March 1998. This results in an estimated true-up credit on line 28 of Schedule E1 (Basic) of 0.1170 ¢/kWh for application in the April through September 1998 projection period.

Q. What are the primary reasons for the projected March 1998 over-recovery of $2.0 million?

A. The $8.2 million actual under-recovery for the period ending September 1997 being rolled forward into the current period, and lower than expected oil prices, were the primary factors contributing to the $2.0 million over-recovery in March.

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 11, following the refueling outage) was developed from the projected cost of fuel added during the current period's refueling outage and the unamortized investment cost of the fuel remaining in the reactor from the prior cycle (Cycle 10). Cycle 11 consists of several "batches," of fuel assemblies which are separately accounted for throughout their life in several fuel cycles. The cost for each batch is determined from the actual cost incurred by the Company, which is audited and reviewed by the Commission's field auditors. The expected available energy from each batch over its life is developed from an evaluation of various fuel management schemes and estimated fuel cycle lengths. From this information, a cost per unit of energy (cents per million BTU) is calculated for each batch. However, since the rate of energy consumption is not uniform among the individual fuel assemblies and batches within the reactor core, an estimate of consumption within each batch must be made to properly weigh the batch unit costs in calculating a composite unit cost for the overall fuel cycle.

Q. How was the rate of energy consumption for each batch within Cycle 11 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 11 is \$0.327 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 PROMOD, along with purchased power information, generating unit operating characteristics, maintenance schedules, and other pertinent data. PROMOD 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 Business Planning Department using the most recently available data. The forecast used for this projection period was prepared in June 1997.

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 Fuel and Special Projects 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.

Q. Please explain the basis for requesting recovery of the cost of converting Suwannee combustion turbine unit #3 to burn natural gas.

A. In Docket No. 850001-EI-B, Order No. 14546 issued on July, 1985, the Commission addressed charges appropriate for recovery through the fuel clause:

> "Fossil fuel-related costs normally recovered through base rates but which were not recognized or anticipated in the cost levels used to determine current base rates and which, if expended, will result in fuel savings to customers. Recovery of such costs should be made on a case by case basis after Commission approval."

Since August of 1995, the Company has converted Intercession City units 7-10, Debary Units 7 & 9, Bartow Units 2 & 4 and Suwannee Unit 1 to burn natural gas. The Commission authorized the Company to recover the conversion cost, including a return on investment, over a five-year period in Order No. PSC-95-1089-FOF-EI dated September 5, 1995. The Company is asking the Commission for the same treatment for one additional units. The conversion cost for Suwannee Unit 3 is $1.9 million. This cost was not part of the cost of the unit when they were included in rate base as part of the 1993 test year.

Q. How is Florida Power proposing to recover the conversion cost?

A. The Company proposes to amortize the $1.9 million conversion cost over a five year period beginning with the plant in-service date of June, 1998. The projected cost during the April 1998 through September 1998 period is $173,125 which consists of an amortization charge of $110,834 and a return (including income taxes) of $62,291 based on the Company's current cost of capital of 8.37%. The fuel savings for the same period are expected to be $225,000 resulting in a net benefit to customers of $51,875. During the five year amortization period, the conversion is estimated to reduce fuel cost by $3.2 million in nominal Dollars for a net benefit of $800,000.

A monthly schedule of amortization expenses and projected fuel savings for April through September 1998 is attached as Part E of my exhibit.

Q. Why is the Company proposing a five-year amortization period rather than expensing the conversion cost or depreciating it over the life of the units?

A. The Company chose five years in order to align recovery of cost with anticipated benefits. The Company is relying on the availability of interruptible gas transportation for the delivery of gas to the site because firm (take or pay) contracts are not economical for a low capacity factor peaking site. The Company is confident that interruptible gas will be available in sufficient quantity to power the two units at the site for the next five years. The Company hopes that some gas will be available beyond that time which will yield additional savings, but we believe it more appropriate to recover costs during the time when the majority of benefits are expected to occur. Amortizing the conversion over the life of the units could burden future customers with costs that do not have corresponding benefits.

Q. What is the Company proposing to do if expected fuel savings are not achieved?

A. As it has done for previous conversions, the Company is willing to assume the risk for achieving projected fuel savings. If fuel savings during any annual period are less than the amortization and return costs, we will limit cost recovery to fuel savings and defer recovery of the difference to future periods. In no case will the Company collect an amount greater than the fuel savings, making this a no-lose proposition for customers.

CAPACITY COST RECOVERY

Q. How was the Capacity Cost Recovery factor developed?

A. The calculation of the capacity cost recovery factor (CCRF) 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 after two months of the current period and re-forecasts the over/(under) recovery balances for the next four months to obtain an ending balance for the current period. This estimated/actual balance of $4,007,164 is then carried forward to Sheet 1, to be refunded during the April through September 1998 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 1996 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 CCRF 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 CCRF for primary and transmission rate classes reflect the application of metering reduction factors of 1% and 2% from the secondary CCRF.

Q. Please discuss the increase in capacity payments compared to the prior six-month period.

A. The increase in capacity payments from $143.2 million in the October 1997 through March 1998 period to $144.9 million for the April through September 1998 period is due to the escalation to the 1998 payment schedule. No new contracts begin before September 1998. The decrease in rates, exhibited on Sheet 5 of Part D on a cents per kWh basis, is due to the greater amount of kWh sales projected for the summer period as compared to the current period.

Q. Does this conclude your testimony?

A. Yes.

FLORIDA POWER CORPORATION
DOCKET NO. 970001-EI

Re: GPIF Reward/Penalty Amount for April through September 1997

DIRECT TESTIMONY OF DARIO B. ZULOAGA

Q. Please state your name and business address.

A. My name is Dario B. Zuloaga. My business address is P. O. Box 14042, St. Petersburg, Florida 33733.

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

A. I am employed by Florida Power Corporation as a Principal Engineer in Energy Supply, Performance 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) amount for the period of April through September 1997. This was developed by comparing the actual performance of the Company's six 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 (DBZ-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 $1,172,147. 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 in 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 Table 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 the actual equivalent availability concern primarily the difference between target and actual planned outage hours for all the GPIF units 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.

In addition, Florida Power has made an adjustment to the actual equivalent availability data to remove maintenance hours and load deratings associated with an algae infestation which occurred in the Gulf of Mexico and traveled into the intake canal of Anclote Units 1 and 2. The algae infestation caused pluggage problems in the steam condensers and the circulating water system which prevented the units from returning to service until the infestation dispersed. Florida Power believes this event is properly classified as a natural disaster, the effects of which are to be excluded from the EAF calculation according to the Implementation Manual. The total maintenance hours removed were 194.80 for Unit 1, and 230.03 for Unit 2. The total derated hours were 18.80 for Unit 1, and 9.46 for Unit 2. Sheet 6 of my exhibit also contains the details for the algae infestation adjustment.

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 23 of my exhibit shows a comparison of target and actual planned outage hours in bar-chart form. Sheets 24 and 25 present as-worked critical path charts for each unit which experienced a planned outage during the period.

Q. Does this conclude your testimony?

A. Yes.

FLORIDA POWER CORPORATION

DOCKET NO. 980001-EI

GPIF Targets and Ranges for April through September 1998

DIRECT TESTIMONY OF DARIO B. ZULOAGA

Q. Please state your name and business address.

A. My name is Dario B. Zuloaga. My business address is Post Office Box 14042, St. Petersburg, Florida 33733.

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

A. I am employed by Florida Power Corporation as a Principal Engineer in Energy Supply, Performance Services.

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

A. Yes, they have.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present the development of the Company's Generating Performance Incentive Factor (GPIF) targets and ranges for the period of April through September, 1998. This development includes the targets and improvement/degradation ranges for unit equivalent availability and unit average net operating heat rate in accordance with the Commission's Generating Performance Incentive Implementation Manual.

Q. Do you have an exhibit to your testimony?

A. Yes, I will sponsor an exhibit containing 75 pages, which consists of the GPIF standard form schedules prescribed in the Implementation Manual and supporting data, including unplanned outage rates, net operating heat rates, and computer analyses and graphs for each of the individual GPIF units, all of which are attached to my prepared testimony.

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

A. We have included the same units as were included for the current period, Crystal River Units 1, 2, 4 and 5 and Anclote Units 1 and 2. The Crystal River 3 Nuclear Unit is scheduled to be available for service starting in January, 1998. Therefore, we have reinstated Crystal River 3 as part of the GPIF units.

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

A. Yes, I have. This information is included in the Target and Range Summary on page 3 of my exhibit.

Q. How were the equivalent availability targets developed?

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

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

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

A. The EAF target for Crystal River Unit 3 is 92.85%. Since no planned outages are scheduled for the upcoming summer period, the unit's EUOR and EUOF targets are both 7.15%.

The availability targets for the current period were developed using historical data from October 1993 through September 1996, due to the fact that the unit has not been available since September 14, 1996. We selected this three year period to reflect a more accurate projection of our nuclear unit's operating history. This three years of historical data is different than all the other GPIF units for this period (October 1994 through September 1997).

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

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

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

A. Yes, I have. This information is included in the Target and Range Summary on Page 3 of my exhibit.

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

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

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

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

Q. How were the GPIF weighting factors determined?

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

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

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

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

TESTIMONY OF RENE SILVA

DOCKET NO. 980001-EI

JANUARY 12, 1998

Q. Please state your name address.

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

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

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

Q. Have you previously testified in this docket?

A. Yes.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present and explain FPL's projections for (1) dispatch costs of heavy fuel oil, light fuel oil, coal and natural gas, (2) availability of natural gas to FPL, (3) generating unit heat rates and availabilities, and (4) quantities and costs of interchange and other power transactions. These projected values were used as input values to the PROSYM model in the calculation of the proposed fuel cost recovery factor for the period April through December, 1998.

Q. Why does your testimony cover the period April through December, 1998?

A. As stated in the testimony of Ms. Korel Dubin, FPL supports Fuel Cost Recovery filings that cover a twelve-month period and that will correspond to the calendar year. As part of the transition to annual filings, FPL has filed a Fuel Cost Recovery Factor that covers the projected period from April through December, 1998. Consequently, my testimony addresses the April through December, 1998 period. The six month calculation of fuel costs and resulting fuel factor is also shown in Appendix III.

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

A. Yes, I have. It consists of pages 1 through 13 of Appendix I of this filing.

Q. In addition to the "Base Case" fuel price forecast, ha.: 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. Our short-term fuel price forecast "Base Case" is prepared in October. It is possible that the conditions that affect the prices of these fuels could change significantly by the date of the filing in early January. For example, fuel oil and gas prices have recently been very volatile, and in fact these prices have dropped from the levels assumed in the October forecast. 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 January fuel price update to rerun our PROSYM system simulation in order to reflect recent changes and still meet our January 12 filing date. Furthermore, while FPL has, in the past, rerun its projections and refiled its fuel cost recovery factor after its initial filing to address changes to the forecast, this approach does not provide the same flexibility to react to changing conditions that use of a banded forecast would provide. Trying to incorporate "last minute" changes still runs the 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 to describe future fuel prices, FPL prepared in October, 1997 "Low" and "High" fuel price forecasts to define a reasonable range of fuel oil and gas prices. We then used these alternate forecasts as inputs to the PROSYM model to determine what the Fuel Factor would be if it were based on fuel prices at either end of this range. This gives us the flexibility to adopt the Fuel Factor that most appropriately reflects our view of future fuel oil and 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 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 gas, as well as the projection for gas availability. Then it describes the "Low" and "High" price forecasts for fuel oil and 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 April through December, 1998 period?

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

In general, world demand for crude oil and petroleum products is projected to be higher in 1998 due to continued world economic growth. However, crude oil supply, augmented by Iraqi oil exports and slightly higher OPEC production quotas, is projected to meet this increase in demand. As a result, crude oil prices and consequently heavy fuel oil prices, for the April through December, 1998 period will be somewhat lower than in 1997.

Q. What is the projected relationship between heavy fuel oil and crude oil prices during the April through December, 1998 period?

A. The price of heavy fuel oil on the U. S. Gulf Coast (1.0% sulfur) is projected to be approximately 75% of the price of West Texas Intermediate (WTI) crude oil.

Q. Please provide FPL's projection for the dispatch cost of heavy fuel oil for the April through December, 1998 period.

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

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

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

Q. Please provide FPL's projection for the dispatch cost of light fuel oil for the period from April through December, 1998.

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

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

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

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

In the case of SJRPP, FPL will continue to blend petroleum coke with the coal in order to reduce fuel costs. It is anticipated that petroleum coke will represent 15% of the fuel blend at SJRPP during 1998. The lower price of petroleum coke is reflected in the weighted average price of fuel delivered to SJRPP.

Q. Please provide FPL's projection for the dispatch cost of coal for the April through December, 1998 period.

A. FPL's projected system average dispatch cost of coal, shown on page 5 of Appendix I, is about $1.60 per million BTU, delivered to plant.

Q. What are the factors that can affect FPL's natural gas prices during the April through December, 1998 period?

A. In general, the key factors are (1) domestic natural gas demand and supply, (2) natural gas imports, (3) heavy fuel oil prices and (4) the terms of FPL's gas supply and transportation contracts. For the April through December, 1998 period, the dominant factor influencing the projected price of natural gas is our perception that growth in natural gas deliverability from the U.S. Gulf Coast to the market will match the increase in demand. As a result, 1998 gas prices are projected to be very close to those in 1997.

Q. What are the factors that affect the availability of natural gas to FPL during the April through December, 1998 period?

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

The current capacity of natural gas transportation facilities into the State of Florida is 1,455,000 million BTU per day (including FPL's firm allocation of 455,000 to 630,000 million BTU per day during this period, depending on the month). Total demand for natural gas in the State during the period (including FPL's firm allocation) is projected to be between 90,000 and 245,000 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 455,000 to 630,000 million BTU per day of firm, "guaranteed" allocation, should it be economically attractive, relative to other energy choices.

Q. Please provide FPL's projections for the dispatch cost and availability (to FPL) of natural gas for the April through December, 1998 period.

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

"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 analysts, there is less than a 10% likelihood that the actual price of each fuel for each month in the April through December, 1998 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 on page 7 of Appendix I, 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 on page 8 of Appendix I. FPL's projections of the system average dispatch cost of natural gas based on the "Low" price forecast are provided on page 9 of Appendix I.

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 analysts, there is less than a 10% likelihood that the actual price of each fuel for each month in the April through December, 1998 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 on page 10 of Appendix I, 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 on page 11 of Appendix I. FPL's projections of the system average dispatch cost of natural gas based on the "High" price forecast are provided on page 12 of Appendix I.

Q. Based on FPL's current (January, 1998) view of the fuel oil and gas markets, at what level do you now project prices will be during the April through December, 1998 period ?

A. Based on current market conditions, and consistent with the trend of decreasing oil and gas market prices since the end of November, 1997, FPL now projects that actual fuel oil and gas prices during the April through December, 1998 period will be significantly lower than those projected in the Base Case forecast. In other words, fuel oil and gas prices are now projected to be closer to on average, to those in the "Low" forecast than the Base Case during 1998. Therefore, the projected fuel costs calculated by PROSYM using the "Low" oil and gas forecast are the most appropriate projected costs for the April through December, 1998 period. As stated in the testimony of Korel Dubin, the "low" oil and gas forecast was used to calculate the proposed fuel factors for the period April 1998 through December 1998. Use of the "Low" forecast produces results that should be reasonably close to results that would be produced by use of a new, revised "Base Case" forecast.

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 on Schedule E4 of Appendix II.

A. The projected Average Net Operating Heat Rates were calculated by the PROSYM 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 PROSYM for this calculation. The heat rate equations and efficiency factors are updated as appropriate, based on historical unit performance and projected changes due to plant upgrades, fuel grade changes, or results of performance tests.

Q. Are you providing the outage factors projected for the period April through December, 1998?

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

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

A. The unplanned outage factors were developed using the actual historical full and partial outage event data for each of the units. The historical unplanned outage factor of each generating unit was adjusted, as necessary, to eliminate non-recurring events and recognize the effect of planned outages to arrive at the projected factor for the April through December, 1998 period.

Q. Please describe significant planned outages for the April through December, 1998 period.

A. Planned outages at our nuclear units are the most significant in relation to Fuel Cost Recovery. Turkey Point Unit No.3 is scheduled to be out of service for refueling beginning on September 28, 1998 and until November 7, 1998, or forty-one days during the projected period. St. Lucie Unit No.2 will be out of service for refueling beginning on November 9, 1998 and until December 19, 1998, or forty-one days during the projected period. There are no other significant planned outages during the projected period.

Q. Are any changes to FPL's "continuous" generation capacity planned during the April through December, 1998 period?

A. Yes, Net Winter Continuous Capability (NWCC) at Port Everglades Unit No.4 will increase by 19 MW, from 387 MW to 406 MW, as a result of refurbishing the unit's boiler and steam turbine. In addition, NWCC at Martin Unit No.2 will increase by 25 MW, from 805 MW to 830 MW, as a result of replacing the unit's generator rotor.

INTERCHANGE and PURCHASED POWER TRANSACTIONS

Q. Are you providing the projected interchange and purchased power transactions forecasted for April through December, 1998?

A. Yes. This data is shown on Schedules E6, E7, E8, and E9 of Appendix II 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 on Schedules E6, E7, E8 and E9 of Appendix II of this filing were developed using the "Low" 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; UPS Replacement Energy - Schedule R and Economic Energy Participation - Schedule EP.

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

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

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

Q. Please provide the projected energy costs to be recovered through the Fuel Cost Recovery Clause for the power purchases referred to above during the April through December, 1998 period.

A. Under the UPS agreement FPL's capacity entitlement during the projected period is 914 MW from April through December, 1998. 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 PROSYM, is based on data provided by the Southern Companies. For the period, FPL projects the purchase of 1,953,510 MWH of UPS Energy at a cost of $36,797,960. In addition, we project the purchase of 1,280,450 MWH of UPS Replacement energy (Schedule R) at a cost of $20,655,170. The total UPS Energy plus Schedule R projections are presented on Schedule E7 of Appendix II.

Energy purchases from the JEA-owned portion of the St. Johns River Power Park generation are projected to be 2,413,610 MWH for the period at an energy cost of $38,158,570. 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 336,162 MWH at a cost of $1,203,200. These projections are shown on Schedule E7 of Appendix II.

In addition, as shown on Schedule E8 of Appendix II, we project that purchases from Qualifying Facilities for the period will provide 4,191,840 MWH at a cost to FPL of $76,278,693.

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 PROSYM model to project FPL's avoided energy cost that is used to set the price of these energy purchases each month. For those contracts that enable FPL to purchase firm capacity and energy, the applicable Unit Energy Cost mechanism prescribed in the contract is used to project monthly energy costs.

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

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

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

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

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

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

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

A. We have projected 408,732 MWH of Economy energy sales for the period. The projected fuel cost related to these sales is $9,634,997. The projected transaction revenue from the sales is $12,439,969. Eighty percent of the gain for Schedule C is $2,243,978 and is credited to our customers.

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

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

Q. What are the forecasted amounts and costs of Economy energy purchases for the April to December, 1998 period?

A. The costs of these purchases are shown on Schedule E9 of Appendix II. For the period FPL projects it will purchase a total of 2,831,600 MWH at a cost of $53,106,000. If generated, we estimate that this energy would cost $61,431,023. Therefore, these purchases are projected to result in savings of $8,325,023.

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 394,036 MWH of energy at a cost of $1,503,720. These projections are shown on Schedule E6 of Appendix II.

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 April through December, 1998, including FPL's "Low" and "High" price forecasts for fuel oil and gas supply. I have stated why I believe that the projected fuel costs developed using the "Low" forecast are the most appropriate for the April through December, 1998 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 were used as inputs to the PROSYM model in developing the projected Fuel Cost Recovery Factor for the April through December, 1998 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. 980001-EI

January 12, 1998

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 PROSYM for the calculation of the proposed fuel cost recovery factor for the period April 1998 through December 1998.

Q. Why does your testimony cover the period April through December, 1998?

A. As stated in the testimony of Ms. Korel Dubin, FPL supports Fuel Cost Recovery filings that cover a twelve-month period and that will correspond to the calendar year. As part of the transition to annual filings, FPL has filed a Fuel Cost Recovery Factor that covers the projected period from April through December, 1998. Consequently, my testimony addresses the April through December, 1998 period. The six month calculation of fuel costs and resulting fuel factor is also shown in Appendix III.

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

A. FPL's nuclear fuel cost projections are developed using energy production at our nuclear units and their operating schedules, consistent with those assumed in PROSYM, for the period April 1998 through December 1998.

Q. Please provide FPL's projection for nuclear fuel unit costs and energy for the period April 1998 through December 1998.

A. FPL projects the nuclear units will produce 188,464,230 MMBTU of energy at a cost of $0.322 per MMBTU, excluding spent fuel disposal costs for the period

April 1998 through December 1998. Projections by nuclear unit and by month are provided on Schedule E-4 of Appendix II.

Q. Please provide FPL's projections for nuclear spent fuel disposal costs for the period April 1998 through December 1998 and what is the basis for FPL's projections.

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

Q. Please provide FPL's projection for Decontamination and Decommissioning (D&D) costs to be paid in the period April 1998 through December 1998 and what is the basis for FPL's projection.

A. FPL's projection of $5.6M for D&D costs to be paid during the period April 1998 through December 1998 is included on Schedule E-2 of Appendix II.

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

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

The first dispute is under FPL's contract with DOE for final disposal of spent nuclear fuel. FPL, along with a number of electric utilities, has filed suit against DOE over DOE's denial of its obligation to accept spent nuclear fuel beginning in 1998. A July 23, 1996, ruling by the U.S. Court of Appeals for the District of Columbia Circuit (D.C. Circuit) said 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, and state utility commissions filed suit on January 31, 1997 in the D.C. Circuit (Northern States Power Co. V. DOE) requesting that the court authorize the utilities to suspend payments into the Nuclear Waste Fund (NWF) until DOE performs on its unconditional obligation to take title to and dispose of spent nuclear fuel.

On May 7, 1997, the utilities supplemented that filing by petitioning for a writ of mandamus that (1) DOE comply with its statutory obligation and begin disposing of spent nuclear fuel by January 31, 1998 or in the alternative, direct

DOE to develop a program that will enable the agency to begin disposing of spent nuclear fuel by January 31, 1998; (2) declaring that the utilities are relieved of the obligation to pay into the NWF and are authorized to place NWF collections into escrow until DOE disposes of the spent nuclear fuel; (3) prohibiting DOE from suspending the contracts with the utilities or from taking any other adverse action under the contracts; and (4) declaring that the suspension of fee payments will not adversely affect the utilities as to timing, manner, or further cost disposal entitlements by reason of such suspension of fee payments.

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. DOE invited its contract holders to comment on its preliminary finding. On August 4, 1997, FPL and other contract holders requested DOE to refrain from issuing a final determination on the issue of avoidability of delay in disposing of spent fuel pending the outcome of the lawsuit against DOE, and in the alternative, allow time for the contract holders to submit arguments addressing whether DOE has jurisdiction to hold a proceeding on the avoidability issue. On September 18, 1997, DOE declined to refrain from issuing a final decision on the unavoidability issue, but allowed the contract holders to submit written argument concerning DOE's jurisdiction to commence an unavoidability proceeding.

On November 3, 1997, FPL and other contract holders filed an objection to DOE's assertion that it could unilaterally commence a proceeding to determine whether its delay was unavoidable, and provided legal arguments why DOE lacked jurisdiction to commence such a proceeding. DOE has not yet responded to the objections filed by contract holders on November 3, 1997.

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. On December 29, 1997, DOE requested rehearing of the panel's decision.

On December 11, 1997, FPL and 26 other utilities filed a petition with DOE's Contracting Officer requesting DOE to authorize suspension of future payments to the Nuclear Waste Fund until DOE begins movement of spent fuel. The utilities have requested a response from DOE by January 9, 1998.

FPL is currently exploring options to seek money damages from DOE for failure to comply with its statutory obligation to take title to and dispose of spent nuclear fuel by January 31, 1998.

Secondly, FPL is currently seeking to resolve a price dispute for uranium enrichment services purchased from the United States (U.S.) Government, prior to July 1, 1993. 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 the DOE's rejection of the Fiscal Year 1993 overcharge claim with the U.S. Court of Federal Claims.

On December 12, 1996, the Court of Federal Claims granted the unopposed motion of all parties to suspend the overcharge proceeding pending the outcome of an appeal to the U.S. Court of Appeals for the Federal Circuit in Barseback Kraft AB v. United States, where the appellants are seeking to recover overcharges for uranium enrichment services under identical contract provisions to those at issue in FPL's overcharge claim.

On July 31, 1997, the Federal Circuit issued a decision in the Barseback case. The Court held in favor of the government in rejecting claims by foreign entities that they were overcharged for uranium enrichment services by the United States Enrichment Corporation (USEC), DOE's successor to the government's uranium enrichment business. FPL believes that the Federal Circuit's decision is not dispositive of its claim against DOE, and in fact may help FPL's claim. The Court distinguished USEC's pricing policy, concluding that USEC is not charging customers to finance D&D efforts, from DOE's pricing policy, which according to the Court "included a D&D component." This may support FPL's claim that DOE was charging an amount for D&D

costs in its enrichment charges after the D&D charges required by the Act were being collected.

Following issuance of the Barseback decision, FPL and the other claimants informed DOE that they were ready to proceed in the case. On October 20, 1997, DOE answered the complaint by denying liability. On December 1, 1997, DOE filed a motion to dismiss the case with the Court of Claims.

Meanwhile, in a related case, Yankee Atomic Electric Company had been challenging the legality 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 November 12, 1997, Yankee filed a petition for a writ of certiorari seeking review of the case by the U.S. Supreme Court. FPL will continue to follow this case and will take actions, as appropriate, consistent with the outcome of the appeal.

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. 970001-EI

November 20, 1997

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 Principal Rate Analyst in the Rates and Tariff Administration 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) Net True-Up amount for the period April 1997 through September 1997. The Net True-Up for the FCR is an underrecovery, including interest, of

$64,381,785. I am requesting Commission approval to include this true-up amount in the calculation of the FCR factor for the period April 1998 through September 1998.

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

A. Yes, I have. It consists of Appendix I which contains the FCR related schedules. FCR Schedules A-1 through A-13 for the April 1997 through September 1997 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.

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

A. Appendix I, page 3, entitled "Summary of Net True-Up", shows the calculation of the Net True-Up for the six-month period April 1997 through September 1997, an underrecovery of $64,381,785, which I am requesting be included in the calculation of the Fuel Cost Recovery Factor for the period April 1998 through September 1998. The calculation of the true-up amount for the period follows the procedures established by this Commission as set forth on Commission Schedule A-2 "Calculation of True-Up and Interest Provision".

The actual End-of-Period underrecovery for the six-month period April 1997 through September 1997 of $49,763,137 shown on line 1, less the estimated/actual End-of-Period overrecovery for the same period of $14,618,648 shown on line 2 that was included in the calculation of the Fuel Cost Recovery Factor for the period October 1997 through March 1998, results in the Net True-Up for the six-month period April 1997 through September 1997 shown on line 3, an underrecovery of $64,381,785.

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

A. Yes. Appendix I, page 4, entitled "Calculation of Final True-up Variances", shows the actual fuel costs and revenues compared to the estimated/actuals for the period April 1997 through September 1997.

Q. What was the variance in fuel costs?

A. As shown on Appendix I, page 4, line A7, actual fuel costs on a Total

Company basis were $65.4 million higher than the estimated/actual projection. This variance is primarily due to a $105.0 million increase in the Fuel Cost of System Net Generation, offset by a $23.5 million decrease in the Energy Cost of Economy Purchases and a $19.2 million variance in the Fuel Cost of Power Sold.

The increase in the Fuel Cost of System Net Generation was primarily due to 11.3% higher than anticipated oil consumption and 8.2% higher than anticipated gas consumption resulting in an approximate $51 million variance. Additionally, the unit cost of oil was 7.3% higher than projected and gas prices were 10.6% higher than projected, resulting in an approximate $54 million variance. The decrease in the Energy Cost of Economy Purchases was primarily due to hot weather in the Southeast which reduced the availability of low cost economy energy. The variance in the Fuel Cost of Power Sold was primarily due to greater than projected opportunity sales due to hot weather in the Southeast.

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

A. As shown on line D1, actual jurisdictional Fuel Cost Recovery revenues, net of revenue taxes, were $927,130 higher than the estimated/actual projection. This increase was due to higher jurisdictional kWh sales. Jurisdictional sales were 35,864,459 kWh

(0.1%) higher than the estimated/actual projection.

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

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

Q. Does this conclude your testimony?

A. Yes, it does.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

TESTIMONY OF KOREL M. DUBIN

DOCKET NO. 980001-EI

January 12, 1998

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 Principal Rate Analyst 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?

A. The purpose of my testimony is to present for Commission review and approval the fuel factors for the Company's rate schedules beginning April 1998. The calculation of the fuel factors is based on projected fuel cost and operational data as set forth in Commission Schedules E1 through E10, H1 and other exhibits filed in this proceeding and data previously approved by the Commission.

My testimony also addresses the change from a semi-annual to an annual Fuel Cost Recovery period.

My testimony presents the schedules necessary to support the calculation of the Estimated/Actual True-up amounts for the Fuel Cost Recovery Clause (FCR) for the period October 1997 through March 1998.

In addition, my testimony includes a request for a midcourse correction to the currently approved Capacity Cost Recovery Clause factors for the period of April through September 1998 and to keep these factors in place through December 1998.

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

A. Yes, I have. It consists of various schedules included in Appendix II, III and IV. Appendix II provides the Fuel Cost Recovery E-Schedules reflecting the change to an annual filing. FPL has also prepared these E-Schedules based on the six month Fuel Cost Recovery method. These schedules are provided in Appendix III.

Appendix IV provides the Capacity Cost Recovery Schedules. (Please note that FPL witness Rene Silva is sponsoring Appendix I which provides forecast assumptions). FCR Schedules A-1 through A-13 for October 1997 and November 1997 have been filed monthly with the Commission and have been 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.

The projected data is the output of our PROSYM simulation computer model. As described in the testimony of FPL witness Rene Silva, in addition to the base case forecast, FPL has developed high and low band oil and gas price forecasts to establish a range of possible future fuel prices. FPL has performed PROSYM simulations using all three forecasts in order to determine the impact on the fuel factor of fuel prices at the high and the low end of the forecast range. The low band oil and gas forecast was used to calculate the proposed fuel factors included in my testimony for the period April 1998 through December 1998. The low band forecast results in a proposed levelized fuel factor of 1.972 ¢ per kWh for the period April 1998 through December 1998.

FUEL COST RECOVERY CLAUSE

Q. Does FPL agree that the Fuel Cost Recovery period should be changed from a semi-annual to an annual recovery period?

A. Yes. FPL believes that the Fuel Cost Recovery period should be changed from a semi-annual to an annual recovery period consistent with the calendar year (January through December). In support of this, FPL requests that the annual recovery period begin with customer billings for January 1999. FPL agrees that interim petitions, like those used in the Environmental clause, be permitted in the Fuel clause for special or unanticipated issues. FPL supports a change to January through December recovery periods effective January 1999 for the other clauses (GPIF, Capacity and Environmental) all of which are already annual filings. Additionally, FPL would support a change to a January through December recovery period for the Conservation Clause (which is already an annual filing, April through March) as stated in the Conservation Cost Recovery testimony of FPL witness L. Busto.

Q. Please explain the benefits of this change.

A. FPL believes that this change to an annual recovery period will minimize the changes in customers' bills from one period to the next because it eliminates seasonality in the fuel charge. It also provides customers with greater certainty. Customers have expressed an interest in this type of change. For example, a customer preparing an annual budget will know in November what their fuel charge will be for the next year. Currently, FPL could only provide customers with charges for the first three months of the year, and there are three different changes in a year. Also, since the fuel data will be in calendar form, it will be easier to use because it will be comparable to the way other information is kept. Additionally, there will be a significant workload reduction. There will only need to be one hearing scheduled each year. And, filing fuel cost recovery on an annual basis will greatly reduce the amount of paperwork produced, filed and processed by FPL, the Commission, and other parties.

Q. Does FPL propose a schedule for this change?

A. Yes. FPL proposes the following schedule for all clauses:

True-up filing	-	Mid September 1998
Projection Filing	-	Beginning of October 1998
Discovery Period	-	Mid September - Mid November
Hearing	-	Mid November 1998
Effective date of factors	-	With customer billings from January 1999 through December 1999

Q. How does FPL propose to handle the transition period?

A. The annual recovery period would begin January 1999, therefore for transition, adjustment factors for all clauses would need to be in place through December 1998. For this transition, FPL has filed projected fuel factors for the period April 1998 through December 1998. The Conservation Testimony to be filed on January 13, 1998 already provides factors for the period April 1998 through December 1998 since it is an annual filing that covers the twelve month period from April 1998 through March 1999. For GPIF, Capacity and Environmental factors, FPL proposes to leave the current factors in place through December 1998. Another option would be to have an additional filing this summer to cover the transition period from October 1998 through December 1998 for the GPIF, Capacity and Environmental Clauses.

Q. What is the proposed levelized fuel factor for the period April 1998 through December 1998 which the Company requests approval?

A. 1.972¢ per kWh. Schedule El, Page 3 of Appendix II shows the calculation of the nine-month levelized fuel factor. Schedule E2, Page 10 of Appendix II indicates the monthly fuel factors for April 1998 through December 1998 and also the nine-month levelized fuel factor for the transition period.

Q. Has the Company developed nine-month levelized fuel factors for its Time of Use rates?

A. Yes. Schedule E1-D, Page 8 of Appendix II provides a nine-month levelized fuel factor of 2.099¢ per kWh on-peak and 1.912¢ 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, with the exception of extending the period of recovery.

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

A. As shown on line 29 of Schedule E1, Page 3, of Appendix II the estimated/actual fuel cost underrecovery for the October 1997 through March 1998 period amounts to $71,127,379. This estimated/actual underrecovery plus the final underrecovery of $64,381,785 for the April 1997 through September 1997 period results in a total underrecovery of $135,509,164. This amount, divided by the projected retail sales of 63,556,052 MWH for April 1998 through December 1998 results in an increase of .2132¢ per kWh before applicable revenue taxes.

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

A. Schedule E1-B, Page 5 of Appendix II shows the calculation of the Fuel Cost Recovery Estimated/Actual True-up amount. The calculation of the estimated/actual true-up amount for the period October 1997 through March 1998 is an underrecovery, including interest, of $71,127,379 (Column 7, lines C7 plus C8). This amount, when combined with the Final True-up underrecovery of $64,381,785 (Column 7, line C9a) deferred from the period April 1997 through September 1997, presented in my Final True-up testimony filed on November 20, 1997, results in the End of Period underrecovery of $135,509,164 (Column 7, line C11).

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

The data for October and November 1997, columns (1) and (2) reflects the actual results of operations and the data for December 1997 through March 1998, columns (3) through (6), are based on updated estimates.

The variance calculation of the Estimated/Actual data compared to the original projections for the October 1997 through March 1998 period is provided in Schedule E1-B-1, Page 6 of Appendix II.

As shown on line A5, the variance in Total Fuel Costs and Net Power Transactions is \$99.4 million a 15.4% increase from the forecast. This variance is primarily due to a \$70.4 million increase in Fuel Cost of System Net Generation, a \$14.5 million increase in Fuel Cost of Purchased Power, a \$4.5 million increase in Energy Payments to Qualifying Facilities and a \$8.0 million decrease in Energy Cost of Economy Purchases offset by a \$18.0 million variance in Fuel Cost of Power Sold.

The increase in the Fuel Cost of System Net Generation was primarily due to higher than projected oil and gas costs. An 8%

increase in the unit cost of oil and a 29% increase in the price of gas resulted in the variance of approximately $70 million. The increase in Fuel Cost of Purchased Power was primarily due to higher than originally projected UPS purchases from Southern Companies as a result of the limited availability of lower cost economy energy. In addition, purchases from SJRPP are expected to be higher than originally projected due to a change in maintenance outage dates. The increase in Energy Payments to Qualifying Facilities (QF) was primarily due to QF fuel costs being slightly higher than originally projected. The decrease in Energy Cost of Economy Purchases was primarily due to the limited availability of low cost economy energy. The decrease in Fuel Cost of Power Sold was primarily due to less than expected Opportunity Sales due to mild weather in the Southeast.

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. Please explain Appendix III.

A. Appendix III provides the Fuel Cost Recovery E Schedules prepared on a <u>six</u> month basis covering the period April 1998 through September 1998. Should the transition to a nine month factor not occur, the fuel factor would increase since the true up amount would be spread over less months. Schedule E1, page 3 of Appendix III shows the calculation of this <u>six</u>-month levelized fuel factor of 2.112¢ per kWh. Schedule E1-D, Page 8 of Appendix III provides a <u>six</u>-month levelized fuel factor of 2.250¢ per kWh on-peak and 2.043¢ per kWh off-peak for our Time of Use rate schedules.

CAPACITY PAYMENT RECOVERY CLAUSE

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

A. FPL is requesting that the Commission approve a midcourse correction to decrease its currently authorized Capacity Cost Recovery Factors, effective with customer billings for April 1998 and to continue these factors through December 1998.

Q. Please explain why FPL is proposing this change.

A. In Order No. PSC - 97 -1045 - FOF-EI, the Commission approved FPL's currently authorized Capacity Cost Recovery Factors (CCR) for the period October 1997 through September 1998. FPL now anticipates a $63.4 million variance for the period through September 1998. FPL's original projections included projected capacity payments for Osceola and Okeelanta Qualifying Facilities

(QF's) for the period June 1997 through September 1998. FPL has not made these capacity payments to Osceola and Okeelanta QF's. Rather than continue to collect and refund these capacity payments from customers, FPL has trued up the capacity costs to date and removed the costs for Osceola and Okeelanta from the remainder of the projections through September 1998. There is litigation pending. If any resolution takes place, FPL will advise the Commission and incorporate any resolution in the appropriate Capacity Cost Recovery Filing. The $63.4 million variance includes an Estimated/Actual overrecovery of $45.4 million for the period April 1997 through March 1998 and approximately $18.0 million for costs associated with capacity payments for Osceola and Okeelanta QF's that were included in the original projections for April 1998 through September 1998. This midcourse correction results in revised CCR factors beginning April 1998. FPL proposes, as a transition to calendar year factors, to extend these factors through December 1998.

FPL believes that the Capacity Cost Recovery Clause should remain on an annual basis but that infrequently a midcourse correction may be appropriate. FPL believes that the magnitude of this overrecovery warrants this change.

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

A. Yes. I have provided pages 1 through 10 of Appendix IV.

Q. Please explain page 3 of Appendix IV.

A. Page 3 of Appendix IV provides a summary of the capacity costs previously approved for recovery during the April 1998 through September 1998 period, excluding capacity payments of $18,001,182 for the Osceola and Okeelanta QF's which is shown on line 2b. Furthermore, line 9a reflects the remainder of the previously approved estimated/actual overrecovery for the period October 1996 through March 1997 of $5,239,866 ($10,479,736 / 12 months * 6 months). The additional midcourse correction overrecovery of $45,444,316 for the period April 1997 through March 1998 (eight months of actuals and 4 months of revised estimates) is reflected on line 9b.

The calculation of this $45,444,316 overrecovery for the period April 1997 through March 1998 is shown on pages 4a and 4b of Appendix IV (page 4a, line 14 + line 15 + line 17).

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

A. Yes, it is. The calculation of the true-up amount follows the procedures established by this Commission as set forth on

Commission Schedule A2 "Calculation of True-Up and Interest Provision" for the Fuel Cost Recovery Clause. The interest calculations are provided as pages 5a and 5b of Appendix IV.

Q. Please explain page 6 of Appendix IV.

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

Q. Please explain page 7 of Appendix IV.

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

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

A. The Company is requesting that the new FCR and CCR factors become effective with customer billings on cycle day 3 of April 1998 and continue through cycle day 2 of December 1998. FPL is also requesting that the current Environmental and GPIF factors remain in place through December 1998. During this transition period, this will provide for 9 months of billing on these factors for all our customers.

Q. What will be the charge for a Residential customer using 1,000 kWh effective April 1998?

A. The total residential bill, excluding taxes and franchise fees, for 1,000 kWh will be $75.09. The base bill for 1,000 residential kWh is $47.46, the Fuel Cost Recovery charge from Schedule E1-E, Page 9 of Appendix II for a residential customer is $19.76, the Conservation charge is $2.11, the Capacity Cost Recovery charge is $4.69, the Environmental Cost Recovery charge is $.31 and the Gross Receipts Tax is $.76. A Residential Bill Comparison (1,000 kWh) is presented in Schedule E10, Page 67 of Appendix II.

Q. Does this conclude your testimony.

A. Yes, it does.

BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 980001-EI
CONTINUING SURVEILLANCE AND REVIEW OF
FUEL COST RECOVERY CLAUSES OF ELECTRIC UTILITIES

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

Q. Please state your name and business address.

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

Q. By whom are you employed?

A. I am employed by Florida Public Utilities Company.

Q. Have you previously testified in this Docket?

A. Yes.

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

A. I will briefly describe the basis for the computations that were made in the preparation of the various Schedules that we have submitted in support of the April 1998 - September 1998 fuel cost recovery adjustments for our two electric divisions. In addition, I will advise the Commission of the projected differences between the revenues collected under the levelized fuel adjustment and the purchased power costs allowed in developing the levelized fuel adjustment for the period October 1997 - March 1998 and to establish a "true-up" amount to be collected or refunded during April 1998 - September 1998.

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

A. Yes.

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

A. We have filed Schedules E1, E1A, E1-B, E1B-1, E2, E7, and E10 for Marianna and E1, E1A, E1-B, E1B-1, E2, E7, E8, and E10 for Fernandina Beach. They are included in Composite Prehearing Identification Number GMB-3.

These schedules support the calculation of the levelized fuel adjustment factor for April 1998 - September 1998. Schedule E1-B shows the Calculation of Purchased Power Costs and Calculation of True-Up and Interest Provision for the period October 1997 - March 1998 based on 2 Months Actual and 4 Months Estimated data.

Q. In derivation of the projected cost factor for the April 1998 - September 1998, period, did you follow the same procedures that were used in the prior period filings?

A. Yes.

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

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

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

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

Q. Please address the calculation of the total true-up amount to be collected or refunded during the April 1998 - September 1998.

A. We have determined that at the end of March 1998 based on two months actual and four months estimated, we will have over-recovered $131,279 in purchased power costs in our Marianna division. Based on estimated sales for the period April 1998 - September 1998, it will be necessary to subtract .08816¢ per KWH to refund this over-recovery.

In Fernandina Beach we will have over-recovered $269,447 in purchased power costs. This amount will be refunded at .19504¢ per KWH during the April 1998 - September 1998 period (excludes GSLD customers). Page 3 and 12 of Composite Prehearing Identification Number GMB-3 provides a detail of the calculation of the true-up amounts.

Q. Looking back upon the April 1997 - September 1997 period, what were the actual End of Period - True-Up amounts for Marianna and Fernandina Beach, and their significance, if any?

A. The Marianna Division experienced an over-recovery of $68,452 and Fernandina Beach Division over-recovered $40,961. The amounts both represent fluctuations of less than 10% from the total fuel charges for the period and are not considered significant variances from projections.

Q. What are the final remaining true-up amounts for the period April 1997 - September 1997 for both divisions?

A. In Marianna the final remaining true-up amount was an over-recovery of $78,655. The final remaining true-up amount for Fernandina Beach was an over-recovery of $106,547.

Q. What are the estimated true-up amounts for the period of October 1997 -March 1998?

A. In Marianna, there is an estimated over-recovery of $52,624. Fernandina Beach has an estimated over-recovery of $162,900.

Q. What will the total fuel adjustment factor, excluding demand cost recovery, be for both divisions for the period April 1998 - September 1998.

A. In Marianna the total fuel adjustment factor as shown on Line 33, Schedule E1, is 2.365¢ per KWH. In Fernandina Beach the total fuel adjustment factor for "other classes", as shown on Line 43, Schedule E1, amounts to 2.326¢ per KWH.

Q. Please advise what a residential customer using 1,000 KWH will pay for the period April 1998 - September 1998 including base rates (which include revised conservation cost recovery factors) and fuel adjustment factor and after application of a line loss multiplier.

A. In Marianna a residential customer using 1,000 KWH will pay $64.75, an decrease of $2.33 from the previous period. In Fernandina Beach a customer will pay $60.30, a decrease of $4.90 from the previous period.

Q. Does this conclude your testimony?

A. Yes.

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GULF POWER COMPANY

Before the Florida Public Service Commission
Prepared Direct Testimony and Exhibit of
Michael F. Oaks
Docket No. 970001-EI
Date of Filing: November 20, 1997

Q. Please state your name and business address.

A. My name is Michael F. Oaks and my business address is One Energy Place, Pensacola, Florida 32520-0328.

Q. What is your occupation?

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

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

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

Q. What are your duties as Fuel Supply Supervisor?

A. I supervise and administer the Company's fuel procurement, transportation, budgeting, contract administration, and quality control to ensure the generating plants are provided a high quality fuel supply at the lowest practical cost.

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

Q. Mr. Oaks, what is the purpose of your testimony in this docket?
A. The purpose of my testimony is to summarize Gulf Power Company's fuel expenses and to certify that these expenses were properly incurred during the period April 1997 through September 1997. Also, it is my intent to be available to answer any questions that may arise among the parties to this docket concerning Gulf Power Company's fuel expenses.

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

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

Q. During the period April 1, 1997, through September 30, 1997, how did Gulf's actual fuel expenses compare with the budget or projected expenses?
A. Gulf's actual fuel expense was $112,795,375 as compared with the projected amount of $115,470,345, or under our estimate by 2.32%. Gulf's total net system generation was 5,805,044 MWH compared to the

projected generation of 5,941,530 MWH or 2.30% less than predicted. The resulting total fuel cost per KWH generated was 1.9431¢/KWH or 0.02% under the projected amount of 1.9434¢/KWH.

Q. How much spot coal did Gulf Power Company purchase during the period ending September 30, 1997?

A. Gulf purchased 1,076,686 tons or 47% of its supply from the spot coal market. My Schedule 1 of Exhibit No. _______ (MFO-1) consists of a list of contract and spot coal suppliers for the period ending September 30, 1997.

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

A. For the period, Gulf's total cost of coal purchased was only 0.2% higher than projected.

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

A. Yes. Gulf's coal purchases were either from long term contracts or the competitive spot market. Coal vendors are selected by procedures designed to assure a deliverable quantity of acceptable quality coal for a specific term at the lowest available delivered cost. Gulf has administered the provisions of these contracts and purchase orders appropriately. Most of Gulf's natural gas was purchased from the spot market on an as-needed basis from both producers and marketers, utilizing interruptible transportation. However, for this reporting period a portion of our gas needs was purchased forward in order to mitigate the cost during high demand summer days. This strategy resulted in net savings of $54,000. All of Gulf's oil purchases were from oil vendors selected by open bids to ensure the most economical price of oil.

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

A. Yes.

GULF POWER COMPANY

Before the Florida Public Service Commission
Prepared Direct Testimony and Exhibit of
Michael F. Oaks
Docket No. 980001-EI
Date of Filing: January 12, 1998

Q. Please state your name and business address.
A. My name is Michael F. Oaks and my business address is One Energy Place, Pensacola, Florida 32520-0328.

Q. What is your occupation?
A. I am the Compliance and Fuel Supply Supervisor at Gulf Power Company.

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

Q. What are your duties as Fuel Supply Supervisor?
A. I supervise and administer the Company's fuel procurement, transportation, budgeting, contract administration, and quality control to ensure the generating plants are provided an adequate low cost fuel

supply with minimal operational problems.

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

A. Yes.

Q. Mr. Oaks, what is the purpose of your testimony in this docket?

A. The purpose of my testimony is to support Gulf Power Company's projection of fuel expenses for the period April 1, 1998 to September 30, 1998 and to be available to answer any questions that may occur concerning the Company's fuel procurement procedures.

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

A. Yes. I have prepared an exhibit consisting of one schedule. Schedule 1 of my exhibit is a tabulation of projected and actual fuel cost for the past ten years. The purpose of this schedule is to illustrate the accuracy of our short-term projections of fuel expenses.

Counsel: We ask that Mr. Oak's exhibit consisting of one schedule be marked as Exhibit No. _______________ (MFO-2).

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

A. No.

Q. Will there be any major changes in Gulf's fuel purchasing program during this period?

A. Yes. As explained in previous testimony, Gulf Power Company recently invoked a market review opener in the long-term contract with Peabody CoalSales and submitted a matching price based on a competitive market evaluation. CoalSales has agreed to the matching price, and on February 1, 1998 the contract price will go to the market adjusted delivered price for 1.9 million tons per year. This will result in substantial savings for Gulf's customers, as reflected in the projection for this period. The contract now continues through the year 2007, with quarterly escalators based on the GDP/IPD, and another market adjustment in 2003.

Q. How much spot market coal does Gulf Power project it will purchase during the April 1998 through September 1998 period.

A. We are projecting the purchase of approximately 738,586 tons on the spot market. This represents approximately 25% of our projected purchase requirements.

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

A. Yes.

GULF POWER COMPANY

Before the Florida Public Service Commission
Prepared Direct Testimony of
Susan D. Cranmer
Docket No. 970001-EI
Fuel and Purchased Power Energy Cost Recovery
Date of Filing: November 20, 1997

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

A. My name is Susan Cranmer. My business address is One Energy Place, Pensacola, Florida 32520. I hold the position of Assistant Secretary and Assistant Treasurer of Gulf Power Company. In this position, I am responsible for supervising the Rates and Regulatory Matters Department.

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

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

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

Q. Have you prepared an exhibit that contains information to which you will refer in your testimony?
A. Yes, I have.

Counsel: We ask that Ms. Cranmer's Exhibit consisting of one schedule be marked as Exhibit No. _____ (SDC-1).

Q. Are you familiar with the Fuel and Purchased Power (Energy) True-up Calculation for the period of April 1997 through September 1997 set forth in your exhibit?
A. Yes. This document was prepared under my supervision.

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

Q. What is the amount to be refunded or collected through the fuel cost recovery factor in the period April 1998 through September 1998?

A. An amount to be refunded of $2,886,443 was calculated as shown in Schedule 1 of my exhibit.

Q. How was this amount calculated?

A. The $2,886,443 was calculated by taking the difference in the estimated April 1997 through September 1997 under-recovery of $857,475 as approved in Order No. PSC-97-1045-FOF-EI, dated September 5, 1997 and the actual over-recovery of $2,028,968 which is the sum of lines 7 and 8 shown on Schedule A-2, page 2 of 3, Period-to-Date of the monthly filing for September 1997.

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

A. Yes, it does.

GULF POWER COMPANY

Before the Florida Public Service Commission
Prepared Direct Testimony of
Susan D. Cranmer
Docket No. 980001-EI
Fuel and Purchased Power Cost Recovery
Date of Filing: January 12, 1998

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

A. My name is Susan Cranmer. My business address is One Energy Place, Pensacola, Florida 32520-0780. I hold the position of Assistant Secretary and Assistant Treasurer for Gulf Power Company.

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

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

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

Q. Have you previously filed testimony before this Commission in Docket No. 980001-EI?
A. Yes, I have.

Q. What is the purpose of your testimony?
A. The purpose of my testimony is to discuss the calculation of Gulf Power's fuel cost recovery factors for the period April 1998 through September 1998.

Q. Are you familiar with the Fuel Cost Recovery Clause Calculation for the period of April 1998 through September 1998?
A. Yes, these documents were prepared under my supervision.

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

Counsel: We ask that Ms. Cranmer's Exhibit

consisting of thirteen schedules,
be marked as Exhibit No. _____(SDC-2).

Q. Ms. Cranmer, what has Gulf calculated as the true-up to be applied in the period April 1998 through September 1998?

A. The true-up for this period is a decrease of .0347¢/kwh. This includes a final true-up over-recovery of $2,886,443 for the April 1997 through September 1997 period. As shown on Schedule E-1A, it also includes an estimated true-up under-recovery of $1,127,041 for the current period. The resulting over-recovery is $1,759,402.

Q. What has been included in this filing to reflect the GPIF reward/penalty for the period of April 1997 through September 1997?

A. This is shown on Line 32b of Schedule E-1 as a decrease of .0059¢/kwh, thereby penalizing Gulf by $300,745.

Q. Ms. Cranmer, what is the levelized projected fuel factor for the period April 1998 through September 1998?

A. Gulf has proposed a levelized fuel factor of 1.626¢/kwh. It includes projected fuel and purchased power energy expenses for April 1998 through September 1998 and projected kwh sales for the same period, as well as the true-up and GPIF amount. The proposed levelized fuel factor also includes the special recovery amount associated with the Air Products contract. The calculation of the special recovery amount is presented on Schedule E-12 of my exhibit. The levelized fuel factor has not been adjusted for line losses.

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

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

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

A. Gulf proposes a standard fuel factor, adjusted for line losses, of 1.646¢/kwh for Group A. Fuel factors for Groups A, B, C, and D are shown on Schedule E-1E. These factors have also been adjusted for line losses.

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

A. These were calculated based on projected loads and system lambdas for the period April 1998 through September 1998. These factors included the GPIF, true-up, and special contract recovery cost amounts and were adjusted for line losses. These time-of-use fuel factors are also shown on Schedule E-1E.

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

A. The current fuel factor for Rate Schedule RS applicable to March 1998 is 2.157¢/kwh compared with the proposed factor of 1.646¢/kwh. For a residential customer who uses 1000 kwh in April 1998, the fuel portion of the bill will decrease from $21.57 to $16.46.

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

A. Yes. A tabulation of these costs is set forth in Schedule E-11 of my Exhibit SDC-1. These costs represent the estimated averages for the period from April 1998 through March 2000.

Q. When does Gulf propose to collect these new fuel charges?

A. The fuel factors will apply to April 1998 through September 1998 billings beginning with Cycle 1 meter readings scheduled on April 1, 1998 and ending with meter readings scheduled on September 29, 1998.

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

A. Yes, it does.

GULF POWER COMPANY
Before the Florida Public Service Commission
Direct Testimony of
G. D. Fontaine
Docket No. 970001-EI
Date of Filing November 20, 1997

Q. Please state your name, address and occupation.

A. My name is George D. Fontaine, my business address is One Energy Place, Pensacola, Florida 32520-0335, and my position is Performance Test Specialist for Gulf Power Company.

Q. Please describe your educational and business background.

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

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

A. Yes, sir.

Q. Mr. Fontaine, what is the purpose of your testimony in this proceeding?

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

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

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

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

A. Yes, it was.

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

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

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

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

A. Actual equivalent availability and adjusted actual equivalent availability figures for each of the Company's GPIF units are shown on page 13 of Schedule 5. Pages 3 through 8 of Schedule 2 contain the calculations for the adjusted actual equivalent availabilities.

A calculation of GPIF availability points based on these availabilities and the targets established by Commission Order PSC-97-0359-FOF-EI is on page 9 of Schedule 2. The results are: Crist 6, +8.57 points; Crist 7, +3.64 points; Smith 1, -10.00 points; Smith 2, +10.00 points; Daniel 1, -10.00 points, and Daniel 2, -10.00 points.

Q. Mr. Fontaine, what were the heat rate results for the period?

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

As was done for the prior GPIF periods, and as indicated on pages 8 through 13 of Schedule 3, the target setting equations were used to adjust actual results to the target bases. These equations, submitted in January 1997, are shown on page 15 of Schedule 3.

As calculated on page 16 of Schedule 3, the adjusted actual average net operating heat rates correspond to GPIF unit heat rate points of: 0.00 for Crist 6, +0.67 for Crist 7; 0.00 for Smith 1, +8.10 for Smith 2; -8.37 for Daniel 1; and -10.00 for Daniel 2.

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

A. Using the unit equivalent availability and heat rate points previously mentioned, along with the appropriate weighting factors, the Company points would be -3.50 as indicated on page 2 of Schedule 4. This calculated to a penalty in the amount of $300,745.

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

A. Yes, Sir. In view of the adjusted actual equivalent availabilities, as shown on page 9 of Schedule 2, and the adjusted actual average net operating heat rates achieved, as shown on page 16 of Schedule 3, evidencing the Company's performance for the period, Gulf calculates a penalty in the amount of $300,745 as provided for by the GPIF plan.

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

A. Yes, Sir.

GULF POWER COMPANY
Before the Florida Public Service Commission
Direct Testimony of
G. D. Fontaine
Docket No. 980001-EI
Date of Filing January 12, 1998

Q. Please state your name, address and occupation.
A. My name is George D. Fontaine, my business address is One Energy Place, Pensacola, Florida 32520-0335, and my position is Performance Test Specialist for Gulf Power Company.

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

Q. Have you previously testified in this Docket?
A. Yes. I have presented testimony regarding the Generating Performance Incentive Factor (GPIF) periodically for the past several years.

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

A. The purpose of my testimony today is to present GPIF targets for Gulf Power Company for the period of April 1, 1998 through September 30, 1998.

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

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

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

A. Yes, it was.

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

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

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

Q. What are the target heat rates Gulf proposes to use in the GPIF for these units for the performance period April 1, 1998 through September 30, 1998?
A. I would like to refer you to Page 32 of Schedule 1 of my exhibit where these targets are listed.

Q. How were these proposed target heat rates determined?
A. In every case they were determined according to the GPIF implementation manual procedures for Gulf. Page 2 of Schedule 1 shows the target average net operating heat rate equations for the proposed GPIF units, and pages 4 through 29 of Schedule 1 contain the weekly historical data used for the statistical development of these equations.
Pages 30 and 31 of Schedule 1 present the calculations which provide the unit target heat rates from the target equations.

Q. Were the maximum and minimum attainable heat rates for each proposed GPIF unit, indicated on page 32 of Schedule 1, calculated according to the appropriate GPIF implementation manual procedures?
A. Yes.

Q. What are the proposed target, maximum and minimum, equivalent availabilities for Gulf's units?
A. The target equivalent availabilities and their ranges are listed on page 4 of Schedule 2.

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

Q. How were the maximum and minimum attainable equivalent availabilities determined for each unit?
A. The maximum and minimum attainable equivalent availabilities, which are presented along with their respective target availabilities on page 4 of Schedule 2, were determined per GPIF manual procedures for Gulf.

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

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

1. Crist Units 6 and 7, Smith Units 1 and 2 and Daniel Units 1 and 2, for inclusion under the GPIF for the period of April 1, 1998 through September 30, 1998.

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

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

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

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

A. Yes, Sir.

GULF POWER COMPANY

Before the Florida Public Service Commission
Direct Testimony of
M. W. Howell
Docket No. 970001-EI
Date of Filing: November 20, 1997

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

A. My name is M. W. Howell, and my business address is One Energy Place, Pensacola, Florida 32520. I am Transmission and System Control Manager for Gulf Power Company.

Q. Have you previously testified before this Commission?

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

Q. Please summarize your educational and professional background.

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

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

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

A. I will summarize Gulf Power Company's purchased power recoverable costs for energy purchases and sales that were incurred during the April 1, 1997 through September 30, 1997 recovery period. I will then compare these actual costs to their projected levels for the period and discuss the primary reasons for the differences.

Q. During the period April 1, 1997 through September 30, 1997, what was Gulf's actual purchased power recoverable cost for energy purchases and how did it compare with the projected amount?

A. Gulf's actual total purchased power recoverable cost for energy purchases, as shown on line 12 of Schedule A-1, was $14,163,434 for 742,839,891 KWH as compared to the projected amount of $10,622,241 for 530,540,000 KWH. The actual cost per KWH purchased was 1.9067 ¢/KWH as compared to the projected 2.0022 ¢/KWH, or 5% below the projection. This lower price is why the amount of energy purchased was 40% over the projected amount.

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

A. During the recovery period, the availability of lower cost pool energy due to lower than budgeted system territorial loads and higher than budgeted nuclear and hydro generation on the Southern electric system during the summer months allowed Gulf to purchase more energy at a lower unit price than was forecasted in order to meet its load obligations.

Q. During the period April 1, 1997 through September 30, 1997, what was Gulf's actual purchased power fuel cost for energy sales and how did it compare with the projected amount?

A. Gulf's actual total purchased power fuel cost for energy sales, shown on line 18 of Schedule A-1, was $20,243,585 for 1,079,735,770 KWH as compared to the projected amount of $17,664,800 for 1,032,484,000 KWH. This resulted in a variance above budget of $2,578,785, or 15%. The actual fuel cost per KWH sold was 1.8749 ¢/KWH as compared to 1.7109 ¢/KWH, or 10% above projection.

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

A. During the recovery period, the Southern electric system experienced a higher than budgeted demand for off-system Unit Power and economy energy. Therefore, Gulf sold more energy at a higher unit price to meet system obligations for these sales.

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

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

Therefore, Southern system energy sales provide a market for Gulf's surplus energy and generally improve unit load factors. The cost of fuel used to make these sales is credited against, and therefore reduces, Gulf's fuel and purchased power costs. Overall, Gulf's Total Fuel and Net Power Transactions for the recovery period, as shown on line 20 of Schedule A-1, were 2% under budget.

Q. Does this conclude your testimony?

A. Yes.

GULF POWER COMPANY

Before the Florida Public Service Commission
Direct Testimony of
M. W. Howell
Docket No. 980001-EI
Date of Filing: January 12, 1998

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

A. My name is M. W. Howell, and my business address is One Energy Place, Pensacola, Florida 32520. I am Transmission and System Control Manager for Gulf Power Company.

Q. Have you previously testified before this Commission?

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

Q. Please summarize your educational and professional background.

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

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

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

A. The purpose of my testimony is to support Gulf Power Company's projection of purchased power recoverable costs for energy purchases and sales for the period April, 1998 - September, 1998.

Q. What is Gulf's projected purchased power recoverable cost for energy purchases for the April, 1998 - September, 1998 recovery period?

A. Gulf's projected recoverable cost for energy purchases, shown on line 12 of Schedule E-1 of the fuel filing, is $7,424,990. These purchases result from Gulf's participation in the coordinated operation of the Southern electric system power pool. This amount is used by Gulf's witness Susan Cranmer as an input in the calculation of the fuel and purchased power cost adjustment factor.

Q. What is Gulf's projected purchased power fuel cost for energy sales for the April, 1998 - September, 1998 recovery period?

A. The projected fuel cost for energy sales, shown on line 18 of Schedule E-1, is $26,149,800. These sales also result from Gulf's participation in the coordinated operation of the Southern electric system power pool. This amount is used by Gulf's witness Susan Cranmer as an input in the calculation of the fuel and purchased power cost adjustment factor.

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

KAREN O. ZWOLAK

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

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

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

A. I received a Bachelor of Arts degree in Microbiology in 1977 and a Bachelor of Science degree in Chemical Engineering in 1985 from the University of South Florida. I began my engineering career in 1986 at the Florida Department of Environmental Regulation and was employed as a Permitting Engineer in the Industrial Wastewater Program. In 1990, I joined Tampa Electric Company as an engineer in the Environmental Planning Department and was responsible for permitting and compliance issues relating to wastewater treatment and disposal. In 1995, I transferred to TEC's

Energy Supply Department and assumed the duties of the plant chemical engineer at the F. J. Gannon Station. In this position, I was responsible for boiler chemistry, water management, and maintenance of environmental equipment and general engineering support. In 1997, I was promoted to Manager, Energy Issues in the Electric Regulatory Affairs Department. My present responsibilities include the areas of fuel adjustment, capacity cost recovery, environmental filings and rate design.

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

A. The purpose of my testimony is to present the net true-up amounts for the April 1997 through September 1997 period for both the Fuel Cost Recovery and the Capacity Cost Recovery Clauses.

FUEL COST RECOVERY CLAUSE

Q. What is the net true-up amount for the fuel cost recovery clause for the period April 1997 through September 1997?

A. An over/(under) - recovery of ($6,042,407). The actual fuel cost over/(under) - recovery, including interest, is ($1,232,698) for the period April 1997 through September

1997 (Schedule A2, page 2 of 3, of September 1997 monthly filing, in Document No. 4, reflects an end of period total net true-up of $694,267. Subtracting the beginning of period deferred true-up of $1,926,965 yields the ($1,232,698). This ($1,232,698) amount, less the actual/estimated over/(under) - recovery approved in the August 1997 fuel hearings of $4,809,709 results in a final over/(under) - recovery for the period of ($6,042,407). This over/(under) - recovery amount of ($6,042,407) will be carried over and applied in the calculation of the fuel recovery factor for the period April 1998 through September 1998.

Q. How much effect will this ($6,042,407) over/(under) - recovery in the April 1997 through September 1997 period, have on the April 1998 through September 1998 period?

A. The ($6,042,407) over/(under) - recovery will cause a 1,000 KWH residential bill to be approximately $0.72 higher.

Q. How are the fuel revenues associated with the Florida Municipal Power Agency and the City of Lakeland wholesale sales treated in this final true-up filing?

A. As per Order No. PSC-97-1273-FOF-EU, Tampa Electric shall credit its fuel clause with an amount equal to the system incremental fuel cost resulting from the Florida Municipal Power Agency and Lakeland Sales. Document No. 2, page 1 of 1, line C6E, reflects an amount of ($2,920,793) to be credited to the fuel clause. The ($2,920,793), for the period December 1996 through September 1997, is the difference between the fuel revenues previously credited each month in the fuel clause and system incremental fuel cost each month, adjusted for jurisdictional separation and losses.

Q. Have you prepared an Exhibit in this proceeding?

A. Yes. Exhibit No. (KOZ-1, Fuel Cost Recovery and Capacity Cost Recovery) which contains four documents. Document No. 3 is used to explain the capacity cost recovery clause which is discussed later in my testimony. Document No. 4 contains Commission Schedules A-1 through A-9 for the months of April 1997 through September 1997. Included with the September 1997 monthly filing is a six months summary for each of Commission Schedules A6, A7, A8, and A9 for the period April 1997 through September 1997.

Q. Please explain Document No. 1.

A. Document No. 1, entitled "Tampa Electric Company Final Fuel Over/(Under) - Recovery for the period April 1997 through September 1997" shows the calculation of the final fuel over/(under) - recovery for the period of ($6,042,407) which will be applied to jurisdictional sales during the period April 1998 through September 1998.

Line 1 shows the total company fuel costs of $198,495,705 for the period April 1997 through September 1997. The jurisdictional amount of total fuel costs is $195,789,824 as shown on line 2. This amount is compared to the jurisdictional fuel revenues applicable to the period on line 3 to obtain the actual over/(under) - recovered fuel costs for the period, shown on line 4. The resulting ($1,293,869) over/(under) - recovered fuel costs for the period, combined with $61,171 of interest shown on line 5, constitute the actual over/(under) - recovery of ($1,232,698) shown on line 6. The ($1,232,698) less the actual/estimated over/(under) - recovery of $4,809,709 shown on line 7, which was approved in the August 1997 fuel hearings, results in the final over/(under) - recovery of ($6,042,407) shown on line 8.

Q. What does Document No. 2 show?

A. Document No. 2, entitled "Tampa Electric Company Calculation of True-Up Amount Actual vs. Original Estimates for the period April 1997 through September 1997," shows the calculation of the actual over/(under) - recovery as compared to the original estimate for the same period.

Q. What was the variance in jurisdictional fuel revenues for the period April 1997 through September 1997?

A. As shown on line C1 of my Document No. 2, the company collected ($5,592,282) less jurisdictional fuel revenues than originally estimated.

Q. What was the total fuel and net power transaction cost variance for the period April 1997 through September 1997?

A. As shown on line A7 of Document No. 2, the fuel and net power transactions cost variance is ($690,146) or (0.3%).

Q. What are the reasons for the total fuel and net power transactions cost being lower by ($690,146) or (0.3%)?

A. The primary reason for the (0.3%) decrease is due to Net Energy for Load being down (255,565) MWH or (2.9%). This (2.9%) combined with the ¢/KWH for Total Fuel and Net Power

Transaction being more than estimated by 2.6%, accounts for the (0.3%) decrease.

CAPACITY COST RECOVERY CLAUSE

Q. What is the net true-up amount for the capacity cost recovery clause for the period April 1997 through September 1997?

A. An over/(under) - recovery of ($642,312). The actual capacity cost over/(under) - recovery, including interest, is ($987,400) for the period April 1997 through September 1997 (Document No. 3, pages 2 and 3 of 5). This amount, less the actual/estimated over/(under) - recovery approved in the August 1997 fuel hearings of ($345,088) results in a final over/(under) - recovery for the period of ($642,312) (Document No. 3, page 5 of 5). This over/(under) - recovery amount of ($642,312) will be carried over and applied in the calculation of the capacity cost recovery factor for the period April 1998 through September 1998.

Q. How much effect will this ($642,312) over/(under) - recovery in the April 1997 through September 1997 period, have on the April 1998 through September 1998 period?

A. The ($642,312) over/(under) - recovery will cause a 1,000 KWH residential bill to be approximately $0.08 higher.

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

KAREN O. ZWOLAK

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

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

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

A. I received a Bachelor of Arts Degree in Microbiology in 1977 and a Bachelor of Science degree in Chemical Engineering in 1985 from the University of South Florida. I began my engineering career in 1986 at the Florida Department of Environmental Regulation and was employed as a Permitting Engineer in the Industrial Wastewater Program. In 1990, I joined Tampa Electric Company as an engineer in the Environmental Planning Department and was responsible for permitting and compliance issues relating to wastewater treatment and disposal. In 1995, I transferred to TEC's

Energy Supply Department and assumed the duties of the plant chemical engineer at the F. J. Gannon Station. In this position, I was responsible for boiler chemistry, water management, and maintenance of environmental equipment and general engineering support. In 1997, I was promoted to Manager, Energy Issues in the Electric Regulatory Affairs Department. My present responsibilities include the areas of fuel adjustment, capacity cost recovery, environmental filings and rate design.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present to the Commission the proposed Total Fuel and Purchased Power Cost Recovery factors, the proposed Capacity Cost Recovery factors and the Temporary Base Rate Reduction factors for the period of April 1998 - September 1998.

<u>**Fuel and Purchased Power Cost Recovery Factors / Capacity Cost Recovery Clause**</u>

Q. Did you review the projected data necessary to calculate the Total Fuel and Purchased Power Cost Recovery factors for the period April 1998 - September 1998?

A. Yes I have.

Q. Do you wish to sponsor an exhibit consisting of Schedules H-1 (April - September, 1995 through 1998) and Schedules E-1 through E-10 (April 1998 - September 1998)?

A. Yes. Also contained in this exhibit are Schedules E-2, E-3, E-5, E-6, E-7, E-8 and E-9 for the prior period October 1997 - March 1998. These schedules are furnished as back-up for the projected true-up for this period and consist of two actual months and four projected months.

(Have identified as Exhibit No. 20 (KOZ-2), Fuel Projection.)

Q. Does Schedule E-1 of Exhibit No. 20 (KOZ-2), Fuel Projection, show the proper value for the Total Fuel and Purchased Power Cost Recovery Clause as projected for the period April 1998 - September 1998?

A. Yes.

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

A. The proper value for the new period is 2.237 cents per kwh before the application of the factors that adjust for variations in line losses.

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

A. The GPIF and True-up factors are provided on Schedule E-1C. We propose that a GPIF penalty of ($363,850) be included in the projection period. The True-up amount for the October 1997 - March 1998 period is an overrecovery of $4,373,121. This overrecovery is comprised of a final True-up underrecovery amount of ($6,042,407) for the April 1997 - September 1997 period and an estimated overrecovery in the amount of $10,415,528 for the October 1997 - March 1998 period.

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

A. Schedule E-1D presents the company's on-peak and off-peak fuel charge factors for the April 1998 - September 1998 period.

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

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

Q. Please recap the proposed Fuel and Purchased Power Cost Recovery factors for the April 1998 - September 1998 period.

A.

Rate Schedule	Fuel Charge Factor (cents per kwh)
Average Factor	**2.337**
RS, GS and TS	**2.354**
RST and GST	**3.334** (on-peak)
	1.883 (off-peak)
SL-2, OL-1 and OL-3	**2.101**
GSD, GSLD, and SBF	**2.340**
GSDT, GSLDT, EV-X and SBFT	**3.314** (on-peak)
	1.872 (off-peak)
IS-1, IS-3, SBI-1, SBI-3	**2.264**
IST-1, IST-3, SBIT-1, SBIT-3	**3.206** (on-peak)
	1.811 (off-peak)

Q. How does Tampa Electric Company's proposed average fuel charge factor of **2.337** cents per kwh compare to the average fuel charge factor for the October 1997 - March 1998 period?

A. The proposed fuel charge factor is 0.033 cents per kwh (or $0.33 per 1000 kwh) higher than the average fuel charge factor of 2.304 cents per kwh for the October 1997 - March 1998 period.

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

A. Yes.

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

A. Yes. It consists of five pages identified as Exhibit No. 21 KOZ-3, Capacity Cost Recovery.

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

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

Q. Please re-cap the proposed Capacity Cost Recovery Clause factors for the April 1998 - September 1998 period.

A.

Rate Schedule	Capacity Cost Recovery Factor (cents per kwh)
RS	0.188
GS and TS	0.181
GSD, EV-X	0.139
GSLD and SBF	0.123
IS-1, IS-3, SBI-1, SBI-3	0.011
SL-2, OL-1 and OL-3	0.022

These factors can be seen in Exhibit No. 21 (KOZ-3), page 3 of 5.

Temporary Base Rate Reduction

Q. Is Tampa Electric requesting to modify the Temporary Base Rate Reduction factor for the period April 1998 through September 1998?

A. Yes. On September 25, 1996, Tampa Electric, the Office of Public Counsel and the Florida Industrial Power Users Group signed a separate stipulation. (Order No. PSC-96-1300-S-EI in Docket No. 960409-EI issued October 24, 1996.) As part of this Stipulation, Tampa Electric has agreed to a temporary base rate reduction in the total amount of $25 million over fifteen months beginning about October 1, 1997. This temporary base rate reduction is shown as a line item on the customer's bill.

This temporary base rate decrease will be 0.130 cent per kWh on average. The factors by rate class, adjusted for line loss, are shown below. The derivation of these factors is shown in Document No. 4 of Exhibit KOZ-2.

Rate Class	Credit Factor cents / kWh
Average Factor	0.130
RS, RST, GS, GST, TS	0.130
GSD, GSDT, GSLD, GSLDT, EV-X, SBF, SBFT	0.130
IS-1&3, IST-1&3, SBIT-1&3	0.125
SL, OL	0.130

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

A. A residential bill for 1,000 kwh will decrease $0.26 beginning April 1998. See table below.

Type of Charge	Oct. 97 thru Mar. 98	Apr. 98 thru Sept. 98
Customer	$ 8.50	$ 8.50
Energy	43.42	43.42
Conservation	1.63	1.65
Environmental	0.54	0.33
Fuel	23.21	23.54
Capacity	2.28	1.88
Deferred Revenue Plan Refund	(1.31)	(1.30)
FGR Tax	2.01	2.00
Total	$ 80.28	$ 80.02

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

A. They should go into effect commensurate with the first billing cycle in April 1998.

Q. Does this conclude your testimony?

A. Yes it does.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

GEORGE A. KESELOWSKY

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

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

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

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

Q. What are your current responsibilities?

A. I am responsible for testing and reportin performance, and the compilation and reportir generation statistics.

Q. What is the purpose of your testimony?

A. My testimony presents the actual performance resul unit equivalent availability and station heat rate determine the Generating Performance Incentive (GPIF) for the period April 1997 through Septembe I will also compare these results to the established prior to the beginning of the period.

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

A. Yes. Under my direction and supervision an exhi been prepared entitled, "Tampa Electric Company 1997 - September 1997, Generating Performance In Factor Results" consisting of 28 pages that was fil this testimony (Have identified as Exhibit GAK-1).

Q. Are the equivalent availability results shown on page 6, column 2, directly applicable to the GPIF table?

A. Not exactly. Adjustments to equivalent availability may be required as noted in section 4.3.3 of the GPIF Manual. The actual equivalent availability including the required adjustment is shown on page 6 of my exhibit. The necessary adjustments as prescribed in the GPIF Manual are further defined by a letter dated October 23, 1981, from Mr. J.H. Hoffsis of the Commission's Staff. The adjustments for each unit are as follows:

Gannon Unit No. 5

On this unit, no planned outage hours were originally scheduled to fall within the Summer 1997 period, and none in fact occurred. Consequently, the actual equivalent availability of 74.7% requires no adjustment, as shown on page 7 of my exhibit.

Gannon Unit No. 6

On this unit, 168 planned outage hours were originally scheduled to fall within the Summer 1997 period. Due to a revision of the outage schedule, this work was accomplished prior to the beginning of the period, and no planned outage hours fell within the period. Consequently, the actual equivalent availability of 82.0% is adjusted to 78.9%, as shown on page 8 of my exhibit.

Big Bend Unit No. 1

On this unit 983 planned outage hours were originally scheduled to fall within the Summer 1997 period. Due to a revision of the outage schedule 1145.4 planned outage hours fell within the period. Consequently, the actual equivalent availability of 62.9% is adjusted to 66.0% as shown on page 9 of my exhibit.

Big Bend Unit No. 2

On this unit no planned outage hours were originally scheduled to fall within the Summer 1997 period, and none in fact occurred. Consequently, the actual equivalent availability of 87.4% requires no adjustment as shown on page 10 of my exhibit.

Big Bend Unit No. 3

On this unit no planned outage hours were originally scheduled to fall within the Summer 1997 period. Due to a revision of the outage schedule, outage activities were moved forward to fall within the period, and required 671.0 hours. Consequently, the actual equivalent availability of 71.3% is adjusted to 84.2% as shown on page 11 of my exhibit.

Big Bend Unit No. 4

This unit was not scheduled to have a planned outage during the Summer 1997 period, and none in fact occurred. Consequently, the actual equivalent availability of 82.8% requires no adjustment as shown on page 12 of my exhibit.

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

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

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

A. The actual heat rate and adjusted actual heat rate for Gannon and Big Bend Station are shown on page 6 of my exhibit. The adjustment was developed based on the guidelines of section 4.3.6 of the GPIF Manual. This procedure is further defined by a letter dated October 23, 1981, from Mr. J.H. Hoffsis of the FPSC Staff. The final adjusted actual heat rates are also shown on page 5 of my exhibit. This heat rate number is entered into the respective GPIP table for the particular unit, shown on pages 21 through 26. Page 4 of my exhibit summarizes the weighted heat rate and equivalent availability points to be awarded.

Q. Were any additional adjustments to heat rate required?

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

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

A. Yes.

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

A. This is shown on page 28 of my exhibit. Essentially, the weighting factors shown on page 4, column 3, plus the equivalent availability points and the heat rate points shown on page 4, column 4, are substituted within the equation. This resultant value, -1.613, is then entered into the GPIF table on page 2. Using linear interpolation, a penalty amount of $363,850 is calculated.

Q. Does this conclude your testimony?

A. Yes, it does.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

GEORGE A. KESELOWSKY

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

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

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

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

Q. What are your current responsibilities?

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

Q. What is the purpose of your testimony?

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

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

A. Yes, I have prepared, under my direction and supervision, an exhibit entitled "Tampa Electric Company, Generating Performance Incentive Factor" April 1998 - September 1998, consisting of 35 pages filed with the Commission on January 14, 1998. (Have identified as Exhibit GAK-2). The data prepared within this exhibit is consistent with the GPIF Implementation Manual previously approved by this Commission.

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

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

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

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

Q. Please continue.

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

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

A. Yes I will. The Planned Outage Factor (POF) and the Equivalent Unplanned Outage Factor (EUOF) were subtracted from 100% to determine the target equivalent availability. The factors for each of the 5 units included within the GPIF are shown on page 5 of my exhibit. For example, the projected EUOF for Big Bend Unit Four is 8.1%. The Planned Outage Factor for this same unit during this period is 0%. Therefore, the target equivalent availability for this unit equals:

$$100\% - [(8.1\% + 0\%)] = 91.9\%$$

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

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

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

Equivalent Availability Maximum

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

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

$EAF_{MAX} = 100\% - [0.8\ (8.1\%) + 0.95\ (0\%)] = 93.5\%$

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

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

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

Equivalent Availability Minimum

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

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

$EAF_{MIN} = 100\% - [1.4\ (8.1\%) + 1.1\ (0\%)] = 88.7\%$

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

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

A. Our planned outages for this period are shown on page 19 of my exhibit. A Critical Path Method (C.P.M.) for each major planned outage which affects GPIF is included in my exhibit. For example, Big Bend Unit 1 is scheduled for an annual maintenance outage May 18 to May 31, 1998. There are 336 planned outage hours scheduled for the summer 1998 period, and a total of 4391 hours during this 6 month period. Consequently, the Planned Outage Factor for Unit 1 at Big Bend is 336/4391 x 100% or 7.7%. This factor is shown on pages 5 and 15 of my exhibit. Big Bend Unit 3 has a planned outage factor of 18.0%. Big Bend Units 2 and 4 have planned outage factors of zero, as does Gannon Unit 5. Gannon Unit 6 has a planned outage factor of 7.7%.

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

A. Grapns of both of these factors (adjusted for planned outages) vs. time are prepared. Both monthly data and 12 month moving average data are recorded. For each unit the most current, September 1997, 12 month ending value was used as a basis for the projection. This value was adjusted up or down by analyzing trends and causes for recent forced and maintenance outages. All projected factors are based upon historical unit performance, engineering judgment, time since last planne_ outage, and equipment performance resulting in a forced or maintenance outage. These target factors are additive and result in a EUOF of 15.2% for Gannon Unit Five. The Equivalent Unplanned Outage Factor (EUOF) for Gannon Unit Five is verified by the data shown on page 13, lines 3, 5, 10 and 11 of my exhibit and calculated using the formula:

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

or

$$EUOF = \frac{(555 + 111)}{4391} \times 100 = 15.2\%$$

Relative to Gannon Unit Five, the EUOF of 15.2% forms the basis of our Equivalent Availability target development as shown on sheets 4 and 5 of my exhibit.

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

<u>Big Bend Unit One</u>

A. The projected EUOF for this unit is 14.0% during this period. This unit will have a planned outage this period and the Planned Outage Factor is 7.7%. This results in a target equivalent availability of 78.3% for the period.

<u>Big Bend Unit Two</u>

The projected EUOF for this unit is 13.6%. This unit will not have a planned outage during this period and the Planned Outage Factor is 0%. Therefore, the target equivalent availability for this unit is 86.4%.

Big Bend Unit Three

The projected EUOF for this unit is 13.2%. This unit will have a planned outage this period and the Planned Outage Factor is 18.0%. Therefore, the target equivalent availability for this unit is 68.8%.

Big Bend Unit Four

The projected EUOF for this unit is 8.1%. This unit will not have a planned outage during this period and the Planned Outage Factor is 0%. This results in a target equivalent availability of 91.9% for the period.

Gannon Unit Five

The projected EUOF for this unit is 15.2%. This unit will not have a planned outage during this period and the Planned Outage Factor is 0%. Therefore, the target equivalent availability for this unit is 84.8%.

Gannon Unit Six

The projected EUOF for this unit is 11.3%. This unit will have a planned outage during this period and the Planned Outage Factor is 7.7%. Therefore, the target equivalent availability for this unit is 81.1%.

Q. Would you summarize your testimony regarding Equivalent Availability Factor (EAF)?

A. Yes I will. Please note on page 5 that the GPIF system weighted Equivalent Availability Factor (EAF) equals 79.2%. This target compares very favorably to previous GPIF periods.

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

A. This adjustment makes these factors more accurate and comparable. Obviously, a unit in a planned outage stage or reserve shutdown stage will not incur a forced or maintenance outage. Since our units are usually base loaded, reserve shutdown is generally not a factor. To demonst ate the effects of a planned outage, note the EUOR and EUOF for Gannon Unit Six on page 14. During the months of April, and June through September, EUOF and EUOR are equal. This is due to the fact that no planned outages are scheduled during these months. During the month of May, EUOR exceeds EUOF. The reason for this difference is the scheduling of a planned outage. The adjusted factors apply to the period hours after planned outage hours have been extracted.

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

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

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

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

Q. How were these targets determined?

A. Net heat rate data for the three most recent summer periods, along with the PROMOD III program, formed the basis of our target development. Projections of unit performance were made with the aid of PROMOD III. The historical data and the target values are analyzed to assure applicability to current conditions of operation. This provides assurance that any periods of abnormal operations, or equipment modifications having material effect on heat rate can be taken into consideration.

Q. The accomplishment of scrubbing the flue gas from Big Bend Unit 3 requires an additional amount of station service power. How do you plan to address the associated effect to net heat rate for GPIF purposes?

A. The change in heat rate for this unit resulting from increased utilization of the Unit 4 scrubber can be quantified, but the operational history is short of GPIF guidelines. The target for Big Bend 3 has, therefore, been developed in the standard fashion using data without scrubber power. In order to assure compatability with this target, scrubber power will be removed prior to calculating Unit 3 heat rate for the subsequent True-Up process. This method has been reviewed and approved by the PSC Staff to be employed until there is sufficient history to meet target preparation guidelines. Successful implementation of this innovation to maximize the potential of existing plant equipment, represents a major cost savings and a significant benefit for our customers.

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

A. Yes.

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

A. The ranges were determined through analysis of historical net heat rate and net output factor data. This is the same data from which the net heat rate vs. net output factor curves have been developed for each unit. This information is shown on pages 27 through 32 of my exhibit.

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

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

Q. Can you summarize your heat rate projection for the summer 1998 period?

A. Yes. The heat rate target for Big Bend Unit 1 is 10,267 Btu/Net kwh. The range about this value, to allow for potential improvement or degradation, is ±366 Btu/Net kwh. The heat rate target for Big Bend Unit 2 is 10,225 Btu/Net kwh with a range of ±330 Btu/Net kwh. The heat rate target for Big Bend Unit 3 is 9,778 Btu/Net kwh, with a range of ±342 Btu/Net kwh. The heat rate target for Big Bend Unit 4 is 9,831 Btu/Net kwh with a range of ±188 Btu/Net kwh. The heat rate target for Gannon Unit 5 is 10,377 Btu/Net kwh with a range of ±178 Btu/Net kwh. The heat rate target for Gannon Unit 6 is 10,527 Btu/Net kwh with a range of ±400 Btu/Net kwh. A zone of tolerance of ± 75 Btu/Net kwh is included within the range for each target. This is shown on page 4, and pages 7 through 12 of my exhibit.

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

A. Yes I do.

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

A. The next step is to calculate the savings and weighting factor to be used for both average net operating heat rate and equivalent availability. This is shown on pages 7 through 12. Our PROMOD III cost simulation model was used to calculate the total system fuel cost if all units operated at target heat rate and target availability for the period. This total system fuel cost of $153,941,200 is shown on page 6 column 2.

The PROMOD III output was then used to calculate total system fuel cost with each unit individually operating at maximum improvement in equivalent availability and each station operating at maximum improvement in average net operating heat rate. The respective savings are shown on page 6 column 4. After all the individual savings are calculated, column 4 is totaled: $6,630,700 reflects the savings if all units operated at maximum improvement. A weighting factor for each parameter is then calculated by dividing individual savings by the total. For Big Bend Unit Two, the weighting factor for equivalent availability is 9.38% as shown in the right hand column on page 6.

Pages 7 thru 12 show the point table, the Fuel Savings/(Loss), and the equivalent availability or heat rate value. The individual weighting factor is also shown. For example, on Big Bend Unit Two, page 10, if the unit operates at 89.1% equivalent availability, fuel savings would equal $622,000 and 10 equivalent availability points would be awarded.

The Generating Performance Incentive Factor Reward/Penalty Table on page 2 is a summary of the tables on pages 7 through 12. The left hand column of this document shows the incentive points for Tampa Electric Company. The center column shows the total fuel savings and is the same amount as shown on page 6, column 4, $6,630,700. The right hand column of page 2 is the estimated reward or penalty based upon performance.

Q. How were the maximum allowed incentive dollars determined?

A. Referring to my exhibit on page 3, line 8, the estimated average common equity for the period April 1998 - September 1998 is shown to be $1,177,502,143. This produces the maximum allowed jurisdictional incentive dollars of $2,371,627 shown on line 15.

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

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

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

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

$$\begin{aligned} GPIP = (\ & 0.0522\ EAP_{GN5} + 0.0506\ EAP_{GN6} \\ & + 0.1092\ EAP_{BB1} + 0.0938\ EAP_{BB2} \\ & + 0.1319\ EAP_{BB3} + 0.0315\ EAP_{BB4} \\ & + 0.0758\ HRP_{GN5} + 0.1009\ HRP_{GN6} \\ & + 0.1115\ HRP_{BB1} + 0.0796\ HRP_{BB2} \\ & + 0.0938\ HRP_{BB3} + 0.0692\ HRP_{BB4}) \end{aligned}$$

Where:

GPIP = Generating performance incentive points.

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

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

Q. Have you prepared a document summarizing the GPIF targets for the April 1998 - September 1998 period?

A. Yes. The availability and heat rate targets for each unit are listed on attachment "A" to this testimony entitled "Tampa Electric Company GPIF Targets, April 1, 1998 - September 30, 1998".

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

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

Q. Briefly describe this exhibit.

A. This exhibit consists of 23 pages. This data is Tampa Electric Company's estimate of the Unit Performance Data and Unit Outage Data for the April 1998 - September 1998 period.

Q. Does this conclude your testimony?

A. Yes.

DIRECT TESTIMONY OF TOM BALLINGER

Q. Please state your name and business address.

A. My name is Tom Ballinger. My business address is 2540 Shumard Oak Boulevard, Tallahassee, Florida, 32399-0850.

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

A. I am employed by the Florida Public Service Commission (FPSC) as a Utility Systems/Communication Engineer Supervisor for the Bureau of System Planning/Conservation and Electric Safety.

Q. Please describe your educational and professional background.

A. In April of 1985, I graduated from the Florida State University with a B.S. in Mechanical Engineering. Since June, 1985, I have been employed by the FPSC. From the beginning of my career, I have been involved with various utility regulatory issues such as power plant and transmission line need determinations, operation and maintenance expenditures, rate cases, performance incentives, reliability criteria, and other issues relating to conservation and system planning. I have also been involved with the non-utility side of regulation with such things as purchased power contract approval, need determinations for qualifying facilities, and competitive bidding. I have provided comments on proposed rules and sponsored testimony and recommendations numerous times before the FPSC. In July, 1993, I was promoted to my current position.

Q. What is the purpose of your testimony?

A. In November of 1997, the Florida Reliability Coordinating Council (FRCC) submitted a Reliability Assessment for Peninsular Florida. As an input to this Assessment, certain assumptions were made regarding the equivalent availability of generating units. The purpose of my testimony is to recommend that the equivalent availability targets filed in the Generation Performance Incentive Factor (GPIF) be consistent with the values assumed in the development of the Reliability Assessment.

Q. Why should the values for a long-term reliability assessment be consistent with a short term target?

A. The values used in the Reliability Assessment are virtually constant every year of the ten year study period. This means that the values are both short and long term expectations of unit performance. As such, no reward or penalty should be imposed if this level of performance is achieved.

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

REBUTTAL TESTIMONY OF K. ADJEMIAN

DOCKET NO. 980001-EI

JANUARY 30, 1998

Q. Please state your name and business address.

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

BACKGROUND

Q. Please describe your present position and responsibilities.

A. I am currently the Manager of Resource Planning of the System Planning Department at Florida Power & Light Company ("FPL"). I have held this title and responsibilities since October 1993. The responsibilities of my present position include managing the group that is responsible for the coordination and the development of FPL's integrated resource plan which is FPL's primary cross-functional program for meeting FPL's customer's needs. My position is also responsible for other related activities such as production cost projections.

Q. What is your educational background?

A. I received a Bachelor of Science degree in Electrical Engineering from the Worcester Polytechnic Institute, Worcester, Massachusetts, in 1975. In 1976, I received a Masters of Science degree in Electrical Engineering from the University of Michigan specializing in Power Systems analysis. In 1983, I received a Masters in Business Administration degree from the Western New England College, Springfield, Massachusetts. I am a registered Professional Engineer in the State of Florida and a member of the Institute of Electrical and Electronic Engineers.

Q. Please describe your other electric utility work experience.

A. Upon graduation from the University of Michigan, I held positions in the area of system planning with various electric utilities. In these positions I was responsible for the planning of distribution, transmission and generation systems. In 1984, I was employed by FPL in the System Planning Department. In 1987, I joined the Power Supply Department and was promoted to Coordinator of Power Supply Contracts. In 1988, I rejoined the System Planning Department and in 1989, I was promoted to the position of Manager of Transmission and Substation Planning. In 1993, I was appointed Manager of Resource Planning.

PURPOSE OF TESTIMONY

Q. What is the purpose of your testimony?

A. The purpose of my rebuttal testimony is to address Mr. Ballinger's recommendation that the equivalent availability target filed in the Generation Performance Incentive Factor (GPIF) be consistent with the values assumed in the 1997 FRCC Reliability Assessment study.

Q. What is the purpose of the GPIF?

A. The purpose of the Generating Performance Incentive Factor (GPIF) is to provide a monetary incentive for the efficient operation of base load generating units.

Q. How are the targets for GPIF currently set?

A. GPIF targets are set using the most recent twelve month ending average forced outage factor (FOF) and maintenance outage factor (MOF) as the starting value for the determination of the target unplanned outage factor (UOF). The UOF is then adjusted to reflect recent monthly performance and known modifications or changes in equipment. Historical UOF is then adjusted to account for planned outages which may have occurred. Finally, the target UOF is adjusted to account for planned outages expected to occur during the GPIF period.

Q. **How is Mr. Ballinger's proposal different from the current approach?**

A. Mr. Ballinger proposes using long term forecasted values taken from the 1997 FRCC Assessment study instead of historical values to set the GPIF targets.

Q. **Is Mr. Ballinger's approach in conflict with the purpose of the GPIF?**

A. Yes. The values used in the Assessment study represent long-term expectations. These values are relatively constant because it is not feasible to forecast planned outages for the long term with the same degree of accuracy as employed in the GPIF. Also, since the purpose of the Assessment study was to identify capacity needs on a statewide basis, precision in individual plant performance is not critical. This approach would be inappropriate for the GPIF which seeks to monetarily reward or penalize unit performance. GPIF studies identify fuel impacts at individual plants in the near term and represent the most current and accurate expected performance of system conditions over the next year. The proposed approach may lead to gross differences and inconsistent rewards and penalties.

Q. **Can you be more specific?**

A. Yes. For example, in the Assessment study FPL's St. Lucie Unit 1 is assumed to have an equivalent annual availability of 85.1% due to a forced outage rate of 7.1% and 4.4 weeks of maintenance outage. The study assumed that this level of maintenance would be required, on the average over a long term, each year.

In fact, St. Lucie Unit 1, just like any other nuclear unit, has a scheduled maintenance outage cycle that is coincident with the unit's refueling schedule. As such there are several years that St. Lucie Unit 1 will not be taken down for maintenance. In GPIF, St. Lucie Unit 1 has an Equivalent Availability Factor (EAF) target of 72.7% due to a scheduled outage within the next period, October 1997 - September 1998. Therefore, it would be inappropriate to base the GPIF targets for St. Lucie Unit 1 to the availability assumptions of a long range planning study such as the Assessment study.

Table 1 presents a comparison of the unit availabilities between the FRCC study and the GPIF targets for the period of October 1997 - September 1998. As shown in column (E), the differences are relatively small with a few exceptions where the specific unit is scheduled for a planned outage during the GPIF period. Generally, planned outages are moved depending on near term system conditions (e.g., other unit availabilities, load, etc.) which cannot be reflected on a long range study such as the Assessment study. Obviously it would be inappropriate to set GPIF targets for those units based on the numbers used in the Assessment study.

Q. Would fossil units exhibit the same problem?

A. Yes. Similar to nuclear units, fossil units have maintenance schedules which follow a regular cycle over several years with varying annual outage schedules.

The planned outage time would be expected to be greater than the long term average in some years and lower in other years.

Q. What is your recommendation?

A. I recommend that we continue to use the current methodologies. Each is appropriate when used in the manner intended.

Q. Does this conclude your testimony?

A. Yes.

MS. PAUGH: Do you wish also to mark exhibits, Commissioner?

COMMISSIONER CLARK: Yes.

MS. PAUGH: You will find those starting on Page 30.

COMMISSIONER CLARK: JS-1 will be marked as Exhibit 1. JS-2 will be marked as Exhibit 2.

KHW-1 will be marked as Exhibit 3. KH -- I'm sorry -- KHW-2 will be marked as Exhibit 4.

DBZ-1 will be marked as Exhibit 5. DBZ-2 will be marked as Exhibit 6.

KMD-1 will be marked as Exhibit 7. And RS-1 will be marked as Exhibit 8.

KMD-2 will be marked as Exhibit 9. KMD-3 will be marked as Exhibit 10. KMD-4 will be marked as Exhibit 11.

GMB-3, noted as a composite exhibit, will be marked as Exhibit 12.

MFO-1 will be marked as Exhibit 13. MFO-2 will be marked as Exhibit 14.

SDC-1 will be marked as Exhibit 15. SDC-2 will be marked as Exhibit 16.

GDF-1 will be marked as Exhibit 17. GDF-2 will be marked as Exhibit 18.

KOZ-1 will be marked as Exhibit 19. KOZ-2 will be marked as Exhibit 20. KOZ-3 will be marked as Exhibit 21. KOZ-4 will be marked as Exhibit 22.

GAK-1 will be marked as Exhibit 23, GAK-2 will be marked as Exhibit 24. GAK-3 will be marked as Exhibit 25.

And KA-1 will be marked as Exhibit 26.

And let the record reflect those exhibits are admitted in the record.

(Exhibits 1-26 marked for identification and received in evidence.)

MS. PAUGH: Thank you, Commissioner. With respect to the unstipulated issues, if I could commence with Issue 4, Staff's position on FPL is stated incorrectly.

COMMISSIONER CLARK: And we have to deal with these because some of the other issues depend on what we do with that; is that correct? Is that why it's appropriate to handle the FPL issue first?

MS. PAUGH: FPL is the only issue outstanding at this time.

COMMISSIONER CLARK: But we haven't approved the other issues yet.

MS. PAUGH: Would you like to do that first?

COMMISSIONER CLARK: Well, I guess my question is, for some of those issues I think they're a fallout issue, and we have to make a decision on FP&L so we make sure that the adjustment factor that is used in some of the other issues is correct. That's how I understand --

MS. PAUGH: That's fine.

COMMISSIONER CLARK: Okay. Am I correct that it is just you, Mr. Childs, and, Ms. Kaufman, who would like to be heard on the issue of the factor?

MR. CHILDS: I believe so.

COMMISSIONER CLARK: Okay. And I would expect it is appropriate to hear from you first.

MS. KAUFMAN: Excuse me. I don't mean to interrupt, Commissioner Clark, but there is an error in the prehearing statement that perhaps we should correct before we go forward. It might make a little more sense.

And that is on issue 10C on Page 20, which is one of the issues that is in contention and remain outstanding, FIPUG's position is reflected there that we have no position, but that's not correct. I think that's just an error.

And our position on that issue would be "no". And as indicated in the correspondence we sent to the parties on Friday, our position is that FPL's overrecovery should be spread over the next two six-month recovery periods.

MS. PAUGH: Vicki, do you mean underrecovery?

MS. KAUFMAN: I'm sorry; underrecovery. You're right.

COMMISSIONER CLARK: Okay. Let me -- just so I'm clear, that there is currently existing underrecovery that has to be made up for?

MS. KAUFMAN: Yes, ma'am.

COMMISSIONER CLARK: Over a future period.

MS. KAUFMAN: There's $135 million underrecovery.

COMMISSIONER CLARK: And you want it spread out over 12 months.

MS. PAUGH: Yes, ma'am.

COMMISSIONER CLARK: And FP&L is suggesting nine in anticipation of going to an annualization.

MS. PAUGH: That's my understanding.

COMMISSIONER CLARK: If we didn't go to an annualization, wouldn't it be six months? If we just did it the regular way, wouldn't it be six months?

MS. KAUFMAN: It would be, but we would still be suggesting to you, because of the amount of the underrecovery, that it is appropriate to spread it over a longer period; and you have done that in the past in other cases.

COMMISSIONER CLARK: Okay. Thank you. Mr. Childs?

MR. CHILDS: Good morning, Commissioners. I think it was in 1993 the Commission itself proposed to convert the fuel adjustment clause into an annual clause, and it voted ultimately not to do so.

In this docket Florida Power & Light Company filed a petition requesting that the fuel adjustment clause as to FPL be converted to an annual clause on a calendar basis. In other words, the Commission would set a factor starting in January 1 of each year, and the factor would run for 12 months.

Florida Power & Light already has an annual clause for the capacity costs; at this filing requests that the Commission convert that annual clause to a calendar basis as well, so that both the capacity clause and the fuel adjustment clause would run on a calendar year basis; and Florida Power & Light propose an implementation schedule for accomplishing that end.

One of the other things that we asked for was that there be a transition, that in order to transition into an annual clause, that the Commission establish a nine-month fuel adjustment factor for Florida Power & Light so the factor that you would establish this time would not terminate as it normally would in September, but instead would run all the way through December. Therefore, if we started with an annual clause, we would have one change to accomplish that end.

10C, Issue 10C, and Issue 21E have been preserved to address those points; that is the point of transitioning into an annual cost recovery factors.

We think that it is very reasonable to have a transition as we have proposed, particularly as to fuel with a nine-month factor, because it avoids setting a factor, say, for three months if the Commission elects to go forward with a -- with an annual clause.

It avoids the jerkiness and the increasing of the variability and changes in the costs, which is -- and I'm trying to stay away from the merits of our request to change the clause -- but which is one of the reasons we're asking you to change the clause, is that it minimizes the frequency of the changes, the volatility.

We also think that it facilitates -- under the circumstances, that it facilities the adoption of an annual fuel adjustment factor, because the Commission is going to proceed to address this issue on the basis of a generic docket, and we think as to FPL that it will position FPL so that it -- assuming the Commission agrees that we ought to change to a 12-month factor, that as to FPL, FPL will be ready to go, because the only thing remaining to do is to set the factor for next year.

We also think that it's important because of -- in changing to the annual cost recovery that we not wait until the year 2000, but that we try to do it in 1999; and, therefore, we also felt that as to FPL, that the nine-month transition for fuel and the three-month transition for capacity was very helpful to accomplish that end.

We did feel that if the Commission in its wisdom chose not to adopt an annual factor, that selecting the transition that we have proposed would not prevent you from reacting to your decision not to go forward with an annual factor, and you would have the ability to revert back to a schedule that was consistent with the way you had been doing it before.

But we're -- I personally had some concern that if we started a PAA proceeding, which I think has been discussed as one way to go forward, if we had a PAA, a proceeding, and we ended up with opposition from a party, that it could be difficult to adopt an annual factor in 1998; that is, to approve the adoption of a factor and then have notice and opportunity for hearing for the factor to be established by January 1, that would put the Commission on a fairly tight schedule. There again, we concluded that the transition approach was helpful.

I did want to comment briefly on the FIPUG position where they stated their position on Issue 10C in reference to a letter that they sent where, as I read the letter, their position is that, no, we shouldn't have the nine-month transition for fuel, instead we should have six months, and also the $135 million underrecovery should be spread over a 12-month period.

My comments are as follows: Number one, the issues of the underrecovery is not new. There are specific issues on this. 1, 2 and 3 in this prehearing order address the underrecovery. Issue 10C relates to the transition. It does not relate to the underrecovery; therefore, I don't think it's appropriate to inject at this time a changed position on the treatment of the underrecovery.

Second, the letter that Ms. Kaufman submits, suggests that the amount of the underrecovery is substantial and usual. Some characterization word like that is used. I would point out that Florida Power & Light Company's fuel costs that are passed through the fuel clause each year are in the neighborhood of 1.5 billion. $135 million is a lot of money, but -- and that's for two recovery periods, not one six months; it's for two six-month periods, and I don't think that to characterize it as she has is accurate.

In the past there have been opportunities where the Commission has addressed spreading an underrecovery over a longer period of time. My information is that as to FPL, we did that where we had a midcourse correction. And that's where you have, you know, say, in month three you have -- under the Commission's procedures, you know, that perhaps you're going to be underrecovered by more than 10% of the total costs, and under your procedures you're supposed to tell the Commission of that and make a decision as to whether to change the factor.

And FPL has done that where we have told you that we had an underrecovery, but if we didn't spread it, that left you with the opportunity to spread the underrecovery only, for instance, over only three months of the period. And we said, don't put all of that money over three months, let's take some of it and spread it over this and the next period.

So I don't think --

COMMISSIONER CLARK: Mr. Childs, just so I'm clear, when Ms. Kaufman had indicated we had done this before, that we've spread it over a greater period, your response is, the only time we've done that is when we have had a midcourse correction?

MR. CHILDS: I want to be careful when I say "only time". I've endeavored to find that, and the only ones that I have found -- and there are three; there's -- it's Order No. 25718 in December 23rd, 1991, Order No. PSC-94-0111-FOF-EI, January 4, 1994, PSC-96-0907-FOF-EI, dated May 31, 1996.

Those were all midcourse corrections where it put the Commission and others in the position of trying to recover a significant amount. By definition, you don't file unless you're going to be 10% off, and then you file -- when you're in a six-month period and you have maybe only one, two or three months to recover the costs, and so -- say, well, we ought to spread that out. And we did, but never to 12 months.

COMMISSIONER CLARK: Okay. I'm sure if there is another one, Ms. Kaufman will tell us.

MR. CHILDS: Okay. The other thing, I think, that is important is Florida Power & Light Company looked at this. It was aware of the underrecovery, and it was also aware, however, that it had overrecovery for the capacity clause which offset -- and that was approximately 63 million, which offset significantly the underrecovery; and that on a total bill basis, it seemed like it was an acceptable objective.

In fact, if you look at the numbers in the rough calculation we've done, it appears to me that the FIPUG approach would reduce the average residential customer bill by about 19 cents; that is, it would be $74.93 if we did what FIPUG proposed as opposed to $75.12 for 1,000 kilowatt hours, and we'll still be left with the additional money to refund and we'd be left with no transition of the nine-month period that we propose.

So we don't think it accomplishes the objective, and I think Ms. Kaufman may have overlooked that there's an offsetting charge for capacity. For these reasons, we urge you to try to approve and look at it as a helpful step of approving a nine-month transition as has been proposed by FPL in this docket.

Thank you.

COMMISSIONER CLARK: Questions

Commissioners? Ms. Kaufman?

MS. KAUFMAN: Thank you, Commissioner Clark. As you're aware, the issues that still remain in contention between FIPUG and FPL are the two issues, 4 and 7, that relate to how the factor is going to be calculated.

I don't think it's correct for Mr. Childs to say that this issue of the underrecovery is one that is still not before the Commission. Those issues are still outstanding; and then Issue 10C, which relates to the fuel factor, and Issue 21E to the capacity factor. As Commissioner Clark knows from the --

COMMISSIONER CLARK: Well, let me just say that it would be incorrect, with respect to 4 and 7, to say that you don't have a position. You do have a position; it ought to be two six-month -- it ought to be spread over 12 months.

MS. KAUFMAN: Yes, ma'am, that's correct; but we thought we had taken care of that in Issue 10C, and 4 and 7 are calculations after you make your utility-specific decisions.

I was going to say, as Commissioner Clark knows from the prehearing, at this point in time FIPUG is opposed to going to an annual fuel filing. We are going to look at that and try and access the impact and figure out what we think about that. Right now we are opposed to it.

The whole Commission will hear this issue, perhaps have an evidentiary hearing about it. And it's not before the panel now, and it's certainly not an issue that should be prejudged in any way, despite Mr. Childs' comments about how helpful a 12-month factor might be. We want to wait until we have the hearing on that and present our evidence on it.

COMMISSIONER CLARK: But you haven't reached a conclusion?

MS. KAUFMAN: Our preliminary conclusion is that we would prefer to remain at six months. However, I will tell the Commissioners that we are going to look at it and discuss it with the utilities. So I haven't foreclosed -- closed the door on going to 12 months.

COMMISSIONER CLARK: Good.

MS. KAUFMAN: But right now we are opposed to it; and at any rate, that's not an issue that you all are going to decide today.

Now, FPL has asked that you approve this nine-month transition factor, and they've asked you to do this in advance of there being any decision on whether we're going to go to an annual factor or not.

And I want to point out that even though it's my understanding that all the utilities perhaps would support an annual factor, none of the others have asked you to approve a transition ahead of you actually making the substantive decision.

I'll also admit to you that FIPUG is in somewhat of a quandary here because the nine-month transition factor that FPL has approved -- has suggested is lower than the six-month factor; and the main reason that it's lower is because of this $135 million underrecovery. And if you review FPL's testimony, Ms. Dubin in particular, this very large underrecovery is in the main part due to an FPL forecasting error, particularly a very large error in the way they've forecasted gas prices.

You are not limited, I do not believe, to spreading this big amount over a 12-month period simply because it doesn't rise to the level of ever requiring a midcourse correction.

COMMISSIONER CLARK: Ms. Kaufman, if you would answer what Mr. Childs said, specifically that they didn't ask for that because they looked at it in terms of total bill. And given the fact that they had an overrecovery in the capacity, it sort of seems reasonable to me.

MS. KAUFMAN: Well, I didn't annualize it in the way that Mr. Childs did. What I did was look at the increase that that's going to mean to the fuel factor from the prior period, and my calculations would indicate to me that it's going to make a big difference. It's about 28% for residential customers' increase, and for industrial customers, depending on their rate class, it's between 27 and 30%.

COMMISSIONER CLARK: Well, do you dispute his point that if we took your -- if we followed what you suggested and did it over a 12-month period, it would, in fact, result in a reduction to bills when we had an underrecovery? I thought that's what you --

MS. KAUFMAN: I might have missed -- I did not hear him say -- I thought that he said that it would only make a 19-cent difference for the residential customers.

COMMISSIONER CLARK: And I thought he said it reduced them. Mr. Childs, can you clarify that?

MS. KAUFMAN: I thought it was the opposite.

MR. CHILDS: What I said is, is that the proposal by FIPUG would result in a bill for the average residential customer of $75.93, or approximately 19 cents less than what FPL's proposed with its nine-month factor of $75.12.

COMMISSIONER CLARK: Okay.

MS. KAUFMAN: That's what I heard, that our approach would result in a reduction. My point was that you are not limited to spreading the increase over 12 months simply because it didn't rise to the level of a midcourse correction. And I want to point out to you that in the conservation docket it was just fully stipulated.

Power Corp had a $22 million underrecovery in regard to their decoupling and they asked if they could spread that over 24 months to lessen the impact and --

COMMISSIONER CLARK: What was the dollar impact to their customers relative to --

MS. KAUFMAN: On a bill basis?

COMMISSIONER CLARK: Yes.

MS. KAUFMAN: I do not know. I only know that it was a $22 million underrecovery. They were required, I believe by the terms of the decoupling order, to spread it over 12 months, and they asked to do 24.

COMMISSIONER CLARK: Well, would you agree with me that probably we should be looking at the impact on the bill in determining whether or not we -- the two are comparable?

MS. KAUFMAN: Well, I think you have to look at the impact on the bill, and I think you also have to look at the difference in the fuel factor as well; and I did not do that analysis for Power Corp.

COMMISSIONER CLARK: Let me ask you one other thing. Mr. Childs mentioned that he thought spreading it over a larger period was related to a midcourse correction. Do you have any cases where it wasn't, except the one we just did today?

MS. KAUFMAN: No, but I did not attempt to go back and find any. I think it's within this Commission's discretion to spread that amount if they think it will benefit the ratepayers. And we think that it will lessen the increase, obviously, in the fuel factor by spreading it over the 12 months rather than the six months.

COMMISSIONER CLARK: Let me ask you a question. If you don't get 12, will you take nine?

MS. KAUFMAN: I would take nine, yes, Commissioner, but I would want it to be absolutely clear that that has no impact on our position in regard to whether we go to an annual fuel filing.

COMMISSIONER CLARK: No. I mean, I think that issue is -- the only reason I find it persuasive, that it provides the opportunity to perhaps avoid work in September. You know, if we don't do it, we're definitely going to have to make an adjustment in September.

MS. KAUFMAN: Well, that presumes that you're going to go to the annual filing.

COMMISSIONER CLARK: No, it doesn't. I think it presumes that if we don't go to the annual filing, we will still be doing something in September, because it's every six months.

MS. KAUFMAN: Right.

COMMISSIONER CLARK: If we go to the annual filing and put this factor into place, we may avoid the work. That's the only way we have the possibility of avoiding work in September, as I understand it.

MS. KAUFMAN: Well, I think you will have waited for FPL. And, I agree if you decide to go to the annual and they have this transition, yes, that's correct. If you don't -- and I'm not sure of the timetable for even -- I'm not even convinced we're going to reach that issue before we have the August fuel adjustment. I don't know what the timetable is for reaching --

COMMISSIONER CLARK: Well, I certainly am -- if I have anything to do with it, I hope we do. I think we've told the Chairman that we'd like to see it done quickly.

MS. KAUFMAN: And certainly, you know, I'm just suggesting if there's a PAA and if there's a protest and if there's an order, I'm just not sure how the time schedules will play out.

COMMISSIONER JACOBS: You touched on a question I had. You agree, though, that if we don't go to an annualized recovery, that the nine-month -- adopting a nine-month transition here allows us the flexibility to go back to the present time line. Do you agree?

MS. KAUFMAN: Yes. FPL would have to make an adjustment, I believe, in August if we remain on the six-month schedule. They would have to make an adjustment when they do their August fuel filing. So I think it would give you that flexibility; I agree.

I want to also touch on Issue 21E, which is the capacity factor issue. And it's already been mentioned we're already on a 12-month schedule for that, but it's not a calendar year schedule.

And if I understand what FPL has done here, they already have their capacity factors set now and it would be changed in August, at the August hearing, for October 1, and if I understand what Mr. Childs told me, they've simply extended that factor for three more months to get to the end of the year.

Again, you know, until there is a change, we think they should remain with their current capacity factor. They should recalculate it so that the underrecovery is appropriately allotted for in the factor that they now have.

COMMISSIONER CLARK: Questions?

MR. CHILDS: Could I briefly comment?

COMMISSIONER CLARK: Yes, Mr. Childs?

MR. CHILDS: One, on that last point we have, we proposed the midcourse correction to reflect that. That's why the bill comes out whereas -- as the capacity costs offset the fuel costs.

And, secondly, I'm not suggesting that Issues 4 and 7 are not outstanding, as Ms. Kaufman argued earlier. What I'm simply saying is, is that a party is supposed to take a position on an issue by the prehearing conference; and I thought that this was a position on an issue that did not reach that -- the issue did not reach the position taken.

COMMISSIONER CLARK: Well, I would agree it seemed to me that if you were going to take the position that you should spread it out over six months, we probably should have had it earlier, but, you know, it's fairly clear where you're coming from.

So no harm done, I think, in this instance.

Let me just ask some questions.

COMMISSIONER GARCIA: Are we going to hear from Staff on this or not?

COMMISSIONER CLARK: Well, I want to ask them some questions before we hear the recommendation.

The midcourse correction will still be available, right, and what we've currently set is a 10% change? Is that kind of the --

MS. KAUFMAN: That's my understanding, that the utilities must come in 10% over or under.

MR. CHILDS: Yes.

COMMISSIONER CLARK: Is it correct that the proposal to go to an annual proceeding, that all the parties agree on the date, that it should be calendar, or are there -- there's no agreement on when the period should be?

MS. KAUFMAN: I think --

MR. CHILDS: Tampa Electric has not agreed that it should be calendar. I believe that Gulf, Florida Power Corporation and Florida Power & Light Company do agree.

COMMISSIONER CLARK: Okay.

MS. KAUFMAN: That's my understanding, that Tampa Electric prefers to remain on the schedule we now have, but go to a year.

COMMISSIONER CLARK: So just so I'm clear, the opposition to annual comes from FIPUG?

MS. KAUFMAN: Yes, ma'am.

COMMISSIONER CLARK: You're still looking at it. But we may not -- even if it turns out everybody agrees that annual is okay, we may not have an agreement on what period that should be. Okay.

Staff?

MS. PAUGH: Commissioner, I'd like to preface my remarks by underscoring that with respect to annualization, which has already been spun out into a separate docket, there are two primary issues.

The first is whether to go annual. FIPUG has the position that we should not. And if we do go annual, what should the time period be. And there is not agreement among the parties, and I believe it goes beyond TECO requesting a fiscal year versus calendar year. So those are the issues that will be handled in this separate docket.

Relative to FPL's nine-month projection period, Staff believes that that is an inappropriate period. It is inappropriate to go three months beyond Commission policy precedent, six-month normal projection period because it has the effect of predetermining the time period in the annualization docket. In other words, it sets a precedent for going for calendar year, and that it is not agreed among the parties that that's --

COMMISSIONER CLARK: Ms. Paugh, let me just say I don't think it sets a precedent.

MS. PAUGH: Okay.

COMMISSIONER CLARK: I mean, I would make it clear that that's not the purpose here.

MS. PAUGH: That's fine. It may have that implication. Let me soften my statement --

COMMISSIONER CLARK: I see what you're saying; just by doing it we might suggest -- it suggests to people that we may personally have a predisposition that that's a good thing --

MS. PAUGH: That's correct; and I can hear parties coming to us and saying, well, you did it in the fuel docket.

COMMISSIONER CLARK: Right.

COMMISSIONER GARCIA: We won't listen, though. When they say that, we won't listen. (Laughter)

MS. PAUGH: Thank you. Our second point with respect to the nine-month FPL proposal is that it sets us up for a $60 million, approximate, underrecovery in this docket.

It's setting an inaccurate factor based upon something the Commission may or may not do, and we believe that's inappropriate.

With respect to FIPUG's six-plus-six recovery period, we believe that it is inappropriate, because the interest that would accrue on that second six-month $70 million would be roughly $750,000, and we don't see that there is a great deal of gain to be had for the $750 million price tag that it would cost to spread it out.

This sort of underrecovery, $135 million, is not all that unusual. It's based on fuel prices and perhaps calculations and that sort of thing. It is something that is routinely handled in the fuel docket on the six-month projection periods.

The ratepayer impact is not that great. Estimates are that for the nine-month period the thousand kilowatt hour difference is for nine months $75.12. For one half of the underrecovery six-month period it would be $75. I believe we've just heard $74.93. And for the six-month normal Commission policy, the thousand kilowatt, our amount, would be $76.54.

So Staff does not believe that the impacts are that great to justify a change in the policy --

COMMISSIONER GARCIA: The six-month period would be $76.54?

MS. PAUGH: Yes; the normal projection period six-month, as opposed to the six-month that is half of 12 months.

COMMISSIONER GARCIA: Right.

COMMISSIONER JACOBS: And what would it be for if we did it for 12?

MS. PAUGH: If we did it for 12 --

COMMISSIONER GARCIA: The 12 months would be 75 --

COMMISSIONER JACOBS: 75 something.

COMMISSIONER GARCIA: 75, right.

MS. PAUGH: Just below 75.

COMMISSIONER GARCIA: Right. $74.94 is it that you said?

MS. PAUGH: $74.93 is what we heard from, I believe, Mr. Childs.

COMMISSIONER GARCIA: Right.

MS. PAUGH: So that's Staff position, that the six-month period is the appropriate period.

Before we get too far, I do need to correct Staff's position in Issue 4, which reflects a factor of a nine-month period, and that was simply an error.

COMMISSIONER GARCIA: Okay.

MS. PAUGH: That was what I tried to do earlier. That number on FPL -- and you'll find this on Page 8 of your prehearing order -- is listed under Staff, FPL as 1.972. That's FPL's nine-month factor, and that's not correct. It needs to be corrected to 2.112. That is the six-month factor.

COMMISSIONER CLARK: Thank you.

COMMISSIONER GARCIA: Can I make a motion, or do you maybe --

COMMISSIONER CLARK: Well, you know, it's always difficult being chair, because you kind of have to wait for what people hear; but I'll entertain a motion.

COMMISSIONER GARCIA: And Leslie can tell me if I'm right in the motion. I'm going to deny Staff and move FPL and move to the nine-month. Do you want me to do that issue by issue, or is it comprehended that we just adopt FPL's position?

MS. PAUGH: I would recommend that we reference Issues 4, 7, 10C and 21E with respect to that motion.

COMMISSIONER GARCIA: Okay. 4, 7, 10C and 21E.

MS. PAUGH: That's correct.

COMMISSIONER CLARK: You move that we use a nine-month period?

COMMISSIONER GARCIA: We use a nine-month. Okay. Is there a second?

COMMISSIONER JACOBS: My only concern is how do we -- with all due respect to Commissioner Garcia, that we just simply won't hear the argument when it comes back, I'm wondering should we stamp this order with some indication of our intent that --

COMMISSIONER GARCIA: Well, you mean in terms of the precedent we're establishing?

COMMISSIONER JACOBS: Yeah.

COMMISSIONER GARCIA: I clearly would adopt the comments that the Chairman made, and obviously the Staff can make it so in what it issues that clearly we're not trying to set precedent with this; we're simply trying to adjust.

You know, I see this as a sort of a chicken and the egg type argument, and I think this is --

COMMISSIONER JACOBS: Let me float this out there. It would appear to me that what we're actually doing here is leaving an option for a correction by the company because if we don't vote for the annual, they're going to have to -- basically this is a midcourse correction. They're going to have to make a midcourse correction, which is pretty much consistent with the other orders.

That's how I rationalize this. That's how I get it to this. You know, basically what we're doing -- I know on the front end Staff is saying we're setting a bad thing on the front end. I see this as basically we're leaving that option open in the event that we don't approve that 12-month recovery.

COMMISSIONER CLARK: I'm willing to be candid on this. I mean, Staff had recommended another time that we go to annual, and we've kind of constantly looked at the notion of going to annual because we are under at least the suggestion and direction that we streamline our procedures over here, and less government is better, you know. It's kind of consistent with the philosophy.

But having that said, you know, I'm willing to hear from FIPUG. They represent large customers, and they have -- and Public Counsel, and they represent how it feels from the customers' standpoint, and I'm always willing to listen on those points.

I guess my view is, the only way we have the opportunity to possibly avoid work in September is to go with the nine months, and it goes partway to what FIPUG has asked for in this case. So I see it as a win-win situation for the two sides of this argument.

I appreciate what Staff says. I think you're right; you know, in one sense one can argue, at least suggest, a favorable look at a year. But, you know, this has been under discussion for a while and there --

COMMISSIONER GARCIA: I agree and I don't --

COMMISSIONER CLARK: -- are merits to that but --

COMMISSIONER GARCIA: And I know you want to get into --

COMMISSIONER CLARK: -- I want to assure you --

COMMISSIONER GARCIA: -- the merits --

COMMISSIONER CLARK: -- I have an open mind.

COMMISSIONER GARCIA: -- philosophy on this because I agree with what you've said, and I have, I guess, some other ideas of why I think this may be a good idea; but I've got an open mind to it and will listen to it.

COMMISSIONER JACOBS: One brief point before I move on. I wanted to go back to Ms. Kaufman to see if there's any significant disagreement with what Staff has represented to be the customer impact of the six-month versus 24-month recovery of -- underrcovery.

MS. KAUFMAN: I did not do the calculations that Staff has done, but I don't take issue with them, Commissioner. I'm sure they're correct.

COMMISSIONER JACOBS: I second the motion.

COMMISSIONER CLARK: All right. Show the decision unanimous to institute the nine-month factor.

MS. PAUGH: Commissioner, if I could, there is now a fallout in Issue 5 which was previously stipulated, and it needs to reflect new wording.

With respect to Issue 5, for Florida Power & Light, the new factors should be effective beginning with the first billing cycle for April, 1998; thereafter, the last billing cycle for December 1998.

We will make that change in the order, if that's acceptable to the Commissioners.

COMMISSIONER CLARK: Show the vote on Issue 4, 7, 10C and 21E as we just took the vote. Show 5 changed, and show the Commission as approving all the other stipulated issues.

MS. PAUGH: Commissioner, I don't believe there has been a vote on the stipulated issues yet.

COMMISSIONER CLARK: I just said show it approved.

MS. PAUGH: Okay. Thank you.

COMMISSIONER CLARK: If you prefer, I'll entertain the motion.

MS. PAUGH: I would prefer that.

COMMISSIONER JACOBS: So moved.

COMMISSIONER GARCIA: So moved, Madam Chairman.

COMMISSIONER CLARK: All right. Show it approved without objection. Is there anything else we have to take up at this time? (No response.)

Thank you all very much.

(Thereupon, the hearing concluded at 10:30 a.m.)

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STATE OF FLORIDA)
: CERTIFICATE OF REPORTER
COUNTY OF LEON)

I, H. RUTHE POTAMI, CSR, RPR Official Commission Reporter,

DO HEREBY CERTIFY that the Hearing in Docket No. 980001-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 225 pages, constitutes a true transcription of my notes of said proceedings and the insertion of the prescribed prefiled testimony of the witnesses.

DATED this 2nd day of March, 1998.

H. RUTHE POTAMI, CSR, RPR
Official Commission Reporter
(904) 413-6732