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
(Video teleconferencing from Miami)
COMMISSIONER E. LEON JACOBS, JR.

DATE: **Monday, November 23, 1998**

TIME: Commenced at 9:30 a.m.
Concluded at 11:30 a.m.

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

REPORTED BY: H. RUTHE POTAMI, CSR, RPR
Official Commission Reporter
(904) 413-6734

APPEARANCES:

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

LEE L. WILLIS, Ausley & McMullen, Post Office Box 391, Tallahassee, Florida 32302, appearing on behalf of **Tampa Electric Company (TECO).**

JOHN McWHIRTER, JR., McWhirter, Reeves, McGlothlin, Davidson, Decker, Kaufman, Arnold & Steen, Post Office Box 3350, Tampa, Florida 32601-3350, appearing on behalf of **Florida Industrial Power Users Group (FIPUG).**

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 32399-0870, appearing on behalf of the **Commission Staff.**

I N D E X

WITNESSES:

INDEX OF EXHIBITS CONTINUED:

MISCELLANEOUS

P R O C E E D I N G S

(Hearing convened at 9:30 a.m.)

COMMISSIONER CLARK: Let's call the hearing to order. Ms. Paugh, if you could walk me through everything I need to do.

MS. PAUGH: We'll commence by reading the notices.

COMMISSIONER CLARK: That's a good idea.

MR. KEATING: Pursuant to notice issued October 19th, 1998, this time and place have been set for a hearing in the following dockets: Docket No. 980001-EI, fuel and purchased power cost recovery clause and generating performance incentive factor; Docket 980002-EG, energy conservation cost recovery clause; Docket No. 980003-GU, purchased gas adjustment true-up; and Docket No. 980007-EI, environmental cost recovery clause.

COMMISSIONER CLARK: Take appearances.

MR. STONE: Commissioner, I'm Jeffrey A. Stone of the law firm Beggs & Lane, appearing today on behalf of Gulf Power Company.

MR. WILLIS: I'm Lee L. Willis of Ausley, McMullen, P.O. Box 391, Tallahassee, Florida, 32302, appearing together with James D. Beasley of the same firm, P.O. Box 391, Tallahassee, Florida 32302, appearing on behalf of Tampa Electric Company.

MS. PAUGH: If counsel could indicate which dockets they're appearing for, that would be helpful for the record.

MR. WILLIS: I'm appearing in both the 01 and 07 docket.

MR. STONE: And stepping back to me, I'm appearing on behalf of Gulf Power Company in the 01, the 02 and the 07 docket.

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

MR. McWHIRTER: My name is John McWhirter, appearing on behalf of the Florida Industrial Power Users Groups, appearing in Dockets 01, 02, 03 and 07.

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, 03 and 07 dockets.

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

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

COMMISSIONER CLARK: Does Staff have a suggestion of how we should proceed?

MS. PAUGH: We do.

MR. KEATING: Staff suggests that we take the 03 docket first, followed by the 02 docket; then the 01 docket, and finally the 07 docket.

COMMISSIONER CLARK: All right. We'll do that.

(Whereupon other dockets were discussed.)

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COMMISSIONER CLARK: Now we move to --

MS. PAUGH: 980001, Commissioner.

COMMISSIONER CLARK: Okay.

MS. PAUGH: Late Friday afternoon Tampa Electric Company was able to resolve with Staff and the parties the outstanding Btu issue, and Tampa Electric Company, I believe, has a handout, or Staff does, that reflects which issues are resolved and how.

COMMISSIONER CLARK: All right. That's on Issues 3, 4, 7, 10B and C?

MS. PAUGH: That's correct, Commissioner.

COMMISSIONER CLARK: And Staff agrees with the resolution of those issues?

MS. PAUGH: We do. You may want to get confirmation from FIPUG, Public Counsel --

COMMISSIONER CLARK: Okay. Well,

Mr. McWhirter and Mr. Howe, are you in agreement with these positions, or do you take no position?

MR. McWHIRTER: FIPUG is in agreement.

COMMISSIONER CLARK: Mr. Howe?

MR. HOWE: Public Counsel is in agreement.

COMMISSIONER CLARK: All right. So then all the issues in 980001 have been stipulated; is that correct?

MR. WILLIS: They have. And the stipulation has a date of November 23rd, 1998, in the upper right-hand corner, which was on the desk there.

COMMISSIONER CLARK: Yes, I have that.

MR. WILLIS: Commissioner, Tampa Electric is also -- and will file with the clerk the revised schedules which are Document 1 of Karen Zwolak's Exhibit KOZ-2 that just conforms with this -- to the numbers.

COMMISSIONER CLARK: Say that again, please.

MR. WILLIS: In order that Tampa Electric's filed schedules with respect to the fuel adjustment conform to the stipulations that we have made, Tampa Electric will file its revised schedules, which are Document 1 to KOZ-2, Exhibit KOZ-2. It's just a pro forma filing to conform with the agreements that we've made.

COMMISSIONER CLARK: Okay. So that -- well, I see all of them are KOZ -- well, two of them are KOZ-1. I suppose the first one is supposed to be 1 on the prehearing order, on Page 26.

MS. PAUGH: That's correct.

COMMISSIONER CLARK: Okay. So when we identify that exhibit it will be with the understanding it will be with the corrected page.

MR. WILLIS: Yes. It's revised as of November 20th, 1998.

UINIDENTIFIED SPEAKER: The first KOZ-2 should be 1.

COMMISSIONER CLARK: Correct. All right. Let's identify the exhibits.

MS. PAUGH: Before we move to that point, I'd like Roberta to clarify the exhibit that will be forthcoming.

MS. BASS: The handout that you were given includes the amount of an adjustment of 6,639,522.

Staff is still looking at the calculation of that amount, the interest calculation associated with the Btu adjustment amount. That number could change, and I think all the parties have agreed that whatever the final number is based on the review of the interest calculation is what the final amount would be.

COMMISSIONER CLARK: Okay. It's a mathematical calculation you have.

MS. BASS: Yes, it is.

MS. PAUGH: In addition, I didn't hear Mr. Willis reflect whether or not on Page 3 of three of the facts that you've been handed, it should say "projected fuel and purchased power".

MR. WILLIS: Yes. And it does, and that was why I referred to the note on the 23rd, 1998, which has that word in there.

MS. PAUGH: Okay. Thank you.

COMMISSIONER CLARK: Mr. McWhirter and Mr. Howe, do you agree with the stipulated issues, or do you take no position?

MR. McWHIRTER: I agree with the stipulated issues.

COMMISSIONER CLARK: Mr. Howe?

MR. HOWE: And here we're referring to the TECO issues, correct?

COMMISSIONER CLARK: Yes.

MR. HOWE: We agree.

COMMISSIONER CLARK: Okay. Let's go ahead and identify the exhibits starting with JS-1 and 2.

MS. PAUGH: I would recommend that the exhibits in the 01 docket not be made into composites because they refer to different schedules, and for the record that may be a little confusing; so if I may just number consecutively.

COMMISSIONER CLARK: That will be fine.

MS. PAUGH: JS-1 is Exhibit 1; JS-2, Exhibit 2; KHW-1, Exhibit 3; KHW-2, Exhibit 4; DBZ-1 is Exhibit 5; DBZ-1, the second one, is Exhibit 6; RS-1 is Exhibit 7 --

COMMISSIONER CLARK: Is that the -- let me just ask you if that is the way it's listed on the exhibit itself. Are there two DBZ-1s?

MS. PAUGH: I'll have to check. And we will make whatever corrections are appropriate with the order.

COMMISSIONER CLARK: Okay.

MS. PAUGH: RS-2 is Exhibit 8; RS-3, Exhibit 9; RS-4, Exhibit 10; RS --

COMMISSIONER CLARK: You're going too fast for me.

MS. PAUGH: Sorry about that.

COMMISSIONER CLARK: Go ahead.

MS. PAUGH: RS-5, Exhibit 11; RS-6, Exhibit 12; RS-7, Exhibit 13; KMD-1, Exhibit 14; KMD-2, Exhibit 15; KMD-3, Exhibit 16; GMB-2, composite, is Exhibit 17; MFO-1 Exhibit 18; SBC-2, Exhibit 19; GDF-1, Exhibit 20; GDF-2, Exhibit 21; GDF-3, Exhibit 22; MWH-1, Exhibit 23; KOZ-1 as corrected in this hearing is Exhibit 24; KOZ-2, Exhibit 25; KOZ-3, Exhibit 26; GAK-1, Exhibit 27; GAK-2, Exhibit 28; GAK-2, the second designation, will be Exhibit 29. We'll check that on the exhibit document. GAK-3, Exhibit 30; RB-1, Exhibit 31; DAB-1, Exhibit 32; MJH-1, Exhibit 33.

We would recommend that the exhibits be moved into the record.

COMMISSIONER CLARK: Those exhibits will be entered in the record without objection.

(Exhibits 1 through 33 marked for identification and received in evidence.)

MS. PAUGH: In addition, Staff recommends that the testimony of the following witnesses be moved into the record as though read. This can be found on Page 5 of the prehearing order, and going on to Page 6.

They are: John Scardino, Jr., Karl Wieland, Daurio Zuloaga, R. Silva, R.L. Wade, K.M. Dubin, George M. Bachman, M.F. Oaks, S.B. Cranmer, G.D. Fontaine, M.W. Howell, Karen O. Zwolak, G.A. Keselowsky, Rod Burkhardt, Deirdre Brown, Mark J. Hornick.

(REPORTER'S NOTE: Pursuant to counsel for the Commission, the testimony of John Scardino was not needed; therefore, it was not inserted in the transcript, and his exhibits, identified as Exhibit Nos. 1 and 2 in the prehearing order, were not admitted.)

COMMISSIONER CLARK: The testimony of those witnesses will be entered in the record as though read.

MR. HOWE: Excuse me, Commissioner Clark.

Lee, given the decision we made on the Btu adjustment, is there any need at this time to have Deirdre Brown's and Mr. Hornick's testimony in the record?

MR. WILLIS: No.

MR. HOWE: Commissioner Clark, I would suggest that those two witnesses' testimony not be introduced into the record since we've reached an agreement on the Btu adjustment.

MS. PAUGH: That's acceptable to Staff.

COMMISSIONER CLARK: Then the testimony of Deirdre Brown and Mr. Hornick will not entered in the record and, likewise, Exhibit 32 and 33 will not be in the record.

MR. WILLIS: We have no objection to that.

MS. PAUGH: Staff has no objection.

(Exhibits 32 and 33 were withdrawn from the record.)

(prelim)

FLORIDA POWER CORPORATION

DOCKET NO. 980001-EI

Levelized Fuel and Capacity Cost Factors
January through December 1999

DIRECT TESTIMONY OF
KARL H. WIELAND

Q. Please state your name and business address.

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

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

A. I am employed by Florida Power Corporation as Manager of Financial Analysis.

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

A. Yes.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present for Commission approval the Company's levelized fuel and capacity cost factors for the period of January through December 1999.

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 E 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.

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 1.893 ¢/kWh (before line loss adjustment). The basic factor consists of a fuel cost for the projection period of 1.91322 ¢/kWh (adjusted for jurisdictional losses), a GPIF penalty of 0.00132 ¢/kWh, and an estimated prior period true-up credit of 0.04494 ¢/kWh. In addition, the basic factor includes a charge of 0.02528 ¢/kWh representing the remaining three months of nuclear replacement fuel replacement cost to be collected per stipulation approved in Docket No. 970261-EI, and a Market Price true-up credit for Powell Mountain in the amount of 0.00079 ¢/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 1.287 On-peak and 0.858 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 1.896 ¢/kWh.

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

A. The average fuel factor decreases from 2.122 ¢/kWh to 1.893 ¢/kWh, a decrease of 10.8%.

Q. Please explain the reasons for the decrease.

A. The decrease is a result of several factors, including the addition of the efficient new Hines Unit 1 combined cycle plant, the annual vs. seasonal fuel factor calculation, an over-recovery credit, and a reduced factor for the recovery of previously approved nuclear fuel replacement costs. The annual fuel factor is lower than the summer seasonal factor on which current rates are based because the additional generation required during the summer period is supplied by more expensive oil and gas fired units.

Q. What portion of the previously approved nuclear replacement fuel costs will be recovered during 1999?

A. Schedule E1, line 28b shows that unrecovered balance of $8,346,290, or 0.02528 ¢/kWh, of the approved recovery amount will be recovered during 1999.

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 eleven 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 units 1 & 3 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 Debary beginning in May, 1999. In addition, line 4 contains the annual payment of $1.3 million to the DOE for the decommissioning and decontamination of their enrichment facilities.

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. The capacity payments associated with the UPS contract are based on the original contract of 400 MWs. The additional 5 MWs are the result of revised SERC ratings for the five units involved in the unit power purchase, providing a benefit to Florida Power in the form of reduced costs per kW. Both of these contracts have been in place and have been approved for cost recovery by the Commission. 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 consists primarily of economy purchases from within or outside the state which are not made through the Florida Broker System. Line 8 also includes energy costs for purchases from Seminole Electric Cooperative (SECI) for load following, and off-peak hydroelectric purchases from the Southeast Electric Power Agency (SEPA). The SECI contract is an ongoing contract under which the Company purchases energy from SECI at 95% of its avoided fuel cost. Purchases from SEPA are on an as-available basis. There are no capacity payments associated with either of these purchases. Other purchases may have non-fuel charges, but since such purchases are made only if the total cost of the purchase is lower than the Company's cost to generate the energy, it is appropriate to recover the associated non-fuel costs through the fuel adjustment clause rather than the capacity cost recovery 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. Florida Power has several wholesale contracts with Seminole, some of which represent Seminole's own firm resources, and others that provide for the sale of supplemental energy to supply the portion of their load in excess of Seminole's own resources, 1080 MW in 1999. The fuel costs charged to Seminole for supplemental sales are calculated on a "stratified" basis, in a manner which recovers the higher cost of intermediate/peaking generation used to provide the energy. New contracts for fixed amounts of intermediate and peaking capacity begin in January of 1999. While those sales are not necessarily priced at average cost, Florida Power is crediting average fuel cost for the appropriate stratification (intermediate or peaking) in accordance with Order No. PSC-97-0262-FOF-EI. Florida Power also has existing wholesale peaking contracts with Georgia Power Company and the Municipal Electric Authority of Georgia (MEAG) 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 system cost basis, an adjustment has been made to remove these costs and the related kWh sales from the fuel adjustment calculation in the same manner that interchange sales are removed from the calculation. This adjustment is necessary to avoid an over-recovery by the Company which would result from the treatment of these fuel costs on an average system cost basis in this proceeding, while actually recovering the costs from these customers on a higher, stratified cost basis. Details on these sales are 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 begins with the actual balance of $(36,210,111), taken from Schedule A2, page 3 of 4, previously submitted for the month of August. This balance was projected to the end of December, 1998, including interest estimated at the August ending rate of 0.462% per month. The development of the estimated true-up amount for April through December 1998 period is shown on Schedule E1B, and summarized on Schedule E1A. The actual September balance will be amortized during October through December, 1998, resulting in a current period estimated over-recovery of $14,837,877 at the end of December 1998. This results in an estimated true-up credit on line 28 of Schedule E1 (Basic) of 0.0449 ¢/kWh for application in the January-December 1999 projection period.

Q. What are the primary reasons for the projected December 1998 over-recovery of $14.8 million?

A. Continuing the summer fuel adjustment factors for October through December, 1998 is the major reason for the over-recovery. This over-recovery was anticipated to be $21.7 million in the Company's June 22 filing for this period, but extreme summer temperatures increased fuel expenses and reduced the expected over-recovery.

Q. How was the market price true-up for Powell Mountain coal purchases calculated?

A. The calculation was performed in accordance with the market pricing methodology approved by the Commission for Powell Mountain coal purchases in Docket No. 860001-EI-G and has been made available for Staff review. The true-up is based on the difference between the previously recovered cost of Powell Mountain coal purchases during 1995, and a calculated cost using the market price index for compliance coal in BOM District 8 for 1997, as adopted in Order No. 22401. The true-up amount of $263,847 also includes interest through May, 1998.

Q. Has Florida Power confirmed the validity of using the "short-cut" method of determining the equity component of EFC's capital structure for calendar year 1997?

A. Yes. Florida Power's Audit Services department has reviewed the analysis performed by Electric Fuels Corporation (EFC). The revenue requirements under a full utility-type regulatory treatment methodology using the actual average cost of debt and equity required to support Florida Power business was compared to revenues billed using equity based on 55% of net long-term assets (short cut method). The analysis showed that for 1997, the short cut method resulted in revenues of $286.4 million which were $0.01 million or 0.004% lower than revenues under the full utility-type regulatory treatment methodology. Florida Power continues to believe that this analysis confirms the appropriateness of the short cut method.

Q. Has Florida Power properly calculated the 1997 price for waterborne transportation services provided by Electric Fuels Corporation?

A. Yes. The 1997 waterborne transportation calculation has been reviewed by Staff and Public Counsel and deemed properly calculated.

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

A. The cost per million BTU of the nuclear fuel which will be in the reactor during the projection period (primarily Cycle 11) was developed from the unamortized investment cost of the fuel in the reactor. 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. The cost per million BTU for cycle 11 was also used for cycle 12 which will be in effect from mid-November through December, 1999, following the fall 1999 refueling outage.

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 $0.34 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 Financial Analysis Department using the most recently available data. The forecast used for this projection period was prepared in June 1998.

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

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

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

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

Q. Please explain the basis for requesting recovery of the cost of converting a third combustion turbine unit (unit 8) at Debary 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, Florida Power has converted Intercession City units 7-10, Debary units 7 and 9, Bartow units 2 and 4, and Suwannee units 1 and 3 to burn natural gas. The Commission previously authorized the Company to recover the conversion cost of these units, including a return on investment, over a five-year period. Florida Power is asking the Commission for the same treatment for Debary Unit 8. The cost to convert Debary Unit 8 is $1.4 million. This conversion cost was not part of the cost of the Debary units 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. Florida Power proposes to amortize the $1.4 million conversion cost for Debary Unit 8 over a five-year period beginning with the plant in-service date of May, 1999. The same amortization period was approved for all previous conversions. The projected cost during 1999 is $215,013 which consists of an amortization charge of $139,998 and a return (including income taxes) of $75,015 based on the Company's current cost of capital of 8.37%. The fuel savings for the same period are expected to be $376,000 resulting in a net benefit to customers of $160,987. During the five year amortization period, the conversion produces fuel savings with a present value of $2.7 million which results in a net benefit to customers of $0.9 million. These savings will grow after the amortization period if gas continues to be available.

A monthly schedule of amortization expenses and projected fuel savings is attached as Part E of my testimony.

Q. Why was Debary Unit 8 not included in the original requests for Units 7 or 9?

A. Florida Power continues to take a very conservative approach in its assessment of gas availability for the Debary site because the availability of gas at the site is limited and difficult to predict. Actual fuel savings for Debary Units 7 and 9 have far exceeded expectation which has made the Company more confident of fuel availability which is critical to achieving the fuel savings. Since their conversion, Debary Units 7 and 9 have reduced fuel cost by $8.5 million compared to an investment of $3.3 million.

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

A. Florida Power chose a five-year period in order to align the recovery of costs 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. Discussions with Florida Gas Transmission as well as actual experience to date for previously converted units at this site indicate that interruptible gas will be available in sufficient quantity to power the converted units for the next five years. Florida Power 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. Achieved fuel savings will be presented in the annual true-up filings until the units are fully amortized.

Q. What does Florida Power propose to do if expected fuel savings are not achieved?

A. As it has proposed with all previously converted units, Florida Power is willing to assume the risk for achieving fuel savings for Debary Unit 8. 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 (CCR) factor is shown in Part D of my exhibit. The factor allocates capacity costs to rate classes in the same manner that they would be allocated if they were recovered in base rates. A brief explanation of the schedules in the exhibit follows.

Sheets 1 and 2: 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 3: Estimated/Actual True-Up. This schedule presents the actual ending true-up balance as of August, 1998 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 $(4,856,714) is then carried forward to Sheet 1, to be collected during the January through December, 1999 period.

Sheet 4: Development of Jurisdictional Loss Multipliers. The same delivery efficiencies and loss multipliers presented on Schedule E1-F.

Sheet 5: Calculation of 12 CP and Annual Average Demand. The calculation of average 12 CP and annual average demand is based on 1997 load research data and the delivery efficiencies on Sheet 3.

Sheet 6: Calculation of Capacity Cost Recovery Factors. The total demand allocators in column (7) are computed by adding 12/13 of the 12 CP demand allocators to 1/13 of the annual average demand allocators. The CCR factor for each secondary delivery rate class in cents per kWh is the product of total jurisdictional capacity costs (including revenue taxes) from Sheet 2, times the class demand allocation factor, divided by projected effective sales at the secondary level. The CCR factor for primary and transmission rate classes reflect the application of metering reduction factors of 1% and 2% from the secondary CCR factor.

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

A. The increase in the average CCR factor from 0.82181 ¢/kWh in the April through September 1998 period to 0.94343 ¢/kWh for the January through December 1999 period is due to the greater amount of kWh sales per dollar of expense during for the summer period than during the full calendar year. In addition, annual increases in capacity payments lead to increases in the factor from one year to the next. A third cause is the small under-recovery that is projected for the end of the year because the lower summer factor remains in place during October through December of this year.

Q. Does this conclude your testimony?

A. Yes.

FLORIDA POWER CORPORATION

DOCKET NO. 980001-EI

GPIF Targets and Ranges for January through December 1999

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 January through December, 1999. These GPIF targets and ranges have been developed from individual unit equivalent availability and average net operating heat rate targets and improvement/degradation ranges for each of Florida Power's GPIF generating units in accordance with the Commission's Generating Performance Incentive Implementation Manual. This initial presentation of GPIF targets and ranges on an annual, calendar-year basis is in accordance with Commission Order No. PSC-98-0691-FOF-PU. In addition, I have previously presented Florida Power's GPIF targets and ranges for the three-month transition period of October through December, 1998 in my testimony submitted for the August, 1998 hearings, which was deferred to the upcoming November hearings.

Q. Do you have an exhibit to your testimony?

A. Yes, I will sponsor an exhibit containing 72 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. I have included the same units as were included for the current period; Crystal River Units 1 through 5 and Anclote Units 1 and 2.

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 80.31%. The unit's next refueling outage is scheduled to begin on October 1 and continue through November 14, which results in a POF of 12.33% for the period. The unit's EUOR target is 7.91%, which equates to an EUOF of 7.36% when planned outage hours are taken into account.

The availability targets for the 1999 period were developed after removing from the historical data all forced outage hours associated with the September 1996 to February 1998 shutdown of the unit to address certain design issues related to backup safety systems, including the emergency diesel generators.

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

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

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

Q. How were the GPIF weighting factors determined?

A. To determine the weighting factors for availability, a series of 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.

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BEFORE THE PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

AMENDED TESTIMONY OF R. SILVA,

ORIGINALLY FILED MAY 27, 1998

DOCKET NO. 980001-EI

OCTOBER 5, 1998

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

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

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

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

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

A. Yes, I have.

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

A. The purpose of my testimony is to amend my original testimony and exhibits filed on May 27, 1998. This amendment is necessary to reflect, in the GPIF results, the thermal uprate of both Turkey Point Units 3 and 4, and the corresponding net capacity increase from the 666 MW used in our earlier reward/penalty calculation, to the correct 693 MW, which was implemented in October of 1996, but not reflected in the monthly reports to the FPSC Staff nor in my original filing of May 27, 1998. An errata sheet is contained in my attached Exhibit (Document No.3).

Q. In what manner does the increase in Unit capacity affect the calculation of reward/penalty for heat rate and availability performance?

A. Applying the increase in Unit capacity to the GPIF equations results in a lower actual heat rate for the Units in question and, in this case, results in no GPIF reward or penalty due to heat rate performance for Turkey Pt. Units 3 and 4. More specifically, the increase in Unit capacity reduces the actual values of Unit Net Operating Factor (NOF) and consequently the values for adjusted actual Adjusted Net Operating Heat Rate (ANOHR) during the period. As a result, the difference between the projected target ANOHR and the corrected adjusted actual ANOHR for these Units now falls within the +/75 BTU/KWH deadband. Therefore there is no reward or penalty for heat rate performance for Turkey Points Units 3 and 4. This calculation, using the correct Unit capacity, and a comparison to the calculation performed using the incorrect Unit capacity, is presented in my attached Exhibit (Document No. 4).

The increase in Unit capacity also reduces the calculated equivalent outage hours for these Units, but not sufficiently to change the adjusted actual availability and the reported reward for availability performance.

Q. Did you perform your revised reward/penalty calculation for heat rate performance using the same methodology as in your original testimony?

A. Yes. As shown in my Exhibit (Document No.4), my revised calculation uses the same equations. The only difference between my original calculation and my revised calculation is one input value, the rated capacity of Turkey Pt. Units No. 3 and 4, which has been corrected from 666 MW to 693 MW.

Q. Is it appropriate to reflect the uprated capacity of Turkey Pt. Units No. 3 and 4 in these reward/penalty calculations?

A. Yes. The higher level of Unit capacity is, in fact, the actual capacity of these Units, which is the value that should be used in these calculations. Moreover, the most significant effect of FPL's actions to uprate these nuclear units is that FPL's system average fuel costs have been lower than they would have otherwise been. Since nuclear fuel costs are the lowest in our system, increasing the capability of these nuclear units has reduced the cost of electricity to our customers. This result is consistent with the intent of the GPIF rule.

Q. What is the effect of this amendment on the GPIF incentive reward/penalty for the period ending September, 1997?

A. The total GPIF incentive reward for FPL's nuclear units increases from $8,943,534 to $9,707,291. The system total GPIF reward increases from

$8,590,204 to $9,353,960

Q. Which lines in your original testimony are affected by these changes?

A. The following lines have changed in my original testimony

1) Page 2 lines 13, 18 and 19

2) Page 5 lines 6,7,8,9,11,12,13,14,24,25

3) Page 6 line 3

These lines have been corrected in my original testimony, and included in an Exhibit which contains my revised testimony in its entirety (Document 2, pages 1 through 6)

Q. Which sheets in your original exhibits are affected by these changes?

A. The following sheets have changed in my original Document 1

1) Sheet 6.203.002

2) Sheet 6.203.004

3) Sheet 6.203.005

4) Sheet 6.203.006

5) Sheet 6.203.007

6) Sheet 6.203.019

7) Sheet 6.203.020

These sheets are included in the revised Exhibit provided in its entirety below as Document 1, pages 1 through 24

Q. Does this conclude your testimony?

A. Yes, it does.

BEFORE THE PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

TESTIMONY OF R. SILVA

DOCKET NO. 980001-EI

OCTOBER 5, 1998

Q. Please state your name and business address.

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

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

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

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

A. Yes, I have.

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

A. The purpose of my testimony is to present the target unit average net operating heat rates and target unit equivalent availability for the periods of (1) October through December, 1998, and (2) January through December, 1999, for use in determining the Generating Performance Incentive Factor (GPIF).

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

A. For the period of October through December, 1998, FPL projects a weighted system equivalent planned outage factor of 12.1 % and a weighted system equivalent unplanned outage factor of 5.8 %, which yield a weighted system equivalent availability target of 82.1 %. For the period of January through December, 1999, FPL projects a weighted system equivalent planned outage factor of 4.7 % and a weighted system equivalent unplanned outage factor of 6.1 %, which yield a weighted system equivalent availability target of 89.2 %. The targets for each of the two periods reflect planned refueling outages for two nuclear units. FPL also projects weighted system average net operating heat rate targets of 9235 BTU/KWH for the period of October through December, 1998, and 9512 BTU/KWH for the period January through December, 1999. As discussed later in this testimony, these targets represent fair and reasonable values when compared to historical data. FPL therefore requests that the targets for these performance indicators be approved by the Commission.

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

A. Yes, I have. It consists of two documents. The first document refers to the period of October through December, 1998. The second document refers to the period of January through December, 1999. The first page of each document is an index to the contents of the document. All other pages are numbered according to the latest revisions of the GPIF Manual as approved by the Commission.

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

A. Yes, I have. Document No.1, pages 6 and 7, contain the information summarizing the targets and ranges for unit equivalent availability and average net operating heat rates for the sixteen (16) generating units which FPL proposes to have considered as GPIF units for the period of October through December, 1998. Similarly, Document No. 2, pages 6 and 7, contain the information summarizing the targets and ranges for unit equivalent availability and average net operating heat rates for the seventeen (17) generating units which FPL proposes to have considered as GPIF units for the period of January through December, 1999. The Sheets presented in these pages were prepared in accordance with the latest revisions of the GPIF Manual. All of these targets have been derived utilizing methodologies as adopted in Section 4, Subsection 2.3 of the GPIF Manual.

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

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

forecasted system net generation for this period. These units were selected in accordance with the GPIF Manual Section 3.1, using the estimated net generation for each unit taken from the production costing simulation program, POWRSYM, which forms the basis for the projected levelized fuel cost recovery factor for the period.

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

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

Q. Does this conclude your testimony?

A. Yes, it does.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

TESTIMONY OF RENE SILVA

DOCKET NO. 980001-EI

OCTOBER 5, 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 POWRSYM model in the calculation of the proposed fuel cost recovery factor for the period January through December, 1999.

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 1 of this filing.

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

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

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

A. The conditions that affect the prices of fuel oil and natural gas can change significantly between the time the forecast is developed and the date of the filing in October. 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 October fuel price forecast update to rerun our POWRSYM system simulation, in order to reflect the latest changes in fuel market conditions, and still meet our October 5 filing date. Furthermore, while FPL has, in the past, rerun its projections and re-filed its fuel cost recovery factor after its initial filing to reflect late changes in fuel market conditions, this approach does not provide the same flexibility to react to those changes that use of a banded forecast provides. Trying to incorporate such "last minute" changes puts us at risk of not having adequate time to produce new computer simulations and all of the associated documentation required for filing.

Therefore, in addition to the "Base Case" forecast to describe future fuel prices, FPL prepared "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 POWRSYM 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 January through December, 1999 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 1999 than in 1998 due to improved world economic conditions expected in 1999. Although crude oil supply, augmented by Iraqi oil exports and slightly higher OPEC production, is projected to meet this increase in demand, there will not be excess production, as has been the case in 1998. As a result, crude oil prices and consequently heavy fuel oil prices, for the January through December, 1999 period are projected to be somewhat higher than in 1998.

Q. What is the projected relationship between heavy fuel oil and crude oil prices during the January through December, 1999 period?

A. The price of heavy fuel oil on the U. S. Gulf Coast (1.0% sulfur) is projected to be approximately 79% 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 January through December, 1999 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 January through December, 1999.

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 18% of the fuel blend at SJRPP during 1999 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 January through December, 1999 period.

A. FPL's projected system average dispatch cost of coal, shown on page 5 of Appendix I, ranges from $1 56 to $1 60 per million BTU, delivered to plant, for this period

Q. What are the factors that can affect FPL's natural gas prices during the January through December, 1999 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 January through December, 1999 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, 1999 gas prices are projected to be very close to those in 1998

Q. What are the factors that affect the availability of natural gas to FPL during the January through December, 1999 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 80,000 and 235,000 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 January through

December, 1999 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 15% likelihood that the actual price of each fuel for each month in the January through December, 1999 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 15% likelihood that the actual price of each fuel for each month in the January through December, 1999 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 (October, 1998) view of the fuel oil and gas markets, at what level do you now project prices will be during the January through December, 1999 period ?

A. Based on current market conditions, FPL now projects that actual fuel oil and gas prices during the January through December, 1999 period will be very close to those projected in the Base Case forecast In other words, fuel oil and gas prices are still projected to be closer to those in the "Base Case" forecast than to the "Low" or "High" forecast during 1999. Therefore, the projected fuel costs calculated by POWRSYM using the "Base Case" oil and gas forecast are the most appropriate projected costs for the January through December, 1999 period As stated in the testimony of Korel Dubin, this "Base Case" oil and gas forecast was used to calculate the proposed Fuel Factor for the period January through December, 1999

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

Q. Are you providing the outage factors projected for the period January through December, 1999?

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 January through December, 1999 period.

Q. Please describe significant planned outages for the January through December, 1999 period.

A. Planned outages at our nuclear units are the most significant in relation to Fuel Cost Recovery. Turkey Point Unit No.4 is scheduled to be out of service for refueling from March 15, 1999, until April 19, 1999, or thirty-five days during the projected period. St. Lucie Unit No.1 will be out of service for refueling from September 6, 1999, until October 11, 1999, or thirty-five 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 January through December, 1999 period?

A. Yes, Net Winter Continuous Capability (NWCC) at Port Everglades Unit No.3 will increase by 15 MW, from 391 MW to 406 MW, and its Net Summer Continuous Capability will increase by 14 MW, from 389 MW to 403 MW, as a result of refurbishing the unit's boiler and steam turbine.

INTERCHANGE and PURCHASED POWER TRANSACTIONS

Q. Are you providing the projected interchange and purchased power transactions forecasted for January through December, 1999?

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 "Base Case" fuel price forecast for fuel oil and gas supply.

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

A. FPL purchases interchange power from others under several types of interchange transactions which have been previously described in this docket: Emergency - Schedule A, Short Term Firm - Schedule B, Economy - Schedule C; Extended Economy - Schedule X, Opportunity Sales - Schedule OS; 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 January through December, 1999 period.**

A. Under the UPS agreement FPL's capacity entitlement during the projected period is 914 MW from January through December, 1999 Based upon the alternate and supplemental energy provisions of UPS, an availability factor of 100% is applied to these capacity entitlements to project energy purchases The projected UPS energy (unit) cost for this period, used as an input to POWRSYM, is based on data provided by the Southern Companies. For the period, FPL projects the purchase of 5,882,729 MWH of UPS Energy at a cost of $73,958,970 In addition, we project the purchase of 940,412 MWH of UPS Replacement energy (Schedule R) at a cost of $16,208,390 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 3,028,551 MWH for the period at an energy cost of $41,323,250. 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 534,467 MWH at a cost of $2,066,100. 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 8,274,232 MWH at a cost to FPL of $143,838,067.

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

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

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

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

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

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

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

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

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

A. We have projected 774,081 MWH of Economy energy sales for the period. The projected fuel cost related to these sales is $19,213,617 The projected transaction revenue from the sales is $24,365,391 Eighty percent of the gain for Schedule C is $4,121,419 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 January to December, 1999 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 3,697,302 MWH at a cost of $69,178,210. If generated, we estimate that this energy would cost $80,780,263. Therefore, these purchases are projected to result in savings of $11,602,053.

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 534,503 MWH of energy at a cost of $1,966,890. 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 January through December, 1999, including FPL's "Low" and "High" price forecasts for fuel oil and gas supply. I have stated that the projected fuel costs developed using the "Base Case" forecast are the most appropriate for the January through December, 1999 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 POWRSYM model in developing the projected Fuel Cost Recovery Factor for the January through December, 1999 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

October 5, 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 January 1999 through December 1999.

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 January 1999 through December 1999.

Q. Please provide FPL's projection for nuclear fuel unit costs and energy for the period January 1999 through December 1999.

A. FPL projects the nuclear units will produce 257,157,502 MBTU of energy at a cost of $0.3281 per MMBTU, excluding spent fuel disposal costs for the period January 1999 through December 1999. 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 January 1999 through December 1999 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 January 1999 through December 1999 and what is the basis for FPL's projection.

A. FPL's projection of $5.75M for D&D costs to be paid during the Period January 1999 through December 1999 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.

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

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

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

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

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

On August 3, 1998, the states and state utility commissions that were parties in the Northern States Power case filed a petition for a writ of certiorari with the U.S. Supreme Court. The state petitioners requested the Court to review the D.C. Circuit's decision that it lacked the authority to order DOE to begin spent fuel disposal. On September 1, 1998, DOE filed a petition for a writ of certiorari with the U.S. Supreme Court, maintaining that the D.C. Circuit lacked jurisdiction to prohibit DOE from invoking the "unavoidable delays" provision of the standard contract. DOE contends that the Court of Federal Claims has exclusive jurisdiction to consider contract claims against the United States. FPL is considering filing a brief opposing DOE's petition. This brief must be submitted by October 3, 1998, if no extension of time is granted.

On June 8, 1998, FPL filed a lawsuit against DOE in the U.S. Court of Federal Claims, claiming in excess of $300,000,000 in damages arising out of DOE's failure to begin spent fuel disposal on January 31, 1998. On July 31, 1998, DOE filed a motion to dismiss FPL's lawsuit on grounds that FPL failed to exhaust its administrative remedies prior to filing the lawsuit and should have first filed a claim with DOE's Contracting Officer. FPL filed its opposition to DOE's motion on August 31, 1998, in which the Company argued that cases involving outright breaches of government contracts by the government can be brought directly in the Court of Federal Claims. It is likely that the Court will hear argument on the motion and issue a decision before the end of 1998. It is possible that the decision of the Court of Federal Claims on the jurisdictional issue could be certified for interlocutory review by the U.S. Court of Appeals for the Federal Circuit.

2(a). Uranium Enrichment Pricing Disputes - FY 1993 Overcharges. Secondly, FPL is currently seeking to resolve a pricing dispute concerning uranium enrichment services purchased from the United States (U.S.) Government, prior to July 1, 1993. FPL's contract for enrichment services with the U.S. Government calls for pricing to be calculated in accordance with "Established DOE Pricing Policy". Such policy had always been one of cost recovery, which included costs related to the Decontamination and Decommissioning (D&D) of the DOE's enrichment facilities. However, the Energy Policy Act of 1992 (The Act) requires utilities to make separate payments to the U.S. Treasury for D&D, starting in Fiscal Year 1993. FPL has been making such payments. Therefore, D&D should not have been included in the price charged by DOE for deliveries during Fiscal Year 1993, and the price should have been reduced accordingly. FPL filed a claim with the DOE Contracting Officer on July 14, 1995, for a refund for such deliveries. On October 13, 1995, the DOE Contracting Officer officially rejected FPL's claim. On October 11, 1996, FPL, along with five other U.S. utilities and one foreign entity, appealed DOE's rejection of the Fiscal Year 1993 overcharge claim with the U.S. Court of Federal Claims (FPL v. DOE).

On August 12, 1998, the Court of Federal Claims dismissed FPL's complaint, holding that the complaint was barred because the issue should have been raised in an earlier lawsuit filed by FPL and other utilities against the U.S. Enrichment Corporation. The Court ruled that the DOE overcharges were part of a pricing claim raised by FPL and other utilities against the government's uranium enrichment enterprise, the U.S. Enrichment Corporation, created by the Act in 1992. In that case (Centerior v. USEC), FPL claimed that USEC had charged too much for uranium enrichment services. While FPL settled its claim against USEC, the Court of Federal Claims ultimately ruled against the utility claimants. The Court in FPL v. DOE held that FPL should have raised the DOE overpricing issue in the Centerior litigation, and was now barred from raising that claim for failing to raise it before.

FPL believes that the Court overlooked significant differences between the overcharges, which involve different agencies, different time periods, and different statutory mandates governing the legality of the pricing claims. Since the claims are different, FPL believes that it should not be barred from raising the 1993 overcharge claim against DOE. FPL has until October 9, 1998 to appeal the decision of the Court of Federal Claims to the U.S. Court of Appeals for the Federal Circuit.

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

FPL believes that the Yankee decision is not necessarily dispositive of its claims against the Government challenging the D&D assessment. As a protective measure, on July 27, 1998, FPL filed a claim before DOE's Contracting Officer and on July 29, 1998, a complaint with the U.S. Court of Federal Claims challenging the D&D assessment on grounds that the D&D assessment is an impermissible retroactive adjustment to previous fixed price uranium enrichment service contracts.

In addition, FPL has joined a complaint filed by 21 U.S. utilities in the U.S. District Court for the Southern District of New York challenging the D&D assessment as a violation of the due process clause of the Fifth Amendment to the U.S. Constitution. (Consolidated Edison Co. v. United States).

The Government has moved for a stay of discovery in the Consolidated Edison case pending resolution of the challenges to the D&D assessment in the Court of Federal Claims.

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

May 27, 1998

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) and Capacity Cost Recovery Clause (CCR) Net True-Up amounts for the period October 1997 through March 1998. The Net True-Up for the FCR is an overrecovery, including interest, of $13,491,202. The Net True-Up for the CCR is an overrecovery, including interest, of $11,771,496. I am requesting

Commission approval to include these true-up amounts in the calculation of the FCR and CCR factors respectively, for the period January 1999 through December 1999.

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

A. Yes, I have. It consists of two appendices. Appendix I contains the FCR related schedules and Appendix II contains the CCR related schedules. FCR Schedules A-1 through A-13 for the October 1997 through March 1998 period have been filed monthly with the Commission and served on all parties. These schedules are incorporated herein by reference.

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

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

FUEL COST RECOVERY CLAUSE (FCR)

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

A. Appendix I, page 3, entitled "Summary of Net True-Up", shows the calculation of the Net True-Up for the six-month period October 1997 through March 1998, an overrecovery of $13,491,202, which I am requesting be included in the calculation of the Fuel Cost Recovery Factor for the period January 1999 through December 1999. 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 October 1997 through March 1998 of $57,636,177 shown on line 1, less the estimated/actual End-of-Period underrecovery for the same period of $71,127,379 shown on line 2 that was included in the calculation of the Fuel Cost Recovery Factor for the period April 1998 through December 1998, results in the Net True-Up for the six-month period October 1997 through March 1998 shown on line 3, an overrecovery of $13,491,202.

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 October 1997 through March 1998.

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 $39.3 million lower than the estimated/actual projection. This variance is primarily due to a $17.3 million decrease in Energy Payments to Qualifying Facilities, a $13.2 million decrease in the Energy Cost of Economy Purchases and a $7.5 million decrease in the Fuel Cost of Purchased Power.

The $17.3 million decrease in Energy Payments to Qualifying Facilities is due to QF purchases being approximately 740,000 MWHs lower than projected. Energy Cost of Economy Purchases is $13.2 million lower than projected since purchases were 615,000 MWHs less than projected due to limited availability of low cost economy energy. Fuel Costs of Purchased Power is $7.5 million lower than projected since UPS purchases from Southern were approximately 350,000 MWH lower than projected and purchases from SJRPP were 110,000 MWH lower than estimated due to a change in maintenance outage dates.

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 $25,781,453 lower than the estimated/actual projection. This decrease was due to lower jurisdictional kWh sales. Jurisdictional sales were 4.1% lower than the estimated/actual projection.

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

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

CAPACITY COST RECOVERY CLAUSE (CCR)

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

A. Appendix II, page 3, entitled "Summary of Net True-Up Amount" shows the calculation of the Net True-Up for the twelve-month period April 1997 through December 1998, an overrecovery of $11,771,496, which I am requesting to be included in the next projection period.

On January 12, 1998 FPL requested a Capacity Cost Recovery midcourse correction of $63.4 million which the Commission approved in Order PSC-98-0412-FOF-EI at the February 1998 hearing. The $63.4 million midcourse correction included an Estimated/Actual overrecovery of $45.4 million for the period April 1997 through March 1998 (Final True-Up April 97–September 97, $36.1 million plus Estimated/Actual True-Up October 97-March 98, $9.3 million) 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.

The actual End-of-Period overrecovery for the six-month period ended September 1997 of $36,119,698 was already included in the factor for the period April 1998 through December 1998 as part of the midcourse correction. This $36,119,698 shown on line 1, plus the true-up overrecovery of $21,096,113 for the six-month period ended March 1998 shown on line 2, less the balance of $45,444,316 from the midcourse correction shown on line 3, results in the overrecovery of $11,771,496 shown on line 4. This $11,771,496 true-up is the net overrecovery to be carried forward to the January 1999 through December 1999 period.

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

A. Yes. Appendix II, page 4, entitled "Calculation of Final True-up Amount", shows the calculation of the CCR End-of period true-up for the six-month period October 1997 through March 1998. The End of-Period true-up shown on line 17 plus line 18 is an overrecovery of $21,096,113.

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

A. Yes it is. The calculation of the true-up amount follows the procedures established by this Commission as set forth on Commission Schedule A-2 "Calculation of True-Up and Interest Provision" for the Fuel Cost Recovery Clause.

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

A. Yes. Appendix II, page 5, entitled "Calculation of Final True-up Variances", shows the actual capacity charges and applicable revenues compared to the estimated/actuals for the period October 1997 through March 1998.

Q. What was the variance in net capacity charges?

A. As shown on line 7, actual net capacity charges on a Total Company basis were $10.9 million lower than the estimated/actual projection. This variance was primarily due to lower than expected payments to non-cogenerators, lower than expected payments to cogenerators and higher than expected revenues from capacity sales.

Payments to non-cogenerators were $4.1 million lower than projected due to capacity rates being lower than expected as a result of lower than forecasted plant investment and fixed expenses. Additionally, payments to cogenerators were lower than anticipated causing a $3.7 million variance. Revenues from capacity sales were $3.4 million higher than projected due to Opportunity Sales being greater than projected for the period.

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

A. As shown on line 12, actual Capacity Cost Recovery revenues, net of revenue taxes, were $1.0 million lower than the estimated/actual projection. This decrease was primarily due to lower jurisdictional kWh sales than projected. Jurisdictional sales were 4.1% lower than the estimated/actual projection.

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

October 5, 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 Tariff Administration 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 and the capacity payment factors for the Company's rate schedules for the period January 1999 through December 1999. 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. I am also providing projections of avoided energy costs for purchases from small power producers and cogenerators and an updated ten year projection of Florida Power & Light Company's annual generation mix and fuel prices.

In addition, my testimony presents the schedules necessary to support the calculation of the Estimated/Actual True-up amounts for the Fuel Cost Recovery Clause (FCR) and the Capacity Cost Recovery Clause (CCR) for the period April 1998 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 Appendices II and III. Appendix II contains the FCR related schedules and Appendix III contains the CCR related schedules.

FCR Schedules A-1 through A-13 for April 1998 through August 1998 have been filed monthly with the Commission, are served on all parties and are incorporated herein by reference.

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

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

FUEL COST RECOVERY CLAUSE

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

A. 1.976¢ per kWh. Schedule EI, Page 3 of Appendix II shows the calculation of this twelve-month levelized fuel factor. Schedule E2, Pages 10 and 11 of Appendix II indicates the monthly fuel factors for January 1999 through December 1999 and also the twelve-month levelized fuel factor for the period.

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

A. Yes. Schedule E1-D, Page 8 of Appendix II provides a twelve-month levelized fuel factor of 2.136¢ per kWh on-peak and 1.908¢ per kWh off-peak for our Time of Use rate schedules.

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

A. Yes, they were.

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

A. As shown on line 29 of Schedule E1, Page 3, of Appendix II the estimated/actual fuel cost underrecovery for the April 1998 through December 1998 period amounts to $129,170,389. This estimated/actual underrecovery for the April 1998 through December 1998 period plus the final overrecovery of $13,491,202 for the October 1997 through March 1998 period results in a total underrecovery of $115,679,187. This amount, divided by the projected retail sales of 83,614,989 MWH for January 1999 through December 1999 results in an increase of 0.1383¢ per kWh before applicable revenue taxes. In his testimony for the Generating Performance Incentive Factor, FPL Witness R. Silva calculated a reward of $9,353,960 for the period ending September 1997 which is being applied to the January 1999 through December 1999 period. This $9,353,960 divided by the projected retail sales of 83,614,989 MWH during the projected period, results in an increase of 0.0112¢ per kWh, as shown on line 33 of Schedule E1, Page 3 of Appendix II.

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

A. Schedule E1-B, Page 5 of Appendix II shows the calculation of the FCR Estimated/Actual True-up amount. The calculation of the estimated/actual true-up amount for the period April 1998 through December 1998 is an underrecovery, including interest, of $129,170,389 (Column10, lines C7 plus C8). This amount, when combined with the Final True-up overrecovery of $13,491,202 (Column 10, line C9a) deferred from the period October 1997 through March 1998, presented in my Final True-up testimony filed on May 27, 1998, results in the End of Period underrecovery of $115,679,187 (Column 10, 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 Provision (lines C4 through C10) for this period, and the End of Period True-up amount (line C11).

The data for April 1998 through August 1998, columns (1) through (5) reflects the actual results of operations and the data for September 1998 through December 1998, columns (6) through (9), are based on updated estimates.

The variance calculation of the Estimated/Actual data compared to the original projections for the April 1998 through December 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 $154.2 million or a 13.8% increase from original projections. This variance is mainly due to a $140 million increase in the Fuel Cost of System Net Generation, a $14 million increase in the Fuel Cost of Purchased Power, and a $20 million increase in Energy Payments to Qualifying Facilities. These amounts are offset by a $7.0 million decrease in the Energy Cost of Economy Purchases and a $13.0 million increase in the Fuel Cost of Power Sold.

The increase in the Fuel Cost of System Net Generation is primarily due to higher than projected costs of heavy oil and natural gas, which are slightly offset by lower than projected cost of coal. The heavy oil variance is approximately $114 million caused primarily by 27% higher than projected use of oil due to the extreme hot weather during the period. Additionally, there is an approximate $29 million variance in natural gas caused primarily by a 13% increase in the unit cost of gas. The increase in the Fuel Cost of Purchased Power was primarily due to higher than projected UPS purchases from Southern Company (586,000 MWH). The increase in Energy Payments to Qualifying Facilities was primarily due to greater than expected deliveries from the Indiantown Cogeneration Limited (ICL) and Cedar Bay facilities (438,000 MWH) for the period. Additionally, the qualifying facilities fuel costs were slightly higher than projected. All of these were the result of the extreme hot weather during the period. The decrease in the

Energy Cost of Economy Purchases was primarily due to lower than projected economy purchases (625,000 MWH) as a result of hot weather in the Southeast which reduced the availability of low cost economy energy. The increase in the Fuel Cost of Power Sold was primarily due to higher than projected Opportunity Sales (600,000 MWH) due to hot 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.

CAPACITY PAYMENT RECOVERY CLAUSE

Q. Please describe Page 3 of Appendix III.

A. Page 3 of Appendix III provides a summary of the requested capacity payments for the projected period of January 1999 through December 1999. Total recoverable capacity payments amount to $390,683,195 (line 12) and include payments of $206,766,729 to non-cogenerators (line1), payments of $321,489,306 to cogenerators (line 2), $3,467,177 of Mission Settlement payments (line 3) and $4,700,000 relating to the St. John's River Power Park (SJRPP) Energy Suspension Accrual (line 4a). This amount is offset by revenues from capacity sales of $6,483,476 (line 4), $1,018,495 of return requirements on Energy Suspension payments (line 4b) and

$56,945,592 of jurisdictional capacity related payments included in base rates (line 8) less a net overrecovery of $77,177,787 (line 9). The net overrecovery of $77,177,787 includes the final overrecovery of $11,771,496 for the April 1997 through March 1998 period plus the estimated/actual overrecovery of $65,406,291 for the April 1998 through December 1998 period.

Q. Please describe Page 4 of Appendix III.

A. Page 4 of Appendix III calculates the allocation factors for demand and energy at generation. The demand allocation factors are calculated by determining the percentage each rate class contributes to the monthly system peaks. The energy allocators are calculated by determining the percentage each rate contributes to total kWh sales, as adjusted for losses, for each rate class.

Q. Please describe Page 5 of Appendix III.

A. Page 5 of Appendix III presents the calculation of the proposed Capacity Payment Recovery Clause (CCR) factors by rate class.

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

A. The Estimated/Actual True-up for the period April 1998 through December 1998 is an overrecovery, including interest, of $65,406,291 (Appendix III, page 7, lines 15 plus 16). Appendix III, page 7 shows the calculation supporting the CCR Estimated/Actual True-up amount.

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

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

Q. Please explain the calculation of the Interest Provision.

A. Appendix III, page 8 shows the calculation of the interest provision and follows the same methodology used in calculating the interest provision for the other cost recovery clauses, as previously approved by this Commission.

The interest provision is the result of multiplying the monthly average true-up amount (line 4) times the monthly average interest rate (line 9). The average interest rate for the months reflecting actual data is developed using the 30 day commercial paper rate as published in the Wall Street Journal on the first business day of the current and subsequent months. The average interest rate for the projected months is the actual rate as of the first business day in August 1998.

Q. Have you provided a schedule showing the variances between

the Estimated/Actuals and the Original Projections?

A. Yes. Appendix III, page 9, shows the Estimated/Actual capacity charges and applicable revenues compared to the original projections for the April 1998 through September 1998 period.

Q. What is the variance related to capacity charges?

A. As shown in Appendix III, page 9, line 7, the variance related to capacity charges is a $77 million decrease. The primary reason for the variance is a $66 million increase in revenues from capacity sales. This increase in expected revenues from capacity sales is primarily due to Opportunity Sales being approximately 600,000 MWH greater than projected for the period as a result of extreme weather conditions. The variance is also due to a $5 million decrease in payments to non-cogenerators and a $24 million decrease in payments to cogenerators. The decrease in payments to non-cogenerators represents Southern Company credit adjustments in the July 1998 and August 1998 invoices. The decrease in payments to cogenerators is primarily due to Cedar Bay's capacity payment being less than projected and Bio-Energy not qualifying for a capacity payment during this period. These amounts were offset by a midcourse correction in April 1998 of $18 million.

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

A. As shown on line 12, Capacity Cost Recovery revenues, net of revenue taxes, are $9 million higher than originally projected.

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

A. The Company is requesting that the new FCR and CCR factors become effective with customer bills for January 1999 through December 1999. This will provide for 12 months of billing on the FCR and CCR factors for all our customers.

Q. What will be the charge for a Residential customer using 1,000 kWh effective January 1999?

A. The total residential bill, excluding taxes and franchise fees, for 1,000 kWh will be $75.56. 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 $19.80, the Conservation charge is $2.15, the Capacity Cost Recovery charge is $5.14, the Environmental Cost Recovery charge is $.24 and the Gross Receipts Tax is $.77. A Residential Bill Comparison (1,000 kWh) is presented in Schedule E10, Page 65 of Appendix II.

Q. Does this conclude your testimony.

A. Yes, it does.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

TESTIMONY OF KOREL M. DUBIN

DOCKET NO. 980001-EI

October 14, 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 address issues set forth in Attachment A of Commission Order No. PSC-98-1270-PCO-EI issued September 25, 1998 regarding transmission revenues associated with economy transactions.

Q. Does the FERC require that revenue from non-firm transmission services, subject to FERC jurisdiction be reflected as a revenue credit in the derivation of firm transmission service rates subject to FERC jurisdiction?

A. Yes. In Order No. 888, issued in Docket Nos. RM95-8-000 and RM94 -7-001 the FERC stated "The Final Rule's general requirement for non-discriminatory transmission access and pricing by public utilities, and its specific requirement that public utilities unbundle their transmission rates and take transmission service under their own tariffs, apply to all public utilities' wholesale sales and purchases of electric energy, including coordination transactions (mimeo page 266)." Additionally, in 1993 for New England Power Co. (FERC 61,153), FERC accepted transmission rates that reflected a credit to the transmission cost of service for nonfirm transmission services provided to others. In that same case, FERC also required the company to credit the transmission cost of service to reflect the transmission component of off-system power sales revenues.

Q. How should the transmission revenues associated with economy transactions over the Energy Broker Network be separated between retail and wholesale jurisdictions?

A. For FPL, transmission revenue associated with economy transactions should continue to be separated based on energy. Although it may be appropriate to use a demand separator, FPL's current energy separation factor and demand separation factor produce virtually the same results. Also, currently all fuel and fuel related costs and revenues that are included in the Fuel Cost Recovery factors are separated based on energy. Introducing another step in the calculation of our fuel factors that would not materially affect the results does not seem beneficial at this time.

FPL's separation factor for energy is calculated by taking actual annual Total Retail Energy at Generation and dividing it by Total Company Energy at Generation. FPL's current separation factor for energy is 98.56%.

FPL's current separation factor for demand is 98.05%. FPL's separation factor for demand is calculated by taking actual annual Retail Average 12 CP at Generation and dividing it by Total Company Average 12 CP at Generation.

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 January 1999 - December 1999 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 April 1998 - December 1998 and to establish a "true-up" amount to be collected or refunded during January 1999 - December 1999.

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, E1-B1, E2, E7, E8, and E10 for Fernandina Beach. They are included in Composite Prehearing Identification Number GMB-2.

These schedules support the calculation of the levelized fuel adjustment factor for January 1999 - December 1999. Schedule E1-B shows the Calculation of Purchased Power Costs and Calculation of True-Up and Interest Provision for the period April 1998 - December 1998 based on 5 Months Actual and 4 Months Estimated data.

Q. In derivation of the projected cost factor for the January 1999 - December 1999, period, did you follow the same procedures that were used in the prior period filings?

A. Yes, with the exception of time period. The period covered has been changed to twelve months and a calendar year.

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 January 1999 - December 1999.

A. We have determined that at the end of December 1998 based on five months actual and four months estimated, we will have over-recovered $60,107 in purchased power costs in our Marianna division. Based on estimated sales for the period January 1999 - December 1999, it will be necessary to subtract .02177¢ per KWH to refund this over-recovery.

In Fernandina Beach we will have over-recovered $126,712 in purchased power costs. This amount will be refunded at .04708¢ per KWH during the January 1999 - December 1999 period (excludes GSLD customers). Page 3 and 13 of Composite Prehearing Identification Number GMB-2 provides a detail of the calculation of the true-up amounts.

Q. Looking back upon the October 1997 - March 1998 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 $256,324 and Fernandina Beach Division over-recovered $390,750. 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 October 1997 - March 1998 for both divisions?

A. In Marianna the final remaining true-up amount was an over-recovery of $125,045. The final remaining true-up amount for Fernandina Beach was an over-recovery of $121,303.

Q. What are the estimated true-up amounts for the period of April 1998 - December 1998?

A. In Marianna, there is an estimated over-recovery of 64,938. Fernandina Beach has an estimated under-recovery of $5,409.

Q. What will the total fuel adjustment factor, excluding demand cost recovery, be for both divisions for the period January 1999 - December 1999.

A. In Marianna the total fuel adjustment factor as shown on Line 33, Schedule E1, is 2.293¢ per KWH. In Fernandina Beach the total fuel adjustment factor for "other classes", as shown on Line 43, Schedule E1, amounts to 2.042¢ per KWH.

Q. Please advise what a residential customer using 1,000 KWH will pay for the period January 1999 - December 1999 including base rates, conservation cost recovery factors, and fuel adjustment factor and after application of a line loss multiplier.

A. In Marianna a residential customer using 1,000 KWH will pay $63.16, an decrease of .65¢ from the previous period. In Fernandina Beach a customer will pay $57.65, an increase of $1.69 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. 980001-EI
Date of Filing: October 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 Speci list, 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 January 1, 1999 to December 31, 1999 and to be available to answer any questions that may occur concerning the Company's fuel procurement procedures.

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

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

Counsel: We ask that Mr. Oaks' exhibit consisting of one schedule be marked as Exhibit No. ____18____ (MFO-1).

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

A. No.

Q. Does the 1999 projection of fuel expenses reflect any major changes in Gulf's fuel purchasing program during this period?

A. No. However, a change in fuel supply for Plant Daniel is planned in 1999. The details of such a change have not been finalized at the time of this filing.

Q. How much spot market coal does Gulf Power project it will purchase during the January 1999 through December 1999 period.

A. We are projecting the purchase of approximately 1,715,436 tons on the spot market. This represents approximately 29% 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. 980001-EI
Fuel and Purchased Power Cost Recovery
Date of Filing: October 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 this testimony is to discuss the calculation of Gulf Power's fuel cost recovery factors for the period January 1999 through December 1999. I will also discuss the calculation of the purchased power capacity cost recovery factors for the period January 1999 through December 1999.

Q. Are you familiar with the Fuel and Purchased Power Cost Recovery Clause Calculation for the period of January 1999 through December 1999?
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 fourteen schedules, be marked as Exhibit No. _____(SDC-1).

Q. Ms. Cranmer, what has Gulf calculated as the fuel cost recovery true-up to be applied in the period January 1999 through December 1999?

A. The fuel cost recovery true-up for this period is an increase of .0454¢/kwh. As shown on Schedule E-1A, this includes an estimated under-recovery for the April through September 1998 period of $3,743,611, less the estimated over-recovery of $1,097,022 for April through September 1998 already being refunded in the current October through December 1998 period. It also includes an estimated true-up over-recovery of $456,058 for the current period of October through December 1998. The resulting under-recovery is $4,384,575.

Q. What has been included in this filing to reflect the GPIF reward/penalty for the period of October 1997 through March 1998?

A. This is shown on Line 32b of Schedule E-1 as an increase of .0006¢/kwh, thereby rewarding Gulf by $62,632.

Q. Ms. Cranmer, what is the levelized projected fuel factor for the period January 1999 through December 1999?

A. Gulf has proposed a levelized fuel factor of 1.662¢/kwh. It includes projected fuel and purchased power energy expenses for January 1999 through December 1999 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 special 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 1.682¢/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 January 1999 through December 1999. 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 December 1998 and how would 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 December 1998 is 1.646¢/kwh compared with the proposed factor of 1.682¢/kwh. For a residential customer who uses 1000 kwh in January 1999, the fuel portion of the bill would increase from $16.46 to $16.82.

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 January 1999 through December 2000.

Q. Ms. Cranmer, you stated earlier that you are responsible for the calculation of the purchased power capacity cost (PPCC) recovery factors. Which schedules of your exhibit relate to the calculation of these factors?
A. Schedule CCE-1, including CCE-1a and CCE-1b, and Schedule CCE-2 of my exhibit relate to the calculation of the PPCC recovery factors for the period January 1999 through December 1999.

Q. Please describe Schedule CCE-1 of your exhibit.
A. Schedule CCE-1 shows the calculation of the amount of capacity payments to be recovered through the PPCC Recovery Clause. Mr. Howell has provided me with Gulf's projected purchased power capacity transactions under the Southern Company Intercompany Interchange Contract

(IIC), Gulf's contract with Solutia, and certain market capacity transactions. Gulf's total projected capacity payments for the period January 1999 through December 1999 are purchases of $7,007,984. The jurisdictional amount is $6,761,494. For the period, Gulf's requested recovery before true-up is the difference between the jurisdictional projected purchased power capacity costs and the approved adjustment for former capacity transactions embedded in current base rates. This adjustment amount was fixed in Order No. PSC-93-0047-FOF-EI, dated January 12, 1993, as an annual embedded credit of $1,678,580, or $1,652,000 net of revenue taxes. Thus, the projected recovery amount that would be collected through the PPCC recovery factors in the period January 1999 through December 1999 is $8,413,494. This amount is added to the total true-up amount to determine the total purchased power capacity transactions that would be recovered in the period.

Q. What has Gulf calculated as the purchased power capacity factor true-up to be applied in the period January 1999 through December 1999?

A. The true-up for this period is an increase of $1,315,167 as shown on Schedule CCE-1a. This includes an estimated under-recovery of $2,467,419 for October 1997 through

September 1998, less the estimated under-recovery of $2,389,778 for October 1997 through September 1998 already being recovered in the current October through December 1998 period. It also includes an estimated under-recovery of $1,237,526 for the current period of October 1998 through December 1998. The resulting under-recovery is $1,315,167.

Q. What methodology was used to allocate the capacity payments to rate class?

A. As required by Commission Order No. 25773 in Docket No. 910794-EQ, the revenue requirements have been allocated using the cost of service methodology used in Gulf's last full requirements rate case and approved by the Commission in Order No. 23573 issued October 3, 1990, in Docket No. 891345-EI. Although the capacity payments in that cost of service study were allocated to rate class using the demand allocator based on the twelve monthly coincident peaks projected for the test year, for purposes of the PPCC Recovery Clause, Gulf has allocated the net purchased power capacity costs to rate class with 12/13th on demand and 1/13th on energy. This allocation is consistent with the treatment accorded to production plant in the cost of service study used in

Gulf's last rate case.

Q. How were the allocation factors calculated for use in the PPCC Recovery Clause?

A. The allocation factors used in the Purchased Power Capacity Cost Recovery Clause have been calculated using the 1997 load data filed with the Commission in accordance with FPSC Rule 25-6.0437. The calculations of the allocation factors are shown in columns A through I on Page 1 of Schedule CCE-2.

Q. Please describe the calculation of the cents/kwh factors by rate class used to recover purchased power capacity costs.

A. As shown in columns A through D on page 2 of Schedule CCE-2, the 12/13th of the jurisdictional capacity cost to be recovered is allocated to rate class based on the demand allocator, with the remaining 1/13th allocated based on energy. The total revenue requirement assigned to each rate class shown in column E is then divided by that class's projected kwh sales for the twelve-month period to calculate the PPCC recovery factor. This factor would be applied to each customer's total kwh to calculate the amount to be billed each month.

Q. What is the amount related to purchased power capacity costs recovered through this factor that will be included on a residential customer's bill for 1000 kwh?
A. The purchased power capacity costs recovered through the clause for a residential customer who uses 1000 kwh will be $1.22.

Q. When does Gulf propose to collect these new fuel charges and purchased power capacity charges?
A. The fuel and capacity factors will be effective beginning with the first Bill Group for January 1999 and continuing through the last Bill Group for December 1999.

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
Transmission Reconsideration
Date of Filing: October 13, 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 allocation of transmission revenues associated with economy sales transactions between the retail and wholesale jurisdictions.

Q. What is the proper jurisdictional separation factor for allocating transmission revenues between the retail and wholesale jurisdictions?

A. A transmission-related separation factor, based on coincident peak demand, properly allocates transmission revenues between the retail and wholesale jurisdictions. This is consistent with the way in which the transmission-related plant costs and operation and maintenance expenses were allocated in Gulf's last rate case.

Q. Does Gulf propose to use a demand allocator to calculate the amount of transmission revenues to flow through the fuel clause?

A. No. For administrative simplicity, Gulf proposes to allocate the transmission revenues flowed through the fuel clause based on energy sales adjusted for line losses, as it has been doing for transmission revenues related to economy sales effective January 1997 pursuant to Commission Order No. PSC-98-0073-FOF-EI dated January 13, 1998. For Gulf Power, the energy allocator and the demand allocator are very similar. For 1997, the average energy allocator was 96.61503%, and for 1998 through August, the average energy allocator was 96.63689%. In Gulf's last rate case, the transmission-related investment and expenses were allocated based on coincident peak demand, with 96.73822% allocated to the retail jurisdiction. For the period January 1997 through August 1998, $525,145 of transmission revenues would have been allocated to the retail jurisdiction using the 96.73822% demand allocator. The actual revenue flowed through the fuel clause during that 20-month period based on energy allocators was $524,260, for a difference of $885. Changing the allocation for these transmission revenues would require fairly substantial changes to Gulf's over/under recovery calculation each month, and to the actual "A" schedules filed each month and the final true-up and projection schedules, each filed annually. In summary, due to the immateriality of the difference in the energy and demand allocators for Gulf Power and the administrative costs involved with changing the allocator for the transmission revenues associated with economy sales, Gulf is proposing to continue using the energy allocator to flow these transmission revenues through the fuel clause to its customers.

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. 980001-EI
Date of Filing May 20, 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. 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 October 1, 1997, through March 31, 1998.

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 20 (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-97-1045-FOF-EI is on page 9 of Schedule 2. The results are: Crist 6, -1.36 points; Crist 7, -10.00 points; Smith 1, -5.83 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 June 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: -2.24 for Crist 6, +2.66 for Crist 7, 0.00 for Smith 1, +7.49 for Smith 2, -0.63 for Daniel 1, and 0.00 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 adjusted weighting factors, the Company points would be +0.73 as indicated on page 2 of Schedule 4. This calculates to a reward in the amount of $62,632.

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

A. Yes, Sir. In view of the adjusted actual equivalent availabilities, as shown on page 9 of Schedule 2, and the adjusted actual average net operating heat rates achieved, as shown on page 16 of Schedule 3, evidencing the Company's performance for the period, Gulf calculates a reward in the amount of $62,632 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 June 22, 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 October 1, 1998 through December 31, 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 October 1, 1998 through December 31, 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 October 1, 1998 through December 31, 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
G. D. Fontaine
Docket No. 980001-EI
Date of Filing October 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 January 1, 1999 through December 31, 1999.

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

A. Yes, I have p ared 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 22 (GDF-3).

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 January 1, 1999 through December 31, 1999?

A. I would like to refer you to Page 32 of Schedule 1 of my exhibit where these targets are listed. A change in fuel at Plant Daniel is planned in 1999. The impact of this change on the Plant Daniel heat rate targets for this period cannot be projected at the time of this filing since the details of the change have not been determined.

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 January 1, 1999 through December 31, 1999.

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 29 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. 980001-EI
Date of Filing: October 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 1965 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 January, 1999 - December, 1999. Also, I will support the Company's projection of purchased power capacity costs for the January, 1999 - December, 1999 recovery period.

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

A. Yes. I have one exhibit to which I will refer. This exhibit was prepared under my supervision and direction.

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

Q. What is Gulf's projected purchased power recoverable cost for energy purchases for the January, 1999 - December, 1999 recovery period?

A. Gulf's projected recoverable cost for energy purchases, shown on line 12 of Schedule E-1 of the fuel filing, is $10,463,260. These purchases result from Gulf's participation in the coordinated operation of the Southern electric system power pool. This amount is used by Ms. 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 January, 1999 - December, 1999 recovery period?

A. The projected fuel cost for energy sales, shown on line 18 of Schedule E-1, is $ 43,762,600. These sales also result from Gulf's participation in the coordinated operation of the Southern electric system power pool. This amount is used by Ms. Cranmer as an input in the calculation of the fuel and purchased power cost adjustment factor.

Q. What information is contained in your exhibit?

A. My exhibit lists the power contracts that are included for capacity cost recovery, their associated megawatt amounts, and the resulting capacity dollar amounts.

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

A. The two primary power contracts that produce recoverable capacity transactions through Gulf's purchased power capacity recovery factors are the Southern electric system's Intercompany Interchange Contract (IIC) and Gulf's cogeneration capacity purchase contract with Solutia, Inc. (formerly Monsanto Company). The Commission has authorized the Company to include capacity transactions under the IIC for recovery through the purchased power capacity cost recovery factors. Gulf will continue to have IIC capacity transactions during the January, 1999 - December, 1999 recovery period. The energy transactions under this contract for these periods are handled for cost recovery purposes through the fuel cost recovery factors.

The Gulf Power/Solutia cogeneration capacity contract enables Gulf to purchase 19 megawatts of firm capacity from June 1, 1996 until June 1, 2005. Gulf has included these costs for recovery during the January, 1999 - December, 1999 recovery period. The energy transactions under this contract have also been approved by the Commission for recovery, and these costs are handled for cost recovery purposes through the fuel cost recovery factors.

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

A. Yes. Gulf and other Southern electric system operating companies have purchased market capacity for 1999, and these purchases will continue through 2001. Gulf will have monthly costs associated with these market purchases for the January, 1999 - December, 1999 recovery period.

Q. Has Southern made any changes to the IIC that were used in the most recent recovery factor adjustment proceedings?

A. No. However, the Southern electric system's November 1, 1997 IIC informational filing with the FERC has been updated in 1998 to reflect new capacity resource amounts for the 1999 budget cycle that are used in the IIC capacity equalization calculation to determine the capacity transactions and costs for each operating company. These updates are reflected in the projection of capacity transactions among the Southern electric system's operating companies for the January, 1999 - December, 1999 recovery period.

Q. What are Gulf's IIC capacity transactions that are projected for the January, 1999 - December, 1999 recovery period?

A. As shown on my exhibit MWH-1, capacity transactions under the IIC vary during each month of the recovery period. IIC capacity purchases in the amount of $1,696,129 are projected for the period. IIC capacity sales during the same period are projected to be $185,449. Therefore, the Company's net capacity transactions under the IIC for the period are net purchases amounting to $1,510,680.

Q. What is the cost of Gulf's capacity purchase from Solutia that is projected for the January, 1999 - December, 1999 recovery period?

A. As shown on my exhibit MWH-1, Gulf is projected to pay $746,424, or $62,202 per month, to Solutia for the firm capacity purchase made pursuant to the Commission approved contract.

Q. What is the cost of Gulf's market capacity purchases
that is projected for the January, 1999 - December, 1999
recovery period?
A. As shown on my exhibit MWH-1, Gulf is projected to pay a
total of $4,750,880 for the committed market capacity
purchases. Capacity in varying amounts will be
purchased during the months of January through December
of 1999. The individual suppliers and megawatt amounts
are not shown, since this is highly sensitive and
confidential information. Public availability of this
information would seriously undermine our competitive
position and cause our customers increased cost.

Q. What are Gulf's total projected net capacity
transactions for the January, 1999 - December, 1999
recovery period?
A. As shown on my exhibit MWH-1, the net purchases under
the IIC, the Solutia contract, and the committed market
capacity purchases will result in a projected net
capacity cost of $7,007,984. This figure is used by Ms.
Cranmer as an input into the calculation of the total
capacity transactions to be recovered through the
purchased power capacity cost recovery factors for this
annual recovery period.

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
TRANSMISSION RECONSIDERATION
Date of Filing: October 14, 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 provide evidentiary support regarding the requirement of the Federal Energy Regulatory Commission (FERC) that revenues from non-firm transmission services shall be reflected as a revenue credit when calculating the firm transmission service rates of the Southern electric system (Southern) which are subject to the FERC's jurisdiction. Gulf Power is an operating company of Southern.

Q. Does the FERC require that revenue from non-firm transmission services subject to FERC jurisdiction be reflected as a revenue credit in the derivation of firm transmission service rates subject to FERC jurisdiction?

A. Yes. The FERC included this requirement in both Order No. 888 and Order No. 888-A for transmission providers using annual system peak load pricing for their transmission services. On page 304 of the FERC's Order No. 888, issued April 24, 1996, the FERC clearly states that as part of a mechanism to prevent over-recovery of costs ". . . revenue from non-firm services should continue to be reflected as a revenue credit in the derivation of firm transmission tariff rates."

This requirement was reaffirmed by the FERC in Order No. 888-A that was issued on March 4, 1997. Page 247 of Order No. 888-A states that ". . . the Commission [FERC] explained that revenue from non-firm transmission services should continue to be reflected as a revenue credit in the derivation of firm transmission service rates. The Commission [FERC] noted that the combination of allocating costs to firm point-to-point service and the use of a revenue credit for non-firm transmission service will satisfy the requirements of a conforming rate proposal enunciated in our Transmission Pricing Policy Statement."

Q. Has the Southern filed its Open Access Transmission Service Tariff to conform to the above mentioned requirements of FERC Order No. 888 and FERC Order No. 888-A?

A. Yes. All of Southern's transmission service tariff filings, including the currently effective transmission service tariff, have complied with the FERC-ordered requirements to include non-firm revenue credits in the firm transmission service rate derivation. Southern's currently effective Open Access Transmission Tariff is a formulary rate tariff that provides for annual updates of the investment, expense, load, and cost of capital components of the firm transmission rate calculation. The scheduled updates provide the occasion for incorporating the most current non-firm transmission revenue credits in the determination of firm transmission rates. At the time of the annual updates to the input components of the formulary rate, the non-firm transmission service revenue credits accumulated since the last update are reflected as a direct reduction to the transmission O&M expense component of the firm transmission service. This mechanism provides a safeguard against over-recovery of costs that could otherwise occur due to FERC's requirement in Order 888 that transmission charges be "unbundled" from economy energy sales. In fact, Southern's annual update filing on May 1, 1998 incorporated the required credit for non-firm transmission revenues received during calendar year 1997 with the result being lower firm transmission rates for use of Southern's (and therefore Gulf's) transmission system from June 1, 1998 until the effective date of the next update.

Q. How would you compare this FERC process of including credit for non-firm transmission revenues in the annual updates to Southern's firm transmission rate with the requirement by the Florida Public Service Commission (FPSC) that transmission revenues associated with economy energy sales be credited to retail customers through the fuel adjustment clause?

A. In principle, the two mechanisms are addressing the same concern. In both cases, the respective commissions are attempting to fashion a mechanism to protect against possible over-recovery of costs that might otherwise result in the short-term due to previously unanticipated revenues associated with the newly unbundled transmission charges. FERC's approach is to apply these revenues as a credit against transmission costs as part of the annual setting of transmission rates subject to its jurisdiction. The FPSC's approach is to take these same revenues and flow them directly to retail customers through the fuel clause in order to avoid ". . . a windfall for the seller." (Order No. PSC-98-0073-FOF-EI at page 7) To the extent that Gulf or any other utility is required to credit the same revenues in both jurisdictions, ". . . it will obviously be forced to credit more revenues than it receives." (Florida Power Corporation Motion for Reconsideration at page 5)

Q. Is the fact that both the FERC and the FPSC are each trying to address the potential of over-recovery by essentially capturing the same revenues twice of any concern?

A. In principle, yes. If both the FERC mechanism for addressing the concern about potential over-recovery by lowering transmission rates and the FPSC mechanism of flowing the same revenues back to customers through the fuel clause are in effect at the same time, the end result would be harm to the selling utility's shareholders due to under-recovery of costs. However, due to circumstances that have arisen recently in a docketed proceeding before the FERC involving Southern's Open Access Transmission Tariff, it appears that the potential that Gulf/Southern would prospectively be crediting the same revenues twice will be avoided for now.

Q. What has happened that has changed Gulf's concern on this issue?

A. The FERC's docketed proceeding in which Southern's Open Access Transmission Tariff is under review has several intervenors who are seeking changes to Southern's transmission rate tariff. Recently, the parties to that docketed proceeding (including the intervenors, the FERC staff and Southern) have reached agreement in principle on a settlement that will, if approved, result in the termination of the contested proceeding. Although the settlement agreement has not yet been reduced to writing and is still subject to review and approval by the Administrative Law Judge assigned to hear the case and the FERC itself, we believe that the settlement will ultimately be approved. The net result of the settlement will be that Southern's firm "open access" transmission rates will be fixed for an undetermined amount of time, and will not be subject to annual updates for changes in investment, cost of capital, expense or load components. The settlement, if approved, also means that the non-firm revenue credits will <u>not</u> be updated annually so long as the fixed rate contemplated by the settlement agreement remains in effect.

Q. How should Gulf Power Company allocate transmission revenues associated with its sale of economy energy between the retail and wholesale jurisdiction?

A. The Company continues to believe that any transmission revenues received by the Company due to economy energy transactions should be credited to operating revenues rather than through the fuel clause. In this fashion, the FPSC's surveillance mechanism would be used to ensure that such revenues do not cause the Company to over-earn. By crediting the revenues to operating revenues, the Company avoids the prospect of having to, in effect, give away the same revenues twice. However, given the Commission's prior decision to credit such transmission revenues through the fuel clause, and given it is likely that for the foreseeable future the non-firm transmission revenues received by Gulf will not be flowed back to the FERC jurisdiction through annual updates to Southern's firm transmission rates, Gulf's only remaining concern relative to this issue involves the use of a transmission-related jurisdictional separation factor to allocate revenues between the wholesale and retail jurisdictions. This concern is addressed in the testimony of Gulf's witness S. D. Cranmer.

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.

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 Tampa Electric's Energy Supply Department and assumed the duties of the plant chemical engineer at the F. J. Gannon Station. 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 and the proposed Capacity Cost Recovery factors for the period of January 1999 through December 1999.

Q. Do you wish to sponsor an exhibit?

A. Yes. Exhibit No. ___ (KOZ-2) is comprised of Schedules H-1 for January - December, 1996 through 1999 and Schedules E-1 through E-10 for January 1999 - December 1999. 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 April through December 1998. These schedules are furnished as back-up for the projected true-up for this period and consist of five actual months and four projected months. These schedules are found in Exhibit No. 24 (KOZ-2), Fuel Projection.

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

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

A. The appropriate value for the new period is 2.255 cents per kwh before the normal application of factors that adjust for variations in line losses. Schedule E-1 of Exhibit No. 24 (KOZ-2), Fuel Projection, shows the appropriate values for the Total Fuel and Purchased Power Cost Recovery Clause as projected for the period January through December 1999.

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

A. The GPIF and true-up factors are provided on Schedule E-1C. Tampa Electric has calculated a GPIF penalty of ($188,231) which is to be included in the calculation of the Total Fuel and Purchased Power Cost Recovery Fuel factors.

Additionally E-1C indicates the net true-up amount for the

April through December 1998 period. The net true-up amount for this period is an overrecovery of $5,261,113. This overrecovery is comprised of a final true-up overrecovery amount of $53,414 for the October 1997 through March 1998 period and an estimated overrecovery in the amount of $8,799,535 for the April 1998 through December 1998 period less the April through September 1998 overrecovery of $3,591,836 which was carried over in the true-up calculation during the period October through December 1998 as a result of extending the Fuel and Purchased Power Cost Recovery factors.

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

A. Schedule E-1D presents Tampa Electric's on-peak and off-peak fuel charge factors for January through December 1999.

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. Have the Fuel Recovery Loss Multiplier that reflect the variation in line-losses been modified?

A. Yes. Document No. 2 of Exhibit (KOZ-2) shows revised Fuel Recovery Loss Multipliers and a revised Jurisdictional Loss Multiplier which have been modified to reflect actual 1997 sales data and losses. Tampa Electric requests approval of these factors for the calculation of fuel factors applicable to each fuel group.

Q. Please summarize the proposed Fuel and Purchased Power Cost Recovery factors by rate schedule for January through December 1999.

A.

Rate Schedule	Fuel Charge Factor (cents per kwh)
Average Factor	2.255
RS, GS and TS	2.271
RST and GST	3.312 (on-peak)
	1.818 (off-peak)
SL-2, OL-1 and OL-3	2.042
GSD, GSLD, and SBF	2.259
GSDT, GSLDT, EV-X and SBFT	3.294 (on-peak)
	1.808 (off-peak)
IS-1, IS-3, SBI-1, SBI-3	2.183
IST-1, IST-3, SBIT-1, SBIT-3	3.184 (on-peak)
	1.747 (off-peak)

Q. How does Tampa Electric's proposed average fuel charge factor of 2.255 cents per kwh compare to the average fuel charge factor for the April through December 1998 period?

A. The proposed fuel charge factor is .082 cents per kwh (or $0.82 per 1000 kwh) lower than the average fuel charge factor of 2.337 cents per kwh for the April through December 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. The Capacity Cost Recovery factors, prepared under my direction or supervision, are provided in Exhibit No. ___ (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 for purchases of power made for retail and all requirements customers, excluding optional provision purchases for interruptible customers.

Q. Please summarize the proposed Capacity Cost Recovery Clause factors by rate schedule for the January through December 1999 period.

A.

Rate Schedule	Capacity Cost Recovery Factor (cents per kwh)
RS	0.206
GS and TS	0.174
GSD, EV-X	0.143
GSLD and SBF	0.129
IS-1, IS-3, SBI-1, SBI-3	0.012
SL-2, OL-1 and OL-3	0.042

These factors are shown in Exhibit No. 26 (KOZ-3), page 3 of 5.

Q. How does the proposed Capacity Cost Recovery factor compare to the previous year's factor?

A. Previous factors were calculated based on six-month periods and the factors fluctuated based on sales between the two periods. Typically the summer factor (April through September) results in lower Capacity Cost Recovery factors than the winter period (October through March) since summer sales are higher. By calculating the factor on a twelve month basis, the capacity factor is "levelized" similar to the Conservation Cost Recovery factor.

<u>Events Affecting the Projection Filing</u>

Q. Are there any events reflected in the calculation of the 1999 Fuel and Purchased Power and Capacity Cost Recovery projections that are not reflected in the April through December 1998 projections as filed in January 1998?

A. Yes. There are three. These are: 1) the completion of a Temporary Base Rate Reduction which removes the related credit on customer's bills, 2) the establishment of new coal waterborne transportation rates which lowers the Fuel and Purchased Power Cost Recovery factors, and 3) the change in how Tampa Electric is serving the Florida Municipal Power Agency (FMPA) wholesale agreement which has no effect on the Fuel and Purchased Power Cost Recovery and Capacity Cost Recovery factors.

Q. When does the Temporary Base Rate Reduction factor cease?

A. Starting with the first billing cycle in January 1999, customer bills will no longer reflect the Temporary Base Rate Reduction. This factor was established on September

25, 1996 when Tampa Electric, the Office of Public Counsel and the Florida Industrial Power Users Group agreed to a stipulation in which Tampa Electric agreed to reflect a $25 million temporary base rate reduction as a line-item credit on customers' bills. This reduction commenced October 1, 1997 and ends 15 months later on December 31, 1998. The actual reduction is to be netted against 1999 refunds which may have otherwise been made pursuant to the stipulations reached in Docket No. 950379-EI approved in Order No. PSC-96-0670-S-EI, issued May 20, 1996 and in Docket No. 960409-EI, approved in Order No. PSC-96-1300-S-EI, issued October 24, 1996.

Q. How will Tampa Electric true-up the actual amount refunded through the Temporary Base Rate Reduction?

A. Tampa Electric has calculated the Base Rate Reduction to be refunded in each upcoming period based on projected revenues for that period. In keeping with the approved stipulation, Tampa Electric proposes to true-up the amount actually refunded at the next available true-up filing in 1999 and requests that recovery of any differential amount be collected or refunded in the January through December 2000 period.

Q. Please describe the second event you identified above.

A. Tampa Electric's current coal transportation contract with TECO Transport will expire December 31, 1998. Tampa Electric has negotiated a new contract with TECO Transport in which new rates have been established which will be effective January 1, 1999 through December 31, 2003.

Q. How will the new transportation rates impact Tampa Electric customers?

A. The new contract establishes waterborne transportation rates which are lower than those contained in the previous contract. Tampa Electric has estimated the savings will be approximately $3 million in transportation costs during 1999 due to this new contract pricing.

Q. How does the new transportation contract pricing compare to the benchmark analysis of rail transportation as provided in Exhibit RB-1, filed with the Commission in June of 1998?

A. Benchmark data for rail transportation submitted by Tampa Electric witness Rod Burkhardt for the June projection filing (Exhibit RB-1), demonstrated that Tampa Electric's transportation costs were significantly lower than those reported by the utilities included in the benchmark analysis. Because Tampa Electric's new contract with TECO Transport will reduce transportation costs, the new contract pricing will also be well below the charges reported in the benchmark data.

Q. Please describe the third event you identified above.

A. Since the January 1998 filing that projected the Fuel and Purchased Power Cost Recovery and Capacity Cost Recovery factors that are in effect through December 1998, Tampa Electric has changed how it is serving the FMPA wholesale agreement by purchasing resources from third parties. The purchases began March 1, 1998 and by April 28, 1998, the total purchases equaled the sale to FMPA.

Q. How are these purchases and the FMPA sale reflected in the calculation of the Fuel and Purchased Power Cost Recovery and Capacity Cost Recovery factors for the period January 1999 through December 1999?

A. These transactions do not affect the cost recovery factor in any way. The energy associated with the FMPA sale, shown in Schedule E6, equals the energy purchased from third parties as shown in Schedule E7. In other words, the energy sold equals the energy purchased and no costs are borne by Tampa Electric customers.

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 increase $0.63 beginning January 1999. See table below.

Type of Charge	Apr. 98 thru Dec. 98	Jan 99 thru Dec. 99
Customer	$ 8.50	$ 8.50
Energy	43.42	43.42
Conservation	1.65	1.65[1]
Environmental	0.33	0.29
Fuel	23.54	22.71
Capacity	1.88	2.06
Subtotal	79.32	78.63
Temporary Base Rate Reduction	(1.30)	0.00
FGR Tax	2.00	2.02
Total	$ 80.02	$ 80.65

[1] Rate approved through March 1999.

Q. Please explain the \$0.63 per 1000 kwh increase in the typical residential bill.

A. The discontinuation of the Temporary Base Rate Reduction Factor increased the bill by \$1.30 per 1,000 kwh. Despite this increase, Tampa Electric was able to achieve lower combined cost recovery clause reductions of \$0.69 per 1,000 kwh so that overall residential customers incurred only a \$0.63 per 1000 kwh increase.

Q. When should the new rates go into effect?

A. The new rates should go into effect concurrent with the first billing cycle in January 1999.

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" October 1998 - December 1998, consisting of 35 pages filed with the Commission on October 5, 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 6 units included within the GPIF are shown on page 5 of my exhibit. For example, the projected EUOF for Big Bend Unit Two is 14.6%. The Planned Outage Factor for this same unit during this period is 0%. Therefore, the target equivalent availability for this unit equals:

$$100\% - [(14.6\% + 0\%)] = 85.4\%$$

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 Two:

$$EAF_{MAX} = 100\% - [0.8\ (14.6\%) + 0.95\ (0\%)] = 88.3\%$$

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:

<u>Equivalent Availability Minimum</u>

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

Again, continuing with our example of Big Bend Unit Two.

$EAF_{MIN} = 100\% - [1.4\ (14.6\%) + 1.1\ (0\%)] = 79.6\%$

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 4 is scheduled for a annual maintenance outage November 7 to November 27, 1998. There are 504 planned outage hours scheduled, and a total of 2209 hours during this 3 month period. Consequently, the Planned Outage Factor for Unit 4 at Big Bend is

504/2209 x 100% or 22.8%. This factor is shown on pages 5 and 16 of my exhibit. Big Bend Unit 1 has a planned outage factor of 27.4%. Big Bend Units 2 and 3 have planned outage factors of zero, as does Gannon Unit 6. Gannon Unit 5 has a planned outage factor of 15.2%.

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

A. Graphs of both of these factors (adjusted for planned outages) vs. time are prepared. Both monthly data and 12 month moving average data are recorded. For each unit the most current, June 1998, 12 month ending value was used as a basis for the projection. This value was adjusted up or down by analyzing trends and causes for recent forced and maintenance outages. All projected factors are based upon historical unit performance, engineering judgment, time since last planned outage, and equipment performance resulting in a forced or maintenance outage. These target factors are additive and result in a EUOF of 18.6% 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

$$EUOF = \frac{(362 + 49)}{2209} \times 100 = 18.6\%$$

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.

Big Bend Unit One

A. The projected EUOF for this unit is 12.3% during this period. This unit will have a planned outage this period and the Planned Outage Factor is 27.4%. This results in a target equivalent availability of 60.3% for the period.

Big Bend Unit Two

The projected EUOF for this unit is 14.6%. 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 85.4%.

Big Bend Unit Three

The projected EUOF for this unit is 18.1%. This unit will not have a planned outage this period and the Planned Outage Factor is 0%. Therefore, the target equivalent availability for this unit is 81.9%.

Big Bend Unit Four

The projected EUOF for this unit i~ 7.6%. This unit will have a planned outage during this period and the Planned Outage Factor is 22.8%. This results in a target equivalent availability of 69.6% for the period.

Gannon Unit Five

The projected EUOF for this unit is 18.6%. This unit will have a planned outage during this period and the Planned Outage Factor is 15.2%. Therefore, the target equivalent availability for this unit is 66.2%.

Gannon Unit Six

The projected EUOF for this unit is 17.4%. 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 82.6%.

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

A. This adjustment makes these factors more accurate and comparable. Obviously, a unit in a planned outage stage or reserve shutdown stage will not incur a forced or maintenance outage. Since our units are usually base loaded, reserve shutdown is generally not a factor. To demonstrate the effects of a planned outage, note the EUOR and EUOF for Gannon Unit Five on page 13. During the months of November, and December, EUOF and EUOR are equal. This is due to the fact that no planned outages are scheduled during these months. During the month of October, 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 IV program, formed the basis of our target development. Projections of unit performance were made with the aid of PROMOD IV. 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. 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 October 1998 through December 1998 period?

A. Yes. The heat rate target for Big Bend Unit 1 is 10,311 Btu/Net kwh. The range about this value, to allow for potential improvement or degradation, is ±353 Btu/Net kwh. The heat rate target for Big Bend Unit 2 is 10,311 Btu/Net kwh with a range of ±363 Btu/Net kwh. The heat rate target for Big Bend Unit 3 is 10,051 Btu/Net kwh, with a range of ±387 Btu/Net kwh. The heat rate target for Big Bend Unit 4 is 9,945 Btu/Net kwh with a range of ±243 Btu/Net kwh. The heat rate target for Gannon Unit 5 is 10,242 Btu/Net kwh with a range of ±519 Btu/Net kwh. The heat rate target for Gannon Unit 6 is 10,453 Btu/Net kwh with a range of ±380 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 IV 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 $56,823,100 is shown on page 6 column 2.

The PROMOD IV 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: $2,610,500 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 6.48% 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 88.3% equivalent availability, fuel savings would equal $169,200 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, $2,610,500. 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 5, the estimated average common equity for the period October 1998 - December 1998 is shown to be $1,192,060,750. This produces the maximum allowed jurisdictional incentive dollars of $1,205,569 shown on line 12.

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):

$$\begin{aligned} GPIP = (\ & 0.0417\ EAP_{GN5} + 0.0613\ EAP_{GN6} \\ & + 0.0673\ EAP_{BB1} + 0.0648\ EAP_{BB2} \\ & + 0.0909\ EAP_{BB3} + 0.0416\ EAP_{BB4} \\ & + 0.0881\ HRP_{GN5} + 0.1176\ HRP_{GN6} \\ & + 0.0854\ HRP_{BB1} + 0.1165\ HRP_{BB2} \\ & + 0.1414\ HRP_{BB3} + 0.0834\ HRP_{BB4} \end{aligned}$$

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 October 1998 - December 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, October 1, 1998 - December 31, 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 October 1998 - December 1998 period.

Q. Does this conclude your testimony?

A. Yes.

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" January 1999 - December 1999, consisting of 35 pages filed with the Commission on October 5, 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 6 units included within the GPIF are shown on page 5 of my exhibit. For example, the projected EUOF for Big Bend Unit Two is 14.0%. The Planned Outage Factor for this same unit during this period is 3.8%. Therefore, the target equivalent availability for this unit equals:

$$100\% - [(14.0\% + 3.8\%)] = 82.2\%$$

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.

<u>Equivalent Availability Maximum</u>

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

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 Two:

$EAF_{MAX} = 100\% - [0.8\ (14.0\%) + 0.95\ (3.8\%)] = 85.2\%$

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

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

A. The potential for unit availability degradation is significantly greater than is the potential for unit availability improvement. This concept was discussed extensively and approved in earlier hearings before this Commission. Tampa Electric Company's approach to incorporating this skewed effect into the unit availability tables is to use a potential degradation range equal to

Twice the potential improvement. Consequently, minimum equivalent availability is arrived at via the following formula:

Equivalent Availability Minimum

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

Again, continuing with our example of Big Bend Unit Two.

$EAF_{MIN} = 100\% - [1.4\ (14.0\%) + 1.1\ (3.8)] = 76.2\%$

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 3 is scheduled for a planned outage February 20 to April 2, 1999. There are 1008 planned outage hours scheduled for the 1999 period, and a total of 8760 hours during this 12 month period. Consequently, the Planned Outage Factor for Unit 3 at Big

Bend is 1008/8760 x 100% or 11.5%. This factor is shown on pages 5 and 17 of my exhibit. Big Bend Unit 4 has a planned outage factor of 5.8%. Big Bend Units 1 and 2 have planned outage factors of 3.8%. Gannon Units 5 and 6 have planned outage factors of 5.8% and 13.4% respectively.

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

A. Graphs of both of these factors (adjusted for planned outages) vs. time are prepared. Both monthly data and 12 month moving average data are recorded. For each unit the most current, June 1998, 12 month ending value was used as a basis for the projection. This value was adjusted up or down by analyzing trends and causes for recent forced and maintenance outages. All projected factors are based upon historical unit performance, engineering judgment, time since last planned outage, and equipment performance resulting in a forced or maintenance outage. These target factors are additive and result in a EUOF of 16.0% for Big Bend Unit Three. The Equivalent Unplanned Outage Factor (EUOF) for Big Bend Unit Three is verified by the data shown on page 17, 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

$$EUOF = \frac{(953 + 449)}{8760} \times 100 = 16.0\%$$

Relative to Big Bend Unit Three, the EUOF of 16.0% forms the basis of our Equivalent Availability target development as shown on sheets 4 and 5 of my exhibit.

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

Big Bend Unit One

A. The projected EUOF for this unit is 16.4% during this period. This unit will have a planned outage this period and the Planned Outage Factor is 3.8%. This results in a target equivalent availability of 79.8% for the period.

Big Bend Unit Two

The projected EUOF for this unit is 14.0%. This unit will have a planned outage during this period and the Planned Outage Factor is 3.8%. Therefore, the target equivalent availability for this unit is 82.2%.

Big Bend Unit Three

The projected EUOF for this unit is 16.0%. This unit will have a planned outage this period and the Planned Outage Factor is 11.5%. Therefore, the target equivalent availability for this unit is 72.5%.

Big Bend Unit Four

The projected EUOF for this unit is 9.2%. This unit will have a planned outage during this period and the Planned Outage Factor is 5.8%. This results in a target equivalent availability of 85.0% for the period.

Gannon Unit Five

The projected EUOF for this unit is 20.6%. This unit will have a planned outage during this period and the Planned Outage Factor is 5.8%. Therefore, the target equivalent availability for this unit is 73.6%.

Gannon Unit Six

The projected EUOF for this unit is 15.1%. This unit will have a planned outage during this period and the Planned Outage Factor is 13.4%. Therefore, the target equivalent availability for this unit is 71.5%.

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 76.9%. This target compares very favorably to previous GPIF periods and is in fact, better than two of the three past periods when compared on a common planned outage factor basis.

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

A. This adjustment makes these factors more accurate and comparable. Obviously, a unit in a planned outage stage or reserve shutdown stage will not incur a forced or maintenance outage. Since our units are usually base loaded, reserve shutdown is generally not a factor. To demonstrate the effects of a planned outage, note the EUOR and EUOF for Gannon Unit Six on page 14. During the months of January through March, and June through December, EUOF and EUOR are equal. This is due to the fact that no planned outages are scheduled during these months. During the months of April and 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 IV program, formed the basis of our target development. Projections of unit performance were made with the aid of PROMOD IV. 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. 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 1999 period?

A. Yes. The heat rate target for Big Bend Unit 1 is 10,230 Btu/Net kwh. The range about this value, to allow for potential improvement or degradation, is ±353 Btu/Net kwh. The heat rate target for Big Bend Unit 2 is 10,247 Btu/Net kwh with a range of ±363 Btu/Net kwh. The heat rate target for Big Bend Unit 3 is 9,992 Btu/Net kwh, with a range of ±387 Btu/Net kwh. The heat rate target for Big Bend Unit 4 is 9,938 Btu/Net kwh with a range of ±243 Btu/Net kwh. The heat rate target for Gannon Unit 5 is 10,150 Btu/Net kwh with a range of ±519 Btu/Net kwh. The heat rate target for Gannon Unit 6 is 10,401 Btu/Net kwh with a range of ±380 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 IV 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 $366,186,700 is shown on page 6 column 2.

The PROMOD IV 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: $13,646,800 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 6.40% 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 85.2% equivalent availability, fuel savings would equal $873,400 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, $13,646,800. The right hand column of page 2 is the estimated reward or penalty based upon performance.

Q. How were the maximum allowed incentive dollars determined?

A. Referring to my exhibit on page 3, line 14, the estimated average common equity for the period January 1999 - December 1999 is shown to be $1,237,459,154. This produces the maximum allowed jurisdictional incentive dollars of $4,959,159 shown on line 21.

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):

$$\begin{aligned} GPIP = (& 0.0454\ EAP_{GN5} + 0.0683\ EAP_{GN6} \\ & + 0.0719\ EAP_{BB1} + 0.0640\ EAP_{BB2} \\ & + 0.0829\ EAP_{BB3} + 0.0432\ EAP_{BB4} \\ & + 0.0884\ HRP_{GN5} + 0.0979\ HRP_{GN6} \\ & + 0.1068\ HRP_{BB1} + 0.1112\ HRP_{BB2} \\ & + 0.1222\ HRP_{BB3} + 0.0978\ HRP_{BB4} \end{aligned}$$

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 January 1999 - December 1999 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, January 1, 1999 - December 31, 1999".

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 January 1999 - December 1999 period.

Q. Does this conclude your testimony?

A. Yes.

ORIGINAL

DOCKET NO. 980001-EI
TAMPA ELECTRIC COMPANY
SUBMITTED FOR FILING 06/23/98

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

ROD BURKHARDT

Q. Please state your name, address and occupation.

A. My name is Rod Burkhardt. My mailing address is P.O. Box 111, Tampa, Florida 33601, and my business address is 6944 U.S. Highway 41 North ,Apollo Beach, Florida 33572. I am Manager, Fuels in the Energy Supply Department of Tampa Electric Company.

Q. Mr. Burkhardt, please furnish a brief outline of your educational background and business experience.

A. I graduated from the University Florida in July, 1977 with a Bachelor of Science degree in Chemistry. I began my career with Tampa Electric Company in July 1977 as a chemist in the Production Department. Between 1977 and 1986, I held various technical and supervisory positions in the Central Testing Lab. In 1986, I became Supervisor-Budgets for Tampa Electric Company and in 1990 assumed the position of Manager-Central Testing Lab. In 1994 I joined the Fuels Department as Manager-Transportation and Planning and was named to my current position as Manager, Fuels in 1995.

Q. Will you describe some of the responsibilities of your present position?

A. As Manager, Fuels, I am responsible for the planning, procurement, delivery, inventory control, and price forecasting of the company's fuel requirements.

Q. Please state the purpose of your testimony.

A. The purpose of my testimony is to report to the Commission the actual 1997 costs of Tampa Electric's affiliated coal and coal transportation transactions compared to the benchmark prices calculated in accordance with Order No. 20298 (coal transportation) and Order No. PSC-93-0443-FOF-EI ("Order No. 93-0443") (coal). I conclude that the 1997 prices paid by Tampa Electric to its affiliates TECO Transport and Trade and Gatliff Coal are reasonable and prudent.

Q. Have you prepared an exhibit which you sponsor in this proceeding?

A. Yes. Exhibit No. (RB-1) titled "Exhibit of Rod Burkhardt", consisting of 2 documents, was prepared under my direction and supervision.

AFFILIATED COAL AND COAL TRANSPORTATION PRICES

Q. Were Tampa Electric's actual affiliated coal transportation prices for 1997 at or below the transportation benchmark?

A. Yes, they were. This is reflected in Document No. 1 of my exhibit.

Q. Were Tampa Electric's actual 1997 affiliated coal prices at or below the benchmark as established in Order No. 93-0443?

A. Yes, they were. This is reflected in Document No. 2 of my exhibit.

Q. Please summarize your testimony.

A. My testimony justifies the prices paid for coal and coal transportation by Tampa Electric Company in 1997 to its affiliated suppliers, Gatliff Coal and TECO Transport. I demonstrate that the average prices for the year 1997 for all coal and coal waterborne transportation services were at or below the appropriate benchmark calculations as directed by Order No. 20298 and Order No. 93-0443 of this Commission. Therefore, Tampa Electric should recover its payments for coal and coal transportation made during 1997.

Q. Does this conclude your testimony?

A. Yes, it does.

COMMISSIONER CLARK: And Staff recommends that the issues in the 001 docket, the stipulated issues, be approved?

MS. PAUGH: We do.

COMMISSIONER CLARK: Is there a motion?

COMMISSIONER GARCIA: I move that.

COMMISSIONER JACOBS: I second.

COMMISSIONER CLARK: Without objection, the issues as stipulated in Docket 980001 will be approved.

(Whereupon other dockets were discussed.)

* * * * *

COMMISSIONER CLARK: Anything further to come before the Commission?

MR. McWHIRTER: I'd like to make a statement for the record, if I may.

COMMISSIONER CLARK: Yes, Mr. McWhirter.

MR. McWHIRTER: This is the first proceeding in which the Commission has moved from semiannual to annual proceeding. And when you first considered this prospect, our firm expressed some serious concern about judicial due process because of the limited period of time in which massive amounts of information would have to be analyzed and dealt with.

The collections that you're approving today are for prospective periods that will be trued up. The due process issue comes out like this: We first saw the testimony and exhibits filed by 12 separate utilities the first week in October. It entails analyzing that information; not only the information that is contained in the filings, but also the information that may have been omitted from the filings.

To understand that, to deal with it effectively it requires expert participation. Utilities have numerous experts that are presenting their testimony. Consumer advocates have to locate and employ an expert. The expert has to have time to consider what's in the record and what has been omitted from the record. And then under your discovery rules, if we pose requests for production and interrogatories, the utilities have 30 days in which to respond.

I would suggest to you humbly that in order to do any even piecemeal analysis in order to determine what the real issues in the case are, it would take 30 days or so. That puts us in the first week of November, and when you have the hearings the third week of November immediately before the Thanksgiving holidays, I would suggest to you that we can't be expected to do a reasonable case in order to present meaningful facts to you in a meaningful way.

I don't suggest that the Commission was wrong in moving to an annual proceeding. I think probably it's appropriate at this time because of the fact that prices are not nearly so volatile as they were when these cost recovery proceedings were instituted initially.

But what I would also suggest to you is that since these rates are prospective and since we've got a year to live with them, that the Commission give a friendly eye to discovery that has -- may be filed subsequent to today's proceeding in which we may wish to plumb certain transactions such as affiliated transactions in which a utility buys product from its sister companies.

As you know, much of the information that's filed in these cases is under the umbrella of secrecy because they're fearful in a competitive environment the utilities' information will be misused, and as a consequence, we don't have the information there.

So we would like to have you give us your pledge, if you would, that when we come in during the course of this year to maybe further investigate some of these circumstances and explore them, that the

Commission not take the attitude that the decision was made today, it is now chiseled in stone, and it's too late to engage discovery.

MR. WILLIS: Before you go do something that is just thrown here on the table at the last minute, I think that you should -- if any such action is taken by Mr. McWhirter, you should take it into account after responses have been filed by the companies that are involved and to take a reasoned decision rather than giving -- making statements off the cuff here in response to something that has just been presented here for the first time.

I think that with respect to the procedures followed here that the planned workshops at the beginning of next year to further discuss how we can make the procedures more meaningful and easy for all concerned -- and that is one of the things that Mr. McWhirter could discuss at that time and can be resolved later by the Commission if no agreement is made among the parties after full discussion.

COMMISSIONER CLARK: Well, Mr. McWhirter, it appears as if we still haven't determined exactly what our procedures are going to be going to a yearly activity. And as I understand what Mr. Willis just said, we'll be having a workshop on how we should proceed in these cases; is that correct, Staff?

MS. PAUGH: That's correct. Those were Issues 7 and 7A, as I recall.

COMMISSIONER CLARK: It sounds like we're going to be looking at it.

MR. McWHIRTER: Well, I think -- I certainly welcome the opportunity to participate in a workshop that's designed to make the procedure more meaningful. But I'm not talking about procedural matters, I'm talking about substantive matters; and all I suggest to you is if we are -- when we seek discovery on substantive issues that were dealt with in this case, that the Commission determine now that it will not summarily dismiss our opportunity to inquire further, since this is an open docket.

COMMISSIONER CLARK: I don't think that's a decision we have to make now. I was going to say, well, who is the prehearing officer, but I seem to recall it's me. (Laughter)

It seems to me that if and when you make that request, it would be appropriate to hear our arguments on the pros and cons of doing that, and I can tell you if it comes before the prehearing officer -- I don't know if it will be me -- I'll have an open mind.

I think we're embarking on a different strategy for these things, and I think we were concerned at the time about the notion of giving enough time to review information and prepare for hearing. So we'll take it up at the time you feel the need to exercise that.

MR. McWHIRTER: Well, I understand from what you've said that your previous prehearing order does not preempt continuing discovery in this matter.

MR. WILLIS: I don't think she made any such decision. That's not before her.

COMMISSIONER CLARK: Mr. McWhirter, I'm not prepared to say yea or nay on that.

COMMISSIONER JACOBS: It's an open docket. That's about it.

MS. PAUGH: These are open ongoing dockets at all times. Discovery can be had at all times. We close the docket down from one year, and at the same time open up the next one. So there is no reason why you can't commence discovery in this docket tomorrow if you so desire.

MR. McWHIRTER: Thank you very much.

COMMISSIONER CLARK: Okay. Anything else we have to take up at this time?

MS. PAUGH: Not from Staff.

COMMISSIONER CLARK: Well, thank you all for your hard work on this case. And I wish you all a happy Thanksgiving.

(Thereupon, the hearing concluded at 11:30 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 206 pages, constitutes a true transcription of my notes of said proceedings and the insertion of the prescribed prefiled testimony of the witnesses.

DATED this 30th day of November, 1998.

H. RUTHE POTAMI, CSR, RPR
Official Commission Reporter
(904) 413-6734