BEFORE THE
FLORIDA PUBIC SERVICE COMMISSION

In the Matter of **Fuel and Purchased Power Cost Recovery Clause and Generating Performance Incentive Factor.**	:	**DOCKET NO. 960001-EI**

VOLUME 1

Pages 1 through 183

PROCEEDINGS: **HEARING**

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

DATE: **Wednesday, February 21, 1996**

TIME: Commenced at 11:45 a.m.

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

REPORTED BY: JOY KELLY, CSR, RPR
Chief, Bureau of Reporting
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JOHN ROGER HOWE, Deputy Public Counsel, Office of Public Counsel, 111 West Madison Street, Room 812, Tallahassee, Florida 32399-1400, Telephone No. (904) 488-9330, appearing on behalf of the **Citizens of the State of Florida.**

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(Hearing convened at 11:40 a.m.)

COMMISSIONER DEASON: We'll go ahead and call the hearing to order. We'll begin with having the notice read, please.

MS. ERSTLING: This time and place was noticed for a hearing in Dockets 960001-EI, Fuel and Purchased Power Cost Recovery Clause and Generating Performance Incentive Factor; Docket No. 960002-EG, Conservation Cost Recovery Clause; Docket No. 960003-GU, Purchased Gas Adjustment; and Docket No. 960007-EI, Environmental Cost Recovery Clause on January 18, 1996.

COMMISSIONER DEASON: Thank you. We'll take appearances.

MR. BEASLEY: Commissioners, I'm James D. Beasley with the law firm of Macfarlane Ausley Ferguson & McMullen, P. O. Box 391, Tallahassee, Florida 32302. And I'm representing Tampa Electric Company in the fuel adjustment docket.

MR. STONE: Commissioners, I'm Jeffrey A. Stone, of the law firm Beggs & Lane, P.O. Box 12950, Pensacola, Florida 32576, representing Gulf Power Company in Docket No. 960001, 960002, and 960007.

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. JOHNSON: Vicki Johnson appearing for Staff in Dockets 01 and 07. Lorna Wagner is also making an appearance in Docket 01.

* * * * *

COMMISSIONER DEASON: Okay. We are back on the record, and we are addressing the 01 docket.

Ms. Johnson.

MS. JOHNSON: Yes. All the issues in the 01 docket have been stipulated with the exception of Issues 4, 7, 17, 18, 19A and 19B. In addition, there are a couple of corrections to the Prehearing Order.

COMMISSIONER KIESLING: Could you give me those numbers again, because I didn't get them all written down. 4, 7 --

MS. JOHNSON: 4, 7, 17, 18, 19A. and 19B.

COMMISSIONER KIESLING: Thank you.

MS. JOHNSON: We have a few corrections to the Prehearing Order. Issue 17, Staff's position should be 161,612 underrecovery, and I'll note that I believe that TECO is going to make a correction to their position on this issue as well.

MR. BEASLEY: Yes, we agree that that number is an underrecovery of $161,612.

COMMISSIONER JOHNSON: 161 thousand --

MR. BEASLEY: -- 612.

COMMISSIONER DEASON: So, then, TECO and Staff are in agreement in regard to Issue 17?

MS. JOHNSON: That's correct.

COMMISSIONER DEASON: Okay. Other corrections?

MS. JOHNSON: For Issue 18, Staff's position should be for TECO, 23,001 underrecovery.

MR. BEASLEY: And we agree with that amount, sir.

COMMISSIONER KIESLING: Could you give me that number again?

MS. JOHNSON: 23,001.

COMMISSIONER KIESLING: Under?

MS. JOHNSON: Under, yes.

COMMISSIONER DEASON: Mr. Beasley, TECO agrees with that number; is that correct?

MR. BEASLEY: Yes.

COMMISSIONER DEASON: So, then, there is agreement on Issue 18.

MS. JOHNSON: Excuse me?

COMMISSIONER DEASON: There is agreement, then, for issue --

MS. JOHNSON: There is agreement on the number; however, not on the caveat that TECO has included it in their position.

COMMISSIONER DEASON: Okay. Other corrections?

MS. JOHNSON: None that Staff has.

COMMISSIONER DEASON: Any other preliminary matters in the 01 docket?

MR. BEASLEY: Commissioners, it's my understanding that we are here primarily on Issues 19A and B, having to do with the oil backout separation issue and the retroactive application of whatever decision pertains to 19A, would have on the Company and that any other issues are fallout issues in connection with those two issues.

COMMISSIONER DEASON: Very well. What we need to do then is to proceed with the testimony of all witnesses who have been stipulated, and those witnesses are found on Page 5 of the Prehearing Order. And it would be all witnesses except for Witness Pennino -- how is that pronounced?

MR. BEASLEY: Pennino.

COMMISSIONER DEASON: Pennino and Witness Townes; is that correct?

MS. JOHNSON: Yes.

COMMISSIONER DEASON: Okay. Is there a motion then to have that testimony inserted into the record?

MS. JOHNSON: Yes, there is.

COMMISSIONER DEASON: There is a motion. And consistent with the Prehearing Order and the stipulation, the testimony of all the witnesses, except the two identified TECO witnesses, will be inserted into the record. And we need to identify the exhibits as well. And those are found on Pages 22 through 24 of the Prehearing Order. And I believe that would be Exhibits 1 through 29; is that correct?

MS. JOHNSON: That is correct.

COMMISSIONER DEASON: And consistent with the stipulation, those exhibits except for -- which exhibits would be excepted, Ms. Johnson? Those for Ms. -- I'm sorry, for Witness Pennino?

MS. JOHNSON: It's my understanding -- and, Mr. Beasley, correct me if I'm wrong -- that those exhibits should have been noted with an asterisk.

MR. BEASLEY: That's correct. That's correct. These witnesses, Ms. Pennino and Ms. Townes, both sponsor other testimony which is not in controversy. There's a very short prepared testimony for each of them on the Issues 19A and B, and that's what they will present when they take the stand. And the other testimony and exhibits are not at issue, and they won't be testifying with regard to those matters.

COMMISSIONER DEASON: Well, I'm just trying to keep the record as clean as possible. And what I want to do is I want to get all the testimony for all other witnesses into the record and their exhibits into the record at this point. And then we'll address exactly what we are going to do with the other witnesses. And I just need to know at this point what exhibits we can go ahead and admit into the record by exhibit number.

MS. JOHNSON: It's my understanding that the only exhibit that can be accepted into the record at this time would be the last exhibit, which would be Exhibit No. 29, WNC/EAT. I understand that the exhibits that are sponsored by Ms. Pennino include the projections and that Issues 19A and 19B have not been taken into account on those schedules.

COMMISSIONER DEASON: Very well. So you are saying that Exhibits 1 through 28 can be admitted at this time without any objection; is that correct?

MS. JOHNSON: No. I said that all exhibits including 29, with the exception of MJP-1, 2 and 3 may be admitted at this time.

COMMISSIONER DEASON: Okay. I got that confused. And what are the exhibit numbers for MJP-1, 2, and 3?

MS. JOHNSON: That's 23, 24, and 25.

COMMISSIONER DEASON: So, then, correct me if I'm wrong, Exhibits 1 through 29 may be admitted with the exception of Exhibits 23, 24 and 25; is that correct?

MS. JOHNSON: That's correct.

COMMISSIONER DEASON: Okay. And is there a motion to that effect then?

MS. JOHNSON: Yes, there is. I so move.

COMMISSIONER DEASON: Without objection, then show that Exhibits 1 through 29, with the exception of Exhibits 23, 24, and 25, are admitted into the record.

(Exhibit Nos. 1 through 22, and 26 through 29 marked for identification and received in evidence.)

FLORIDA POWER CORPORATION

DOCKET NO. 950001-EI

Re: Fuel Cost Recovery and
Capacity Cost Recovery
Final True-up Amounts for
April through September 1995

DIRECT TESTIMONY OF
DAVID P. DEVELLE

Q. Please state your name and business address.

A. My name is David P. Develle. My business address is P. O. Box 14042, St. Petersburg, Florida 33733.

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

A. I am employed by Florida Power Corporation as Director, Regulatory Accounting.

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 describe the Company's Fuel Cost Recovery Clause final true-up amount for the period of April 1995 through September 1995, and the Company's Capacity Cost Recovery Clause final true-up amount for the same period.

Q. Have you prepared exhibits to your testimony?

A. Yes, I have prepared a three-page true-up variance analysis which examines the difference between the estimated fuel true-up and the actual period-end fuel true-up. This variance analysis is attached to my prepared testimony and designated exhibit (DPD-1). Also attached to my prepared testimony and designated exhibit (DPD-2) are the Capacity Cost Recovery Clause true-up calculations for the April 1995 through September 1995 period. Also, I will sponsor the applicable Schedules A1 through A9 for the month of September 1995 (period-to-date), which have been previously filed with the Commission and are also attached to my prepared testimony for ease of reference and designated as exhibit (DPD-3).

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

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

FUEL COST RECOVERY

Q. What is the Company's jurisdictional ending balance as of September 30, 1995 for fuel cost recovery?

A. The actual ending balance as of September 30, 1995 for true-up purposes is an under-recovery of $10,032,296.

Q. How does this amount compare to the Company's estimated ending balance to be included in the October 1995 through March 1996 period?

A. When the estimated under-recovery of $10,649,438 to be collected during the period of October 1995 through March 1996 is taken into account, the final true-up ending balance attributable to the six month period ended September 30, 1995 is an over-recovery of $617,142

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

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

Q. What factors contributed to the period-ending jurisdictional under-recovery of $10.0 million as shown on exhibit (DPD-1)?

A. The factors contributing to the over-recovery are summarized on Sheet 1 of 3. The actual jurisdictional kwh sales were higher than the original estimate by 636,989,162 kwh. This increase in kwh sales, attributable to abnormally warm weather, resulted in higher jurisdictional revenues of $10.0 million and also accounted for approximately $14 million of the total $18 million unfavorable variance in jurisdictional fuel and purchased power expense. The remaining $4 million unfavorable variance in fuel expense can be primarily attributable to heat rate variances.

When these differences in jurisdictional revenues and jurisdictional fuel expenses are combined, the net result is an under-recovery of $8 million related to the April 1995 through September 1995 time period. Other variances not directly related to the period result in the actual ending balance under-recovery of $10.0 million as of September 30, 1995.

Q. Please explain the components shown on exhibit (DPD-1), Sheet 2 of 3 which produced the $19 million unfavorable system variance from the projected cost of fuel and net purchased power transactions.

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

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

A. As can be seen from Sheet 2 of 3, variances in the amount of MWH requirements from each energy source (column B) combined to produce a cost increase of $14.3 million. I will discuss this component of the variance analysis in greater detail below.

The heat rate variance for each source of generated energy (column C) produced a net cost increase of $4.7 million. Higher than anticipated heat rates for oil generating units were the largest component of the cost variance. On the Company's Schedule A3, exhibit (DPD-3), all BTU's for light oil are included in the light oil heat rate computation. However since no Kwh generation is associated with light oil consumed at steam plants, the resulting heat rate shown on A3 is distorted. In order to compute the true heat rate variance, light oil consumed at steam units is shown separately on line 23 of Sheet 2 of 3 of exhibit (DPD-1).

Q. Please explain the analysis shown on Sheet 3 of 3 of your exhibit (DPD-1)

A. The analysis on Sheet 3 of 3 attempts to identify the effect that generation mix has on total net system fuel and purchased power cost. Although this interrelationship is generally understood to exist, it is not readily apparent from the individual variances contained in the FPSC "A" Schedules or in the analysis presented on Sheet 2 of 3. For example, an increase in the Mwh requirements of nuclear generation shows up on Schedule A3 and on Sheet 2 of my exhibit as a cost increase of $.4 million. While this may be correct in isolation, the true effect of increased nuclear generation is obviously a corresponding decrease in the MWH requirements of a number of other more costly energy sources, primarily coal and light oil. The result is a lower net system cost of $1.6 million even if total system MWH requirements remain unchanged.

In addition to the effect of variances in generation mix, this analysis also attempts to identify the independent effect of the <u>net</u> variance in total system Mwh requirements from all energy sources combined (internal and external). In this true-up period, for example, total system requirements were higher than the original forecast by 603,000 MWH. This would have led to higher net costs of $11.4 million even if the mix of generation had not changed, since the higher system load increases coal generation at a cost above the system average.

Q. Please explain how this analysis was performed.

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

Q. What were the major contributors to the $14.3 million cost increase associated with the variance in MWH requirements?

Q. What factors contributed to the actual period-end over-recovery of $3.6 million?

A. Exhibit (DPD-2), sheet 1 of 3, entitled "Capacity Cost Recovery/Summary of Actual True-Up Amount", compares the summary items from sheet 2 of 3 to the original forecast for the period. As can be seen from sheet 1, actual jurisdictional capacity cost revenues were $4.4 million greater than forecast due to higher residential Kwh sales during the period. Jurisdictional capacity costs were $.7 million higher than forecast. The major factor contributing to this variance was Orange Cogen. Actual payments to Orange Cogen were $165,000 higher than forecast and the classification of capacity payments to Orange Cogen was appropriately changed from an Intermediate resource in our original forecast (83.5% jurisdictional separation factor) to a Base resource on an Actual basis (94.6% jurisdictional separation factor). This reclassification was made in accordance with the Company's current stratification of QF resources with respect to their expected relative energy cost.

Q. Does this conclude your testimony?

A. Yes, it does.

FLORIDA POWER CORPORATION

DOCKET NO. 960001-EI

Levelized Fuel and Capacity Cost Factors
April through September 1996

DIRECT TESTIMONY OF
KARL H. WIELAND

Q. Please state your name and business address.

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

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

A. I am employed by Florida Power Corporation as Director of Business Planning.

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

A. Yes.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present for Commission approval the Company's levelized fuel and capacity cost factors for the period of April through September 1996.

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 Intercession City combustion turbines 8 and 10 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 1.887 ¢/kWh (before line loss adjustment). The basic factor consists of a fuel cost for the projection period of 1.8401 ¢/kWh (adjusted for jurisdictional losses), a GPIF reward of .00862 ¢/kWh, and an estimated true-up charge of 0.0369 ¢/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 1.309 ¢/kWh On-peak and 0.833 ¢/kWh 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 1.891 ¢/kWh.

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 four combustion turbine units at Intercession City to burn natural gas instead of distillate oil. Recovery of the conversion of units 7 and 9 was approved by this Commission in August, 1995. In this filing the Company is requesting approval to add the conversion costs of two additional units (8 and 10) beginning in June, 1996.

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 409 MWs under a Unit Power Sales (UPS) agreement with the Southern Company. During October-December 1995, the Southern Company purchase provides of 407 MW of unit power. Beginning January 1996, the SERC ratings of the units supporting this purchase will be revised to 409 MW. The capacity payments associated with the UPS contract are based on the original contract of 400 MW. The additional 9 MW are the result of revised SERC ratings for the five units involved in the unit power purchase, providing a benefit to Florida Power Corporation in the form of reduced costs per kW. Both of these contracts have been in place and have been approved for cost recovery by the Commission. Capacity costs for these purchases are included in the capacity cost recovery factor.

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

A. Line 8 includes energy costs for purchases from Seminole Electric Cooperative (SECI) for load following, off-peak hydroelectric purchases from the Southeast Electric Power Agency (SEPA), and miscellaneous economy purchases from within or outside the state which are not made through the Florida Broker System. The SECI contract is an ongoing contract under which the Company purchases energy from SECI at 95% of its avoided fuel cost. Purchases from SEPA are on an as-available basis. There are no capacity payments associated with either of these purchases. Other purchases, such as a new 20 MW economy purchase from the Orlando Utilities Commission (reported on Schedule E9), 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 are reported on line 10.

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

A. The Company has a wholesale contract with Seminole for the sale of supplemental energy to supply the portion of their load in excess of 689 MW. The fuel costs charged to Seminole for these supplemental sales are calculated on a "stratified" basis, in a manner which recovers the higher cost of intermediate/peaking generation used to provide the energy. The Company also has wholesale contracts with the municipal utilities of Kissimmee and St. Cloud and with Georgia Power Company under which fuel costs are charged in a similar manner. The fuel costs of wholesale sales are normally included in the total cost of fuel and net power transactions used to calculate the average system cost per kWh for fuel adjustment purposes. However, since the fuel costs of the Stratified sales are not recovered on an average cost basis, an adjustment has been made to remove these costs and the related kWh sales from the fuel adjustment calculation in the same manner that interchange sales are removed from the calculation. This adjustment is necessary to avoid an over-recovery by the Company which would result from the treatment of these fuel costs on an average cost basis in this proceeding, while actually recovering the costs from these customers on a higher, stratified cost basis. The development of this adjustment is shown on Schedule E6.

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

A. The total true-up amount was determined in two parts. First, a period-to-date actual under-recovery of $2,291,039 through November 1995 was obtained from Schedule A2, page 3 of 4, previously submitted for the month of November. This balance was projected to the end of March 1996, including interest estimated at the November ending rate of 0.4833% per month. Second, the total estimated under-recovery of $6,533,077 for the current period was combined with the prior period (April through September 1995) under-recovery of $10,032,296 and $10,649,438 being collected during the current period for a total under-recovery of $5,915,935 at the end of March 1996. This results in an estimated true-up charge on line 28 of Schedule E1 of 0.0369 ¢/kWh for application in the April through September 1996 projection period. The development of the estimated true-up amount for the current April through September 1996 period is shown on Schedule E1-B, Sheet 1.

Q. What are the primary reasons for the projected March 1996 under-recovery of $5.9 million?

A. The under-recovery is primarily a result of abnormal weather conditions which occurred in October through December, 1995.

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

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

Q. How was the rate of energy consumption for each batch within Cycle 11 estimated for the upcoming projection period?

A. The consumption rate of each batch has been estimated by utilizing a core physics computer program which simulates reactor operations over the projection period. When this consumption pattern is applied to the individual batch costs, the resultant composite Cycle 11 is $0.327 per million BTU.

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

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

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

A. The system sales forecast is made by the Forecasting section of the Business Planning Department using the most recently available data. The forecast used for this projection period was prepared in June 1995.

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

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

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

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

Q. Please explain the basis for requesting recovery of the cost of converting combustion turbine units 8 and 10 at the Intercession City site 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."

In August of 1995, the Company converted Intercession City units 7 and 9 to burn natural gas. The Commission authorized the Company to recover the conversion cost, including a return on investment, over a five-year period in Order No. PSC-95-1089-FOF-EI dated September 5, 1995. The Company is asking the Commission for the same treatment for two additional units at the same sit. The conversion cost for units 8 and 10 is $2.6 million. This cost was not part of the cost of Intercession City units 8 and 10 when they were included in rate base as part of the 1993 test year.

Q. How is FPC proposing to recover the conversion cost?

A. The Company proposes to amortize the $2.6 million conversion cost over a five year period beginning with the plant in-service date of June, 1996. The projected cost during the April 1996 through September 1996 period is $236,906 which consists of an amortization charge of $151,666 and a return (including income taxes) of $85,240 based on the Company's current cost of capital of 8.37%. The fuel savings for the same period are expected to be $1,460,448 resulting in a net benefit to customers of $1,223,542. For comparison purposes, actual fuel savings produced by the conversion of units 7 and 9 from August through November of 1995 are in excess of $1.5 million.

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

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

A. The Company chose five years in order to align recovery of cost with anticipated benefits. The Company is relying on the availability of interruptible gas transportation for the delivery of gas to the site because firm (take or pay) contracts are not economical for a low capacity factor peaking site. Discussions with Florida Gas Transmission (FGT) and a private consultant's report indicate that they expect interruptible gas to be available in sufficient quantity to power the two units at the site for the next five years. The Company hopes that some gas will be available beyond that time which will yield additional savings, but we believe it more appropriate to recover costs during the time when the majority of benefits are expected to occur. Expensing the conversion cost would burden existing customers with costs that exceed benefits while amortizing the conversion over the life of the units could burden future customers with costs that do not have corresponding benefits.

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

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

CAPACITY COST RECOVERY

Q. How was the Capacity Cost Recovery factor developed?

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

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

Sheet 2: Estimated/Actual True-Up. This schedule presents the actual ending true-up balance after two months of the current period and re-forecasts the over/(under) recovery balances for the next four months to obtain an ending balance for the current period. This estimated/actual balance of $4,119,749 is then carried forward to Sheet 1, to be refunded during the April through September 1996 period.

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

Sheet 4: Calculation of 12 CP and Annual Average Demand. The calculation of average 12 CP and annual average demand is based on 1994 load research data and the delivery efficiencies on Sheet 3.

Sheet 5: Calculation of Capacity Cost Recovery Factors. The total demand allocators in column (7) are computed by adding 12/13 of the

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

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

A. The increase in capacity payments from $138.2 million in the October 1995 through March 1996 period to $141.9 million for the April through September 1996 period is due to the escalation to the 1996 payment schedule. No new contracts begin before September 1996. The decrease in rates, exhibited on sheet 5 on a cents per kWh basis, is due to the greater amount of kWh sales projected for the summer period as compared to the current period.

Q. Does this conclude your testimony?

A. Yes.

FLORIDA POWER CORPORATION

DOCKET NO. 950001-EI

Re: GPIF Reward/Penalty Amount for
April through September 1995

DIRECT TESTIMONY OF
LARRY G. TURNER

Q. Please state your name and business address.

A. My name is Larry G. Turner. My business address is P. O. Box 14042, St. Petersburg, Florida 33733.

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

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

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 describe the calculation of the Company's Generation Performance Incentive Factor (GPIF) amount for the period of April through September 1995. This was developed by comparing the actual performance of the Company's seven GPIF generating units to the approved targets set for these units prior to the period.

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

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

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

A. I have calculated the Company's GPIF incentive amount to be a reward of $1,456,161. This amount was developed in a manner consistent with the GPIF Implementation Manual. Sheet 1 of my exhibit shows the calculation of system GPIF points and the corresponding reward. The summary of weighted incentive points earned by each individual unit can be found on Sheet 3.

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

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

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

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

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

A. Yes, Sheet 23 of my exhibit shows a comparison of target and actual planned outage hours in bar-chart form. Sheets 24 through 26 present as-worked critical path charts for each unit which experienced a planned outage during the period.

Q. Does this conclude your testimony?

A. Yes.

FLORIDA POWER CORPORATION

DOCKET NO. 960001-EI

GPIF Targets and Ranges for
April through September 1996

DIRECT TESTIMONY OF
LARRY G. TURNER

Q. Please state your name and business address.

A. My name is Larry G. Turner. 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 Senior Performance Engineer.

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

A. Yes, they have.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present the development of the Company's Generating Performance Incentive Factor (GPIF) targets and ranges for the period of April through September, 1996. This development includes the targets and improvement/degradation ranges for unit equivalent availability and unit average net operating heat rate in accordance with the Commission's Generating Performance Incentive Implementation Manual.

Q. Do you have an exhibit to your testimony?

A. Yes, I will sponsor an exhibit containing 73 pages, which consists of the GPIF standard form schedules prescribed in the Implementation Manual and supporting data, including unplanned outage rates, net operating heat rates, and computer analyses and graphs for each of the individual GPIF units, all of which are attached to my prepared testimony.

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

A. We have included the same units as were included for the current period, Crystal River Units 1 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 <u>rates</u> can then be converted into an overall equivalent unplanned outage <u>factor</u> (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 90.00%. The unit's next mid-cycle outage is scheduled to begin February 29, and continue through April 15, resulting in a Summer period POF of 8.20%. The unit's EUOR target is 1.97, which results in an EUOF of 1.81% when planned outage hours are taken into account.

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

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

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

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

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

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

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

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

Q. How were the GPIF weighting factors determined?

A. To determine the weighting factors for availability, a series of PROMOD simulations were made in which each unit's maximum equivalent availability was substituted for the target value to obtain a new system fuel cost. The differences in fuel costs between these cases and the target case determines the contribution of each unit's availability to fuel savings. Except for Crystal River 3, 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. For Crystal River 3, the contribution of heat rate to fuel savings was developed in a manner similar to the fuel savings from availability, since an improvement in the nuclear unit's efficiency results in a corresponding increase in the unit's generating capacity. Weighting factors were then calculated by dividing each individual unit's fuel savings by total system fuel savings.

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

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

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

TESTIMONY OF B.T. BIRKETT

DOCKET NO. 950001-EI

November 17, 1995

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

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

Q. Have you previously testified in this docket?

A. Yes, I have.

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

A. The purpose of my testimony is to present the schedules necessary to support the actual Fuel Cost Recovery Clause (FCR) and Capacity Cost Recovery Clause (CCR) Net True-Up amounts for the period April 1995 through September 1995. The Net True-Up for FCR is an underrecovery, including interest, of $33,181,566. The Net True-Up for CCR is an overrecovery, including interest, of $23,587,130. I am requesting Commission approval to include these true-up amounts in the calculation of the FCR and CCR factors respectively, for the period April 1996 through September 1996.

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 three appendices. Appendix I contains the FCR related schedules and Appendix II contains the CCR related schedules. Also attached to this filing is Appendix III which contains Commission Schedules A-1 through A-13 for the April 1995 through September 1995 period.

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 Amount", shows the calculation of the Net True-Up for the period, an underrecovery of $33,181,566, which I am requesting be included in the calculation of the Fuel Cost Recovery Factor for the period April 1996 through September 1996. 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 of $71,580,775 shown on line 1 less the estimated/actual End-of-Period underrecovery of $38,399,209 shown on line 2 that was included in the calculation of the Fuel Cost Recovery Factor for the period October 1995 through March 1996, results in the Net True-Up for the period shown on line 3, an underrecovery of $33,181,566.

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 Amount", shows the actual fuel costs and revenues compared to the estimated/actuals for the period April 1995 through September 1995.

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 $56.0 million higher than the estimated/actual projection. This increase is primarily due to a 34% increase in heavy oil generation as a result of 3.2% higher than projected sales and 29% lower than projected generation from St. Lucie Unit No. 1.

The lower than projected generation from St Lucie Unit No. 1 was primarily caused by a number of unplanned events that took place during July, August and September 1995. The events are listed below. (These events have been described in greater detail in FPL's response to Staff's Third Set of Interrogatories in this Docket that were filed with the Commission on November 3, 1995.)

DATE	EVENT
Jul 8, 1995	Turbine Trip During Surveillance Testing
Jul 10, 1995	Vehicle in Discharge Canal
Aug 1, 1995	Hurricane Erin
Aug 2, 1995	1A2 Reactor Coolant Pump Seal Package Failure
Aug 9, 1995	Power Operated Relief Valve Failures
Aug 17, 1995	Inadvertent Spray Down of Containment
Sep 1, 1995	1B2 EDG Rocker Arm Adjusting Screw Lock Nut
Sep 11, 1995	Pressurizer Code Safety Valve Flange Leakage

Sep 19, 1995	1B Emergency Diesel Generator Hold Down Bolts
Sep 22, 1995	1A & 1B EDG Governor Stability
Sep 24, 1995	Pressurizer Code Safety Valve Alignment Modifications

The St. Lucie nuclear units were taken off line on August 1, 1995 due to Hurricane Erin. After the threat of the Hurricane had passed, FPL began the process of returning both units to service. Unit 2 was successfully returned to service on August 5, 1995. During the start up of Unit 1, FPL encountered equipment problems (listed above) which required repair prior to returning the unit to service.

FPL's nuclear management has made an extensive review of the events listed above. Additionally in September 1995, FPL's management requested that an independent team of utility experts examine some of these events for the purpose of identifying commonality among the events and to determine plant weaknesses which may have contributed to the events. The team conducted interviews, reviewed documents, and observed plant operations on all shifts. FPL believes its management of these events was reasonable and prudent and the appropriate actions have been taken to correct these situations.

These unplanned events at St. Lucie Unit No. 1, most of which followed the shutdown caused by Hurricane Erin, resulted in a GPIF Equivalent Availability Factor (EAF) penalty of approximately $1.3 million. During the period of April to July 1995, prior to the hurricane, St. Lucie Unit 1 had performed well above its approved GPIF EAF Target. Consequently, if Unit 1 had performed at its target level during August and September, FPL would have received a maximum reward of $1.3 million for St. Lucie Unit No. 1. Therefore, the effect of the outages at St. Lucie Unit No. 1 is to have eliminated the potential to receive the GPIF reward and instead the Company will receive a penalty.

During this April 1995 through September 1995 fuel cost recovery period, St. Lucie Unit 2 performed well above its approved EAF target and achieved a GPIF maximum EAF reward of almost $1.1 million. Therefore the combined EAF performance of the St. Lucie nuclear plant was a penalty of more than $0.2 million. The FPL nuclear units at the Turkey Point site also performed well above their approved targets during the same period with maximum rewards for each unit's EAF performance.

Since 1991, all four of FPL's nuclear units have consistently performed above the nuclear industry average for forced (unplanned) outages. For example, in 1994, while the industry average for forced outages was approximately 10.6%, FPL's nuclear units had forced outage rates of less than 4%. Other significant gains in nuclear unit availability were achieved through the reduction in the length of planned outages. Between 1992 and 1994 the average number of days off line for planned outages at FPL's nuclear sites has decreased from more than 63 days to less than 44 days. In contrast, the nuclear industry average for planned outages was approximately 65 days in 1992 and 56 days in 1994. FPL's excellent nuclear performance has provided substantial savings to our customers in replacement fuel costs.

The GPIF program has rewarded FPL for having its nuclear units perform well. In this instance, the GPIF program (as intended) has penalized FPL at St. Lucie Unit 1, as a result of its outages during August and September.

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 $21.5 million higher than the estimated/actual projection. This increase was due to higher jurisdictional kWh sales. Jurisdictional sales were 1,259,358,636 kWh (3.2%) higher than the estimated/actual projection.

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

A. In the determination of Jurisdictional kWh sales, only kWh sales associated with RTP baseline load are included, consistent with projections (Appendix 1, page 4, Line C3). In the determination of Jurisdictional Fuel Costs, revenues associated with RTP Incremental kWh sales are included as 100% Retail (Appendix 1, page 4, Line D4c) in order to offset incremental fuel used to generate these kWh sales.

CAPACITY COST RECOVERY CLAUSE (CCR)

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

A. Appendix II, page 3, entitled "Summary of Net True-Up Amount" shows the calculation of the Net True-Up for the period, an overrecovery of $23,587,130, which I am requesting be included in the calculation of the Capacity Cost Recovery Factor for the period April 1996 through September 1996.

The actual End-of-Period overrecovery of $20,971,244, shown on line

1 less the estimated/actual End-of-Period underrecovery of $2,615,886, shown on line 2 that was included in the Capacity Cost Recovery Factor for the period October 1995 through March 1996, results in the Net True-Up shown on line 3, an overrecovery of $23,587,130.

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 period April 1995 through September 1995. The End of-Period true-up shown on line 19 is an overrecovery of $20,971,244.

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. Please explain the calculation of the interest provision.

A. Appendix II, page 5, entitled "Calculation of Interest Provision", shows the calculation of the interest provision for the period April 1995 through September 1995 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 (line 4) by the monthly average interest rate (line 9). The average interest rate 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 interest calculated during the period amounts to $340,470 as shown on line 10.

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

A. Yes. Appendix II, page 6, entitled "Calculation of Final True-up Variances", shows the actual capacity charges and applicable revenues compared to the estimated/actuals for the period April 1995 through September 1995.

Q. What was the variance in net capacity charges?

A. As shown on line 6, actual net capacity charges on a Total Company basis were $17.8 million lower than the estimated/actual projection. This variance was primarily due to lower than expected capacity payments to the Southern Company for Unit Power Sales (UPS), lower than expected capacity payments to Qualifying Facilities (QF's) and higher than expected Revenues from Capacity Sales. Actual UPS capacity charges were $9.1 million lower than projected primarily due to a prior period credit adjustment of $9.5 million reflected on the September invoice. Actual QF capacity charges were $7.8 million lower than projected primarily due to the fact that ICL did not declare commercial operation in September as originally estimated. Revenues from Capacity Sales were $0.8 million higher than projected due to higher than projected Opportunity Sales as a result of the hot weather throughout the Southeast.

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

A. As shown on line 13, actual Capacity Cost Recovery revenues, net of revenue taxes, were $6.0 million higher than the estimated/actual projection. This increase was primarily due to higher jurisdictional kWh sales than projected. Jurisdictional sales were 1,259,358,636 kWh (3.2%) higher than 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 BARRY T. BIRKETT

DOCKET NO. 950001-EI

January 22, 1996

Q. Please state your name and address.

A. My name is Barry T. Birkett and my business address is 9250 West Flagler Street, Miami, Florida 33174.

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

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

Q. Have you previously testified in this docket?

A. Yes, I have.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present for Commission review and approval the fuel factors and the capacity payment factors for the Company's rate schedules, including the Time of Use rates, for the period April 1996 through September 1996. 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 providing updated projections of avoided energy costs for purchases from small power producers and cogenerators and 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 October 1995 through March 1996.

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

Appendix III contains the Commission Schedules A1 through A9 for October through December 1995. These schedules were prepared by various departments including Power Supply, Rates, Power Generation and Accounting, and present a monthly comparison between the original projections and the actual generation, sales and fuel costs for the three months.

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

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

FUEL COST RECOVERY CLAUSE

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

A. 2.071¢ per kWh. Schedule El, Page 3 of Appendix II shows the calculation of this six-month levelized fuel factor. Schedule E2, Page 10 of Appendix II indicates the monthly fuel factors for April 1996 through September 1996 and also the six-month levelized fuel factor for the period.

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

A. Yes. Schedule E1-D, Page 8 of Appendix II provides a six-month levelized fuel factor of 2.322¢ per kWh on-peak and 1.941¢ per kWh off-peak for our Time of Use rate schedules.

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

A. Yes, they were.

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

A. As shown on line 28 of Schedule E1, Page 3, of Appendix II the estimated/actual fuel cost underrecovery for the October 1995 through March 1996 period amounts to $64,536,189. This estimated/actual underrecovery for the October 1995 through March 1996 period plus the final underrecovery $33,181,566 for the April 1995 through September 1995 period results in a total underrecovery of $97,684,026. This amount, divided by the projected retail sales of 40,689,121 MWH for April 1996 through September 1996 results in an increase of .2389¢ per kWh before applicable revenue taxes. In his testimony for the Generating Performance Incentive Factor, FPL Witness R. Silva calculated a reward of $2,159,086 for the period ending September 1995, to be applied to the April 1996 through September 1996 period. This $2,159,086 divided by the projected retail sales of 40,889,121 MWH during the projected period, results in an increase of .0053¢ per kWh, as shown on line 32 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 October 1995 through March 1996 is an underrecovery, including interest, of $64,536,189 (Column 7, lines C7 plus C8). This amount, when combined with the Final True-up underrecovery of $33,181,566 (Column 7, line C9a) deferred from the period April 1995 through September 1995, presented in my Final True-up testimony filed on November 15, 1995, results in the End of Period underrecovery of $97,684,026 (Column 7, line C11).

Pursuant to Commission Order No. PSC-95-1089-FOF-EI, this $97,684,026 underrecovery includes the Oil Backout overrecovery of $33,729 for the period through September 1995. The order states that "Cost recovery through the oil backout cost recovery clause, which is currently a rate of .012 cents per kWh, will cease with the final billing cycle in September 1995. Any remaining true-up amount related to oil backout costs through September 1995 will be recovered or refunded as a one time line item adjustment to fuel costs through the fuel and purchased power cost recovery clause during the period April 1, 1996 through September 30, 1996."

This schedule also provides a summary of the Fuel and Net Power

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

The data for October through December 1995, columns (1) through (3) reflects the actual results of operations and the data for January through March 1996, columns (4) through (6), are based on updated estimates.

The variance calculation of the Estimated/Actual data compared to the original projections for the October 1995 through March 1996 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 $75.9 million or a 13.0% increase. This variance is mainly due to a 20.0% increase in Fuel Cost of System Net Generation as shown on line A1a.

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 in this proceeding in Appendix III.

CAPACITY PAYMENT RECOVERY CLAUSE

Q. **Please describe Page 3 of Appendix IV.**

A. Page 3 of Appendix IV provides a summary of the requested capacity payments for the projected period of April 1996 through September 1996. Total recoverable capacity payments amount to $160,561,638, and include payments of $107,102,004 to non-cogenerators and payments of $150,874,748 to cogenerators. This amount is offset by revenues from capacity sales of $1,910,161 and $28,472,796 of jurisdictional capacity related payments included in Base Rates plus the net overrecovery of $62,546,424 reflected on line 8. The net overrecovery of $62,546,424 includes the final overrecovery of $23,587,130 for the April 1995 through September 1995 period less the estimated/actual overrecovery of 38,959,291 for the October 1995 through March 1996 period.

Q. **Please describe Page 4 of Appendix IV.**

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

Q. **Please describe Page 5 of Appendix IV.**

A. Page 5 of Appendix IV 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. Appendix IV, page 6, shows the calculation of the CCR Estimated/Actual True-up amount. The Estimated/Actual True-up for the period October 1995 through March 1996 is an overrecovery, including interest, of $38,959,291 (Column 7, lines 14 plus 15). This amount, plus the Final True-up overrecovery of $23,587,130 (Column 7, line 17) deferred from the period April 1995 through September 1995, presented in my Final True-up testimony filed on November 15, 1995, results in the End of Period overrecovery of $62,546,424 (Column 7, line 19).

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

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

The resulting overrecovery of $62,546,424 has been included in the calculation of the Capacity Cost Recovery factor for the period April

1996 through September 1996.

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

A. Appendix IV, page 7, 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 December 1995.

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

A. Yes. Appendix IV, page 8, shows the Estimated/Actual capacity charges and applicable revenues compared to the original projections for the period.

Q. **What is the variance related to capacity charges?**

A. The variance related to capacity charges is a $31.4 million decrease. This variance is primarily due to a $23.3 million decrease in Qualifying Facilities (QF) Capacity Charges. This decrease is primarily due to the inclusion of the Indiantown Cogeneration Limited (ICL) Contract of $18.6 million in original projections for October 1995 and November 1995 when commercial operations were not declared until December 1995. In addition, the Okeelanta Contract of $4.5 million was included in original projections for January 1996 but has now been scheduled for June 1996.

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

A. As shown on line 13, Capacity Cost Recovery revenues, net of revenue taxes, are now estimated to be $6.8 million higher than originally projected. This increase is primarily due to higher jurisdictional kWh sales. Jurisdictional sales are now estimated to be 746,170,577 kWh (2.1%) higher than originally projected.

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

A. The Company is requesting that the new factors become effective with customer billings on cycle day 3 of April 1996 and continue through Customer billings on cycle day 2 of September 1996. This will provide for 6 months of billing on these factors for all our customers.

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

A. The total residential bill, excluding taxes and franchise, for 1,000 kWh will be $75.64. 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 $20.75, the Conservation charge is $2.09, the Capacity Recovery charge is $4.42, the Environmental Cost Recovery charge is $.15 and the Gross Receipts Tax is $.77. A Residential Bill Comparison (1,000 kWh) is presented in Schedule E10, Page 34 of Appendix II.

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. 950001-EI

NOVEMBER 17, 1996

Q. Please state your name and business address.

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

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

A. I am the Manager of Forecasting and Regulatory Response for 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 actual performance results for the Equivalent Availability Factor (EAF) and Average Net Operating Heat Rate (ANOHR) for the twenty (20) units used to determine the Generating Performance Incentive Factor (GPIF) and to compare these actual results to the targets that were approved in Commission Order No. PSC-95-0450-FOF-EI issued March 31, 1995 for the period April, 1995 through September, 1995. On the basis of this comparison, I have calculated an incentive amount for the period.

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

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

Q. What is the incentive amount you have calculated for the period April, 1995 through September, 1995?

A. I have calculated a GPIF reward of $ 2,159,086.

Q. Will you please explain how the reward amount is calculated?

A. The steps involved in making this calculation are contained in Document No. 1. Page 2 of Document No. 1 is the GPIF Reward/Penalty Table (Actual) and shows an overall GPIF performance point value of +2.4720 which corresponds to a GPIF reward of $ 2,159,086. Page 3 is the calculation of the maximum allowed incentive dollars. The calculation of the system actual GPIF performance is shown on page 4. This page lists each unit, the performance indicators (ANOHR and EAF), the weighing factors and the associated GPIF points.

Page 5 is the actual EAF and adjustments summary. This page lists each of the twenty (20) units, the actual outage factors and the actual EAF in columns 1 through 5. Column 6 is the adjustment for planned outage variation, which is shown on page 6. Column 7 is the adjusted actual EAF and Column 8 is the target EAF. Column 9 contains the Generating Performance Incentive Points for availability as determined from the tables submitted to and approved by the Commission prior to the start of the period. These tables are shown on pages 8 through 27.

Page 7 shows the adjustments to ANOHR. For each of the twenty (20) units, it shows the target heat rate formula, the actual Net Output Factor (NOF) and the actual ANOHR in columns 1 through 4. Since heat rate varies with NOF, it is necessary to determine both the target and actual heat rates at the same NOF. This adjustment is to provide a common basis for comparison purposes and is shown numerically for each GPIF unit in columns 5 through 8. Column 9 contains the Generating Performance Incentive Points that have been determined from the table submitted for each unit and approved by the Commission. These same tables are shown on pages 8 through 27.

Q. Are there any changes to the targets approved through Commission Order N0. PSC-95-0450-FOF-EI ?

A. No, the approved targets have not changed. However, the actual availability (EAF) of St. Lucie Units No. 1 and 2, used in the calculation of the GPIF, have been adjusted to compensate for the loss in unit availability resulting from externally caused events during the months of July and August, 1995.

Q. Can you describe these externally caused events ?

A. Yes. On July 9, 1995 a vehicle unlawfully entered FPL property. The vehicle crossed the berm and drove into the discharge canal. The vehicle sank and became lodged in the discharge pipe delaying the startup of St. Lucie Unit 1. On August 1, 1995 the approach of Hurricane Erin at the St. Lucie Plant caused FPL to remove both units from service. Following the passing of Hurricane Erin, St. Lucie Unit 2 was returned to service. St. Lucie Unit 1's return to service was initially delayed by the failure of a Reactor Coolant Pump Seal.

Q. How was the actual EAF of St. Lucie Unit No.1 and 2 affected by the external events?

A. The full forced outage hours encountered by each unit during these events have been removed from the total equivalent forced outage hours for the April, 1995 through September, 1995 period. Consistant with prior occurances of externally caused events, the period hours have also been adjusted by the number of full forced outage hours caused by the external events. The Adjusted Actual EAF for both St. Lucie Units have been recalculated with the adjusted outage hours and period hours.

The equivalent forced outage hours for St. Lucie Unit No.1 was reduced by 34.2 hours for the event caused by the vehicle in the discharge canal and 27.0 hours for Hurricane Erin. The total equivalent forced outage hours were reduced by 61.2 hours from 1537.4 equivalent forced outage hours to 1476.2 hours. The period hours for St. Lucie Unit No. 1 have also been adjusted by 61.2 hours from 4391 hours to 4329.8 hours. The equivalent forced outage hours for St. Lucie Unit No.2 have been reduced by 71.3 hours for Hurricane Erin from 144.2 equivalent forced outage hours to 72.9 hours. The period hours for St. Lucie Unit No. 2 have also been adjusted by 71.3 hours from 4391 hours to 4319.7 hours. Since externally caused events are unpredictable, neither FPL nor the customer should be penalized for the resulting losses in availability. The losses in availability resulting from these externally caused events has been excluded from the calculations of the EAF during the April, 1995 through September, 1995 period, and will be excluded from the calculations performed to determine future availability targets for St Lucie Unit No. 1 and 2.

Q. Mr. Silva, will you explain the primary reason or reasons why FPL will be rewarded under the GPIF for the period period April, 1995 through September, 1995 ?

A. Yes. The primary reason that FPL will receive a reward for the period was that Turkey Point Nuclear Unit 3, Turkey Point

Nuclear Unit 4 and St. Lucie Nuclear Unit 2 had better availability than was projected.

Q. Mr Silva, would you please summarize the performance of FPL's nuclear unit availability ?

A. Turkey Point Unit 3 operated at an adjusted actual EAF of 89.7% as compared to its target of 85.1%. This will result in a +10.00 point reward which corresponds to a GPIF reward of $ 929,323.

Turkey Point Unit 4 operated at an adjusted actual EAF of 99.2% as compared to its target of 93.1%. This will result in a +10.00 point reward which corresponds to a GPIF reward of $ 1,048,982.

St. Lucie Unit 1 operated at an adjusted actual EAF of 65.9% as compared to its target of 93.6%. This will result in a -10.00 point penalty which corresponds to a GPIF penalty of ($1,347,693).

St. Lucie Unit 2 operated at an adjusted actual EAF of 96.3% as compared to its target of 83.3%. This will result in a +10.00 point reward which corresponds to a GPIF reward of $1,079,552.

The total GPIF reward for the nuclear units' availability performance is $1,710,164.

Q. Mr. Silva, please summarize the nuclear units performance as it relates to the ANOHR of the units.

A. Turkey Point nuclear unit 3 operated with an adjusted actual ANOHR of 11190 BTU/KWH which was poorer than projected by 57 BTU/KWH. This ANOHR is within ± 75 BTU/KWH of the projected target , therefore there is no GPIF reward or penalty.

Turkey Point nuclear unit 4 operated with an adjusted actual ANOHR of 11149 BTU/KWH which was better than projected by 69 BTU/KWH. This ANOHR is within ± 75 BTU/KWH of the projected target , therefore there is no GPIF reward or penalty.

St. Lucie nuclear unit 1 operated with an adjusted actual ANOHR of 10945 BTU/KWH which was poorer than projected by 63 BTU/KWH. This ANOHR is within ± 75 BTU/KWH of the projected target , therefore there is no GPIF reward or penalty.

St. Lucie nuclear unit 2 operated with an adjusted actual ANOHR of 11063 BTU/KWH which was poorer than projected by 186 BTU/KWH. This will result in a -9.60 point penalty which corresponds to a GPIF penalty of ($254,900).

The total penalty for the nuclear units' heat rate performance is ($254,900).

Q. Mr. Silva, what will the total GPIF incentive reward be for the FPL nuclear units for EAF and ANOHR?

A. $1,455,264.

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

A. The performance of the sixteen (16) fossil units included in the GPIF for the period of April, 1995 through September, 1995 will receive a total combined GPIF reward of $703,822 for EAF and ANOHR.

Eleven (11) of the units performed better than their availability targets, while the remaining five (5) performed poorer than their targets. The combined fossil unit availability performance will result in a GPIF reward of $322,770.

Ten (10) of the units operated with ANOHR's that were better than projected and three (3) units operated with ANOHR's that were poorer than projected. The remaining three (3) units were within the + 75 BTU/KWH dead band and they will receive no incentive reward or penalty. The combined fossil unit heat rate performance will result in a GPIF reward of $381,052.

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

A. Yes, it does.

BEFORE THE PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

TESTIMONY OF R. SILVA

DOCKET NO. 960001-EI

JANUARY 22, 1996

Q. Please state your name and business address.

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

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

A. I am the Manager of Forecasting and Regulatory Response for 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 availabilities for the period April, 1996 through September, 1996, for use in determining the Generating Performance Incentive Factor (GPIF). The improvement and degradation range for each performance indicator is also presented in this testimony.

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

A. FPL projects a weighted system equivalent planned outage factor of 11.4% and a weighted system equivalent unplanned outage factor of 9.3% which yield a weighted system equivalent availability of 79.3%. This target includes the refueling of two nuclear units during the April, 1996 through September, 1996 period. FPL also projects a weighted system average net operating heat rate of 9391 BTU/KWH. As discussed in later in this testimony, these targets represent fair and reasonable values when compared to historical data . I therefore ask that the targets for these performance indicators and the respective improvement/degradation ranges in my testimony be approved by the Commission for FPL.

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

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

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

A. Yes, I have. Document No. 1, pages 6 and 7 contain the information summarizing the targets and ranges for unit equivalent availability and average net operating heat rates for the nineteen (19) generating units which FPL proposes to have considered. These sheets were prepared in accordance with the latest revisions of the GPIF Manual, except that, for consistency with previous GPIF filings, it is necessary to divide the format of Sheet 3.505 of the GPIF Manual into two sheets. 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 monthly performance and known modifications or changes in equipment.

For most units in the GPIF this adjustment is usually done for units which had or are forecast to have planned outages. When a unit is in a planned outage state the unit cannot incur an unplanned outage. For this reason, when historical data, which contains a planned outage, is used for developing targets, the UOF will be lower than if the unit had operated the entire period. To account for this, the historical UOF is increased in proportion to the planned outage duration for that period. Similarly, if a unit is forecast to have a planned outage in the projection period the adjusted historical UOF will be higher than it should because it will not be exposed to unplanned outages for the entire period. In this case the UOF is reduced in proportion to the forecast planned outage duration.

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

A. Yes.

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

A. The nineteen (19) units which FPL proposes to use represent the top 84.58% of the forecast system net generation for the April, 1996 through September, 1996 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. To fully appreciate why these targets are reasonable, and in some cases ambitious, it would be necessary to discuss the development of both the heat rate and availability targets for each of the nineteen (19) units in the GPIF. However, a less rigorous approach of comparing weighted system values of these targets to actual values for prior periods will provide a valuable insight into the appropriateness of the targets.

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. 960001-EI

January 22, 1996

Q Please state your name and address.

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

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

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

Q. Have you previously testified in this docket?

A. Yes.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present and explain FPL's projections for (1) dispatch costs of heavy fuel oil, light fuel oil, coal and natural gas, (2) availability of natural gas to FPL, (3) generating unit heat rates and availabilities, and (4) quantities and costs of interchange and other power transactions. These projected values were used as input values to POWRSYM in the calculation of the proposed fuel cost recovery factor for the period April through September, 1996.

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 7 of Appendix I of this filing.

Q. What are the key factors that could affect FPL's price for heavy fuel oil during the April through September, 1996 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 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 in 1996 is projected to be moderately higher than in 1995, as a result of continued economic growth in the Pacific Rim countries.

On the supply side, total non-OPEC crude oil production in 1996 is projected to be slightly higher than in 1995 due to increases in the North Sea and Latin America.

It is projected that OPEC production in 1996 will match demand for OPEC crude oil.

Based on these factors 1996 crude oil prices, and consequently heavy fuel oil prices, will be slightly higher than 1995 prices.

Q. **What is the projected relationship between heavy fuel oil and crude oil prices during the April through September, 1996 period?**

A. The price of heavy fuel oil on the U. S. Gulf Coast (1.0% sulfur) is projected to be approximately 77% of the price of West Texas Intermediate (WTI) crude oil.

Q. **Please provide FPL's projection for the dispatch cost of heavy fuel oil for the April through September, 1996 period based on FPL's evaluation of the key factors discussed above.**

A. FPL's projection for the system average dispatch cost of heavy fuel oil, by sulfur grade, by month, is provided on page 3 of Appendix I in dollars per barrel. We project that during this period the system average dispatch cost of heavy fuel oil with a 2.5% sulfur grade will range from $15.42 to $17.00 per barrel; that of 2.0% sulfur grade fuel oil will range from $15.55 to $17.07 per barrel; that of 1.0% sulfur grade fuel oil will range from $15.72 to $17.12 per barrel; and that of 0.7% sulfur grade fuel oil will range from $16.68 to $17.91 per barrel, depending on the month.

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. Therefore the price of light fuel oil is projected to be slightly higher in 1996 than in 1995.

Q. Please provide FPL's projection for the dispatch cost of light fuel oil for the period from April through September, 1996 based on FPL's evaluation of the key factors discussed above.

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

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

A. FPL's projected dispatch cost of coal at 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 Sherer 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.

Q. **Please provide FPL's projection for the dispatch cost of coal for the April through September, 1996 period.**

A. FPL's projected system average dispatch cost of coal, shown on page 5 of Appendix I, is about $1.49 per million BTU, delivered to plant.

Q. **Has FPL changed the unit of measurement used to report the quantity of coal utilized at its Scherer Unit No.4?**

A. Yes. In October 1995 FPL began to report the quantity of coal utilized at Scherer Unit No.4 in British Thermal Units (BTU), a measure of the energy contained in the coal. Prior to that time, FPL had used tons, a measure of the weight of the fuel, as the unit of measurement.

Q. **Why has FPL made this change for Scherer Unit No.4?**

A. Because reporting coal quantity in terms of tons is impractical due to the fact that FPL purchases two types of coal with very different energy contents, measured in British Thermal Units (BTU) per pound of coal.

Specifically, in order to minimize its fuel cost, FPL purchases bituminous (Eastern) coal, with an energy content of about 12,000 BTU per pound of coal, as well as sub-bituminous (Western) coal, with an energy content of about 8,500 BTU per pound.

Because of this great disparity in energy content, reporting coal quantity in "tons of coal purchased" and coal cost in "$ per ton of coal" would not provide a practical, meaningful measure of the amount of energy used, nor of the cost of that energy. In fact, any Scherer coal data reported in terms of "tons" would have to specify the type of coal it referred to, and the data corresponding to one type of coal could not be combined with the data related to the other type because the result would be misleading.

On the other hand, reporting coal quantity in BTU's and coal cost in terms of $ per BTU provides useful measures because BTU's report the quantity of energy, which is what we ultimately purchase. Therefore FPL is now using BTU's to measure and report the quantity of energy in the coal and $ per BTU to measure and report the cost of energy in the coal at Scherer Plant.

Q. **What are the factors that affect FPL's natural gas prices during the April through September, 1996 period?**

A. The key factors are (1) domestic natural gas demand and supply, (2) foreign natural gas imports, (3) heavy fuel oil prices and (4) the terms of FPL's gas supply and transportation contracts.

In general, domestic demand for natural gas during in 1996 is projected to be higher than in 1995 due primarily to (1) colder than normal weather in January, 1996, and (2) increased gas usage for electric generation throughout the year. On the supply side, although U.S. production of natural gas and Canadian imports are projected to increase moderately in 1996, the level of gas stored in inventory at the start of 1996 is about 18% lower than the level at the beginning of 1995. As indicated previously, heavy fuel oil prices are projected to be higher in 1996 than in 1995.

Based on these factors we project that 1996 natural gas prices will be higher than 1995 prices.

Q. **What are the factors that affect the availability of natural gas to FPL during the April through September, 1996 period?**

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

The current capacity of natural gas transportation facilities into the State of Florida is 1,455,000 million BTU per day (including FPL's firm allocation of 480,000 to 630,000 million BTU per day, 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 1,190,000 million BTU per day and 1,345,000 million BTU per day, or from 265,000 to 110,000 million BTU per day below the pipeline's total capacity. This projected available pipeline capacity could enable FPL to acquire and deliver additional natural gas, beyond FPL's 480,000 to 630,000 million BTU per day of firm, "guaranteed" allocation, should it be economically attractive, relative to other energy choices.

Q. Please provide FPL's projections for the dispatch cost and availability (to FPL) of natural gas for the April through September, 1996 period based on FPL's evaluation of these factors.

A. FPL's projections of the system average dispatch cost and availability of natural gas for the April through September, 1996 period are provided on page 6 of Appendix I.

Q. Are the projected dispatch prices for fuel oil and natural gas for the April through September, 1996 period, provided in pages 3, 4 and 6 of Appendix I, significantly different from those for December, 1995 through March, 1996?

A. Yes. Prices for fuel oil and natural gas have risen very sharply since early December. For example, the actual dispatch price of natural gas (delivered under firm transportation) on January 8 was \$3.26 per million BTU, compared to \$1.85 per million BTU in late November, 1995. We anticipate that oil and gas prices will remain high through March, 1996. These high prices are reflected in FPL's calculation of the "estimated-actual" component of the proposed fuel factor for the projected period.

Conversely, our projected fuel oil and natural gas dispatch prices for the April through September, 1996 period, presented in Appendix I, reflect our view that when heating demand for oil and gas ends, prices will decrease rapidly. For example, the projected dispatch price of natural gas (delivered under firm transportation) for April, 1996 is \$1.34 per million BTU, much lower than the current price.

Q. **Why did oil and gas prices rise in December and January?**

A. Fuel oil and natural gas prices have risen primarily as a result of very high demand caused by colder than normal weather throughout the country. Another contributor to the current high price of natural gas has been the fact that the total volume of natural gas inventory placed in storage throughout the country in preparation for the 1995-1996 heating season was lower than in previous years.

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

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

A. We will continue to monitor developments in fuel supply and demand conditions, as well as movements in the market prices of fuel oil and natural gas. If, prior to the time of the February fuel hearings before the Commission, we determine that market forces will keep the prices of fuel oil and\or natural gas higher than we have projected for the April through September, 1996 period, we will present supplemental testimony reflecting our revised projections.

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

A. The projected Average Net Operating Heat Rates were developed using the actual monthly Average Net Operating Heat Rates and the corresponding Net Output Factors from previous October through March periods. This historical data was used to calculate an efficiency factor, or heat rate multiplier, for each generating unit. The most recent unit dispatch heat rate curves, modified by the unit's efficiency factors, were provided as input to the POWRSYM model.

Q. Are you providing the outage factors projected for the period October, 1995 through March, 1996?

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

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

A. The unplanned outage factors were developed using the actual historical full and partial outage event data for each of the units. The actual unplanned outage factor of each generating unit for the previous twelve-month period was adjusted, as necessary, to eliminate non-recurring events and recognize the effect of planned outages to arrive at the projected factor for the October, 1995 through March, 1996 period.

Q. Please describe significant planned outages for the April through September, 1996 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 1 until April 22, 1996, or twenty two days during the projected period. St. Lucie Unit No.1 is scheduled to be out of service for refueling from March 26 until May 28, 1996, or fifty eight days during the period. There are no other significant planned outages during the projected period.

Q. Are any changes to FPL's generation capacity planned during the October, 1995 through March, 1996 period?

A. No.

Q. Are you providing the projected interchange and purchased power transactions forecasted for October, 1995 through March, 1996?

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

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

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

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

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

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

Q. Please provide the projected energy costs to be recovered through the Fuel Cost Recovery Clause for the power purchases referred to above during the April through September, 1996 period.

A. Under the UPS agreement FPL's capacity entitlement during the projected period is 920 MW from April through September, 1996. Based upon the alternate and supplemental energy provisions of UPS, an availability factor of 100% is applied to these capacity entitlements to project energy purchases. The projected UPS energy (unit) cost for this period, used as input to POWRSYM, is based on data provided by the Southern Companies. For the period, FPL projects the purchase of 2,340,024 MWH of UPS Energy at a cost of $43,306,210. In addition, we project the purchase of 1,442,047 MWH of UPS Replacement energy (Schedule R) at a cost of $25,477,620. The total UPS Energy plus Schedule R projections are presented on Schedule E7 of Appendix II.

Energy purchases from the JEA-owned portion of the St. Johns River Power Park generation are projected to be 1,470,710 MWH for the period at an energy cost of $22,680,750. 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 261,668 MWH at a cost of $1,087,100. 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 2,920,077 MWH at a cost to FPL of $56,153,965.

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, corrected to remove non-recurring factors.

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

A. We have projected 329,247 MWH of Economy energy sales for the period. The projected fuel cost related to these sales is $8,619,768. The projected transaction revenue from the sales is $12,771,425. Eighty percent of the gain for Schedule C is $3,321,326 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?

A. The costs of these purchases are shown on Schedule E9 of Appendix II. For the April through September, 1996 period FPL projects it will purchase a total of 1,985,566 MWH at a cost of $37,880,270. If generated, we estimate that this energy would cost $41,871,141. Therefore, these purchases are projected to result in savings of $3,990,871.

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 176,304 MWH of energy at a cost of $724,197. These projections are shown on Schedule E6 of Appendix II.

Q. Would you please summarize your testimony?

A. Yes. In my testimony I have presented FPL's fuel price projections for the fuel cost recovery period of April through September, 1996. In addition, I have presented FPL's projections for generating unit heat rates and availabilities, and the quantities and costs of interchange and other power transactions for the same period. These projections were based on the best information available to FPL, and were used as inputs to POWRSYM in developing the projected Fuel Cost Recovery Factor for the April through September, 1996 period.

Q. Does this conclude your testimony?

A. Yes, it does.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

TESTIMONY OF C. VILLARD

DOCKET NO. 960001-EI

January 22, 1996

Q. Please state your name and address.

A. My name is Claude Villard. My business address is 700 Universe Boulevard, Juno Beach, Florida 33408.

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

A. I am employed by Florida Power & Light Company (FPL) as Manager of Nuclear Fuel.

Q. Have you previously testified in this docket?

A. Yes, I have.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present and explain FPL's projections of nuclear fuel costs for the thermal energy (MMBTU) to be produced by our nuclear units and costs of disposal of spent nuclear fuel. Both of these costs were input values to POWRSYM for the calculation of the proposed fuel cost recovery factor for the period

April 1996 through September 1996.

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

A. FPL's nuclear fuel cost projections are developed using energy production at our nuclear units and their operating schedules, consistent with those assumed in POWRSYM, for the period April 1996 through September 1996.

Q. **Please provide FPL's projection for nuclear fuel unit costs and energy for the period April 1996 through September 1996.**

A. We estimate the nuclear units will produce 115,870,877 MBTU of energy at a cost of $0.349 per MMBTU, excluding spent fuel disposal costs for the period April 1996 through September 1996. Projections by nuclear unit and by month are provided on Schedule E-4 of Appendix II.

Q. **Please provide FPL's projections for nuclear spent fuel disposal costs for the period April 1996 through September 1996 and what is the basis for FPL's projections.**

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

Q. **Please provide FPL's projection for Decontamination and Decommissioning (D&D) costs to be paid in the period April 1996 through September 1996 and what is the basis for FPL's projection.**

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

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

A. No.

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

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

The first dispute is under FPL's contract with the Department of Energy (DOE) for final disposal of spent nuclear fuel. FPL, along with a number of electric utilities, has filed suit against the DOE over DOE's denial of its obligation to accept spent nuclear fuel beginning in 1998. There has been no substantive progress on this issue since our last report.

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

Our contract for enrichment services with the U.S. Government calls for pricing to be calculated in accordance with "Established DOE Pricing Policy". Such policy had always been one of cost recovery, which included costs related to the Decontamination and Decommissioning (D&D) of the DOE's enrichment facilities. However, the Energy Policy Act of 1992 (The Act) requires utilities to make separate payments to the U.S. Treasury for D&D, starting in Fiscal 1993, as FPL has been doing. Therefore, D&D should not have been included in the price charged by DOE since then, and the price should have been reduced accordingly. FPL had filed a claim with the Contracting Officer, on July 14, 1995. On October 13, 1995, the DOE Contracting Officer officially rejected FPL's claim. Meanwhile, in a related case, the U.S. Court of Federal Claims ruled that the special assessment for D&D was unlawful. The Court found that the special assessment was essentially a retroactive price increase on a contract which had already been performed, and was therefore illegal. The DOE has appealed this decision. FPL is following these events closely and is currently assessing all of its options.

Q. Does this conclude your testimony?

A. Yes, it does.

BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 960001-EI
CONTINUING SURVEILLANCE AND REVIEW OF
FUEL COST RECOVERY CLAUSES OF ELECTRIC UTILITIES

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

Q. Please state your name and business address.
A. George M. Bachman, 401 South Dixie Highway, West Palm Beach, FL 33401.
Q. By whom are you employed?
A. I am employed by Florida Public Utilities Company.
Q. Have you previously testified in this Docket?
A. Yes.
Q. What is the purpose of your testimony at this time?
A. I will briefly describe the basis for the computations that were made in the preparation of the various Schedules that we have submitted in support of the April 1996 - September 1996 fuel cost recovery adjustments for our two electric divisions. In addition, I will advise the Commission of the projected differences between the revenues collected under the levelized fuel adjustment and the purchased power costs allowed in developing the levelized fuel adjustment for the period October 1995 - March 1996 and to establish a "true-up" amount to be collected or refunded during April 1996 - September 1996.
Q. Were the schedules filed by your Company completed under your direction?

A. Yes.

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

A. We have filed Schedules E1, E1A, E1-B, E1B-1, E2, E7, E8 and E10 for Marianna and Fernandina Beach. They are included in Composite Prehearing Identification Number GMB-1. These schedules support the calculation of the levelized fuel adjustment factor for April 1996 - September 1996. Schedule E1-B shows the Calculation of Purchased Power Costs and Calculation of True-Up and Interest Provision for the period October 1995 - March 1996 based on 2 Months Actual and 4 Months Estimated data.

Q. In derivation of the projected cost factor for the April 1996 - September 1996 period, did you follow the same procedures that were used in the prior period filings?

A. Yes.

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

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

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

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

Q. Please address the calculation of the total true-up amount to be collected or refunded during the April 1996 - September 1996 period.

A. We have determined that at the end of March 1996 based on two months actual and four months estimated, we will have over-recovered $131,476 in purchased power costs in our Marianna division. Based on estimated sales for the period April 1996 - September 1996, it will be necessary to subtract .09743¢ per KWH to refund this over-recovery.

In Fernandina Beach we will have over-recovered $52,680 in purchased power costs. This amount will be refunded at .04125¢ per KWH during the April 1996 - September 1996 period. Page 3 and 12 of Composite Prehearing Identification Number GMB-1 provides a detail of the calculation of the true-up amounts.

Q. Looking back upon the April 1995 - September 1995 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 $162,693 and Fernandina Beach Division under-recovered $5,146. The amounts both represent fluctuations of less than 10% from the total fuel charges for the period and are not considered significant variances from projections.

Q. What are the final remaining true-up amounts for the period April 1995 through September 1995 for both divisions?

A. In Marianna the final remaining true-up amount was an over-recovery of $189,630. The final remaining true-up amount for Fernandina Beach was an over-reccvery of $40,349.

Q. What are the estimated true-up amounts for the period of October 1995 through March 1996?

A. In Marianna, there is an estimated under-recovery of $58,154. Fernandina Beach has an estimated over-recovery of $12,331.

Q. What will the total fuel adjustment factor, excluding demand cost recovery, be for both divisions for the period April 1996 - September 1996?

A. In Marianna the total fuel adjustment factor as shown on Line 33, Schedule E1, is 2.898¢ per KWH. In Fernandina Beach the total fuel adjustment factor for "other classes", as shown on Line 43, Schedule E1, amounts to 3.295¢ per KWH.

Q. Please advise what a residential customer using 1,000 KWH will pay for the period April 1996 - September 1996 including base rates (which include revised conservation cost recovery factors) and fuel adjustment factor and after application of a line loss multiplier.

A. In Marianna a residential customer using 1,000 KWH will pay $73.68, an increase of $2.54 from the previous period. In Fernandina Beach a customer will pay $67.34, a decrease of $4.99 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 of
M. L. Gilchrist
Docket No. 950001-EI
Date of Filing: November 17, 1995

Q. Please state your name and business address.

A. My name is Malcolm Lane Gilchrist and my business address is 500 Bayfront Parkway, Post Office Box 1151, Pensacola, Florida 32520-0328.

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

A. I am the Manager of Fuel and Environmental Affairs for Gulf Power Company.

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

A. I graduated from Auburn University in 1958 with a Bachelor of Science Degree in Electrical Engineering. I joined Gulf Power Company in 1961 as a Field Engineer. Since then, I have held various positions with the Company, including Power Sales Engineer; Division Sales Supervisor; Division Engineer; Supervisor of Fuel Supply; Assistant Plant Manager, Crist Electric Generating Plant; and Manager of Interchange and Fuel Supply. I was promoted to my present position in June 1989.

Q. What are your duties as Manager of Fuel and Environmental Affairs?

A. I manage the fuel supply and environmental compliance activities of the Company. My responsibilities include fuel procurement, contract administration, and budgeting.

Q. Are you the same Malcolm Lane Gilchrist who has previously testified before this Commission on various fuel matters?

A. Yes.

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

A. The purpose of my testimony is to summarize Gulf Power Company's fuel expenses and to certify that these expenses were properly incurred during the period April 1995 through September 1995. Also, it is my intent to be available to answer any questions that may arise among the parties to this docket concerning Gulf Power Company's fuel expenses.

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

A. Yes. I have prepared an exhibit consisting of one Schedule.

Counsel: We ask that Mr. Gilchrist's exhibit consisting of one schedule be marked as Exhibit No. 17 (MLG-1).

Q. During the period April 1, 1995, through September 30, 1995, how did Gulf's actual fuel expenses compare with the budget or projected expenses?

A. Gulf's actual fuel expense was $114,120,442 as compared with the projected amount of $113,193,885, or over our estimate by 0.82%. Gulf's total net system generation was 5,609,425 MWH compared to the projected generation of 5,533,480 MWH or 1.37% more than predicted.

The resulting total fuel cost per KWH generated was 2.0344¢/KWH or 0.55% under the projected amount of 2.0456¢/KWH.

Q. Mr. Gilchrist, did Gulf Power make any significant changes in its fuel purchasing program during the six months ending September 1995?

A. No.

Q. What is the status of the Plant Daniel seasonal coal supply program?

A. The current fuel supply program, called the Seasonal Powder River Basin (PRB) Fuel Program, was implemented in 1994 as a cost-saving strategy for Plant Daniel. During the off peak season, when full plant capacity is not normally needed, the plant will burn lower cost PRB coal. During the peak season, when full plant capacity is required, the plant will burn high Btu western coal. This change in coal supply also involved a change in coal suppliers.

Q. How was the transition between suppliers handled contractually?

A. In order to satisfy an existing contract for delivery of coal to Plant Daniel, another sister company in the Southern electric system, Georgia Power Company, agreed to take deliveries of the contract coal at one of its plants for two years. These deliveries will be in lieu of spot market coal purchases that Georgia Power would otherwise be making.

During the two years that Georgia Power is taking deliveries of the coal originally contracted for delivery to Plant Daniel, Mississippi Power and Gulf will reimburse Georgia for any differential between the actual delivered price (MMBtu) achieved under the contract and the delivered price (MMBtu) that Georgia would have otherwise incurred through spot market purchases. Gulf's share of this reimbursement for 1994, the first year of the two year transition period, was made in July 1995. Gulf's share for 1994 amounted to approximately $90,000.

Q. How much spot coal did Gulf Power Company purchase during the period ending September 30, 1995?

A. Gulf purchased 611,568 tons or 29% of its supply from the spot coal market. My Schedule 1 of Exhibit No. _________ (MLG-1) consists of a list of contract and spot coal suppliers for the period ending September 30, 1995.

Q. How are coal prices determined under Gulf's long-term contracts?

A. Under all of Gulf's long-term coal contracts, Gulf pays a base price per ton plus cost escalations that have occurred since the coal contract began. The base price with cost escalations type contract is a long term agreement on quantity, quality, and escalation factors that provides the buyer with an assured source of coal of known quality. The price of coal supplied under this type of contract will not go up and down with current market conditions.

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

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

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

A. For the period, Gulf's average unit cost of coal purchased was 1.67% less than projected.

Q. What caused Gulf's average unit cost of coal purchased to be 1.67% less than projected?

A. Gulf Power's unit cost of coal was down due to an increase in generation, resulting in the purchase of a greater amount of spot market coal which reduced the overall unit cost.

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

A. Yes.

GULF POWER COMPANY

Before the Florida Public Service Commission
Prepared Direct Testimony of
M. L. Gilchrist
Docket No. 960001-EI
Date of Filing January 22, 1996

Q. Please state your name and business address.

A. My name is M. L. Gilchrist, and my business address is 500 Bayfront Parkway, Pensacola, Florida, 32520-0328.

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

A. I am Manager of Fuel and Environmental Affairs for Gulf Power Company.

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

A. I graduated from Auburn University in 1958 with a Bachelor of Science Degree in Electrical Engineering. I joined Gulf Power Company in 1961 as a Field Engineer. Since then, I have held various positions with the Company, including Power Sales Engineer, Division Sales Supervisor, Division Engineer, Supervisor of Fuel Supply, Assistant Plant Manager at Crist Electric Generating Plant, and Manager of Interchange and Fuel Supply. I was promoted to my present position June 1, 1989.

Q. What are your duties as Manager of Fuel and Environmental Affairs?

A. I manage the fuel supply and environmental compliance activities of the Company. My responsibilities include fuel procurement, fuel contract administration, and fuel budgeting.

Q. Are you the same Lane Gilchrist who has previously testified before this Commission on various fuel matters?

A. Yes.

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

A. The purpose of my testimony is to support Gulf Power Company's projection of fuel expenses for the period April 1, 1996 to September 30, 1996 and to be available to answer any questions that may occur concerning the Company's fuel procurement

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. Gilchrist's exhibit, consisting of one schedule, be marked as Exhibit No. 18 (MLG-2).

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

A. No.

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

A. Yes. The July 1, 1994 agreement between Gulf Power Company and Peabody CoalSales called for Peabody to supply Gulf with a total of 1.9 million tons of coal annually, of which one million tons is supplied from Venezuela and 900,000 tons from Illinois. These two coals are blended at the Alabama State Docks in Mobile and then shipped by barge to Plants Crist and Smith. A letter agreement between Gulf Power and Peabody CoalSales, dated December 28, 1995, calls for Gulf to buy out of the Venezuelan coal for the period January 1, 1996, through January 31, 1998. Gulf will continue to receive the Illinois coal during this time period.

Q. Why did Gulf Power Company approach Peabody CoalSales with a partial buyout proposal?

A. This partial buyout of the Peabody contract permits Gulf to take advantage of the current coal market by replacing the Venezuelan coal with a lower cost domestic coal that will not require blending with the Illinois coal.

Q. What is the buyout cost and projected cost savings?

A. Gulf Power paid Peabody CoalSales $22 million for the partial buyout. Based on an economic analysis performed by Southern Company Services, Gulf estimates this partial buyout of the Peabody Contract will produce savings of approximately $9.1 million over a period of 25 months.

Gulf will conduct an ongoing benefits test that will compare cumulative actual savings with the cumulative amortization of the buyout cost.

Q. How will Gulf account for the Peabody buyout?

A. The Peabody buyout costs incurred at the end of 1995 have been deferred in a regulatory asset account (FERC 182). Accrued interest will be added to this account as the related two-year financing amortizes. The corresponding note(s) payable that is financing the buyout will be recorded in Account 224 as a credit. As the replacement coal is received over the 25-month period, a per-ton adder will be applied consisting of interest and principal and based on a 1,000,000 ton annual receipt. A corresponding amount will be transferred from Account 182 to Account 174. As the coal is burned, principal and interest amounts will be removed on a per-ton basis from Account 174 and charged to Account 506 and Account 427 respectively.

Q. How much spot market coal does Gulf Power project it will purchase during the April 1996 through September 1996 period?

A. We are projecting the purchase of approximately 890,000 tons. This represents approximately 66% of our projected purchase requirements.

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

A. Yes.

GULF POWER COMPANY

Before the Florida Public Service Commission
Direct Testimony of
M. W. Howell
Docket No. 950001-EI
Date of Filing: November 17, 1995

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

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

Q. Have you previously testified before this Commission?

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

Q. Please summarize your educational and professional background.

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

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

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

A. I will summarize Gulf Power Company's purchased power recoverable costs for energy purchases and sales that were incurred during the April 1, 1995 through September 30, 1995 recovery period. I will then compare these actual costs to their projected levels for the period and discuss the primary reasons for the differences.

Q. During the period April 1, 1995 through September 30, 1995, what was Gulf's actual purchased power recoverable cost for energy purchases and how did it compare with the projected amount?

A. Gulf's actual total purchased power recoverable cost for energy purchases, as shown on line 12 of Schedule A-1, was \$16,510,768 as compared to the projected amount of \$10,212,000. This resulted in a variance above budget of \$6,298,768, or 62%. The actual cost per KWH purchased was 2.1145 ¢/KWH as compared to the projected 1.8146 ¢/KWH, or 17% above the projection.

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

A. The Summer of 1995 has been one of the hottest in the last few decades. Because of higher than projected territorial loads across the Southern system, Gulf purchased more economy power through the Southern electric power pool at a higher unit price than was forecasted for the period in order to meet its load obligations. Gulf purchased 780,832,960 KWH, shown on line 12 of Schedule A-1, as compared to the estimate of 562,780,000 KWH, or 39% more.

Q. During the period April 1, 1995 through September 30, 1995, what was Gulf's actual purchased power fuel cost for energy sales and how did it compare with the projected amount?

A. Gulf's actual total purchased power fuel cost for energy sales, as shown on line 18 of Schedule A-1, was \$21,825,245 as compared to the projected amount of \$17,870,200. This resulted in a variance above budget of \$3,955,045, or 22%. The actual fuel cost per KWH sold was 2.0695 ¢/KWH as compared to 1.8651 ¢/KWH, or 11% above the projection.

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

A. Gulf's pool and off-system sales, shown on line 18, were 1,054,634,016 KWH, or 13% over the projection for the period. These sales were over the projection due to Gulf's increased sale of energy to the Southern electric system power pool to meet the system's higher territorial load requirements. The lower cost of energy available from Gulf's resources compared with the cost of energy generated by the other pool members allowed Gulf to sell more energy than budgeted.

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

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

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

Q. Does this conclude your testimony?

A. Yes.

GULF POWER COMPANY

Before the Florida Public Service Commission
Direct Testimony of
M. W. Howell
Docket No. 960001-EI
Date of Filing: January 22, 1996

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

A. My name is M. W. Howell, and my business address is 500 Bayfront Parkway, Pensacola, Florida 32501. I am Manager of Transmission and System Control 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 Manager of Transmission and System Control. My experience with the Company has included all areas of distribution operation, maintenance, and construction; transmission operation, maintenance, and construction; relaying and protection of the generation, transmission, and distribution systems; planning the generation, transmission, and distribution system additions in the future; bulk power interchange administration; overall management of fuel planning and procurement; and operation of the system dispatch center.

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

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

A. The purpose of my testimony is to support Gulf Power Company's projection of purchased power recoverable costs for energy purchases and sales for the period April, 1996 - September, 1996.

Q. What is Gulf's projected purchased power recoverable cost for energy purchases for the April, 1996 - September, 1996 recovery period?

A. Gulf's projected recoverable cost for energy purchases, shown on line 12 of Schedule E-1 of the fuel filing, is $11,237,118. These purchases result from Gulf's participation in the coordinated operation of the Southern electric system power pool. This amount is used by Gulf's witness Susan Cranmer as an input in the calculation of the fuel and purchased power cost adjustment factor.

Q. What is Gulf's projected purchased power fuel cost for energy sales for the April, 1996 - September, 1996 recovery period?

A. The projected fuel cost for energy sales, shown on line 18 of Schedule E-1, is $19,181,800. These sales also result from Gulf's participation in the coordinated operation of the Southern electric system power pool. This amount is used by Gulf's witness Susan Cranmer as an input in the calculation of the fuel and purchased power cost adjustment factor.

Q. Does this conclude your testimony?

A. Yes.

GULF POWER COMPANY

Before the Florida Public Service Commission
Prepared Direct Testimony of
Susan D. Cranmer
Docket No. 950001-EI
Fuel and Purchased Power Capacity Cost Recovery
Date of Filing: November 17, 1995

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

A. My name is Susan Cranmer. My business address is 500 Bayfront Parkway, Pensacola, Florida 32501. I hold the position of Supervisor of Rate Services 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. I have held various positions with Gulf including Computer Modeling Analyst and Senior Financial Analyst. In 1991, I assumed the position of Supervisor of Rate Services and presently serve in that capacity.

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

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

Counsel: We ask that Ms. Cranmer's Exhibit consisting of one schedule be marked as Exhibit No. 19 (SDC-1).

Q. Are you familiar with the Fuel and Purchased Power (Energy) True-up Calculation for the period of April 1995 through September 1995 set forth in your exhibit?
A. Yes. This calculation is the subject of the schedule in my exhibit. This document was prepared under my supervision.

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

Q. What is the amount to be refunded or collected through the fuel cost recovery factor in the period April 1996 through September 1996?

A. An amount to be refunded of $1,760,840 was calculated as shown in Schedule 1 of my exhibit.

Q. How was this amount calculated?

A. The $1,760,840 was calculated by taking the difference in the estimated April 1995 through September 1995 under-recovery of $875,443 as approved in Order No. PSC-95-1089-FOF-EI, dated September 5, 1995 and the actual over-recovery of $885,397 which is the sum of lines 7, 8, and 12 shown on Schedule A-2, page 2 of 3, Period-to-date of the monthly filing for September 1995.

Q. Ms. Cranmer, are you also responsible for the Purchased Power Capacity Cost True-up Calculation?

A. Yes. As a result of the change to an annual recovery period for PPCC, the final true-up filing will be made each May. Any under/over recovery identified in that filing will be collected/refunded in the next annual projection period beginning each October. Also, the estimated true-up included in the projection filing filed each June will include eight months of actual data and four months of projected data.

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. 960001-EI
Fuel and Purchased Power Cost Recovery
Date of Filing: January 22, 1996

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

A. My name is Susan Cranmer. My business address is 500 Bayfront Parkway, Pensacola, Florida 32501. I hold the position of Supervisor of Rate Services 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. I have held various positions with Gulf including Computer Modeling Analyst and Senior Financial Analyst. In 1991, I assumed the position of Supervisor of Rate Services and presently serve in that capacity.

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

Q. Have you previously filed testimony before this Commission in Docket No. 960001-EI?

A. Yes, I have.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to discuss the calculation of Gulf Power's fuel cost recovery factors for the period April 1996 through September 1996.

Q. Are you familiar with the Fuel and Purchased Power Cost Recovery Clause Calculation for the period of April 1996 through September 1996?

A. Yes, these documents were prepared under my supervision.

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

A. Yes, I have.

Counsel: We ask that Ms. Cranmer's Exhibit consisting of thirteen schedules, along with Schedules A1 through A9 previously filed with the Commission for the months of June, July, August, September, October, and November 1995, be marked as Exhibit No. 20 (SDC-2).

Q. Ms. Cranmer, what has Gulf calculated as the true-up to be applied in the period April 1996 through September 1996?

A. The true-up for this period is a decrease of .0265¢/kwh. This includes a final true-up over-recovery of $1,760,840. As shown on Schedule E-1A, it also includes an estimated true-up under-recovery of $496,180 for the current period. The resulting over-recovery is $1,264,660.

Q. What has been included in this filing to reflect the GPIF reward/penalty for the period of April 1995 through September 1995?

A. This is shown on Line 32b of Schedule E-1 as a decrease of .0101¢/kwh, thereby penalizing Gulf by $483,077.

Q. Ms. Cranmer, what is the levelized projected fuel factor for the period April 1996 through September 1996?

A. Gulf has proposed a levelized fuel factor of 2.166¢/kwh. It includes projected fuel and purchased power energy expenses for April 1996 through September 1996 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 2.193¢/kwh kwh for Group A. Fuel factors for

Groups A, B, C, and D are shown on Schedule E-1E. These factors have also been adjusted for line losses.

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

A. These were calculated based on projected loads and system lambdas for the period April 1996 through September 1996. These factors included the GPIF, true-up, and special contract recovery cost amounts and were adjusted for line losses. These time-of-use fuel factors are also shown on Schedule E-1E.

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

A. The current fuel factor applicable to March 1996 is 2.237¢/kwh compared with the proposed factor of 2.193¢/kwh. For a residential customer who uses 1000 kwh in April 1996, the fuel portion of the bill will decrease from $22.37 to $21.93.

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

COMMISSIONER DEASON: So at this point it leaves the two TECO witnesses whose testimony has not been admitted into the record.

MS. JOHNSON: Correct.

COMMISSIONER DEASON: Mr. Beasley.

MR. BEASLEY: If I could get clarification from Ms. Johnson, would that mean that the testimony sponsored by Ms. Pennino and Ms. Townes, other than that related to 19A and 19B, is admitted into the record?

COMMISSIONER DEASON: Is there any objection to having that testimony admitted at this point?

MS. JOHNSON: There is an objection, because it's my understanding that the testimony reflects the schedules which we have already identified that should not be entered into the record at this time.

COMMISSIONER DEASON: Mr. Beasley, just go ahead and we'll call your witnesses and you can seek to insert.

MR. BEASLEY: Sure.

COMMISSIONER DEASON: If there is any objection, we'll deal with it at that point.

(Transcript continues in sequence in Volume 2.)

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-2. These costs represent the estimated averages for the period from April 1996 through March 1998.

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

A. These factors will apply to April 1996 through September 1996 billings beginning with Cycle 1 meter readings scheduled on March 29, 1996 and ending with meter readings scheduled on September 26, 1996.

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. 950001-EI
Date of Filing November 17, 1995

Q. Please state your name, address and occupation.

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

Q. Please describe your educational and business background.

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

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

A. Yes, sir.

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

A. The purpose of my testimony is to present GPIF results for Gulf Power Company for the period of April 1, 1995, through September 30, 1995.

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 31 (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-95-0450-FOF-EI is on page 9 of Schedule 2. The results are: Crist 6, +10.00 points; Crist 7, +10.00 points; Smith 1, +10.00 points; Smith 2, +10.00 points; Daniel 1, -10.00 points, and Daniel 2, -10.00 points.

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

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

As was done for the prior GPIF periods, and as indicated on pages 8 through 13 of Schedule 3, the target setting equations were used to adjust actual results to the target bases. These equations, submitted in January 1995, 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: -6.95 for Crist 6, -6.08 for Crist 7; -0.17 for Smith 1, -1.80 for Smith 2; -10.00 for Daniel 1; and -6.89 for Daniel 2.

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

A. Using the unit equivalent availability and heat rate points previously mentioned, along with the appropriate weighting factors, the Company points would be -5.68 as indicated on page 2 of Schedule 4. This calculated to a penalty in the amount of $483,077.

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

A. Yes, Sir. In view of the adjusted actual equivalent availabilities, as shown on page 9 of Schedule 2, and the adjusted actual average net operating heat rates achieved, as shown on page 16 of Schedule 3, evidencing the Company's performance for the period, Gulf calculates a penalty in the amount of $483,077 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. 960001-EI
Date of Filing January 22, 1996

Q. Please state your name, address and occupation.

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

Q. Please describe your educational and business background.

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

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

A. Yes, sir.

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

A. The purpose of my testimony today is to present GPIF targets for Gulf Power Company for the period of April 1, 1996 through September 30, 1996.

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

A. Yes, Sir, I have prepared an exhibit consisting of three 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 22 (GDF-2).

Q. Mr. Fontaine, 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. Mr. Fontaine, what are the target heat rates Gulf proposes to use in the GPIF for these units for the performance period April 1, 1996 through September 30, 1996?

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, Sir.

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

A. The target equivalent availabilities and their ranges are listed on page 4 of Schedule 2.

Q. How are these target equivalent availabilities determined?

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

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

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

Q. Mr. Fontaine, has Gulf completed the GPIF minimum filing requirements data package?

A. Yes, we have completed the required data. Schedule 3 of my exhibit contains this information.

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

A. Yes. Gulf asks that the Commission accept:

1. Crist Units 6 and 7, Smith Units 1 and 2 and Daniel Units 1 and 2, for inclusion under the GPIF for the period of April 1, 1996 through September 30, 1996.

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.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

GEORGE A. KESELOWSKY

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

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

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

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

Q. What are your current responsibilities?

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

Q. What is the purpose of your testimony?

A. My testimony presents the actual performance results from unit equivalent availability and station heat rate used to determine the Generating Performance Incentive Factor (GPIF) for the period April 1995 through September 1995. I will also compare these results to the targets established prior to the beginning of the period.

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

A. Yes. Under my direction and supervision an exhibit has been prepared entitled, "Tampa Electric Company, April 1995 - September 1995, Generating Performance Incentive Factor Results" consisting of 28 pages that was filed with this testimony (Have identified as Exhibit GAK-1).

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

A. Yes I have. This is shown on page 4 of my exhibit. Based upon +1.853 GPIF points, the result is a reward amount of $376,230 for the period.

Q. Please proceed with your review of the actual results for the April 1995 - September 1995 period.

A. On page 3 of my exhibit, the actual average common equity for the period is shown on line 8 as $1,002,275,843. This produces the maximum penalty or reward figure of $2,030,383 as shown on line 15, page 3, and also page 2 of my exhibit.

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

A. Yes I will. Operating data on each of our operating units is filed monthly with the Florida Public Service Commission on the Actual Unit Performance data form. Additionally, outage information is reported to the Commission on a monthly basis. A summary of this data for the six months provides the basis for the GPIF.

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

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

<u>Gannon Unit No. 5</u>

This unit was not scheduled to have a planned outage during the Summer 1995 period, and did not in fact have one. Consequently, the actual equivalent availability of 91.5% requires no adjustment, as shown on page 7 of my exhibit.

<u>Gannon Unit No. 6</u>

On this unit, 240 planned outage hours were originally scheduled to fall within the Summer 1995 period. The actual planned outage activities required 220.8 hours. Consequently, the actual equivalent availability of 87.8% is adjusted to 87.4%, as shown on page 8 of my exhibit.

<u>Big Bend Unit No. 1</u>

On this unit, 48 planned outage hours were originally scheduled to fall within the Summer 1995 period. Actual planned outage activities were completed such that 8.6 hours were required at the beginning of the period. Consequently, the actual equivalent availability of 88.7% is adjusted to 87.9% as shown on page 9 of my exhibit.

Big Bend Unit No. 2

This unit was not scheduled to have a planned outage during the Summer 1995 period and did not in fact have one. Consequently, the actual equivalent availability of 88.5% requires no adjustment as shown on page 10 of my exhibit.

Big Bend Unit No. 3

On this unit 1008 planned outage hours were originally scheduled to fall within the Summer 1995 period. Actual planned outage activities required 937.4 hours. Consequently, the actual equivalent availability of 63.3% is adjusted to 62.0% as shown on page 11 of my exhibit.

Big Bend Unit No. 4

This unit was not scheduled to have a planned outage during the Summer 1995 period, and did not in fact have one. Consequently, the actual equivalent availability of 92.4% requires no adjustment as shown on page 12 of my exhibit.

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

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

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

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

Q. Were any additional adjustments to heat rate required?

A. Yes. On June 20, 1995 operation of the Big Bend 4 scrubber was increased to include scrubbing all flue gas from Big Bend 3. Since that time Big Bend 3 heat rates have been calculated with the added power required for scrubbing. In order to maintain compatibility with target history, Big Bend 3 June through September 1995 heat rates are calculated without this added power for the GPIF process. This is reflected in my exhibit. Successful completion of this project to maximize the potential of existing plant equipment represents a major cost savings and benefit to our customers.

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

A. Yes.

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

A. This is shown on page 28 of my exhibit. Essentially, the weighting factors shown on page 4, column 3, plus the equivalent availability points and the heat rate points shown on page 4, column 4, are substituted within the equation. This resultant value, +1.853, is then entered into the GPIF table on page 2. Using linear interpolation, a reward amount of $376,230 is calculated.

Q. Does this conclude your testimony?

A. Yes, it does.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

GEORGE A. KESELOWSKY

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

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

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

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

Q. What are your current responsibilities?

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

Q. What is the purpose of your testimony?

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

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

A. Yes, I have prepared, under my direction and supervision, an exhibit entitled "Tampa Electric Company, Generating Performance Incentive Factor" April 1996 - September 1996, consisting of 35 pages filed with the Commission on January 22, 1996. (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 One is 13.3%. The Planned Outage Factor for this same unit during this period is 0%. Therefore, the target equivalent availability for this unit equals:

$$100\% - [(13.3\% + 0\%)] = 86.7\%$$

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 One:

$$EAF_{MAX} = 100\% - [0.8\ (13.3\%) + 0.95\ (0\%)] = 89.4\%$$

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 One,

$EAF_{MIN} = 100\% - [1.4\ (13.3\%) + 1.1\ (0\%)] = 81.4\%$

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, Gannon Unit 6 is scheduled for a major unit inspection from March 26 to May 20, 1996. There are 1199 planned outage hours scheduled for the summer 1996 period, and a total of 4391 hours during this 6 month period. Consequently, the Planned Outage Factor for Unit 6 at Gannon is 1199/4391 x 100% or 27.3%. This factor is shown on pages 5 and 14 of my exhibit. Big Bend Units 1 through 4 as well as Gannon Unit 5 have planned outage factors of zero.

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

A. Graphs of both of these factors (adjusted for planned outages) vs. time are prepared. Both monthly data and 12 month moving average data are recorded. For each unit the most current, September 1995, 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 9.6% 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

$$EUOF = \frac{(372 + 48)}{4391} \times 100 = 9.6\%$$

Relative to Gannon Unit Five, the EUOF of 9.6% forms the basis of our Equivalent Availability target development as shown on sheets 4 and 5 of my exhibit.

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

<u>Big Bend Unit One</u>

A. The projected EUOF for this unit is 13.3% during this period. This unit will not have a planned outage this period and the Planned Outage Factor is 0.0%. This results in a target equivalent availability of 86.7% for the period.

<u>Big Bend Unit Two</u>

The projected EUOF for this unit is 14.1%. This unit will not have a planned outage during this period and the Planned Outage Factor is 0%. Therefore, the target equivalent availability for this unit is 85.9%.

Big Bend Unit Three

The projected EUOF for this unit is 12.9% during this period. This unit will not have a planned outage this period and the Planned Outage Factor is 0.0%. Therefore, the target equivalent availability for this unit is 87.1%.

Big Bend Unit Four

The projected EUOF for this unit is 10.3%. This unit will not have a planned outage during this period and the Planned Outage Factor is 0%. This results in a target equivalent availability of 89.7% for the period.

Gannon Unit Five

The projected EUOF for this unit is 9.6%. 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 90.4%.

Gannon Unit Six

The projected EUOF for this unit is 7.9%. This unit will have a planned outage during this period and the Planned Outage Factor is 27.3%. Therefore, the target equivalent availability for this unit is 64.8%.

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

A. Yes I will. Please note on page 5 that the GPIF system weighted Equivalent Availability Factor (EAF) equals 84.0%. This target compares very favorably to previous GPIF periods in that it is better than three of the five previous periods, as well as the five period average EAF. These targets represent an outstanding level of performance for our system.

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

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

EUOF. The reason for this difference is the scheduling of a planned outage. The adjusted factors apply to the period hours after planned outage hours have been extracted.

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

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

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

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

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

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

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

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

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

Q. How were these targets determined?

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

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

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

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

A. Yes.

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

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

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

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

Q. Can you summarize your heat rate projection for the summer 1996 period?

A. Yes. The heat rate target for Big Bend Unit 1 is 10,077 Btu/Net kwh. The range about this value, to allow for potential improvement or degradation, is ±228 Btu/Net kwh. The heat rate target for Big Bend Unit 2 is 10,020 Btu/Net kwh with a range of ±243 Btu/Net kwh. The heat rate target for Big Bend Unit 3 is 9,777 Btu/Net kwh, with a range of ±255 Btu/Net kwh. The heat rate target for Big Bend Unit 4 is 10,149 Btu/Net kwh with a range of ±200 Btu/Net kwh. The heat rate target for Gannon Unit 5 is 10,343 Btu/Net kwh with a range of ±200 Btu/Net kwh. The heat rate target for Gannon Unit 6 is 10,443 Btu/Net kwh with a range of ±342 Btu/Net kwh. A zone of tolerance of ± 75 Btu/Net kwh is included within the range for each target. This is shown on page 4, and pages 7 through 12 of my exhibit.

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

A. Yes I do.

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

A. The next step is to calculate the savings and weighting factor to be used for both average net operating heat rate and equivalent availability. This is shown on pages 7 through 12. Our PROMOD III cost simulation model was used to calculate the total system fuel cost if all units operated at target heat rate and target availability for the period. This total system fuel cost of $135,353,100 is shown on page 6 column 2.

The PROMOD III output was then used to calculate total system fuel cost with each unit individually operating at maximum improvement in equivalent availability and each station operating at maximum improvement in average net operating heat rate. The respective savings are shown on page 6 column 4. After all the individual savings are calculated, column 4 is totaled: $4,631,700 reflects the savings if all units operated at maximum improvement. A weighting factor for each parameter is then calculated by dividing individual savings by the total. For Big Bend Unit One, the weighting factor for equivalent availability is 10.02% 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 One, page 9, if the unit operates at 89.4% equivalent availability, fuel savings would equal $464,000 and 10 equivalent availability points would be awarded.

The Generating Performance Incentive Factor Reward/Penalty Table on page 2 is a summary of the tables on pages 7 through 12. The left hand column of this document shows the Tampa Electric Company's incentive points. The center column shows the total fuel savings and is the same amount as shown on page 6, column 4, $4,631,700. The right hand column of page 2 is the estimated reward or penalty based upon performance.

Q. How were the maximum allowed incentive dollars determined?

A. Referring to my exhibit on page 3, line 8, the estimated average common equity for the period April 1996 - September 1996 is shown to be $1,068,831,000. This produces the maximum allowed jurisdictional incentive dollars of $2,155,275 shown on line 15.

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

A. Yes. Incentive dollars are not to exceed fifty percent of fuel savings. Page 2 of my exhibit demonstrates that the incentive amount calculated on page 3 meets this constraint.

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

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

$$GPIP = (0.0295\ EAP_{GN5} + 0.0538\ EAP_{GN6}$$
$$+ 0.1002\ EAP_{BB1} + 0.1084\ EAP_{BB2}$$
$$+ 0.1027\ EAP_{BB3} + 0.0847\ EAP_{BB4}$$
$$+ 0.0450\ HRP_{GN5} + 0.0893\ HRP_{GN6}$$
$$+ 0.0924\ HRP_{BB1} + 0.0980\ HRP_{BB2}$$
$$+ 0.1063\ HRP_{BB3} + 0.0897\ HRP_{BB4})$$

Where:

GPIP = Generating performance incentive points.

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

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

Q. Have you prepared a document summarizing the GPIF targets for the April 1996 - September 1996 period?

A. Yes. The availability and heat rate targets for each unit are listed on attachment "A" to this testimony entitled "Tampa Electric Company GPIF Targets, April 1, 1996 - September 30, 1996".

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 22 pages. This data is Tampa Electric Company's estimate of the Unit Performance Data and Unit Outage Data for the April 1996 - September 1996 period.

Q. Does this conclude your testimony?

A. Yes.