BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 010001-EI

In the Matter of

FUEL AND PURCHASED POWER
COST RECOVERY CLAUSE AND
GENERATING PERFORMANCE
INCENTIVE FACTOR
_________________________________/

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VOLUME 4

Pages 396 through 521

PROCEEDINGS: HEARING

BEFORE: CHAIRMAN E. LEON JACOBS, JR.
COMMISSIONER J. TERRY DEASON
COMMISSIONER LILA A. JABER
COMMISSIONER BRAULIO L. BAEZ
COMMISSIONER MICHAEL A. PALECKI

DATE: Wednesday, November 21, 2001

TIME: Commenced at 8:35 a.m.

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

REPORTED BY: TRICIA DeMARTE
Official FPSC Reporter
(850) 413-6736

APPEARANCES: (As heretofore noted.)

I N D E X

WITNESSES

INDEX OF WITNESSES CONTINUED:

EXHIBITS

PROCEEDINGS

(Transcript continues in sequence from Volume 3.)

MR. BADDERS: Next, we'd like to move into the record Witness Douglass, along with his Exhibits JRD-1, JRD-2.

CHAIRMAN JACOBS: Without objection, show the testimony of Mr. Douglass is entered into the record as though read, and show marked as Composite Exhibit 15 his testimony exhibits.

(Exhibit 15 marked for identification.)

GULF POWER COMPANY
Before the Florida Public Service Commission
Direct Testimony of
J. R. Douglass
Docket No. 010001-EI
Date of Filing April 2, 2001

Q. Please state your name, address and occupation.

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

Q. Please describe your educational and business background.

A. I received my Bachelor of Aviation Management Degree from Auburn University in 1989. Following graduation, I served as a commissioned officer in the U.S. Navy filling several shipboard roles including Electrical Division Officer, Engineering Officer of the Watch, and Deck Division Officer. After serving in the Navy, I worked in the Generation Planning and Development Department of Southern Company Services as a System Planning Analyst for six years and, as I previously stated, my current position is Performance Test Specialist at Gulf Power Company.

Q. Mr. Douglass, have you previously testified in this Docket?
A. Yes, sir.

Q. Mr. Douglass, 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 January 1, 2000, through December 31, 2000.

Q. Mr. Douglass, 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. Douglass, was this exhibit prepared by you or under your direction and supervision?
A. Yes, it was.

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

Q. Mr. Douglass, were average net operating heat rate (ANOHR) targets that included the new BTU/LB independent variable used for plant Daniel Units 1 & 2 for this period?

A. Yes. The target heat rate equations for Plant Daniel Units 1 and 2 included the BTU/LB independent variable as described in the year 2000 GPIF target filing dated October 1, 1999 and subsequently approved in Commission order PSC-99-2512-FOF-EI. The actual monthly BTU/LB parameters used are shown on pages 6 and 7 of Schedule 3. All results for plant Daniel Units 1 and 2 reflect the use of this variable and both units earned 0.00 GPIF heat rate points for the period.

Q. Mr. Douglass, is there any other 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 that was submitted monthly to the Commission during this period. These corrections are based on discoveries made during our final review. The Actual Unit Performance Data tables on pages 14 to 25 of Schedule 5 incorporate these changes. The data contained on these tables is the data upon which the GPIF calculation was made.

Q. Mr. Douglass, 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-99-2512-FOF-EI is on page 9 of Schedule 2. The results are: Crist 6, -10.00 points; Crist 7, +7.04 points; Smith 1, +10.00 points; Smith 2, +10.00 points; Daniel 1, +10.00 points, and Daniel 2, +10.00 points.

Q. Mr. Douglass, 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.

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 October 1999, 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: +1.60 for Crist 6, 0.00 for Crist 7; +1.28 for Smith 1, 0.00 for Smith 2; 0.00 for Daniel 1; and 0.00 for Daniel 2.

Q. Mr. Douglass, 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 +2.28 as indicated on page 2 of Schedule 4. This calculated to a reward in the amount of $379,732.

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

A. Yes, Sir. In view of the adjusted actual equivalent availabilities, as shown on page 9 of Schedule 2, and the adjusted actual average net operating heat rates achieved, as shown on page 16 of Schedule 3, evidencing the Company's performance for the period, Gulf calculates a reward in the amount of $379,732 as provided for by the GPIF plan.

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

GULF POWER COMPANY
Before the Florida Public Service Commission
Direct Testimony of
J. R. Douglass
Docket No. 010001-EI
Date of Filing September 20, 2001

Q. Please state your name, address and occupation.

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

Q. Please describe your educational and business background.

A. I received my Bachelor of Aviation Management Degree from Auburn University in 1989. Following graduation, I served as a commissioned officer in the U.S. Navy filling several shipboard roles including Electrical Division Officer, Engineering Officer of the Watch, and Deck Division Officer. After serving in the Navy, I worked in the Generation Planning and Development Department of Southern Company Services as a System Planning Analyst for six years and, as I previously stated, my current position is Performance Test Specialist at Gulf Power Company.

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

A. The purpose of my testimony today is to present GPIF targets for Gulf Power Company for the period of January 1, 2002 through December 31, 2002.

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

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

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

A. Yes, it was.

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

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

A. We propose that Crist Units 4, 6, and 7, Smith Units 1 and 2, and Daniel Units 1 and 2 be the Company's GPIF units. Crist Unit 4 has been added to the other six GPIF units in order to ensure that at least 80% of Gulf's expected generation for the period is represented by the units included in the GPIF. Combined-cycle unit Smith 3 will come on-line in June of 2002. This unit will be considered for inclusion in the GPIF after it has been in commercial operation for at least 1 year as described in the GPIF implementation manual for Gulf.

Q. What are the target heat rates Gulf proposes to use in the GPIF for these units for the performance period January 1, 2002 through December 31, 2002?

A. I would like to refer you to Page 39 of Schedule 1 of my exhibit _____ (JRD-2) where these targets are listed.

Q. How were these proposed target heat rates determined?

A. They were determined according to the GPIF implementation manual procedures for Gulf. For Plant Daniel, use of the BTU/LB independent variable in the heat rate regression equations has been discontinued. This is due to regression analysis which determined that this variable is not significant to a 90% confidence interval for either unit. It is anticipated that high-BTU coal with a reasonably consistent average heat content will be used at Plant Daniel for the foreseeable future and the resulting heat rate equations are valid for those conditions.

Q. Describe how the targets were determined for Gulf's proposed GPIF units.

A. Page 2 of Schedule 1 of exhibit _____ (JRD-2) shows the target average net operating heat rate equations for the proposed GPIF units, and pages 4 through 35 of Schedule 1 contain the weekly historical data used for the statistical development of these equations. Pages 36 through 38 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 39 of Schedule 1 of exhibit _____ (JRD-2), calculated according to the appropriate GPIF implementation manual procedures?

A. Yes.

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

A. The target equivalent availabilities and their ranges are listed on page 4 of Schedule 2 of exhibit _____(JRD-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 of exhibit (JRD-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 of exhibit (JRD-2), were determined per GPIF manual procedures for Gulf.

Q. Mr. Douglass, has Gulf completed the GPIF minimum filing requirements data package?
A. Yes, we have completed the required data. Schedule 3 of my exhibit _____ (JRD-2) contains this information.

Q. Mr. Douglass, would you please summarize your testimony?
A. Yes. Gulf asks that the Commission accept:
1. Crist Units 4, 6 and 7, Smith Units 1 and 2 and Daniel Units 1 and 2, for inclusion under the GPIF

for the period of January 1, 2002 through December 31, 2002.

2. The target, maximum attainable, and minimum attainable average net operating heat rates, as proposed by the Company and as shown on page 39 of Schedule 1 and also page 5 of Schedule 3 of my exhibit _____ (JRD-2).

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 _____ (JRD-2).

4. The weekly average net operating heat rate least squares regression equations, shown on page 2 of Schedule 1 and also pages 19 through 32 of Schedule 3 of my exhibit _____ (JRD-2), for use in adjusting the annual actual unit heat rates to target conditions.

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

MR. BADDERS: Next, we'll have Witness Mr. Howell. He also has exhibits. It would be MWH-1.

CHAIRMAN JACOBS: Just one moment. Without objection, show the testimony of Mr. Howell is entered into the record as though read, and show marked as Exhibit 16 his Exhibit MWH-1.

(Exhibit 16 marked for identification.)

GULF POWER COMPANY

Before the Florida Public Service Commission
Direct Testimony of
M. W. Howell
Docket No. 010001-EI
Date of Filing: April 2, 2001

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

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

Q. Have you previously testified before this Commission?

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

Q. Please summarize your educational and professional background.

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

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

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

A. I will summarize Gulf Power Company's purchased power recoverable costs for energy purchases and sales that were incurred during the January 2000 through December 2000 recovery period. I will then compare these actual costs to their projected levels for the period and discuss the primary reasons for the differences.

I will also summarize the actual capacity expenses that were incurred during the January 2000 through December 2000 recovery period. I will compare these figures to their projected levels and discuss the reasons for the differences.

Q. During the period January 2000 through December 2000, 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 the

December 2000 Period-to-Date Schedule A-1 was $59,472,461 for 1,858,330,624 KWH as compared to the originally projected amount of $31,622,732 for 1,081,420,000 KWH that was filed October 1, 1999 in Docket No. 990001-EI. The actual cost per KWH purchased was 3.2003 ¢/KWH as compared to the projected 2.9242 ¢/KWH, or 9% over the projection.

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

A. During the recovery period, Gulf’s increased energy purchases to meet its total load obligations were primarily driven by the extremely hot and dry weather that prevailed in July and August of 2000. The unit prices for the purchases during the January through December period were higher than projected due to the unavailability of low cost generation from Southern electric system (SES) hydro units and the dispatch of higher cost SES fossil steam generation to meet higher SES territorial and off-system loads. Therefore, Gulf purchased more energy at a higher unit price than was forecasted during the January through December 2000 period in order to meet its total load obligations.

Q. During the period January 2000 through December 2000, 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 the December 2000 Period-to-Date Schedule A-1 was $83,972,815 for 3,629,966,149 KWH as compared to the October 1999 projected amount of $43,471,000 for 2,312,065,000 KWH. The actual fuel cost per KWH sold was 2.3133 ¢/KWH, or 23% over the projected amount of 1.8802 ¢/KWH.

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

A. Gulf's energy sales were over the projection due to the higher SES territorial demand and off-system customer demand for Unit Power energy during the recovery period. Because of this higher demand, Gulf was able to sell more of its higher cost energy to these customers and to other SES pool members to satisfy their total load obligations. Overall, Gulf's energy sales produced revenues that more than offset its increased cost of energy purchases for the recovery period.

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

A. Gulf, as a member of the SES power pool, participates in these energy sales. Gulf's generating units are economically dispatched to meet the needs of its territorial customers, the system, and off-system customers. The SES energy sales provide a market for any surplus energy resulting from the dispatch of Gulf's units and, therefore, generally improve Gulf's generating 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. During the period January 2000 through December 2000, how did Gulf's actual net purchased power capacity cost compare with the net projected cost?

A. The actual net capacity cost for the January 2000 through December 2000 recovery period was $12,873,981. Gulf's projected net purchased power capacity cost for the January 2000 through December 2000 recovery period was $12,308,433, as indicated on revised Schedule CCE-1 that was filed in Docket No. 990001-EI on November 12, 1999. The difference between the actual net capacity cost and the projected net capacity cost for the recovery period is $565,548, or an increase of 4.6%.

Q. Please explain the reason for the increase in capacity cost.

A. The $565,548 capacity cost net increase for the January 2000 through December 2000 recovery period is attributable to updated SES load and owned capacity data inputs for the summer months that are used in the Intercompany Interchange Contract (IIC) capacity equalization process to determine Gulf's annual IIC costs and Gulf's lower than projected transmission revenues. Gulf's actual IIC costs increased by $1,995,049, while Gulf's actual transmission revenues were $227,531 below the original projection. These cost increases, however, were largely offset by the combined effect of a $848,282 decrease in January through December market capacity purchase costs and a $808,750 capacity payment adjustment collected from a qualifying facility (QF) for its failure to meet contracted cogeneration unit availability requirements. Therefore, the net effect of these cost changes is the above-mentioned $565,548 capacity cost increase for the January 2000 through December 2000 cost recovery period.

Q. Does this conclude your testimony?

A. Yes.

GULF POWER COMPANY

Before the Florida Public Service Commission
Direct Testimony of
M. W. Howell
Docket No. 010001-EI
Date of Filing: August 20, 2001

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

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

Q. Have you previously testified before this Commission?

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

Q. Please summarize your educational and professional background.

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

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

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

A. The purpose of my testimony is to summarize Gulf Power Company's actual / estimated true-up projections of purchased power recoverable energy purchases and sales for the January 2001 through December 2001 recovery period. I will compare these January 2001 through December 2001 estimated true-up amounts to the amounts originally projected in Gulf's September 2000 fuel filing for the period and discuss the reason for the difference.

I will also summarize the actual / estimated true-up projection of net capacity expenses for the January 2001 through December 2001 recovery period. I will compare these figures to the amounts originally projected in Gulf's September 2000 capacity filing for the period and discuss the reason for the difference.

Q. During the period January 2001 through December 2001, what is Gulf's actual / estimated purchased power recoverable cost for energy purchases and how does it compare with the September 2000 projected amount?

A. Using seven months actual data and five months originally projected data, Gulf's total estimated purchased power recoverable cost for energy purchases, as shown on line 12 of the January 2001 - December 2001 Schedule E-1B1 is $58,879,266 for 1,883,589,539 KWH as compared to the September 2000 projected amount of $53,620,570 for 1,618,627,000 KWH. The estimated true-up cost per KWH purchased is 3.1259 ¢/KWH as compared to the originally projected cost of 3.3127 ¢/KWH, or 6% under the projection made last fall.

Q. What is the primary reason for the difference between the two projections of Gulf's energy purchases?

A. During January through July of the 2001 recovery period, Gulf purchased more energy than projected from Southern electric system (SES) operating companies and non-associated entities to meet its increased territorial and off-system loads. The unit prices for these purchases during the January through July period were lower than projected due to the mild spring and early summer weather in the Southeast U. S. that increased availability of lower cost market energy from neighboring utilities and power marketers. Therefore, the two projections differ because Gulf actually purchased more pool and market energy at a lower overall unit price than was forecasted during the January through July period in order to meet its higher total load obligations.

Q. During the period January 2001 through December 2001, what is Gulf's actual / estimated purchased power fuel cost for energy sales and how does it compare with the September 2000 projected amount?

A. Using seven months actual data and five months originally projected data, Gulf's total estimated purchased power fuel cost for energy sales, as shown on line 18 of the January 2001 - December 2001 Schedule E-1B1 is $62,888,086 for 3,157,926,772 KWH as compared to the September 2000 projected amount of $70,452,000 for 3,102,125,000 KWH. The estimated true-up cost per KWH sold is 1.9914 ¢/KWH as compared to 2.2711 ¢/KWH, or 12% under the projection.

Q. What is the primary reason for the difference between the two projections of Gulf's energy sales?

A. During January through July of the 2001 recovery period, Gulf's energy sales were slightly over the projection due to higher Unit Power sales to south Florida utilities and higher sales to other off-system customers. The unit prices for these sales during the January through July period were lower than projected due to the mild regional weather conditions that increased availability of lower cost energy to be sold to the off-system market. Therefore, the two projections differ because Gulf sold more energy to off-system customers at a lower unit price than was projected during the January through July period.

Q. During the period January 2001 through December 2001, what is Gulf's projection of actual / estimated net purchased power capacity transactions and how does it compare with the September 2000 projection of net capacity transactions?

A. The total estimated net capacity cost for the January 2001 through December 2001 recovery period, consisting of actual January through July costs and a revised projection of August through December costs, is $15,693,362 as compared to Gulf's September 2000 projected purchased power capacity cost of $17,084,405. The difference between these projections is a $1,391,043 cost decrease, or 8% lower than costs that were filed in

September 2000.

Q. Please explain the reason for the decrease in capacity cost.

A. The projected $1,391,043 capacity cost decrease for the January 2001 through December 2001 period is primarily attributable to changes in the SES operating companies' owned capacity amounts that are used in the Intercompany Interchange Contract (IIC) capacity equalization calculation to determine Gulf's monthly IIC costs. Gulf's IIC costs during January through July were lower than projected because the actual IIC owned capacity amounts for other SES operating companies decreased by a greater amount as compared to Gulf's owned capacity. This resulted in Gulf being a lower net purchaser of capacity through the IIC during the January through July period.

Gulf's revised projection for IIC and market capacity costs during August through December 2001 is only slightly higher than the original projection for these months. Therefore, the above mentioned change that lowered Gulf's actual IIC costs for January through July is the primary reason for Gulf's $1,391,043 capacity cost decrease during the January 2001 through December 2001 cost recovery period.

Q. Does this conclude your testimony?
A. Yes.

GULF POWER COMPANY

Before the Florida Public Service Commission
Direct Testimony and Exhibit of
M. W. Howell
Docket No. 010001-EI
Date of Filing: September 20, 2001

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

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

Q. Have you previously testified before this Commission?

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

Q. Please summarize your educational and professional background.

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

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

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

A. The purpose of my testimony is to support Gulf Power Company's (Gulf) projection of purchased power recoverable costs for energy purchases and sales for the period January 2002 - December 2002. I will also support Gulf's projection of purchased power capacity costs for the January 2002 - December 2002 recovery period. I will address the issues raised by the Commission Staff related to managing wholesale energy transaction risks and the outage at Crist Unit 2. Finally, I will discuss a recent outage at Gulf's Plant Crist that will impact Gulf's actual purchased power costs for the remainder of 2001.

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

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

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

Q. What is Gulf's projected purchased power recoverable cost for energy purchases for the January 2002 - December 2002 recovery period?

A. Gulf's projected recoverable cost for energy purchases, shown on line 12 of Schedule E-1 of the fuel filing, is $21,710,832. These purchases result from Gulf's participation in the coordinated operation of the Southern electric system (SES) power pool, as well as the cogeneration purchased power contract with Solutia, Inc. (Solutia) and market power purchases. This amount is used by Gulf's witness Ms. Davis as an input in the calculation of the fuel and purchased power cost adjustment factor.

Q. What is Gulf's projected purchased power fuel cost for energy sales for the January 2002 - December 2002 recovery period?

A. The projected fuel cost for energy sales, shown on line 18 of Schedule E-1, is $105,918,000. These sales also result from Gulf's participation in the coordinated operation of the SES power pool. This amount is used by Gulf's witness Ms. Davis as an input in the calculation of the fuel and purchased power cost adjustment factor.

Q. What information is contained in your exhibit?

A. My exhibit lists the long-term power contracts that are included for capacity cost recovery, their associated megawatt amounts, the resulting capacity dollar amounts, and the cost of market capacity purchases.

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

A. Two power contracts that produce recoverable capacity transactions through Gulf's purchased power capacity adjustment factor are the SES Intercompany Interchange Contract (IIC) and Gulf's cogeneration purchased power contract with Solutia. The Commission has authorized the Company to include capacity transactions under the IIC for recovery through the purchased power capacity cost adjustment factor. Gulf will continue to have IIC capacity transactions during the January 2002 - December 2002 recovery period. The energy transactions under this contract are handled for cost recovery purposes through the fuel cost adjustment factor.

The Gulf Power/Solutia cogeneration purchased power contract enables Gulf to purchase 19 megawatts of firm capacity until June 1, 2005. Gulf has included the contract's annual costs for the January 2002 through December 2002 recovery period in this projection. The energy transactions under this contract have also been approved by the Commission for recovery, and these costs are handled for cost recovery purposes through the fuel cost adjustment factor.

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

A. Yes. Gulf and other SES operating companies have purchased market capacity for 2002, and these purchases will continue through May 2002. Gulf will have monthly costs associated with these market purchases for the January 2002 - December 2002 recovery period. Again, the energy transactions related to these purchases are handled for cost recovery purposes through the fuel cost adjustment factor.

Q. What are Gulf's IIC capacity transactions that are projected for the January 2002 - December 2002 recovery period?

A. As shown on my Exhibit MWH-1, capacity transactions under the IIC vary during each month of the recovery period. IIC capacity purchases in the amount of $2,881,897 are projected for the year. IIC capacity sales during the same period are projected to be $1,031,220. Therefore, the Company's net capacity transactions under the IIC for the recovery period are net purchases amounting to $1,850,677.

Q. What is the cost of Gulf's capacity purchase from Solutia that is projected for the January 2002 - December 2002 recovery period?

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

Q. What is the cost of Gulf's market capacity purchases that is projected for the January 2002 - December 2002 recovery period?

A. As shown on my Exhibit MWH-1, Gulf is projected to pay a total net cost of $1,065,504 for the committed market capacity purchases. Capacity will be purchased during the months of January through May of 2002. Smith Unit 3 is scheduled to be in service by June 1, 2002, and Gulf's market capacity purchases will end at that time. The individual suppliers and megawatt amounts are not shown, since this is highly sensitive and confidential information. Public availability of this information would seriously undermine our competitive position and cause our customers increased cost.

Q. What are Gulf's total projected net capacity transactions for the January 2002 - December 2002 recovery period?

A. As shown on my Exhibit MWH-1, the net purchases under the IIC, the Solutia contract purchases, and the net committed market capacity purchases will result in a projected net capacity cost of $3,662,605. This figure is used by Gulf's witness Ms. Davis as an input into the calculation of the total capacity transactions to be recovered through the purchased power capacity cost adjustment factor for this annual recovery period. As shown on Schedule CCE-2 of Ms. Davis' testimony, the purchased power capacity cost adjustment factor is 0.032 ¢/KWH. This represents an 85% decrease over the January 2001 – December 2001 recovery period cost adjustment factor.

Q. Please explain the reason for the decrease in Gulf's purchased power capacity cost adjustment factor for the January 2002 - December 2002 recovery period.

A. The decrease in the projected capacity cost adjustment factor is a result of Gulf's lower 2002 IIC capacity cost and a reduction of capacity costs due to the expiration of several market capacity purchase contracts. The IIC cost is projected to be $1,420,740 lower than the 2001 IIC capacity cost projection due to increased owned capacity from Gulf's Smith Unit 3 capacity addition that is needed to meet growing customer loads.

The major reason for the overall decrease, however, is Gulf's reduced market capacity purchase costs that are estimated to be $12,412,060 lower than the costs contained in the 2001 projection. When Gulf's combined cycle unit, Smith Unit 3, comes on-line in June 2002, the capacity from these market capacity contracts will no longer be needed.

Q. Earlier in your testimony, you stated that you would address issues concerning Gulf's management of wholesale energy risks that were raised by the Commission Staff. Would you please generally discuss these issues.

A. Gulf and Southern are currently evaluating the relative merits of engaging in hedging practices to effectively manage risks associated with wholesale energy transactions. This is a relatively new practice in the industry, and the limits of reasonable wholesale energy transaction risks clearly need to be explored and agreed to by this Commission. Such factors as treatment of hedging losses, appropriate levels of risk, types of allowable risks, and other factors need to have general guidelines established up front. As addressed in Gulf's responses to Staff's Second Set of Interrogatories, Gulf's agent, Southern Company Generation and Energy Marketing (SCGEM), has a documented risk management policy that SCGEM energy traders must adhere to when engaging in wholesale energy transactions. SCGEM's trading activities are guided by the general principle of directing the lowest cost off-system wholesale market energy to the territorial customers of Gulf and the other SES operating companies, if such energy can reasonably be expected to result in cost savings. The SCGEM risk management policy provides the guidelines for effectively executing this energy trading strategy.

Q. Were Gulf's replacement fuel costs for the unplanned outage at Crist Unit 2, that began on August 2, 2000, reasonable?

A. Yes. Gulf did not buy any additional fuel to specifically compensate for the unavailability of this peaking unit. In the case of this particular unplanned outage, Crist Unit 2 would not have been called upon in economic dispatch for the majority of the outage period had it been available. If the unit had been needed to meet system load requirements, Gulf would have purchased replacement power from the most economical resource available.

Q. Has Plant Crist Unit 7 experienced a recent forced outage?

A. Yes. On August 16, 2001, the unit's main power transformer failed.

Q. How is this outage expected to influence Gulf's fuel and purchased power recovery clause?

A. There should be no impact during 2002. A spare transformer is being delivered from Georgia Power Company and it will be placed in service as soon as possible in 2001. This spare transformer will remain at Plant Crist until a permanent replacement is secured. During the outage, Gulf's recoverable energy costs will be slightly higher since Crist Unit 7 is expected to be off line a total of six to eight weeks. Therefore, this outage should only impact Gulf's actual purchased energy costs for the 2001 recovery period.

Q. Does this conclude your testimony?

A. Yes.

CHAIRMAN JACOBS: Without objection, show Exhibits 14, 15, and 16 are entered into the record.

(Exhibits 14, 15, and 16 admitted into the record.)

CHAIRMAN JACOBS: Does that take care of all your witnesses?

MR. BADDERS: Actually, I have one more, Witness McMillan.

CHAIRMAN JACOBS: Very well.

MR. BADDERS: And he does not have an exhibit.

CHAIRMAN JACOBS: Very well. Without objection, show the testimony of Mr. McMillan is entered into the record as though read.

MR. BADDERS: Thank you.

GULF POWER COMPANY

Before the Florida Public Service Commission
Prepared Direct Testimony of
Richard J. McMillan
Docket No. 010001-EI
Fuel and Purchased Power Cost Recovery Clause
Date of Filing: September 20, 2001

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

A. My name is Richard J. McMillan. My business address is One Energy Place, Pensacola, Florida 32520. I am General Accounting Manager of Gulf Power Company.

Q. Please describe your educational and professional background.

A. I graduated from Louisiana State University in 1976 with a Bachelor of Science Degree in Accounting. Immediately following graduation, I was employed by Gulf Power Company as an Internal Auditor. I have held various accounting positions, including Staff Internal Auditor, Staff Financial Analyst, Staff Accountant, Coordinator of Internal Accounting Controls, Supervisor of Financial Planning; and in March 1992, I was promoted to my current position as General Accounting Manager. Also, during my employment, I graduated from the University of West Florida in 1983 with a Master of Science Degree in Business Administration.

Q. Briefly describe your duties and responsibilities as General Accounting Manager.

A. My responsibilities include: all external accounting reporting and administration, regulatory accounting requirements, tax accounting, fuel accounting, actual FPSC recovery clause calculations and support, cost accounting, bank reconciliations, coordination and preparation of the Accounting department budget and Company budgets for general corporate expenses, and assistance with various other projects and assignments as required.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to address the appropriate regulatory treatment of the gains, losses and other costs or receipts related to hedging of the investor-owned electric utility's fuel and energy transactions. I will also address the appropriate regulatory treatment for capital projects and the corrective actions that Gulf has taken regarding the overstatement of Interchange Sales in 2000.

Q. What is the appropriate regulatory treatment for gains, losses and other costs or receipts related to hedging of the Company's fuel and energy transactions?

A. All gains, losses and other costs or receipts related to fuel and energy transactions should be included in the determination of the recoverable fuel costs. These gains, losses and other costs and receipts related to fuel and energy transactions include but are not limited to the gains and losses from either futures or option contracts, the premium costs and other transaction costs associated with fuel related hedging activities. The primary objective of an effective fuel program is to provide stable or more predictable fuel prices for our customers. All costs and benefits associated with fuel related hedging activities must be included in recoverable fuel costs along with the cost of the fuel and energy transactions in order to provide for timely matching of all costs and benefits.

Q. Should utilities continue to be allowed to recover carrying costs through the fuel cost recovery clause for capital projects?

A. Yes, if the capital project is related to the fuel program. For example, a capital project incurred with the expectation and purpose of reducing long-term fuel costs should be recoverable through the fuel clause because the benefits of such a project will ultimately flow through to the utility's customers through the fuel clause. Ms. Davis addresses the specific components of the utility's carrying costs on such capital projects that have been and are allowed in this and other cost recovery clauses.

Q. Please explain the Audit Disclosure pertaining to Interchange Sales and the corrective actions taken by the Company.

A. The Company inadvertently overstated the emission allowance costs related to Interchange Sales in August 2000, which understated the net recoverable fuel expense by $385,796 in 2000. The error was found, documented and provided to the FPSC auditor during his audit. Gulf made a correcting entry in July 2001 by reducing the emission costs for July by the same amount.

Q. Does this conclude your testimony.

A. Yes.

CHAIRMAN JACOBS: That takes care of all of Gulf's case?

MR. BADDERS: Yes.

CHAIRMAN JACOBS: Thank you. And we are then ready for Mr. Hartzog.

MR. KEATING: Did we get -- I'm sorry --

CHAIRMAN JACOBS: I'm sorry.

MR. KEATING: -- did we get staff's composite exhibit marked?

CHAIRMAN JACOBS: We did not. Hold on just a moment. Marked as Composite Exhibit Number 17.

(Exhibit 17 marked for identification.)

MR. KEATING: We previously talked to the parties. It's our understanding that this material could be stipulated, but since they haven't had the actual exhibit in front of them yet, we will wait to move it in till the end to give everybody a chance to make sure it's what it says it is.

CHAIRMAN JACOBS: Very well. You may proceed Mr. Childs.

MR. CHILDS: Commissioners, the testimony that I am going to be inquiring of the witnesses at this time is the testimony that bears the date November 5, 2001. There are various sets of testimony from FPL witnesses, but the only portion that hasn't been stipulated is the set that has that date.

CHAIRMAN JACOBS: Will we move them all in at the same time?

MR. CHILDS: Well, actually, I thought staff was going to do it all, but if I can, I will go ahead with the ones who have to testify who were not excused at this time.

CHAIRMAN JACOBS: Very well.

JOHN R. HARTZOG

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

DIRECT EXAMINATION

BY MR. CHILDS:

Q Mr. Hartzog, would you state your name and address?

A John Hartzog, 700 Universe Boulevard, Juno Beach, Florida.

Q By whom are you employed and in what capacity?

A I'm employed by Florida Power & Light Company as the manager of nuclear financial and information services.

Q Do you have before you a document entitled, "Supplemental Testimony of J. R. Hartzog, Docket Number 010001-EI, November 5, 2001"?

A Yes, I do.

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

A Yes, it was.

Q Do you have any changes or corrections to make to it?

A No, I do not.

Q Do you adopt it as your testimony?

A I do.

MR. CHILDS: Mr. Chairman, we do ask that this testimony of Mr. Hartzog be inserted into the record as though read.

CHAIRMAN JACOBS: You requested Mr. Portuondo's testimony -- I'm sorry, Mr. --

MR. CHILDS: Hartzog.

CHAIRMAN JACOBS: I'm out of time here. And without objection, show Mr. Hartzog's testimony -- we'll go ahead -- all of his testimony we'll enter them into the record as though read.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

SUPPLEMENTAL TESTIMONY OF J. R. HARTZOG

DOCKET NO. 010001 - EI

NOVEMBER 5, 2001

Q. Please state your name and address.

A. My name is John R. Hartzog. 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, Nuclear Financial & Information Services in the Nuclear Business Unit.

Q. Have you previously filed testimony 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 incremental security costs associated with the events of September 11, 2001 to be included in the proposed fuel cost recovery factors. The recovery of these costs is discussed in the supplemental Testimony of FPL witness K. M. Dubin.

Q. **What is the basis for the additional security costs?**

A. FPL's nuclear plants rely on a "defense in depth" approach to security. Essentially, multiple barriers of increasing restrictions for access to plant components and systems are utilized. Historically, FPL has had a highly effective security program as demonstrated by Nuclear Regulatory Commission "force on force" inspections utilizing military Special Forces as mock adversaries. Both Turkey Point and St. Lucie successfully passed such inspections within the last few years. As a result of the September 11th events, FPL has deepened the security defense in depth, requiring additional manpower. This is consistent with new expectations regarding nuclear plant security and NRC Advisories. FPL is in frequent contact with the NRC, and NRC recommendations are implemented as made. The incremental cost of this additional manpower is being captured in accounts established for that purpose. In the past, FPL's fossil units have had security based on fences, gates and limited personnel access. In light of the events of September 11, 2001 especially at Turkey Point and its close proximity to the nuclear units, FPL has also enhanced the security at selected fossil units.

Q. How much are the incremental security costs in response to the September 11, 2001 events?

A. FPL expects to expend approximately $1.5 Million for additional security at its nuclear facilities, and $300,000 at its fossil facilities in 2002. There are significant uncertainties in these costs, since it is vital that FPL respond to changing threat levels in a proactive manner. In addition, various assistance levels from governmental organizations will be required, including, as a minimum, local law enforcement and the Florida National Guard. FPL anticipates that some of these governmental organizations will seek reimbursement of associated costs for providing assistance.

Q. Does this conclude your testimony?

A. Yes, it does.

CHAIRMAN JACOBS: And then if you will excuse me for a moment, we were just confirming on TECO's stipulated witnesses. Did we move them into the record yet?

MR. BEASLEY: We haven't yet, sir. I'll be happy to do that.

CHAIRMAN JACOBS: Just so we keep everything in order, it helps me.

MR. BEASLEY: Mr. Brian Buckley's testimony which is adopted by Mr. Keselowsky.

CHAIRMAN JACOBS: Very well. Without objection, show Mr. Buckley's testimony as adopted by Mr. Keselowsky is entered into the record as though read.

TAMPA ELECTRIC COMPANY
DOCKET NO. 010001-EI
FILED: 04/02/01

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

BRIAN S. BUCKLEY

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

A. My name is Brian S. Buckley. My mailing address is Post Office Box 111, Tampa, Florida 33601 and my business address is 6944 U.S. Highway 41 North, Apollo Beach, Florida 33572. I am employed by Tampa Electric Company ("Tampa Electric" or "company") in the position of Generation Operations Engineer - Energy Supply in the Financial Services Department.

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

A. In 1997, I received a Bachelor of Mechanical Engineering Degree from the Georgia Institute of Technology in Atlanta, Georgia. After graduation, I worked at Siemens and subsequently joined Tampa Electric in 1999. Currently, I am responsible for unit performance analysis and reporting of generation statistics.

Q. What is the purpose of your testimony?

A. My testimony presents Tampa Electric's actual performance results from unit equivalent availability and station heat rate used to determine the Generating Performance Incentive Factor ("GPIF") for the period January 2000 through December 2000. I also compare these results to the targets established prior to the beginning of the period.

Q. Have you prepared any exhibits to support your testimony?

A. Yes, Exhibit No. _____ (BSB-1), consisting of two documents, was prepared under my direction and supervision. Document No. 1, entitled "Tampa Electric Company, Generating Performance Incentive Factor, January 2000 - December 2000, True-up" is consistent with the GPIF Implementation Manual previously approved by the Florida Public Service Commission ("Commission"). In addition, Document No. 2 provides the company's actual unit performance data for the 2000 period.

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

A. Six of the company's coal-fired units are included. These are Big Bend Station Units 1, 2, 3, and 4, and Gannon Station Units 5 and 6.

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 in Document 1, page 5 of my exhibit. Based upon 2.217 GPIF points, the result is a reward amount of $1,095,745 for the period.

Q. Please proceed with your review of the actual results for the January 2000 through December 2000 period.

A. On page 4, Document 1, of my exhibit, the actual average common equity for the period is shown on line 14 as $1,235,512,385. This produces the maximum penalty or reward figure of $4,943,131 as shown on line 21.

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

A. Yes. Operating data on each of the units is filed monthly with the 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 twelve months provides the basis for the GPIF.

Q. Are the equivalent availability results shown in Document 1, page 7, 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 in Document 1, page 7, 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>Big Bend Unit No. 1</u>

On this unit, 504 planned outage hours were originally scheduled for 2000. Actual outage activities required 325.9 planned outage hours. Consequently, the actual equivalent availability of 75.8% was adjusted to 74.3% as shown in Document 1, page 8, of my exhibit.

Big Bend Unit No. 2

On this unit, 432 planned outage hours were originally scheduled for 2000. Actual outage activities required 181.0 planned outage hours. Consequently, the actual equivalent availability of 85.6% was adjusted to 83.2% as shown in Document 1, page 9, of my exhibit.

Big Bend Unit No. 3

On this unit, 504 planned outage hours were originally scheduled for 2000. Actual outage activities required 984.8 planned outage hours. Consequently, the actual equivalent availability of 75.0% was adjusted to 79.6% as shown in Document 1, page 10, of my exhibit.

Big Bend Unit No. 4

On this unit, 168 planned outage hours were originally scheduled for 2000. Actual outage activities required 0 planned outage hours. Consequently, the actual equivalent availability of 87.8% was adjusted to 86.1% as shown in Document 1, page 11, of my exhibit.

Gannon Unit No. 5

On this unit, 336 planned outage hours were originally scheduled for 2000. Actual outage activities required

566.3 planned outage hours. Consequently, the actual equivalent availability of 55.6% was adjusted to 57.2% as shown in Document 1, page 12, of my exhibit.

Gannon Unit No. 6

On this unit, 2015 planned outage hours were originally scheduled for 2000. Actual outage activities required 784.0 planned outage hours. Consequently, the actual equivalent availability of 33.2% was adjusted to 28.2%, as shown in Document 1, page 13, 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 in Document 1, page 7, column 4, of my exhibit. This number is entered into the respective Generating Performance Incentive Point ("GPIP") Table for each particular unit in Document 1 on pages 22 through 27. Document 1, page 5, of my exhibit summarizes the equivalent availability points to be awarded or penalized.

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

A. The actual heat rate and adjusted actual heat rate for Big Bend Units 1, 2, 3, and 4, and Gannon Units 5 and 6 are shown in Document 1, page 7, of my exhibit. The adjustment was developed based on the guidelines of section 4.3.16 of the GPIF Manual. This procedure is further defined by a letter dated October 23, 1981, from Mr. J.H. Hoffsis of the Commission Staff. The final adjusted actual heat rates are also shown in Document 1, page 6, of my exhibit. This heat rate number is entered into the respective GPIP table for the particular unit, shown in Document 1, pages 22 through 27. Document 1, page 5, of my exhibit summarizes the weighted heat rate and equivalent availability points to be awarded.

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

A. This is shown in Document 1, page 29, of my exhibit. Essentially, the weighting factors shown in Document 1, page 5, column 3, plus the equivalent availability points and the heat rate points shown in Document 1, page 5, column 4, are substituted within the equation. This resultant value, 2.217, is then entered into the GPIF table in Document 1, page 3. Using linear interpolation, a reward amount of $1,095,745 is calculated.

Q. Does this conclude your testimony?

A. Yes, it does.

MR. BEASLEY: And then Mr. Keselowsky's own testimony.

CHAIRMAN JACOBS: And without objection, show Mr. Keselowsky's testimony is entered into the record as though read.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

GEORGE A. KESELOWSKY

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

A. My name is George A. Keselowsky. My mailing address is Post Office Box 111, Tampa, Florida 33601 and my business address is 6944 U.S. Highway 41 North, Apollo Beach, Florida 33572. I am employed by Tampa Electric Company ("Tampa Electric" or "company") in the position of Senior Consulting Engineer - Energy Supply in the Plant Technical Services Department.

Q. Please provide 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 and supervisory positions since that time. I currently have responsibility for unit performance analysis and the planning, scheduling and coordination of unit outages.

Q. What is the purpose of your testimony?

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

Q. Have you prepared any exhibits to support your testimony?

A. Yes, Exhibit No. _____ (GAK-1), consisting of two documents, was prepared under my direction and supervision. Document No. 1, Part A entitled "Generating Performance Incentive Factor January 2002 through December 2002" is consistent with the GPIF Implementation Manual previously approved by the Commission. In addition, Document 1, Part B provides the company's estimate of Unit Performance Data for the 2002 period. Finally, Document No. 2 is a summary of the GPIF targets for the 2002 period.

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

A. Six of the company's coal-fired units and one integrated gasification combined cycle unit are included. These are Gannon Station Units 5 and 6, Big Bend Station Units 1, 2, 3, and 4, and Polk Power Station Unit 1.

Q. Please describe how Tampa Electric developed the various factors associated with the GPIF.

A. Targets were established for equivalent availability and heat rate for each unit considered for the 2002 period. A range of potential improvements and degradations was determined for each of these parameters.

Q. How were the target values for unit availability determined?

A. The Planned Outage Factor ("POF") and the Equivalent Unplanned Outage Factor ("EUOF") were subtracted from 100% to determine the target Equivalent Availability Factor ("EAF"). The factors for each of the seven units included within the GPIF are shown on page 5 of Document No. 1, Part A.

To give an example for the 2002 period, the projected Equivalent Unplanned Outage Factor for Big Bend Unit 1 is

18.9% and the Planned Outage Factor is 3.8%. Therefore, the target equivalent availability factor for Big Bend Unit 1 equals 77.3% or:

$$100\% - [(18.9\% + 3.8\%)] = 77.3\%$$

This is shown on page 4, column 3 of Document No. 1, Part A.

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

A. Maximum equivalent availability is derived by using the following formula:

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

The factors included in the above equations are the same factors that determine the target equivalent availability. To determine the maximum incentive points, a 20% reduction in Equivalent Forced Outage Factor ("EUOF") and Equivalent Maintenance Outage Factor ("EMOF"), plus a 5% reduction in the Planned Outage Factor are necessary. Continuing with the Big Bend Unit 1 example:

$$EAF_{MAX} = 100\% - [0.8\ (18.9\%) + 0.95\ (3.8\%)] = 81.2\%$$

This is shown on page 4, column 4 of Document No. 1, Part A.

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

A. The potential for unit availability degradation is significantly greater than the potential for unit availability improvement. This concept was discussed extensively and approved in earlier hearings before the Commission. To incorporate this biased effect into the unit availability tables, Tampa Electric uses a potential degradation range equal to twice the potential improvement. Consequently, minimum equivalent availability is calculated using the following formula:

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

Again, continuing with the Big Bend Unit 1 example,

$$EAF_{MIN} = 100\% - [1.4 \ (18.9\%) + 1.1 \ (3.8\%)] = 69.3\%$$

The equivalent availability MAX and MIN for the other six units is computed in a similar manner.

Q. How did Tampa Electric determine the Planned Outage, Maintenance Outage, and Forced Outage Factors?

A. The company's planned outages for January 2002 through December 2002 are shown on page 21 of Document No. 1, Part A. Also, a Critical Path Method (C.P.M.) for each major planned outage, which affects GPIF, is shown on pages 22 and 23 of Document No. 1, Part A. Planned Outage Factors are calculated for each unit. For example, Big Bend Unit 1 is scheduled for a planned outage February 16 through March 01, 2002. There are 336 planned outage hours scheduled for the 2002 period, and a total of 8,760 hours during this 12-month period. Consequently, the Planned Outage Factor for Unit 1 at Big Bend is 3.8% or:

$$\frac{336}{8,760} \times 100\% = 3.8\%$$

The factor for each unit is shown on pages 5 and 14 of Document No. 1, Part A. Big Bend Unit 2 has a Planned Outage Factor of 19.2%. Big Bend Unit 3 has a Planned Outage Factor of 15.3%. Big Bend 4 has a Planned Outage Factor of 5.8%. Gannon Unit 5 has a Planned Outage

Factor of 15.3%. Gannon Unit 6 has a Planned Outage Factor of 18.1%. Polk Unit 1 has a Planned Outage Factor of 7.7%.

Q. How did you determine the Forced Outage and Maintenance Outage Factors for each unit?

A. Graphs for both factors (adjusted for planned outages) versus time were prepared. Monthly data and 12-month rolling average data were recorded. For each unit the most current 12-month ending value, June 2001, was used as a basis for the projection. This value was adjusted 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 an Equivalent Unplanned Outage Factor of 18.9% for Big Bend Unit 1. The Equivalent Unplanned Outage Factor for Big Bend Unit 1 is verified by the data shown on page 14, lines 3, 5, 10 and 11 of Document No. 1, Part A and calculated using the following formula:

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

Or

$$EUOF = \frac{(733 + 927)}{8{,}760} \times 100 = 18.9\%$$

Relative to Big Bend Unit 1, the EUOF of 18.9% forms the basis of the equivalent availability target development as shown on pages 4 and 5 of Document No. 1, Part A.

Big Bend Unit 1

The projected Equivalent Unplanned Outage Factor for this unit is 18.9%. This unit will have a planned outage in 2002 and the Planned Outage Factor is 3.8%. Therefore, the target equivalent availability for this unit is 77.3%.

Big Bend Unit 2

The projected Equivalent Unplanned Outage Factor for this unit is 14.1%. This unit will have a planned outage in 2002 and the Planned Outage Factor is 19.2%. Therefore, the target equivalent availability for this unit is 66.7%.

Big Bend Unit 3

The projected Equivalent Unplanned Outage Factor for this unit is 17.2%. This unit will have a planned outage in 2002 and the Planned Outage Factor is 15.3%. Therefore, the target equivalent availability for this unit is 67.5%.

Big Bend Unit 4

The projected Equivalent Unplanned Outage Factor for this unit is 11.6%. This unit will have a planned outage in 2002 and the Planned Outage Factor is 5.8%. Therefore, the target equivalent availability for this unit is 82.6%.

Gannon Unit 5

The projected Equivalent Unplanned Outage Factor for this unit is 27.9%. This unit will have a planned outage in 2002 and the Planned Outage Factor is 15.3%. Therefore, the target equivalent availability for this unit is 56.7%.

Gannon Unit 6

The projected Equivalent Unplanned Outage Factor for this unit is 18.0%. This unit will have a planned outage in 2002 and the Planned Outage Factor is 18.1%. Therefore, the target equivalent availability for this unit is

63.9%.

Polk Unit 1

The projected Equivalent Unplanned Outage Factor for this unit is 14.3%. This unit will have a planned outage in 2002 and the Planned Outage Factor is 7.7%. Therefore, the target equivalent availability for this unit is 78.0%.

Q. Please summarize your testimony regarding Equivalent Availability Factor.

A. The GPIF system weighted Equivalent Availability Factor of 68.5% is shown on Page 5 of Document No. 1, Part A. This target compares favorably to the June 2000 - July 2001 GPIF period.

Q. When graphing and monitoring Forced and Maintenance Outage Factors, why are they adjusted for planned outage hours?

A. The adjustment makes the 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 the units in the GPIF are usually base loaded, reserve shutdown is generally not a factor.

To demonstrate the effects of a planned outage, note the Equivalent Unplanned Outage Rate and Equivalent Unplanned Outage Factor for Big Bend Unit 1 on page 14 of Document No. 1, Part A. During the months of January and April through December, the Equivalent Unplanned Outage Rate and the Equivalent Unplanned Outage Factor are equal. This is due to the fact that no planned outages are scheduled during these months. During the months of February and March, Equivalent Unplanned Outage Rate exceeds Equivalent Unplanned Outage Factor due to the scheduling of a planned outage. Therefore, the adjusted factors apply to the period hours after the planned outage hours have been extracted.

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

A. Yes. Rates provide a proper and accurate method of determining the unit parameters, which are subsequently converted to factors. Therefore,

$$FOF + MOF + POF + EAF = 100\%$$

Since factors are additive, they are easier to work with and to understand.

Q. Has Tampa Electric prepared the necessary heat rate data required for the determination of the GPIF?

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

Q. How were these targets determined?

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

Q. The accomplishment of scrubbing the flue gas from Big Bend Units 1 and 2 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 these units resulting from utilization of the new scrubber can be quantified, but the operational history is short of GPIF guidelines. Therefore, targets for Big Bend Units 1 and 2 have been developed in the standard fashion using data without scrubber power. In order to assure compatibility with the targets, scrubber power will be removed prior to calculating Units 1 and 2 heat rates for the subsequent true-up process. This method was approved by the Commission for Big Bend Unit 3 when it began scrubbing operation. The company will utilize the aforementioned method until there is sufficient history to meet target preparation guidelines.

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 versus net output factor curves have been developed for each unit. This information is shown on pages 31 through 37 of Document No. 1, Part A.

Q. Please elaborate on the analysis used in the determination of the ranges.

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

Q. Please summarize your heat rate projection (Btu/Net kWh) and the range about each target to allow for potential improvement or degradation for the 2002 period.

A. The heat rate target for Big Bend Unit 1 is 10,231 Btu/Net kWh. The range about this value, to allow for potential improvement or degradation, is ±634 Btu/Net kWh.

The heat rate target for Big Bend Unit 2 is 9,928 Btu/Net kWh with a range of ±415 Btu/Net kWh. The heat rate target for Big Bend Unit 3 is 10,036 Btu/Net kWh, with a range of ±628 Btu/Net kWh. The heat rate target for Big Bend Unit 4 is 10,089 Btu/Net kWh with a range of ±379 Btu/Net kWh. The heat rate target for Gannon Unit 5 is 10,716 Btu/Net kWh with a range of ±692 Btu/Net kWh. The heat rate target for Gannon Unit 6 is 10,704 Btu/Net kWh with a range of ±605 Btu/Net kWh. The heat rate target for Polk Unit 1 is 10,087 Btu/Net kWh with a range of ±840 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 13 of Document No. 1, Part A.

Q. Do the heat rate targets and ranges in Tampa Electric's projection meet the criteria of the GPIF and the philosophy of the Commission?

A. Yes.

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 13. The PROMOD IV cost simulation model was used to calculate the total system fuel cost if all units operated at target heat rate and target availability for the period. This total system fuel cost of $543,574,800 is shown on page 6, column 2.

The PROMOD IV output was then used to calculate total system fuel cost with each unit individually operating at maximum improvement in equivalent availability and each station operating at maximum improvement in average net operating heat rate. The respective savings are shown on page 6, column 4 of Document No. 1, Part A.

After all of the individual savings are calculated column 4 totals $27,494,500, which reflects the savings if all of the 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 1, the weighting factor for equivalent availability is 5.32% as shown in the right-hand column on page 6. Pages 7 through 13 of Document No. 1, Part A 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 1, page 7, if the unit operates at 81.2% equivalent availability, fuel savings would equal $1,461,700 and ten equivalent availability points would be awarded.

The GPIF Reward/Penalty Table on page 2 is a summary of the tables on pages 7 through 13. The left-hand column of this document shows the incentive points for Tampa Electric. The center column shows the total fuel savings and is the same amount as shown on page 6, column 4, $27,494,500. The right hand column of page 2 is the estimated reward or penalty based upon performance.

Q. How were the maximum allowed incentive dollars determined?

A. Referring to page 3, line 14, the estimated average common equity for the period January 2002 through December 2002 is $1,452,018,692. This produces the maximum allowed jurisdictional incentive dollars of $5,691,728 shown on line 21.

Q. Are there any other constraints set forth by the Commission regarding the magnitude of incentive dollars?

A. Yes. Incentive dollars are not to exceed 50 percent of fuel savings. Page 2 of Document No. 1, Part A demonstrates that this constraint is met.

Q. Please summarize your testimony on the GPIF?

A. Tampa Electric has fully complied with the Commission's directions, philosophy, and methodology in our determination of GPIF. The GPIF is determined by the following formula for calculating Generating Performance Incentive Points (GPIP):

$$
\begin{aligned}
GPIP: = (\ & 0.0532\ EAP_{BB1} + 0.0617\ EAP_{BB2} \\
& + 0.0582\ EAP_{BB3} + 0.0303\ EAP_{BB4} \\
& + 0.0619\ EAP_{GN5} + 0.1046\ EAP_{GN6} \\
& + 0.0498\ EAP_{PK1} + 0.1135\ HRP_{BB1} \\
& + 0.0697\ HRP_{BB2} + 0.0996\ HRP_{BB3} \\
& + 0.0748\ HRP_{BB4} + 0.0428\ HRP_{GN5} \\
& + 0.0687\ HRP_{GN6} + 0.1112\ HRP_{PK1}\ )
\end{aligned}
$$

Where:

GPIP = Generating Performance Incentive Points.

EAP = Equivalent Availability Points awarded/deducted for Big Bend Units 1, 2, 3 and 4, Gannon Units 5 and 6, and Polk Unit 1.

HRP = Average Net Heat Rate Points awarded/deducted for Big Bend Units 1, 2, 3 and 4, Gannon Units 5 and 6, and Polk Unit 1.

Q. Have you prepared a document summarizing the GPIF targets for the January 2002 - December 2002 period?

A. Yes. Document No. 2 entitled "Tampa Electric Company, Summary of GPIF Targets, January 2002 - December 2002" provides the availability and heat rate targets for each unit.

Q. Does this conclude your testimony?

A. Yes.

MR. BEASLEY: And Ms. Wehle's testimony.

CHAIRMAN JACOBS: Without objection, show Ms. Wehle's testimony is entered into the record as though read. Thank you.

TAMPA ELECTRIC COMPANY
DOCKET NO. 010001-EI
FILED: 09/20/01

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

JOANN T. WEHLE

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

A. My name is Joann T. Wehle. My mailing address is P.O. Box 111, Tampa, Florida 33601, and my business address is 6944 U.S. Highway 41 North, Apollo Beach, Florida 33572. I am employed by Tampa Electric Company ("Tampa Electric" or "company") as Director, Fuels in the Fuels Department.

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

A. I received a Bachelor's of Business Administration Degree in Accounting in 1985 from St. Mary's College, South Bend, Indiana. I am a CPA in the State of Florida and worked in several accounting positions prior to joining Tampa Electric. I began my career with Tampa Electric in 1990 as an auditor in the Audit Services Department. I became Sr. Contracts Administrator, Fuels in 1995. In 1999,. I was promoted to Director, Audit Services and subsequently rejoined the Fuels Department as Director in

April 2001. I am responsible for managing Tampa Electric's fuel-related activities including planning, procurement, inventory, usage and combustion by-product management.

Q. Please state the purpose of your testimony.

A. The purpose of my testimony is to report to the Florida Public Service Commission ("Commission") the 2000 actual costs of Tampa Electric's affiliated coal transportation transactions compared to the benchmark prices calculated in accordance with Order No. 20298. As shown by that comparison, the 2000 prices paid by Tampa Electric to its affiliated company, TECO Transport, are reasonable and prudent. I will also address a change regarding Tampa Electric's fuel needs for 2002 and beyond. In addition, I will address steps Tampa Electric has taken to manage fuel price and supply volatility. This will include the company's perspective regarding the appropriateness of encouraging utilities to enter into exchange-traded derivative instruments to manage risk associated with fuel transactions.

Benchmark Prices For Affiliated Coal Transportation

Q. Have you prepared any exhibits pertaining to the transportation benchmark?

A. Yes. Exhibit No. ___ (JTW-1) was prepared under my direction and supervision.

Q. Were Tampa Electric's actual affiliated coal transportation prices for 2000 at or below the transportation benchmark?

A. Yes, as shown in my exhibit, the affiliated coal transportation prices for 2000 were at or below the transportation benchmark. Accordingly, it is appropriate for Tampa Electric to recover its payments included in the Fuel and Purchased Power Cost Recovery Clause for 2000 coal transportation. The average price for the year were at or below the appropriate benchmark calculations as directed by Order No. 20298 of this Commission.

2002 Fuel Mix Change

Q. Do you anticipate any changes to Tampa Electric's fuel mix in 2002?

A. Although not significantly in 2002, the company will begin its transition of adding natural gas to its portfolio. Tampa Electric Company has entered into a firm gas transportation service agreement with Florida Gas Transmission Company for expected needs for its new Polk Unit 3, a new combustion turbine scheduled for in-service by May 2002, as well as the Bayside facility. The agreement commences on May 1, 2002 and provides for service at 50,000 MMBtu per day. No other gas commodity contracts have been entered into other than this transportation services agreement at this time.

Risk Management Practices

Q. Has Tampa Electric taken reasonable steps to manage the risks associated with its fuel transactions through the use of physical financial hedging practices?

A. Yes, Tampa Electric has taken reasonable steps to manage risks associated with fuel transactions. Because coal accounts for over 95 percent of Tampa Electric's fuel mix, the company has entered into physical, bilateral coal purchase contracts that vary in duration and allow for variable delivery quantities to manage price and physical supply volatility. The company has not taken offsetting financial positions to hedge its fuel purchases, because the company has an expected need for its entire fuel supply. Therefore, Tampa Electric has tried to maintain a mix of 60 percent long- and mediumterm and 40 percent short-term or spot coal contracts to reduce the overall exposure to price volatility in the spot market while leaving some tonnage available for spot market pricing. By continually striving for an optimal blend of fuel supply contracts, the company has been able to mitigate price volatility, while maintaining an adequate fuel supply to ensure system reliability.

Q. Should the Commission encourage each investor-owned electric utility to enter exchange-traded derivative instruments to manage the risks associated with its fuel transactions?

A. It would be appropriate for the Commission to encourage utilities to investigate how exchange-traded derivative instruments can be used in connection with utility's current fuel activities. These instruments may not be available to all utilities given their fuel mix and operating characteristics. Both the Commission and each utility need to fully understand and assess the risks and rewards associated with these instruments.

Q. As the Commission continues to examine hedging practices, what considerations should it take into account?

A. Although it is certainly appropriate for the Commission to explore hedging practices, it should be noted that hedging in and of itself is not a panacea for managing fuel pricing and supply volatility. It is simply another tool that may be considered by utilities. It is also important to consider that each utility has its own specific fuel needs and not all hedging activities will be available to each utility. For example, as I stated earlier, Tampa Electric's current fuel mix currently is over 95 percent coal, a commodity that is neither homogenous nor is it actively traded on an exchange. Likewise, there is a cost associated with conducting these transactions. Therefore in the long-term, the overall price of fuel will be greater because of the additional costs to further mitigate or insulate customers from price volatility.

Q. Does this conclude your testimony?

A. Yes it does.

MR. McGEE: Mr. Chairman, while we're at that, Florida Power also has two other witnesses whose testimony has been stipulated and that would be Witness Michael F. Jacob and Thomas R. Connolly. And I would ask that their testimony be inserted into the record as though read.

CHAIRMAN JACOBS: Without objection, show the testimonies of Mr. Jacob and Mr. Connolly --

MR. McGEE: Yes. And Mr. Jacob has an exhibit. It consists of MFJ-1 and 2. It's listed on Page 33 of the prehearing order. We would ask that that exhibit be admitted into the evidence.

CHAIRMAN JACOBS: Those testimonies are entered into the record as though read. Show marked as Composite Exhibit 18 Mr. Jacob's Exhibits MFJ-1 and 2. And without objection, show Exhibit 18 is entered into the record.

(Exhibit 18 marked for identification and admitted into the record.)

MR. McGEE: Thank you.

FLORIDA POWER CORPORATION

Docket No. 010001-EI

GPIF Reward/Penalty Amount for January through December 2000

DIRECT TESTIMONY OF MICHAEL F. JACOB

Q. Please state your name and business address.

A. My name is Michael F. Jacob. My business address is Post Office Box 14042, St. Petersburg, Florida 33733.

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

A. I am employed by Florida Power Corporation as Manager of Generation Modeling and Analysis.

Q. What are your responsibilities as Manager of Generation Modeling and Analysis?

A. As Manager of Generation Modeling and Analysis, I am responsible for managing the development and application of the models, analysis and data used for generation planning purposes. In particular, my duties include responsibility for the preparation of the information and material required by the Commission's GPIF mechanism.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to describe the calculation of the Company's Generation Performance Incentive Factor (GPIF) reward/penalty amount for the period of January through December 2000. This was developed by comparing the actual performance of the Company's nine 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, my exhibit (MFJ-1) consists of the 27 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 $266,919. 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 each unit's Generating Performance Incentive Points Table found on Sheets 8 through 16 of my exhibit.

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

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

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

A. Yes. Sheet 26 of my exhibit summarizes the planned outages experienced by the Company's GPIF units during the period. Sheet 27 presents an as-worked schedule for each individual planned outage.

Q. Does this conclude your testimony?

A. Yes.

FLORIDA POWER CORPORATION

Docket No. 010001-EI

Re: GPIF Targets and Ranges for January through December 2002

DIRECT TESTIMONY OF MICHAEL F. JACOB

Q. Please state your name and business address.

A. My name is Michael F. Jacob. My business address is 410 South Wilmington Street, Raleigh, North Carolina, 27601.

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

A. I am employed by Carolina Power & Light Company as Manager of Generation Modeling and Analysis.

Q. What are your responsibilities as Manager of Generation Modeling and Analysis?

A. As Manager of Generation Modeling and Analysis, I am responsible for the development and application of the models, analysis and data used for generation planning purposes. In particular, my duties include responsibility for the preparation of the information and material required by the Commission's Generation Performance Incentive Factor (GPIF) mechanism.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present the development of the Company's Generation Performance Incentive Factor (GPIF) targets and ranges for the period of January through December 2002. These GPIF targets and ranges have been developed from individual unit equivalent availability and average net operating heat rate targets and improvement/degradation ranges for each of Florida Power's GPIF generating units, in accordance with the Commission's Generating Performance Incentive Implementation Manual. This presentation of GPIF targets and ranges on an annual, calendar-year basis is in accordance with Commission Order No. PSC-98-0691-FOF-PU.

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

A. Yes, I am sponsoring an exhibit containing 94 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. This exhibit is attached to my prepared testimony.

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

A. I have included the same units as were included for the 2001 period, Anclote Units 1 and 2, Bartow Unit 3, Crystal River Units 1 through 5, and

Tiger Bay Unit 1. The Company's Hines Unit 1 was not included for this projection period because its current performance history is not yet sufficient to provide a representative data base for setting targets and ranges.

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

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

Q. How were the equivalent availability targets developed?

A. The equivalent availability targets were developed using the methodology established for the Company's GPIF units, as set forth in Section 4 of the Implementation Manual. This method describes the formulation of graphs based on each unit's historic performance data for the four individual unplanned outage rates (i.e., forced, partial forced, maintenance and partial maintenance outage rates), which in combination constitute the unit's equivalent unplanned outage rate (EUOR). From operational data and these graphs, the individual target rates are determined by inspecting two years of twelve-month rolling averages and the scatter of monthly data points during the two-year period. The unit's four target rates are then used to calculate its unplanned outage hours for the projection period. When the unit's projected planned outage hours are taken into account, the hours calculated from these individual unplanned outage rates can then be converted into an overall equivalent unplanned outage factor (EUOF). Because factors are additive (unlike rates), the unplanned and planned outage factors (EUOF and POF) when added to the equivalent availability factor (EAF) will always equal 100%. For example, an EUOF of 15% and 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 96.21%. The unit's EUOR and EUOF targets are both 3.79% since there are no planned outage hours estimated for the year 2002.

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

A. In general, the methodology described in the Implementation Manual was used. Ranges were first established for each of the four unplanned outage rates associates 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 term 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. This information is included in the Target and Range Summary on page 3 of my exhibit.

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

A. The development of the heat rate targets and ranges for the upcoming period utilized historical data from the past three years, as described in the Implementation Manual. A "least squares" procedure was used to curve-fit the heat rate data within ranges having a 90% confidence level of including all data. The 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 incentive points. The maximum savings (loss) dollars are the same as those used in the calculation of the weighting factors.

Q. How were the GPIF weighting factors determined?

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

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

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

Q. Does this conclude your testimony?

A. Yes.

FLORIDA POWER CORPORATION

DOCKET NO. 010001-EI

DIRECT TESTIMONY OF THOMAS R. CONNOLLY

Q. Please state your name and business address.

A. My name is Thomas R. Connolly. 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 (Florida Power or the Company) in the capacity of Manger, Engineering Programs.

Q. What are the duties and responsibilities of your position with Florida Power?

A. As Manager of Engineering Programs, I am responsible for engineering programs, testing and inspection, and document management support for Florida Power's fossil fuel generating units, as well as those owned by other subsidiaries of Progress Energy located in North Carolina, South Carolina and Georgia.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to address Issue 19E identified in the Prehearing Officer's September 11, 2001 revised procedural order, regarding the reasonableness of the replacement fuel costs associated with the unplanned outage at the Company's Crystal River Unit 2 (CR2) coal plant that began on June 1, 2000 and concluded on September 6, 2000.

Q. What caused the 14-week unplanned outage at CR2?

A. The outage began when a high voltage disconnect switch between CR2's generator and an auxiliary station service transformer failed, which resulted in a high energy fault that caused significant damage to the generator rotor. The 60 ton, 40-foot long rotor had to be removed from the generator and shipped to the service facility of the generator vendor, General Electric, in Jacksonville for repair and then to the vendor's major equipment facility in New York for final testing and balancing. Finally, the rotor was shipped back to the Crystal River plant site and reinstalled, and CR2 was then returned to service.

Q. What were the replacement power costs associated with this unplanned outage?

A. Florida Power's response to Interrogatory No. 6 in Staff's first set of interrogatories to the Company describes the production cost modeling study that calculated total replacement fuel and purchased power costs of $36.5 million associated with CR2's unplanned outage.

Q. Could this outage have been avoided or its duration shortened?

A. Based on what the Company has learned from the outage at CR2, I doubt that the cause of this outage would occur today. Because of the outage, Florida Power decided that, system wide, this type of switch will no longer be operated while the related generating unit is on line. At the time CR2's outage occurred, however, I can think of no reason why anyone on the plant's maintenance staff could have foreseen that the operation of that particular switch, which had been operated under similar circumstances many times, would lead to the significant damage to the generator rotor that took place.

Regarding the duration of the outage, it was only through the persistence of the Florida Power employees assigned to this project that a substantially longer outage was avoided. The vendor's initial recommendation was that the damage to the generator rotor was too extensive to be satisfactorily repaired and would have to be replaced. An extensive search disclosed that no existing replacement rotors suitable for use at CR2 were available. As a result, a new rotor would have to have been manufactured, which would have required the plant to be out of service for at least a year, and possibly as long as 18 months. Instead, after the Florida Power representatives requested the vendor to conduct additional evaluations of repair possibilities, a plan was devised under which temporary repairs were made to the rotor that enabled CR2 to be placed back in service in only three months. This plan also allowed the time consuming process of obtaining a replacement rotor to take place while the unit is in operation. Florida Power will then be able to install the new rotor in conjunction with other required maintenance work during a scheduled outage of the unit, which is currently planned for early 2002.

Q. Please describe the specific events that led to this outcome.

A. As I mentioned earlier, a high voltage disconnect switch failed during opeation on June 1, 2000, while attempting to place an auxiliary station service transformer back in operation. The transformer had been taken out of service several days earlier for maintenance and repair after sampling tests on the transformer's oil indicated a high percentage of combustibles.

The switch failure caused a high-energy electrical fault to occur, which tripped the generator off-line while the unit was operating at full load. Recognizing that a fault of this type had the potential to damage to the turbine generator and other components, a full visual inspection and test was performed immediately on critical major system components, *i.e.*, the generator stator, generator field rotor, step-up transformer, auxiliary transformers and the steam turbine.

The initial inspection of the generator rotor conducted with video probe instrumentation revealed significant surface damage that required further inspection, which required that the rotor be removed from the stator. All other major components showed relatively minor or no damage during the initial inspection. After the rotor was removed from the stator, the rotor forging was observed to have suffered serious electric arc strikes and metal spatter from end to end.

Consequently, the decision was made to ship the rotor to GE's service facility in Jacksonville for disassembly and further damage assessment. Based on the results of this assessment, GE advised Florida Power that no experiential repairs were available and that the rotor should be replaced. This would have been a serious setback, since the availability of an existing replacement rotor was uncertain and the need to manufacture a new rotor would require a lengthy extension of CR2's unplanned outage. A subsequent search disclosed that, in fact, no replacement rotors suitable for use at CR2 were available.

For this reason, Florida Power asked GE to conduct additional evaluations to confirm whether concerns over the reliability, scope, and limitations of repairs to the rotor precluded this alternative and required replacement of the rotor. These evaluations involved extensive multiple tests of hundreds of systematically selected locations on the surface of the rotor, which were then repeated two, and in some cases, three times. Analysis of the test results led to the conclusion that repairs could be made that would allow the rotor to be used for limited period, thus avoiding the need to extend CR2's unplanned outage until a replacement rotor could be obtained and installed.

The rotor repairs were performed in the Jacksonville service shop under the direction of specialists with GE Engineering from its headquarters in Schenectady, New York. Upon completion of the repairs, a boresonic evaluation of the rotor was performed, which confirmed that the rotor was ready for final testing. The rotor was then shipped to GE's major testing facility in Schenectady on August 7, 2000 for high-speed balancing and dynamic thermal testing to insure that the rotor could be reliably returned to service.

The work at the GE testing facility was completed on August 17th and the rotor was shipped back at the Crystal River plant site, where it was received on August 22nd. Florida Power maintenance crews were awaiting the rotor's arrival and were able to complete the reinstallation of the rotor the same day. After completion of start-up testing, CR2 was returned to service on September 6th.

All of the repairs, shipping and testing of the rotor were performed on a expedited basis. The overall generator rotor repair activity was the "critical path" component for the entire outage and the activity was worked in this manner to minimize its impact on the duration of the outage.

Q. Does this conclude your testimony?

A. Yes.

COMMISSIONER JABER: And Mr. Chairman --

MR. BEASLEY: Our witness -- I'm sorry.

COMMISSIONER JABER: -- on TECO, I know TECO offered a stipulation on Mr. Hornick, but did we move that testimony into the record?

CHAIRMAN JACOBS: Not in this docket. We had testimony from him in another docket but not in this one.

MR. BEASLEY: I would ask that Mr. Hornick's testimony be inserted into the record.

CHAIRMAN JACOBS: I did have him checked off, though. Why did I have him checked off?

COMMISSIONER JABER: TECO offered yesterday that the parties have agreed to allow the testimony to come into the record without cross, but I don't think we ever inserted it into the record.

CHAIRMAN JACOBS: Subject to checking in the record again and in an abundance of caution, we'll go ahead and enter Mr. Hornick's testimony into the record as though read unless it was previously done. I'll confirm that.

(REPORTER'S NOTE: Mr. Hornick's testimony was inserted in Volume 1 of 010001-EI.)

MR. BEASLEY: We have three additional exhibits, Mr. Chairman. The first one being that of Mr. Buckley, BSB-1.

CHAIRMAN JACOBS: Just one moment. Very well. Show marked as Exhibit 19 the exhibit of Mr. Buckley, BSB-1.

(Exhibit 19 marked for identification.)

MR. BEASLEY: And then Mr. Keselowsky's Exhibit GAK-1.

CHAIRMAN JACOBS: Show it marked as Exhibit 20.

(Exhibit 20 marked for identification.)

MR. BEASLEY: And Joann Wehle's Exhibit JTW-1.

CHAIRMAN JACOBS: Show it marked as Exhibit 21.

(Exhibit 21 marked for identification.)

MR. BEASLEY: And I would move that Exhibits 19, 20, 21 be admitted into the record.

CHAIRMAN JACOBS: Without objection, show Exhibits 19, 20, and 21 are entered into the record. Thank you.

(Exhibits 19, 20, and 21 admitted into the record.)

MR. KEATING: And, Mr. Chairman, while we are cleaning things up, there are two other witnesses that have been excused. They're listed in the prehearing order, George Bachman for Florida Public Utilities Company and Kathy Welch who filed testimony on behalf of staff. Staff would recommend that those two pieces of testimony be moved into the record as though read.

CHAIRMAN JACOBS: That is the testimony of Mr. Bachman --

MR. KEATING: Yes.

CHAIRMAN JACOBS: -- and Ms. Welch?

MR. KEATING: Yes.

CHAIRMAN JACOBS: Without objection, show the testimonies of Mr. Bachman and Ms. Welch are entered into the record as though read.

MR. KEATING: And Mr. Bachman has two exhibits, GMB-1 and 2. Staff would recommend that those be marked, I believe it's 22 is the next exhibit number.

CHAIRMAN JACOBS: Show that marked as Exhibit 22.

(Exhibit 22 marked for identification.)

MR. KEATING: And finally --

CHAIRMAN JACOBS: Let me make sure I have those checked off as well here. GMB-1. And Ms. Welch?

MR. KEATING: Ms. Welch has three exhibits, KLW-1, KLW-2, and KLW-3. The issue to which her second exhibit went towards has been removed from this proceeding, so we would ask that KLW-1 and KLW-2 (sic) be marked for identification.

CHAIRMAN JACOBS: Show those marked as Composite Exhibit 23.

(Exhibit 23 marked for identification.)

CHAIRMAN JACOBS: And without objection, show Exhibits 22 and 23 are admitted.

(Exhibits 22 and 23 admitted into the record.)

BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 010001-EI
CONTINUING SURVEILLANCE AND REVIEW OF
FUEL COST RECOVERY CLAUSES OF ELECTRIC UTILITIES

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

Q. Please state your name and business address.

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

Q. By whom are you employed?

A. I am employed by Florida Public Utilities Company.

Q. Have you previously testified in this Docket?

A. Yes.

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

A. I will briefly describe the basis for the computations that were made in the preparation of the various Schedules that we have submitted in support of the January 2002 - December 2002 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 January 2001 - December 2001 and to establish a "true-up" amount to be collected or refunded during January 2002 - December 2002.

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

A. Yes.

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

A. We have filed Schedules E1, E1A, E1-B, E1B-1, E2, E7, and E10 for

Marianna and E1, E1A, E1-B, E1-B1, E2, E7, E8, and E10 for Fernandina Beach. They are included in Composite Prehearing Identification Number GMB-2. Schedule E1-B and E1-B1 for both Marianna and Fernandina Beach were filed last month in Composite Prehearing Identification Number GMB-1.

These schedules support the calculation of the levelized fuel adjustment factor for January 2002 - December 2002. Schedule E1-B shows the Calculation of Purchased Power Costs and Calculation of True-Up and Interest Provision for the period January 2001 - December 2001 based on 6 Months Actual and 6 Months Estimated data.

Q. In derivation of the projected cost factor for the January 2002 - December 2002, 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 January 2002 - December 2002.

A. We have determined that at the end of December 2001 based on six months actual and six months estimated, we will have under-recovered $62,173 in purchased power costs in our Marianna division. Based on estimated sales for the period January 2002 - December 2002, it will be necessary to add .02050¢ per KWH to collect this under-recovery.

In Fernandina Beach we will have under-recovered $16,863 in purchased power costs. This amount will be collected at .00528¢ per KWH during the January 2002 - December 2002 period (excludes GSLD customers). Page 3 and 10 of Composite Prehearing Identification Number GMB-2 provides a detail of the calculation of the true-up amounts.

Q. Looking back upon the January 2000 - December 2000 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 $87,926 and Fernandina Beach Division over-recovered $508,053. 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 January 2000 - December 2000 for both divisions?

A. In Marianna the final remaining true-up amount was an under-recovery of $60,625. The final remaining true-up amount for Fernandina Beach was under-recovery of $109,370.

Q. What are the estimated true-up amounts for the period of January 2001 - December 2001.

A. In Marianna, there is an estimated under-recovery of $1,548. Fernandina Beach has an estimated over-recovery of $92,507.

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

A. In Marianna the total fuel adjustment factor as shown on Line 33, Schedule E1, is 2.333¢ per KWH. In Fernandina Beach the total fuel adjustment factor for "other classes", as shown on Line 43, Schedule E1, amounts to 2.095¢ per KWH.

Q. Please advise what a residential customer using 1,000 KWH will pay for the period January 2001 - December 2001 including base rates, conservation cost recovery factors, and fuel adjustment factor and after application of a line loss multiplier.

A. In Marianna a residential customer using 1,000 KWH will pay $63.04, an increase of 2.28 from the previous period. In Fernandina Beach a customer will pay $59.91, an increase of $5.30 from the previous period.

Q. Does this conclude your testimony?

A. Yes.

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DIRECT TESTIMONY OF KATHY L. WELCH

Q. Please state your name and business address.

A. My name is Kathy L. Welch. My business address is 3625 NW 82nd Ave, Suite 400, Miami, Florida.

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

A. I am employed by the Florida Public Service Commission as a Regulatory Analyst Supervisor in the Division of Auditing and Financial Analysis.

Q. How long have you been employed by the Commission?

A. I have been employed by the Florida Public Service Commission for twenty-two years.

Q. Briefly review your educational and professional background.

A. I have a Bachelor of Business Administration degree with a major in accounting from Florida Atlantic University. I have a Certified Public Manager certificate from Florida State University. I am also a Certified Public Accountant licensed in the State of Florida. I was hired as a Public Utilities Analyst I by the Florida Public Service Commission in June of 1979. I was promoted to Regulatory Analyst Supervisor on January 2, 1990.

Q. Please describe your current responsibilities.

A. Currently, I am a Regulatory Analyst Supervisor with the responsibilities of administering the Miami District Office, reviewing workload and allocating resources to complete field work and issue audit reports. I also supervise, plan, and conduct utility audits of manual and automated accounting systems for historical and forecasted financial statements and exhibits.

Q. Have you testified before this Commission or any other regulatory agency?

A. Yes. I have filed testimony in the following cases before this Commission: Tamiami Village Utility, Inc. rate case, Docket No. 910560-WS; Tamiami Village Utility, Inc. transfer to North Fort Myers, Docket No. 940963-SU; General Development Utilities, Inc. rate case, Docket No. 911030-WS; Econ Utilities Corporation transfer to Wedgefield Utilities, Inc., Docket No. 960235-WS; and Gulf Utility Company rate case, Docket No. 960329-WS.

Q. What is the purpose of your testimony today?

A. The purpose of my testimony is to sponsor three staff audit reports:

- Florida Power & Light: Fuel Adjustment Clause; Docket Number 010001-EI; Audit Control Number 01-053-4-1. This audit report is filed with my testimony and is identified as KLW-1.
- Florida Power and Light: Purchasing and Selling Practices for Natural Gas; Undocketed; Audit Control Number is 00-353-4-1. A redacted copy of the audit report is filed with my testimony and is identified as KLW-2.
- Florida Public Utilities Company (FPUC): Fuel Adjustment Clause; Docket Number 010001-EI; Audit Control Number 01-053-4-2. This audit report is filed with my testimony and is identified as KLW-3.

Q. Let's begin by discussing the first audit report, the Florida Power & Light (FPL) fuel audit. Did you prepare or cause to be prepared under your supervision, direction, and control this audit report?

A. Yes, I supervised the audit work performed and reviewed the report before it was filed.

Q. Could you summarize your findings in this audit?

A. Yes. Audit Disclosure No. 1 discusses adjustments to the coal inventory and the company compliance with Commission Order PSC 97-0359-FOF-EI. FPL has an interest in two plants using coal, St. Johns River Park Plant (SJRPP) and Scherer Unit #4 (Scherer). The Commission Order states that adjustments to coal inventory should be booked in the month the survey is conducted. At SJRPP, a survey was conducted for the six months ended March 31, 2000. The adjustment was booked in May 2000. Another survey was done for the six months ended August 31, 2000, and the adjustment booked in October 2000. All four Scherer surveys were booked the first week of the month following the survey.

The order also requires the company to notify the Commission with the survey results by the 15th of the month subsequent to the month during which the surveys are conducted. FPL discloses any adjustments for both SJRPP and Scherer by footnotes to the A-5 schedules submitted monthly instead of by letter notification as required by the Commission Order.

For the Scherer plant, aerial surveys are conducted four times a year which is more than the semi-annual survey required in the order.

Additionally, the order states that if the difference between the book inventory and the survey quantity results is greater than 3%, the adjustment should be recorded. The adjustment amount should be the inventory amount plus or minus the survey results that have been adjusted for a plus or minus 3% variance. For Scherer, each quarterly difference was greater than 3%, computed correctly, and recorded.

The order also states that the adjustment to inventory was to be computed using a weighted average cost based on the most recent six months inventory data. For Scherer, the cost used was a weighted average unit cost for only the month prior to the survey.

Q. Are you providing any testimony on the reasonableness of FPL's adjustments to coal inventory?

A. No. I am only stating the treatment followed by the company.

Q. Have you reviewed the testimony presented by Korel M. Dubin regarding this issue on pages 4 and 5 of her supplemental testimony filed September 20, 2001, in this docket?

A. Yes, I have reviewed her testimony.

Q. Do you agree with her statement of facts?

A. Yes, I agree with her statements of facts.

Q. Now, in regard to the second audit report regarding the FPL purchasing and selling practices for natural gas, did you prepare or cause to be prepared under your supervision, direction, and control this audit report?

A. Yes, this report was prepared under my supervision.

Q. Could you summarize your findings in this audit?

A. The report contains seven audit disclosures. Audit Disclosure Number 1 provides the methodology used by FPL to record the cost of gas and to show that the sales of gas to affiliates is removed from inventory cost at the sales price, which is based on the daily market rate. This cost is sometimes higher than the purchase price and sometimes lower. Lower prices are usually a result of a contract made the prior month. A schedule summarizing the average sales price, the highest price and the lowest price of all gas sold by FPL by month for the year 2000 and the average unit price sold to its affiliate, Energy Services (FPLES) is contained in the disclosure. The schedule shows that FPLES paid more than the average price of gas sold each month and that there were sales at both higher and lower prices. Review of daily sales tickets show that sales made to FPLES were at an amount at or over the daily market rate.

Audit Disclosure Number 2 simply states that fuel transactions are exempt from the affiliated transaction rule.

Audit Disclosure Number 3 discusses that the pricing model used by FPLES may be contributing to low prices. --

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Audit Disclosure Number 4 outlines the difference between in-territory and out-of-territory treatment of revenues and expenses for FPLES gas sales. The disclosure reports that although FPLES customers in FPL's utility territory receive bills from FPLES, the revenues, cost of gas, transportation costs, sales, and administrative costs related to these in-territory sales are recorded in the FPL utility books in a revenue account for revenue enhancing products. The disclosure also reports that in-territory gas sales operated at a loss in the year 2000 and, therefore, that loss was passed through to the utility customers. Staff determined that the loss was higher than recorded because for in-territory sales, administrative costs did not include corporate overhead costs and payroll costs. These costs were recorded in FPL utility operating expenses. The loss reported on the books was $216,363. Corporate overhead costs determined by staff were $123,133.18 and payroll was $192,622.78.

Audit Disclosure Number 5 relates to the company methodology for allocating corporate overhead known as the management fee. The disclosure computes the $123,133.18 discussed in Disclosure 4 and, in addition, reports that the management fee included a charge called change of control. This charge was determined to be for performance incentives paid as a result of the approval by the Board of Directors of the company's merger with Entergy. The incentive program contains a clause that requires payment of the incentives when the Board of Directors approved a merger. The amounts reported in the disclosure as being part of the management fee are currently being audited as part of a new audit looking into the attempted merger with Entergy Corporation.

Audit Disclosure Number 6 discusses the results of interviews with employees, the audit of payroll costs, and examination of sales brochures and mailings. During this part of the audit, it was determined that the payroll costs for in-territory gas sales were never charged to FPLES and are not on the In-Territory Income Statement as discussed in Disclosure 4. The disclosure also contained some minor allocation problems between in-territory and out-of-territory costs.

Audit Disclosure Number 7 reports that risk management expenses have been treated inconsistently from year to year. FPLES appears to have paid for all of the costs related to the Nucleus software in 1998, 1999, and 2000, as opposed to allocating the costs between in-territory and out-of-territory. In the year 2000, FPLES is only paying for a minor portion of risk management salaries.

Q. Are you providing any testimony on the reasonableness of FPL's treatment?

A. No. I am only stating the treatment followed by the company.

Q. Have you reviewed the testimony presented by Korel M. Dubin regarding these issues on pages 6 and 7 of her supplemental testimony filed September 20, 2001, in this docket?

A. Yes, I have reviewed her testimony.

Q. Do you agree with her statement of facts?

A. Yes, I agree with her statements of facts.

Q. Now, in regard to the third audit report regarding the Florida Public Utilities Company fuel audit, did you prepare or cause to be prepared under your supervision, direction, and control this audit report?

A. Yes, I was the audit manager in charge of this audit.

Q. Could you summarize your findings in this audit?

A. The report contained one audit disclosure regarding billing errors. Audit Disclosure Number 1 discusses that in October 2000, the company implemented a new billing system. When the system was first implemented, several errors occurred. The company under billed several customers during this time period. It decided not to retroactively bill the customers because the time it would take to determine who should be billed and to correct the billing would cost more than the revenue loss. When October revenues were recomputed using kilowatts times approved rates, the revenue that should have been billed was $2,686 more than what was actually billed. The majority of the error, $1,829 was because the company did not bill GSD customers .00988 of the approved .03596 rate. The schedules should and do reflect actual billings. However, actual billings are less than the approved revenues.

Q. Are you providing any testimony on the what corrections should be made by Florida Public Utilities Company?

A. No. I am only stating the treatment followed by the company.

Q. Does that conclude your testimony?

A. Yes.

CHAIRMAN JACOBS: And we have the composite. Very well. Sorry to interrupt you Mr. --

MS. GORDON-KAUFMAN: Mr. Chairman, since we're in the housecleaning mode, I think there's one more outstanding exhibit which was staff's Number 4. And it was a composite exhibit that we talked about yesterday. And in regard to Mr. Hornick's deposition, we discussed whether the entire deposition should come in or just the selected excerpts that related to Issues 24A and 24B. And I discussed that with staff, and I believe they have identified the pages that relate to the issues, and they want only those pages inserted.

MR. KEATING: That's correct.

MS. GORDON-KAUFMAN: And we would have no objection to that.

MR. KEATING: That's correct. The page numbers from Mr. Hornick's deposition that are included is the last item in staff's Composite Exhibit 4 that staff would ask to be included in the record are Pages 15 through 17.

CHAIRMAN JACOBS: Very well. That was -- we marked that as Exhibit --

MR. BEASLEY: Would you want to include the cover page to show whose deposition it was, perhaps?

MR. KEATING: Yes. We would just -- actually, the entire deposition is included in the hard copy, but for purposes of what's going to be in the record for this proceeding, it would just be substance Pages 15 to 17 plus the cover page, I hope.

CHAIRMAN JACOBS: Here it is. And that was -- show that marked -- and those page numbers, again? I'm sorry, give me -- we entered it subject to your objection, and now, you're removing that objection pursuant to this modification.

MS. GORDON-KAUFMAN: Right, that only those three pages will be included in the record.

CHAIRMAN JACOBS: Give me those pages again, please.

MR. KEATING: Pages 15, 16, and 17.

CHAIRMAN JACOBS: Got it.

COMMISSIONER JABER: Let's not forget the cover page.

CHAIRMAN JACOBS: And the cover page. Do not leave that out. Thank you. Very well.

Now, back to Mr. Hartzog.

MR. CHILDS: What I'd like to do, I guess, is, I thought staff was going to move all of it at the end, but I'm going to put it in, if I can, Mr. Chairman. On Page 7 of the prehearing order are the witnesses identified for Florida Power & Light Company starting with Mr. Yupp and ending with Mr. Silva. And what I'd like to do is to ask for all of that testimony to be moved into the record as though read. I'm going to call the three that are supplemental witnesses. I'd like to do that all at once.

CHAIRMAN JACOBS: Very well. Let's go off the record just a second.

MR. CHILDS: And then --

CHAIRMAN JACOBS: We need to go off the record for just a second, Mr. Childs.

MR. CHILDS: All right.

(Off the record.)

(Transcript continues in sequence in Volume 5.)

STATE OF FLORIDA)

: CERTIFICATE OF REPORTER

COUNTY OF LEON)

I, TRICIA DeMARTE, Official Commission Reporter, do hereby certify that the foregoing proceeding was heard at the time and place herein stated.

IT IS FURTHER CERTIFIED that I stenographically reported the said proceedings; that the same has been transcribed under my direct supervision; and that this transcript constitutes a true transcription of my notes of said proceedings.

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

DATED THIS 3RD DAY OF DECEMBER, 2001.

Tricia DeMarte

TRICIA DeMARTE
FPSC Official Commission Reporter
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