BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In Re: Fuel and Purchased Power Cost Recovery Clause and Generating Performance Incentive Factor.	DOCKET NO. 940001-EI ORDER NO. PSC-94-0266-PHO-EI ISSUED: 03/08/94

Pursuant to Notice, a Prehearing Conference was held on March 4, 1994, in Tallahassee, Florida, before Chairman J. Terry Deason, as Prehearing Officer.

APPEARANCES:

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On behalf of Florida Power Corporation.

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On behalf of Florida Power and Light Company.

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On behalf of Florida Public Utilities Company.

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On behalf of Gulf Power Company.

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On behalf of Tampa Electric Company.

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On behalf of Florida Industrial Power Users Group.

MARK K. LOGAN, Esquire, Bryant, Miller & Olive, 201 South Monroe Street, Suite 500, Tallahassee, Florida 32301 AND THOMAS J. SCHMIDT, General Counsel, Orgulf Transport Company, 1400-580 Building, Post Office Box 1460, Cincinnati, Ohio 45201
On behalf of Orgulf Transport Company.

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On behalf of the United Mine Workers of America.

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On behalf of the Citizens of the State of Florida

MARTHA CARTER BROWN, Esquire and DONNA L. CANZANO, Esquire, Florida Public Service Commission, 101 E. Gaines Street, Tallahassee, Florida 32399-0863
On behalf of the Commission Staff.

PRENTICE P. PRUITT, Esquire, Florida Public Service Commission, 101 E. Gaines Street, Tallahassee, Florida 32399-0862
On behalf of the Commissioners.

PREHEARING ORDER

I. CASE BACKGROUND

As part of the Commission's continuing fuel and energy conservation cost, purchased gas cost, and environmental cost recovery proceedings, a hearing is set for March 9-10, 1994 in this docket and in Dockets No. 940002-EG, 940003-GU and 940042-EI. The hearing will address the issues set out in the body of this prehearing order.

II. PROCEDURE FOR HANDLING CONFIDENTIAL INFORMATION

A. Any information provided pursuant to a discovery request for which proprietary confidential business information status is requested shall be treated by the Commission and the parties as confidential. The information shall be exempt from Section 119.07(1), Florida Statutes, pending a formal ruling on such request by the Commission, or upon the return of the information to the person providing the information. If no determination of confidentiality has been made and the information has not been used in the proceeding, it shall be returned expeditiously to the person providing the information. If a determination of confidentiality has been made and the information was not entered into the record of the proceeding, it shall be returned to the person providing the information within the time periods set forth in Section 366.093, Florida Statutes.

B. It is the policy of the Florida Public Service Commission that all Commission hearings be open to the public at all times. The Commission also recognizes its obligation pursuant to Section 366.093, Florida Statutes, to protect proprietary confidential business information from disclosure outside the proceeding.

In the event it becomes necessary to use confidential information during the hearing, the following procedures will be observed:

1) Any party wishing to use any proprietary confidential business information, as that term is defined in Section 366.093, Florida Statutes, shall notify the Prehearing Officer and all parties of record by the time of the Prehearing Conference, or if not known at that time, no later than seven (7) days prior to the beginning of the hearing. The notice shall include a procedure to assure that the confidential nature of the information is preserved as required by statute.

2) Failure of any party to comply with 1) above shall be grounds to deny the party the opportunity to present evidence which is proprietary confidential business information.

3) When confidential information is used in the hearing, parties must have copies for the Commissioners, necessary staff, and the Court Reporter, in envelopes clearly marked with the nature of the contents. Any party wishing to examine the confidential material that is not subject to an order granting confidentiality shall be provided a copy in the same fashion as provided to the Commissioners, subject to execution of any appropriate protective agreement with the owner of the material.

4) Counsel and witnesses are cautioned to avoid verbalizing confidential information in such a way that would compromise the confidential information. Therefore, confidential information should be presented by written exhibit when reasonably possible to do so.

5) At the conclusion of that portion of the hearing that involves confidential information, all copies of confidential exhibits shall be returned to the proffering party. If a confidential exhibit has been admitted into evidence, the copy provided to the Court Reporter shall be retained in the Commission Clerk's confidential files.

III. PREFILED TESTIMONY AND EXHIBITS; WITNESSES

Testimony of all witnesses to be sponsored by the parties has been prefiled. All testimony which has been prefiled in this case will be inserted into the record as though read after the witness has taken the stand and affirmed the correctness of the testimony and associated exhibits. All testimony remains subject to appropriate objections. Each witness will have the opportunity to orally summarize his or her testimony at the time he or she takes the stand. Upon insertion of a witness' testimony, exhibits appended thereto may be marked for identification. After all parties and Staff have had the opportunity to object and cross-examine, the exhibit may be moved into the record. All other exhibits may be similarly identified and entered into the record at the appropriate time during the hearing.

Witnesses are reminded that, on cross-examination, responses to questions calling for a simple yes or no answer shall be so answered first, after which the witness may explain his or her answer.

The Commission frequently administers the testimonial oath to more than one witness at a time. Therefore, when a witness takes the stand to testify, the attorney calling the witness is directed to ask the witness to affirm whether he or she has been sworn.

Witnesses whose names are preceded by an asterisk (*) have been excused. The parties have stipulated that the testimony of those witnesses will be inserted into the record as though read, and cross-examination will be waived. The parties have also stipulated that all exhibits submitted with the witnesses' testimony shall be identified as shown in Section VII of this Prehearing Order and admitted into the record.

IV. ORDER OF WITNESSES

Witness	Appearing For	Issues #
*Karl H. Wieland	FPC	1-8, 11-14
*William C. Micklon	FPC	9 and 10
*R. Silva	FPL	1-4, 13-14
*D. C. Poteralski	FPL	1-4
*B. T. Birkett	FPL	1-9, 15-23
*G.M. Bachman	FPUC	1-7
*M.L. Gilchrist	Gulf	1, 2,4,20,21,23
*M.W. Howell	Gulf	1, 2, 4,16, 17, 19
*S.D. Cranmer	Gulf	1, 2, 3, 4 6,7,8, 19,20, 21,22,23
*G.D. Fontaine	Gulf	13,14
*Mary Jo Pennino	TECO	1,2,3,4,5,6,7,8, 11,19,20,21,22,23
*G.A. Keselowsky	TECO	13,14
*R.F. Tomczak/ *E.A. Townes	TECO	15,16,17,18

V. BASIC POSITIONS

FLORIDA POWER CORPORATION (FPC): None necessary.

FLORIDA POWER AND LIGHT COMPANY (FPL): None necessary.

FLORIDA PUBLIC UTILITIES COMPANY (FPUC): Florida Public Utilities has properly projected its costs and calculated its true-up amounts and purchased power cost recovery factors. Those factors should be approved by the Commission.

GULF POWER COMPANY (GULF): It is the basic position of Gulf Power Company that the proposed fuel factors and capacity cost recovery factors present the best estimate of Gulf's fuel and purchased power expense (both energy and capacity) for the period April 1994 through September 1994 including the true-up calculations, GPIF and other adjustments allowed by the Commission.

TAMPA ELECTRIC COMPANY (TECO): The Commission should approve Tampa Electric's calculation of its fuel adjustment, capacity cost recovery, GPIF, and oil backout cost recovery true-up calculations and projections, including the proposed fuel adjustment factor of 2.894 cents per KWH before application of factors which adjust for variation in line losses; the proposed capacity cost recovery factors; a GPIF penalty of $214,237; and an oil backout cost recovery factor of .073 cents per KWH.

FLORIDA INDUSTRIAL POWER USERS GROUP (FIPUG): None at this time.

ORGULF TRANSPORT COMPANY (ORGULF): The Florida Public Service Commission should deny Gulf's petition with respect to all costs related to the Peabody Coal contract buy-out and any other costs related to the administration, suspension, and cancellation of the Orgulf transportation contract as these costs were not prudently incurred. The Commission should also deny recovery for any alternative fuel transportation costs incurred by Gulf Power outside of its transportation agreement with Orgulf.

Alternatively, the Commission should order that Gulf Power be prohibited from recovering all costs associated with the Peabody Coal contract buy-out and other costs relative to the Orgulf transportation agreement for the time period in question until the pending litigation between Gulf and Orgulf Transport is concluded. At such time the Commission can better determine whether costs associated with the administration of the Peabody and Orgulf contracts and other related transportation costs have been prudently incurred and are therefore recoverable from Gulf's ratepayers.

UNITED MINE WORKERS OF AMERICA (UMWA): Gulf Power Company (Gulf) should not be permitted to recover costs associated with the Peabody coal contract buyout (suspension) or the litigation initiated by Orgulf Transport for Gulf's alleged breach of its barge transport contract. The potential damages Gulf is exposed to in the Orgulf litigation greatly outweigh the claimed benefits of the Peabody contract buyout. The Peabody contract buyout would not have been necessary had Gulf reasonably and prudently anticipated the enactment of acid rain legislation when it renegotiated the Peabody contract in 1988. Moreover, none of the principal assumptions underlying Gulf's analysis of the Peabody contract buyout, including continued transport of coal by Orgulf, has come to pass since the buyout was consummated.

In the alternative, any amounts for the Peabody contract buyout or for the Orgulf litigation determined to be recoverable by the Commission in this docket should be subject to refund with interest pending the final disposition of Orgulf's claims against Gulf. Finally, should the Commission determine that this issue should be considered in a subsequent proceeding in this docket or a separate spin-out docket, the UMWA would urge that amounts associated with the Peabody contract buyout would also be held subject to refund pending the outcome of that proceeding.

OFFICE OF PUBLIC COUNSEL (OPC): None necessary.

STAFF: Staff's positions are preliminary and based on materials filed by the parties and on discovery. The preliminary positions are offered to assist the parties in preparing for the hearing. Staff's final positions will be based upon all the evidence in the record and may differ from the preliminary positions.

VI. ISSUES AND POSITIONS

Generic Fuel Adjustment Issues

STIPULATED ISSUE 1: What are the appropriate final fuel adjustment true-up amounts for the period April, 1993 through September, 1993?

POSITION:

FPC:	$18,573,496 underrecovery.
FPL:	$54,419,628 overrecovery.
FPUC:	$87,558 underrecovery. (Marianna) $17,891 underrecovery. (Fernandina Beach)
GULF:	$1,734,229 underrecovery.
TECO:	$8,343,904 underrecovery.

STIPULATED ISSUE 2: What are the estimated fuel adjustment true-up amounts for the period October, 1993 through March, 1994?

FPC: $89,384,887 over-recovery. (Wieland)

FPL:	$57,093,363 overrecovery. (BIRKETT)	
FPUC:	Marianna: Fernandina Beach:	$ 61,995 overrecovery $136,110 overrecovery

POSITION:

FPC:	$23,541,004 overrecovery.
FPL:	$89,231,019
FPUC:	$61,955 overrecovery. (Marianna) $136,110 overrecovery. (Fernandina Beach)
GULF:	$2,995,885 underrecovery.
TECO:	$5,354,211 underrecovery.

STIPULATED ISSUE 3: What are the total fuel adjustment true-up amounts to be collected during the period April, 1994 through September, 1994?

POSITION:

FPC:	$4,967,508 overrecovery.
FPL:	$143,804,515 overrecovery.
FPUC:	$25,603 underrecovery. (Marianna) $118,219 overrecovery. (Fernandina Beach)
GULF:	$4,730,114 underrecovery.
TECO:	$13,698,115 underrecovery.

STIPULATED ISSUE 4: What are the appropriate levelized fuel cost recovery factors for the period April, 1994 through September, 1994?

FPC:

1.968 cents per kWh - Standard rates*
2.692 cents per kWh - TOU On-Peak rates*
1.587 cents per kWh - TOU Off-Peak rates*

*Before line loss adjustment.

FPL: 1.488 cents/kwh is the levelized recovery charge for non-time differentiated rates and 1.633 cents/kwh and 1.415 cents/kwh are the levelized fuel recovery charges for the on-peak and off-peak periods, respectively, for the differentiated rates.

FPUC:

Marianna:	2.793¢/kwh
Fernandina Beach:	3.856¢/kwh

GULF: 2.158 cents per KWH.

TECO: 2.894 cents per KWH before application of the factors which adjust for variations in line losses.

STIPULATED ISSUE 5: What should be the effective date of the new fuel adjustment charge, oil backout charge and conservation cost recovery charge for billing purposes?

POSITION: The factor should be effective beginning with the specified fuel cycle and thereafter for the period April, 1994 through September, 1994. Billing cycles may start before April 1, 1994, and the last cycle may be read after September 30, 1994, so that each customer is billed for six months regardless of when the adjustment factor became effective.

STIPULATED ISSUE 6: What are the appropriate fuel recovery line loss multipliers to be used in calculating the fuel cost recovery factors charged to each rate class?

POSITION:

FPC:

Group	Delivery Voltage Level	Line Loss Multiplier
A.	Transmission	0.9725
B.	Distribution Primary	0.9826
C.	Distribution Secondary	1.0038
D.	Lighting Service	1.0038

FPL: See response to Issue 7.

FPUC: Marianna

Rate Schedule	Multiplier
RS	4.717
GS	4.489
GSD	4.115
GSLD	3.955
OL, OL-2	2.828
SL-1, SL-2	2.760

Fernandina Beach

All Rate Schedules 1.000

GULF: See table below:

Group	Rate Schedules	Line Loss Multipliers
A	RS, GS, GSD, OSIII, OSIV	1.01228
B	LP	0.98106
C	PX	0.96230
D	OSI, OSII	1.01228

TECO:

Group	Multiplier
Group A	1.0064
Group A1	1.0064*
Group B	1.0012
Group C	0.9721
System	1.0000

*Group A1 is based on Group A, 15% of On-Peak and 85% of Off-Peak. (Pennino)

STIPULATED ISSUE 7: What are the appropriate Fuel Cost Recovery Factors for each rate group adjusted for line losses?

POSITION:

FPC:

Group	Delivery Voltage Level	Fuel Cost Factors (cents/kWh) Standard	Time Of Use On-Peak	Time Of Use Off-Peak
A.	Transmission	1.914	2.618	1.543
B.	Distri. Primary	1.934	2.645	1.559
C.	Distri. Secondary	1.975	2.702	1.593
D.	Lighting Service	1.800		

(Wieland)

FPL:

GROUP	RATE SCHEDULE		FUEL RECOVERY LOSS MULTIPLIER	FUEL RECOVERY FACTOR
A	RS-1,GS-1,SL-2		1.00161	1.490
A-1*	SL-1,OL-1		1.00161	1.452
B	GSD-1		1.00155	1.490
C	GSLD-1 & CS-1		1.00046	1.488
D	GSLD-2,CS-2,OS-2 & MET		0.99449	1.480
E	GSLD-3 & CS-3		0.96430	1.435
A	RST-1,GST-1	ON-PEAK	1.00161	1.636
		OFF-PEAK	1.00161	1.417
B	GSDT-1 &	ON-PEAK	1.00155	1.636
	CILC-1(G)	OFF-PEAK	1.00155	1.417
C	GSLDT-1 &	ON-PEAK	1.00046	1.634
	CST-1	OFF-PEAK	1.00046	1.416
D	GSLDT-2 &	ON-PEAK	0.99449	1.624
	CST-2	OFF-PEAK	0.99449	1.407
E	GSLDT-3,CST-3,	ON-PEAK	0.96430	1.575
	CILC-1(T) & ISST-1(T)	OFF-PEAK	0.96430	1.365
F	CILC-1(D)	ON-PEAK	0.99643	1.627
	ISST-1(D)	OFF-PEAK	0.99643	1.410
	ISST-1(D)			(BIRKETT)

FPUC: Marianna

Rate Schedule	Adjustment
RS	4.765¢/kwh
GS	4.437¢/kwh
GSD	4.020¢/kwh
OL, OL-2	2.746¢/kwh
SL-1, SL-2	2.680¢/kwh

Fernandina Beach

Rate Schedule	Adjustment
RS	5.308¢/kwh
GS	5.042¢/kwh
GSD	4.853¢/kwh
OL, SL, CSL	4.268¢/kwh

GULF: See table below: (Cranmer)

Group	Rate Schedules	Fuel Cost Factors ¢/KWH		
		Standard	Time of Use	
			On-Peak	Off-Peak
A	RS, GS, GSD, OSIII, OSIV	2.185	2.281	2.139
B	LP	2.117	2.210	2.073
C	PX	2.077	2.168	2.033
D	OSI, OSII	2.151	N/A	N/A

TECO:

	Standard	On-Peak	Off-Peak
Group A	2.913	3.815	2.460
Group A1	2.663	-	-
Group B	2.897	3.796	2.447
Group C	2.813	3.685	2.376
System (Pennino)	2.894	3.791	2.444

STIPULATED ISSUE 8: What is the appropriate revenue tax factor to be applied in calculating each company's levelized fuel factor for the projection period of April through September, 1994?

POSITION:

FPC:	1.00083	
FPL:	1.01609	
FPUC:	1.00083	(Marianna)
	1.01609	(Fernandina Beach)
GULF:	1.01609	
TECO:	1.00083	

Company-Specific Fuel Adjustment Issues

Florida Power and Light Company

STIPULATED ISSUE 9: Should FPL be authorized to defer recognition of cost changes for the April 1994 through September 1994 to the October 1994 through March 1995 period?

FPL: Yes. The sum of the changes decreases the costs for the April 1994 through September 1994 period by approximately $56 million. In an attempt to better levelize the bill, it is FPL's preference to defer the inclusion of these costs to the October 1994 through March 1995 period. FPL's alternative proposal is to incorporate a $38,533,605 change in the computation of the fuel charge for the April 1994 through September 1994 period from that filed on January 18, 1994. This $38,533,605 reflects those cost changes that would typically be incorporated in the estimated/actual true-up amount. Therefore, under FPL's alternative proposal FPL recommends against inclusion of approximately $18 million in revised estimates for February and March 1994 in the estimated/actual true-up amount. (Birkett)

Florida Power Corporation

STIPULATED ISSUE 10a: How should "governmental impositions" be included in the price of water-borne transportation in accordance with the market pricing mechanism approved by the Commission at the August 1993 fuel adjustment hearings? [FPC's proposed rewarding]

POSITION: In accordance with Order No. PSC-93-1331-FOF-EI, the market price is to be adjusted "for the cost of governmental impositions on EFC's transportation suppliers which cause an increase or decrease in EFC's water-borne transportation costs not in effect as of December 31, 1992." In this case, the federal government has imposed additional Waterway User Taxes on EFC's river barge transportation suppliers in the form of a "per gallon" tax on fuel. Since EFC's coal originates at various barge loading points at differing distances from New

Orleans, different amounts of fuel and, thus, taxes are associated with each origin. Accordingly, FPC has converted these varying gallons and tax amounts into a "per ton" amount based on projected origin points and volumes, which are subject to true-up when actual results become available.

STIPULATED ISSUE 10b: How should the affiliated coal transportation market-based pricing method be amended to calculate a transportation charge for foreign coal?

POSITION: The existing market pricing mechanism for the transportation of domestic coal should be modified to exclude cost components (e.g., river barging costs) not involved in the transportation of foreign coal. The Company proposes that this be accomplished by establishing a price equal to 50.2% of the then-current domestic coal market price (less governmental impositions not related to transloading or trans-Gulf barging) for water-borne transportation of foreign coal purchased F.O.B. IMT. The figure of 50.2% is the proportion of transloading and trans-gulf barging costs to EFC's total 1992 water-borne transportation costs used to derive the initial market price for water-borne transportation of domestic coal.

Tampa Electric Company

ISSUE 11: Has Tampa Electric Company prudently administered its contract with Consol Coal Company?

POSITION: This issue has been deferred to the August fuel hearings.

Gulf Power Company

ISSUE 12: What costs, if any, are appropriate for Gulf to recover through the fuel cost recovery clause as a result of the Peabody contract suspension?

POSITION: This issue should be deferred to the August fuel hearings.

Generic Generating Performance Incentive Factor Issues

STIPULATED ISSUE 13: What is the appropriate GPIF reward or penalty for performance achieved during the period April, 1993 through September, 1993?

POSITION:

FPC:	$1,100,739 reward.
FPL:	$871,893 reward.
GULF:	$128,552 reward.
TECO:	$214,237 penalty.
	(See Attachment 1)

STIPULATED ISSUE 14: What should the GPIF targets/ranges be for the period April, 1994 through September, 1994?

POSITION: The GPIF targets for the period April 1994 through September 1994 are shown on Attachment 1 for FPC, FPL, GULF and TECO.

Company-Specific GPIF Issues

Staff knows of no company-specific GPIF issues at this time.

Generic Oil Backout Issues

STIPULATED ISSUE 15: What is the final oil backout true-up amount for the April, 1993 through September, 1993 period?

POSITION:

FPL:	$191,376 overrecovery.
TECO:	$193,724 overrecovery.

STIPULATED ISSUE 16: What is the estimated oil backout true-up amount for the period October, 1993 through March, 1994?

POSITION:

FPL:	$248,851 underrecovery.
TECO:	$415,515 overrecovery.

STIPULATED
ISSUE 17: What is the total oil backout true-up amount to be collected during the period April, 1994 through September, 1994?

POSITION:

FPL:	$57,475 underrecovery.
TECO:	$609,239 overrecovery.

STIPULATED
ISSUE 18: What is the projected oil backout cost recovery factor for the period April, 1994 through September, 1994?

POSITION:

FPL:	0.012 ¢/kwh.
TECO:	0.073 ¢/kwh.

Company-Specific Oil Backout Issues

Staff knows of no company-specific oil backout issues at this time.

Generic Capacity Cost Recovery Issues

STIPULATED
ISSUE 19: What is the appropriate final capacity cost recovery true-up amount for the period April, 1993 through September, 1993?

POSITION:

FPC:	$2,576,367 Overrecovery.
FPL:	$6,291,909 Overrecovery.
GULF:	$183,938 Overrecovery.
TECO:	$4,897 Overrecovery.

STIPULATED
ISSUE 20: What is the estimated capacity cost recovery true-up amount for the period October, 1993 through March, 1994?

POSITION:

FPC:	$193,412 Underrecovery.
FPL:	$17,123,942 Underrecovery.
GULF:	$41,833 Underrecovery.
TECO:	$918,803 Underrecovery.

STIPULATED
ISSUE 21: What is the total capacity cost recovery true-up amount to be collected during the period April, 1994 through September, 1994?

POSITION:

FPC:	$2,382,955 Overrecovery.
FPL:	$10,832,033 Underrecovery.
GULF:	$142,105 Overrecovery.
TECO:	$913,906 Underrecovery.

STIPULATED
ISSUE 22: What is the appropriate projected net purchased power capacity cost recovery amount to be included in the recovery factor for the period April, 1994 through September, 1994?

POSITION:

FPC:	$60,263,005.
FPL:	$189,974,524. (Birkett)
GULF:	$1,180,247
TECO:	$11,106,718.

STIPULATED
ISSUE 23: What are the appropriate capacity cost recovery factors for the period April, 1994 through September, 1994?

FPC:

FPL:

RATE CLASS	CAPACITY RECOVERY FACTOR ($/KW)	CAPACITY RECOVERY FACTOR ($/KWH)
RS1	-	0.00564
GS1	-	0.00491
GSD1	1.75	-
OS2	-	0.00402
GSLD1/CS1	1.79	-
GSLD2/CS2	1.95	-
GSLD3/CS3	1.92	-
ISST1D	0.56	-
SST1T	0.37	-
SST1D	0.64	-
CILCD/CILCG	1.71	-
CILCT	1.65	-
MET	1.86	-
OL1/SL1	-	0.00223
SL2	-	0.00336

(BIRKETT)

GULF: See table below: (Cranmer)

RATE CLASS	CAPACITY COST RECOVERY FACTORS ¢/KWH
RS, RST	0.031
GS, GST	0.031
GSD, GSDT	0.024
LP, LPT	0.021
PX, PXT	0.017
OSI, OSII	0.003
OSIII	0.019
OSIV	0.002
SS	0.017

TECO: The appropriate factors are as follows:

Rate Schedules	Factor
RS	.205 cents per KWH
GS, TS	.168 cents per KWH
GSD	.141 cents per KWH
GSLD, SBF	.125 cents per KWH
IS-1 & 3, SBI-1 & 3	.011 cents per KWH
SL, OL	.012 cents per KWH

(Pennino)

STAFF:

Company-Specific Capacity Cost Recovery Issues

Staff knows of no company-specific capacity cost recovery issues at this time.

VII. EXHIBIT LIST

Witness	Proffered By	I.D. No.	Description
Wieland	FPC	1 (KHW-1)	True-up Variance Analysis
Wieland	FPC	2 (KHW-2)	Schedules A1 through A13
Wieland	FPC	3 (KHW-3)	Forecast Assumptions and Capacity Cost Recovery Schedules (Parts A-D)
Wieland	FPC	4 (KHW-4)	Schedules E1 through E11 and H1
Micklon	FPC	5 (WCM-1)	Standard Form GPIF Schedules (Reward/ Penalty)
Micklon	FPC	6 (WCM-2)	Standard Form GPIF Schedules (Targets/ Ranges)
Birkett	FPL	7 (BTB-1)	Appendix I/Fuel Cost Recovery True-Up Calculation
Birkett	FPL	8 (BTB-2)	Appendix II/Capacity Cost Recovery True-Up Calculation
Birkett	FPL	9 (BTB-3)	Appendix III/Oil Backout Cost Recovery True-Up Calculation
Birkett	FPL	10 (BTB-4)	Appendix IV/A Schedules
Birkett	FPL	11 (BTB-5)	Appendix II/Fuel Cost Recovery Calculation of Factor

Witness	Proffered By	I.D. No.	Description
Birkett	FPL	12 (BTB-6)	Appendix III/Fuel Cost Recovery Estimated /Actual True-Up Calculation
Birkett	FPL	13 (BTB-7)	Appendix IV/Capacity Cost Recovery Calculation of Factors
Birkett	FPL	14 (BTB-8)	Appendix V/Oil Backout Cost October 1992 - March 1993
Birkett	FPL	15 (BTB-9)	Appendix II, Fuel Cost Recovery, Calculation of Factor - Revised
Birkett	FPL	16 (BTB-10)	Appendix III, Fuel Cost Recover Estimated /Actual True-Up Calculation - Revised
Silva	FPL	17 (RS-1)	Appendix I/Fuel Cost Recovery Forecast Assumptions
Silva	FPL	18 (RS-2)	Document No. 1/GPIF Results
Silva	FPL	19 (RS-3)	Document No. 1/GPIF Targets and Ranges
Bachman	FPUC	20 (GMB-1)	Schedules E, E1, E1b, E2, E4, E8, E10, E11, H1 & M1 (Marianna (Division) Schedules E, E1, E1b, E2, E4, E8, E8A, E10, E11, H1 & F1 (Fernandina Beach Division)

Witness	Proffered By	I.D. No.	Description
Gilchrist	Gulf	21 (MLG-1)	Coal Suppliers Apr.'93 - Oct.'93
Gilchrist	Gulf	22 (MLG-2)	Projected vs. Actual Fuel Cost
Howell	Gulf	23 (MWH-1)	Projected Capacity Transactions Apr.'94 - Sept.'94
Cranmer	Gulf	24 (SDC-1)	Fuel Adjustment Final True-up Calculation
Cranmer	Gulf	25 (SDC-2)	Schedules E-1 through E-11; 12; 13; H-1; CCE-1, CCE-1a; CCE-1b; CCE-2; & monthly A-1 thru A-12, June '93 thru Nov.'93; (development of fuel cost and capacity cost recovery factors)
Fontaine	Gulf	26 (GDF-1)	GPIF Results Schedules
Fontaine	Gulf	27 (GDF-2)	GPIF Targets and Ranges
Pennino	TECO	28 (MJP-1)	Levelized fuel cost recovery final true-up, April 1993 - September 1993
Pennino	TECO	29 (MJP-2)	Fuel adjustment projection, April 1994 - September 1994
Pennino	TECO	30 (MJP-3)	Capacity cost recovery projection, April 1994 - September 1994
Keselowsky	TECO	31 (GAK-1)	Generating Performance Incentive Factor Results, April 1993 - September 1993

Witness	Proffered By	I.D. No.	Description
Keselowsky	TECO	32 (GAK-2)	GPIF Targets and Ranges for April 1994 - September 1994
Keselowsky	TECO	33 (GAK-3)	Estimated Unit Performance Data, April 1994 - September 1994
Tomczak/ Townes	TECO	34 (RFT/EAT-1)	Schedules Supporting Oil Backout Cost Recovery Factor - Actual, April 1993 - September 1993
Tomczak/ Townes	TECO	35 (RFT/EAT-2)	Schedules Supporting Oil Backout Cost Recovery Factor, April 1994 - September 1994
Tomczak/ Townes	TECO	36 (RFT/EAT-3)	Gannon Conversion Project Comparison of Projected Payoff with Original Estimate as of November 1993

Parties and Staff reserve the right to identify additional exhibits for the purpose of cross-examination.

VIII. PROPOSED STIPULATIONS

All issues are stipulated

IX. RULINGS

On January 18, 1994, TECO filed a Motion for Extension of Time to file its fuel adjustment petition and supporting testimony and exhibits relative to its proposed fuel adjustment factor and oil backout cost recovery for the forthcoming recovery period. The testimony was filed January 24, 1994. No responses were filed to TECO's motion. This motion is granted.

On February 24, 1994, Orgulf Transport Company filed a Petition for Intervention. This petition is granted.

It is therefore,

ORDERED by Chairman J. Terry Deason, as Prehearing Officer, that this Prehearing Order shall govern the conduct of these proceedings as set forth above unless modified by the Commission.

By ORDER of Chairman J. Terry Deason, as Prehearing Officer, this 8TH day of MARCH, 1994.

J. Terry Deason
CHAIRMAN J. TERRY DEASON
and Prehearing Officer

(S E A L)
MCB/DLC:bmi

NOTICE OF FURTHER PROCEEDINGS OR JUDICIAL REVIEW

The Florida Public Service Commission is required by Section 120.59(4), Florida Statutes, to notify parties of any administrative hearing or judicial review of Commission orders that is available under Sections 120.57 or 120.68, Florida Statutes, as well as the procedures and time limits that apply. This notice should not be construed to mean all requests for an administrative hearing or judicial review will be granted or result in the relief sought.

Any party adversely affected by this order, which is preliminary, procedural or intermediate in nature, may request: 1) reconsideration within 10 days pursuant to Rule 25-22.038(2), Florida Administrative Code, if issued by a Prehearing Officer; 2) reconsideration within 15 days pursuant to Rule 25-22.060, Florida Administrative Code, if issued by the Commission; or 3) judicial review by the Florida Supreme Court, in the case of an electric, gas or telephone utility, or the First District Court of Appeal, in the case of a water or wastewater utility. A motion for reconsideration shall be filed with the Director, Division of Records and Reporting, in the form prescribed by Rule 25-22.060, Florida Administrative Code. Judicial review of a preliminary, procedural or intermediate ruling or order is available if review of the final action will not provide an adequate remedy. Such review may be requested from the appropriate court, as described above, pursuant to Rule 9.100, Florida Rules of Appellate Procedure.

Staff Attachment 1
Page 1 of 2

GPIF REWARDS/PENALTIES
April 1993 to September 1993

Florida Power Corporation	$1,100,739	Reward
Florida Power and Light Company	$871,893	Reward
Gulf Power Company	$128,552	Reward
Tampa Electric Company	$214,237	Penalty

Utility/ Plant/Unit	EAF		Heat Rate	
FPC	Target	Adj. Actual	Target	Adj. Actual
Anclote 1	83.4	83.1	9,764	9,667
Anclote 2	94.7	96.0	9,886	9,845
Crystal River 1	84.3	89.8	9,988	10,090
Crystal River 2	78.1	77.4	9,975	10,075
Crystal River 3	72.2	82.9	10,462	10,582
Crystal River 4	83.2	83.0	9,245	9,258
Crystal River 5	94.9	94.6	9,301	9,233
FPL	Target	Adj. Actual	Target	Adj. Actual
Cape Canaveral 1	83.8	85.0	9,082	8,995
Cape Canaveral 2	79.5	78.2	9,202	9,222
Fort Myers 2	91.9	94.9	9,414	9,327
Manatee 1	83.7	93.3	9,710	9,573
Manatee 2	95.4	95.9	9,521	9,645
Martin 1	90.7	89.8	9,172	9,209
Martin 2	96.0	94.0	9,138	9,022
Port Everglades 1	94.8	98.8	9,791	9,657
Port Everglades 2	91.0	97.4	9,713	9,646
Port Everglades 3	93.9	95.5	9,301	9,307
Port Everglades 4	95.4	97.8	9,353	9,306
Riviera 3	91.1	88.4	9,864	9,758
Riviera 4	56.3	57.6	9,776	9,716
Sanford 4	93.8	93.5	9,979	9,718
St. Johns River 1	97.3	96.6	9,344	9,367
St. Johns River 2	98.0	95.7	9,258	9,392
St. Lucie 1	62.5	66.2	10,813	10,791
St. Lucie 2	93.6	88.4	10,795	10,911
Turkey Point 1	74.1	67.8	9,324	8,792
Turkey Point 2	82.5	90.2	9,480	9,476
Turkey Point 3	90.7	98.4	11,258	11,090
Turkey Point 4	60.1	56.2	11,216	11,121
Gulf	Target	Adj. Actual	Target	Adj. Actual
Crist 6	87.8	91.8	10,247	10,163
Crist 7	62.0	64.0	9,989	10,103
Smith 1	84.8	84.2	10,178	10,199
Smith 2	91.8	74.3	10,227	10,292
Daniel 1	98.0	93.5	10,498	10,131
Daniel 2	97.8	99.4	10,408	10,226
TECO	Target	Adj. Actual	Target	Adj. Actual
Big Bend 1	81.0	82.4	9,994	10,106
Big Bend 2	84.0	90.1	9,984	9,985
Big Bend 3	72.6	71.4	9,634	9,739
Big Bend 4	87.0	84.4	9,914	10,128
Gannon 5	59.[illegible]	58.5	10,442	10,436
Gannon 6	81.8	80.8	10,268	10,494

Staff Attachment 1
Page 2 of 2

GPIF TARGETS
April 1994 to September 1994

Utility/ Plant/Unit	Equivalent Availability Company			Staff	Heat Rate Company	Heat Rate Staff
FPC	EAF	POF	EUOF			
Anclote 1	92.6	3.8	3.6	Agree	9,634	Agree
Anclote 2	81.7	15.3	3.0	Agree	9,596	Agree
Crystal River 1	85.9	0.0	14.1	Agree	10,118	Agree
Crystal River 2	83.9	0.0	16.1	Agree	10,081	Agree
Crystal River 3	59.8	33.3	6.8	Agree	10,533	Agree
Crystal River 4	87.2	8.2	4.7	Agree	9,268	Agree
Crystal River 5	94.7	0.0	5.3	Agree	9,315	Agree
FPL	EAF	POF	EUOF			
Cape Canaveral 1	94.7	0.0	5.3	Agree	8,978	Agree
Cape Canaveral 2	93.2	0.0	6.8	Agree	9,400	Agree
Fort Myers 1	95.2	0.0	4.8	Agree	10,054	Agree
Fort Myers 2	94.0	0.0	6.0	Agree	9,418	Agree
Manatee 1	92.7	0.0	7.3	Agree	9,658	Agree
Manatee 2	94.5	0.0	5.5	Agree	9,785	Agree
Port Everglades 1	96.0	0.0	4.0	Agree	9,960	Agree
Port Everglades 2	95.3	0.0	4.7	Agree	9,936	Agree
Port Everglades 3	95.2	0.0	4.8	Agree	9,320	Agree
Port Everglades 4	87.1	8.2	4.7	Agree	9,372	Agree
Putnam 1	89.4	4.1	6.5	Agree	8,183	Agree
Putnam 2	94.2	0.0	5.8	Agree	8,302	Agree
Riviera 3	65.4	27.9	6.7	Agree	9,691	Agree
Riviera 4	90.4	0.0	9.6	Agree	9,717	Agree
Sanford 4	94.6	0.0	5.4	Agree	9,760	Agree
Sanford 5	94.1	0.0	5.9	Agree	9,534	Agree
Scherer 4	95.9	0.0	4.1	Agree	8,855	Agree
St. Johns River 1	95.6	0.0	4.4	Agree	9,370	Agree
St. Johns River 2	95.3	0.0	4.7	Agree	9,302	Agree
St. Lucie 1	93.4	0.0	6.6	Agree	10,846	Agree
St. Lucie 2	70.3	10.4	19.3	Agree	10,796	Agree
Turkey Point 1	82.6	0.0	17.4	Agree	9,444	Agree
Turkey Point 2	87.4	0.0	12.6	Agree	9,624	Agree
Turkey Point 3	67.0	28.4	4.6	Agree	11,086	Agree
Turkey Point 4	93.6	0.0	6.4	Agree	11,216	Agree
Gulf	EAF	POF	EUOF			
Crist 6	66.6	24.6	8.9	Agree	10,391	Agree
Crist 7	82.1	0.0	17.9	Agree	10,231	Agree
Smith 1	80.8	13.1	6.1	Agree	10,162	Agree
Smith 2	90.8	0.0	9.2	Agree	10,192	Agree
Daniel 1	86.8	9.3	3.9	Agree	10,449	Agree
Daniel 2	96.8	0.0	3.2	Agree	10,089	Agree
TECO	EAF	POF	EUOF			
Big Bend 1	58.6	30.6	10.8	Agree	10,062	Agree
Big Bend 2	87.6	0.0	12.4	Agree	10,069	Agree
Big Bend 3	83.5	0.0	16.5	Agree	9,676	Agree
Big Bend 4	88.1	0.0	11.9	Agree	10,114	Agree
Gannon 5	82.7	4.4	12.9	Agree	10,408	Agree
Gannon 6	83.1	0.0	16.9	Agree	10,454	Agree

TOTAL FUEL COST FOR THE PERIOD: April 1994 – September 1994

DATE 03/10/94
PAGE 1 of 10

	PROPOSED April 1994 – September 1994			PRESENT February 1994 – March 1994			DIFFERENCE				PROPOSED
				Februar	Cents per kwh			Cents per kwh		RESIDENTIAL LINE LOSS	RESIDENTIAL FUEL
COMPANY	Levelized	On/Peak	Off/Peak	Levelized	On/Peak	Off/Peak	Levelized	On/Peak	Off/Peak	MULTIPLIER	FACTOR
Fla. Power & Light (5)	1.488	1.633	1.415	1.811	1.940	1.760	−0.323	−0.307	−0.345	1.00161	1.490
Fla. Power Corp.	1.968	2.692	1.587	1.880	2.176	1.757	0.088	0.516	−0.170	1.00380	1.975
Tampa Electric	2.894	3.791	2.444	2.508	2.946	2.346	0.386	0.845	0.098	1.00640	2.913
Gulf Power	2.158	2.253	2.113	1.965	2.012	1.949	0.193	0.241	0.164	1.01228	2.185
Fla. Public											
Marianna (1)	4.658	NA	NA	4.948	NA	NA	0.290	NA	NA	1.01260	4.717
Fernandina (1)(2)	5.308	NA	NA	5.733	NA	NA	−0.425	NA	NA	1.00000	5.308

COST FOR 1,000 KWH RESIDENTIAL SERVICE

PRESENT: February 1994 – March 1994

	Fla. Power & Light	Fla. Power Corp.	Tampa Electric (5)	Gulf Power (6)	Florida Public Utilities Marianna (7)	Florida Public Utilities Fernandina
Base	47.38	49.05	51.92	43.25	20.43	19.20
Fuel (3)	15.84	18.87	24.51	19.89	49.48	57.33
Oil Backout	0.16	NA	1.00	NA	NA	NA
Energy Conservation	2.30	5.90	1.45	0.33	0.13	0.05
Environmental Cost Recovery	0.00	N/A	N/A	1.48	N/A	N/A
Capacity Recovery	5.95	4.75	2.13	0.87	NA	NA
Gross Receipts Tax (4)	0.73	2.01	2.08	0.68	1.03	0.79
Total	$72.36	$80.58	$83.09	$66.50	$71.07	$77.37

PROPOSED: April 1994 – September 1994

	Fla. Power & Light	Fla. Power Corp.	Tampa Electric	Gulf Power	Florida Public Utilities Marianna	Florida Public Utilities Fernandina
Base	47.38	49.05	51.92	43.25	20.43	19.20
Fuel (3)	14.90	19.75	29.13	21.85	47.17	53.08
Oil Backout	0.12	NA	0.73	NA	NA	NA
Energy Conservation	2.43	4.40	1.87	0.26	0.12	0.05
Environmental Cost Recovery	0.13	N/A	N/A	1.48	N/A	N/A
Capacity Recovery	5.64	5.11	2.05	0.31	NA	NA
Gross Receipts Tax (4)	0.72	2.01	2.20	0.69	1.74	0.74
Total	$71.32	$80.32	$87.90	$67.84	$69.46	$73.07

DIFFERENCE	Fla. Power & Light	Fla. Power Corp.	Tampa Electric	Gulf Power	Florida Public Utilities Marianna	Florida Public Utilities Fernandina
Base	0.00	0.00	0.00	0.00	0.00	0.00
Fuel (3)	−0.94	0.88	4.62	1.96	−2.31	−4.25
Oil Backout	−0.04	NA	−0.27	NA	NA	NA
Energy Conservation	0.13	−1.50	0.42	−0.07	−0.01	0.00
Environmental Cost Recovery	0.13	N/A	N/A	N/A	N/A	N/A
Capacity Recovery	−0.31	0.36	−0.08	−0.56	NA	NA
Gross Receipts Tax (4)	−0.01	0.00	0.12	0.01	0.71	−0.05
Total	−1.04	−0.26	4.81	1.34	−1.61	−4.30

(1) Fuel costs include purchased power demand costs of 1.889 for Marianna and 1.452 cents/KWH for Fernandina allocated to the residential class. (2) All classes except GSLD. (3) Adjusted for line loss.
(4) Additional gross receipts tax is 1% for Gulf, FPL, and FPUC–Fernandina. FPC, TECO and FPUC–Marianna have removed GRT from rates. The entire 2.5% is thus shown seperately.
(5) TECO present rates reflect a rate increase effective January 1, 1994 resulting from Docket No. 920324–EI. (6) Gulf Power present rates reflect $1.48 increase because of the Environmental Cost Recovery Clause, Docket No. 930613, effective February 1, 1994. (7) FPUC–Marianna rate reflect an increase effective February 1994, resulting from Docket No. 930400–EI.

FUEL ADJUSTMENT CENTS PER KWH BASED ON LINE LOSSES BY RATE GROUP

DIVISION OF ELECTRIC AND GAS
DATE: 03/10/94
PAGE 2 of 10

FOR THE PERIOD: April 1994 – September 1994

			WITHOUT LINE LOSS MULTIPLIER			LINE LOSS	WITH LINE LOSS MULTIPLIER		
COMPANY	GROUP	RATE SCHEDULES	Levelized	* On/Peak	Off/Peak	MULTIPLIER	Levelized	On/Peak	Off/Peak
FP&L	A	RS-1,RST-1,GST-1,GS-1,SL-2	1.488	1.633	1.415	1.00161	1.490	1.636	1.417
	A-1	SL-1,OL-1	1.450	NA	NA	1.00161	1.452	NA	NA
	B	GSD-1,GSDT-1	1.488	1.633	1.415	1.00155	1.490	1.636	1.417
	C	GSLD-1,GSLDT-1,CS-1,CST-1	1.488	1.633	1.415	1.00046	1.488	1.634	1.416
	D	GSLD-2,GSLDT-2,CS-2,CST-2,OS-2,MET	1.488	1.633	1.415	0.99449	1.480	1.624	1.407
	E	GSLD-3,CS-3,GSLDT-3,CST-3,CILC-1(T),ISST-1(T)	1.488	1.633	1.415	0.96430	1.435	1.575	1.365
	F	CILC-1(D),ISST-1(D)	NA	1.633	1.415	0.99643	NA	1.627	1.410
FPC *	A	Distribution Secondary Delivery	1.968	2.692	1.587	1.00380	1.975	2.702	1.593
	A-1	OL-1,SL-1	1.793	NA	NA	1.00380	1.800	NA	NA
	B	Distribution Primary Delivery	1.968	2.692	1.587	0.98260	1.934	2.645	1.559
	C	Transmission Delivery	1.968	2.692	1.587	0.97250	1.914	2.618	1.543
TECO	A	RS,GS,TS	2.894	3.791	2.444	1.00640	2.913	3.815	2.460
	A-1	SL-1,2,3,OL-1,2	2.646	NA	NA	1.00640	2.663	NA	NA
	B	GSD,GSLD	2.894	3.791	2.444	1.00120	2.897	3.796	2.447
	C	IS-1,IS-3	2.894	3.791	2.444	0.97210	2.813	3.685	2.376
GULF	A	RS,GS,GSD,OS-III,OS-IV	2.158	2.253	2.113	1.01228	2.185	2.281	2.139
	B	LP	2.158	2.253	2.113	0.98106	2.117	2.210	2.073
	C	PX	2.158	2.253	2.113	0.96230	2.077	2.168	2.033
	D	OS-1,OS-2	2.125	NA	NA	1.01228	2.151	NA	NA
FPUC									
Fernandina	A	RS	5.308	NA	NA	1.00000	5.308	NA	NA
	B	GS	5.042	NA	NA	1.00000	5.042	NA	NA
	C	GSD	4.853	NA	NA	1.00000	4.853	NA	NA
	D	OL, OL-2, SL-2, SL-3, CSL	4.268	NA	NA	1.00000	4.268	NA	NA
	E	GSLD					4.799 (1) $4.69/CP KW		
Marianna	A	RS	4.658	NA	NA	1.01260	4.717	NA	NA
	B	GS	4.505	NA	NA	0.99630	4.489	NA	NA
	C	GSD	4.130	NA	NA	0.99630	4.115	NA	NA
	D	GLSD	3.969	NA	NA	0.99630	3.955	NA	NA
	E	OL, OL-2	2.793	NA	NA	1.01260	2.828	NA	NA
	F	SL-1, SL-2	2.793	NA	NA	0.98810	2.760	NA	NA

DIVISION OF ELECTRIC AND GAS
DATE: 03/10/94
PAGE 3 of 10

PROPOSED CAPACITY COST RECOVERY FACTORS
For the Period: April 1994 – September 1994

COMPANY	RATE SCHEDULE	RECOVERY FACTOR (CENTS PER KWH)
FPL	RS1	0.564
	GS1	0.491
	OL1/SL1	0.223
	SL2	0.336
	OS2	0.402
		RECOVERY FACTOR (DOLLARS PER KWH)
	GSD1	1.750
	GSLD1/CS1	1.790
	GSLD2/CS2	1.950
	GSLD3/CS3	1.920
	ISST1D	0.560
	SST1T	0.370
	SST1D	0.640
	CILCD,CILCG	1.710
	CILCT	1.650
	MET	1.860
FPC *	RS	0.511
	GS–Transmission	0.000
	GS–Primary	0.349
	GS–Secondary	0.358
	GS – 100% Load Factor	0.270
	GSD–Transmission	0.294
	GSD–Primary	0.308
	GSD–Secondary	0.316
	CS – Primary	0.243
	CS – Secondary	0.247
	IS–Transmission	0.254
	IS–Primary	0.258
	IS–Secondary	0.265
	LS – Lighting Service	0.101
TECO	RS	0.205
	GS,TS	0.168
	GSD	0.141
	GSLD,SBF	0.125
	IS–1 & 3,SBI–1 & 3	0.011
	SL/OL	0.012
GULF	RS,RST	0.031
	GS,GST	0.031
	GSD,GSDT	0.024
	LP,LPT	0.021
	PX,PXT	0.017
	OS–I,OS–II	0.003
	OS–III	0.019
	OS–IV	0.002
	SS	0.017

FUEL & PURCHASED POWER COST RECOVERY
CLAUSE CALCULATION

DIVISION OF ELECTRIC AND GAS
DATE: 03/10/94
PAGE 4 OF 10

ESTIMATED FOR THE PERIOD: April 1994 – September 1994

FLORIDA POWER & LIGHT COMPANY

CLASSIFICATION	Classification Associated $	Classification Associated KWH	Classification Associated Cents/KWH
1.Fuel Cost of System Net Generation (E3)	562,387,620	34,718,270,000	1.61986
2.Spent NUC Fuel Disposal Cost (E2)	9,495,091	10,339,857,000 (a)	0.09183
3.Fuel Related Transactions	6,293,600	0	0.00000
4. Natural Gas Pipeline Enhancements	0	0	0.00000
4a. Fuel Cost of Sales to FKEC	(8,763,525)	(420,047,000)	2.08632
5.TOTAL COST OF GENERATED POWER	569,412,786	34,298,223,000	1.66018
6.Fuel Cost of Purchased Power – Firm (E8)	117,022,609	6,376,013,000	1.83536
7.Energy Cost of Sch.C,X Economy Purchases (Broker) (E9)	245,270	10,876,000	2.25515
8.Energy Cost of Economy Purchases (Non–Broker) (E9)	0	0	0.00000
9.Energy Cost of Sch.E Purchases (E9)	0	0	0.00000
10.Capacity Cost of Sch.E Economy Purchases (E2)	0	0	0.00000
11.Payments to Qualifying Facilities (E8A)	40,223,265	2,237,419,000	1.79775
12.TOTAL COST OF PURCHASED POWER	157,491,144	8,624,308,000	1.82613
13.TOTAL AVAILABLE KWH		42,922,531,000	
14.Fuel Cost of Economy Sales (E7)	(18,862,594)	(728,699,000)	2.58853
15.Gain on Economy Sales – 80% (E7A)	(4,557,878)	(728,699,000)(a)	0.62548
16.Fuel Cost of Unit Power Sales (SL2 Partpts) (E7)	(1,389,207)	(259,647,000)	0.53504
17.Fuel Cost of Other Power Sales (E7)	0	0	0.00000
18.TOTAL FUEL COST AND GAINS OF POWER SALES	(24,809,679)	(988,346,000)	2.51022
19.Net Inadvertant Interchange (E4)	0	0	0.00000
20.TOTAL FUEL AND NET POWER TRANSACTIONS	702,094,251	41,934,185,000	1.67428
21.Net Unbilled (E4)	(9,932,791)(a)	(588,119,000)	−0.02602
22.Company Use (E4)	(2,145,978)(a)	(127,063,000)	−0.00562
23.T & D Losses (E4)	(51,503,346)(a)	(3,049,505,000)	−0.13493
24.Adjusted System KWH Sales	702,094,251	38,169,498,000	1.83941
25.Wholesale KWH Sales	2,475,405	133,411,000	1.85547
26.JURISDICTIONAL KWH SALES	699,618,846	38,036,087,000	1.83936
27.Jurisdictional KWH Sales Adjusted for Line Loss – 1.00035	699,863,713	38,036,087,000	1.84000
28.True–up * (derived in Attachment C)	(143,804,515)	38,036,087,000	−0.37807
29.TOTAL JURISDICTIONAL FUEL COST	556,059,198	38,036,087,000	1.46190
30.Revenue Tax Factor			1.01609
31.Fuel Cost Adjusted for Taxes			1.48542
32.GPIF*	871,893	38,036,087,000	0.00229
33.Total fuel cost including GPIF	556,931,091	38,036,087,000	1.48771
34.TOTAL FUEL COST FACTOR ROUNDED TO THE NEAREST .001 CENTS PER KWH:			1.488

*Based on Jurisdictional Sales
(a) included for informational purposes only.

FUEL & PURCHASED POWER COST RECOVERY
CLAUSE CALCULATION

DIVISION OF ELECTRIC AND GAS
DATE: 03/10/94
PAGE 5 OF 10

ESTIMATED FOR THE PERIOD: April 1994 – September 1994

FLORIDA POWER CORPORATION

CLASSIFICATION	Classification Associated $	Classification Associated KWH	Classification Associated cents/KWH
1.Fuel Cost of System Net Generation (E3)	233,151,971	13,778,384,000	1.69216
2.Spent NUC Fuel Disposal Cost (E3A)	1,904,281	2,036,664,000 (a)	0.09350
3.Coal Car Investment	0	0	0.00000
4.Adjustments to Fuel Cost	172,868	0	0.00000
5.TOTAL COST OF GENERATED POWER	235,229,120	13,778,384,000	1.70723
6.Energy Cost of Purchased Power – Firm (E8)	4,925,130	246,707,000	1.99635
7.Energy Cost of Sch.C,X Economy Purchases (Broker) (E9)	16,070,200	790,000,000	2.03420
8.Energy Cost of Economy Purchases (Non–Broker) (E9)	493,176	23,580,000	2.09150
9.Energy Cost of Sch.E Purchases (E9)	2,851,424	135,820,000	2.09941
10.Capacity Cost of Sch.E Economy Purchases (E9)	0	0 (a)	0.00000
11.Payments to Qualifying Facilities (E8A)	53,527,490	2,364,286,000	2.26400
12.TOTAL COST OF PURCHASED POWER	77,867,420	3,560,393,000	2.18705
13.TOTAL AVAILABLE KWH		17,338,777,000	
14.Fuel Cost of Economy Sales (E7)	(3,036,700)	(190,000,000)	1.59826
14a.Gain on Economy Sales – 80% (E7A)	(466,640)	(190,000,000)(a)	0.24560
15.Fuel Cost of Other Power Sales (E7)	0	0	0.00000
15a.Gain on Other Power Sales (E8)	0	0 (a)	0.00000
16.Fuel Cost of Seminole Backup Sales (E7)	0	0	0.00000
16a.Gain on Seminole Back–up Sales (E7B)	0	0 (a)	0.00000
17.Fuel Cost of Seminole Supplemental Sales (E7)	(6,465,100)	(272,101,000)	2.37599
18.TOTAL FUEL COST AND GAINS OF POWER SALES	(9,968,440)	(462,101,000)	2.15720
19.Net Inadvertant Interchange (E4)	0	0	
20.TOTAL FUEL AND NET POWER TRANSACTIONS	303,128,100	16,876,676,000	1.79614
21.Net Unbilled (E4)	7,769,049 (a)	(432,551,000)	0.05099
22.Company Use (E4)	1,697,315 (a)	(94,500,000)	0.01114
23.T & D Losses (E4)	20,020,552 (a)	(1,114,668,000)	0.13141
24.Adjusted System KWH Sales	303,128,100	15,234,957,000	1.98969
25.Wholesale KWH Sales(Excluding Seminole Supplemental)	(10,537,961)	(529,657,000)	1.98958
26.JURISDICTIONAL KWH SALES	292,590,139	14,705,300,000	1.98969
27.Jurisdictional KWH Sales Adjusted for Line Loss – 1.0014	292,999,765	14,705,300,000	1.99248
28.Prior Period True–Up *	(4,967,508)	14,705,300,000	–0.03378
28a. Market Price Refund for 1992	0	0	0.00000
29.TOTAL JURISDICTIONAL FUEL COST	288,032,257	14,705,300,000	1.95870
30.Revenue Tax Factor			1.00083
31.Fuel Cost Adjusted for Taxes			1.96030
32.GPIF*	1,100,737	14,705,300,000	0.00750
33.Total fuel cost including GPIF	289,132,994	14,705,300,000	1.96780
34.TOTAL FUEL COST FACTOR ROUNDED TO THE NEAREST .001 CENTS PER KWH:			1.968

*Based on Jurisdictional Sales

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FUEL & PURCHASED POWER COST RECOVERY
CLAUSE CALCULATION

DIVISION OF ELECTRIC AND GAS
DATE: 03/10/94
PAGE 6 OF 10

ESTIMATED FOR THE PERIOD: April 1994 – September 1994

TAMPA ELECTRIC COMPANY

CLASSIFICATION	Classification Associated $	Classification Associated KWH	Classification Associated cents/KWH
1.Fuel Cost of System Net Generation (E3)	204,538,452	8,530,330,000	2.39778
2.Spent NUC Fuel Disposal Cost (E3A)	0	0 (a)	0.00000
3.Coal Car Investment	0	0	0.00000
4.Adjustments to Fuel Cost	0	0	0.00000
5.TOTAL COST OF GENERATED POWER	204,538,452	8,530,330,000	2.39778
6.Fuel Cost of Purchased Power – Firm (E8)	4,207,200	83,697,000	5.02670
7.Energy Cost of Sch.C,X Economy Purchases (Broker) (E9)	931,600	25,077,000	3.71496
8.Energy Cost of Economy Purchases (Non–Broker) (E9)	0	0	0.00000
9.Energy Cost of Sch.E Purchases (E9)	0	0	0.00000
10.Capacity Cost of Sch.E Economy Purchases	0	0 (a)	0.00000
11.Payments to Qualifying Facilities (E8A)	3,846,400	190,220,000	2.02208
12.TOTAL COST OF PURCHASED POWER	8,985,200	298,994,000	3.00514
13.TOTAL AVAILABLE KWH		8,829,324,000	
14.Fuel Cost of Economy Sales (E7)	8,262,400	524,099,000	1.57650
15.Gain on Economy Sales – 80% (E7A)	1,270,000	524,099,000 (a)	0.24232
16.Fuel Cost of Scedule D Sales (E7)	3,704,000	272,547,000	1.35903
16a.Fuel Cost of Schedule G Sales (E7)	0	0	0.00000
17.Fuel Cost Schedule J Sales (E7)	66,400	4,702,000	1.41217
17a.Fuel Cost Schedule D TPS Sales (E7)	3,463,200	156,891,000	2.20739
18.TOTAL FUEL COST AND GAINS OF POWER SALES	16,766,000	958,239,000	1.74967
19.Net Inadvertant Interchange (E4)	0	0	
19b.Interchange and Wheeling Losses	0	17,247,000	
20.TOTAL FUEL AND NET POWER TRANSACTIONS	196,757,652	7,853,838,000	2.50524
21.Net Unbilled (E4)	(3,578,034)(a)	142,822,000	–0.04918
22.Company Use (E4)	420,880 (a)	16,800,000	0.00578
23.T & D Losses (E4)	10,483,402 (a)	418,459,000	0.14409
24.Adjusted System KWH Sales	196,757,652	7,275,757,000	2.70429
25.Wholesale KWH Sales	(719,001)	(26,586,000)	2.70443
26.JURISDICTIONAL KWH SALES	196,038,651	7,249,171,000	2.70429
27.Jurisdictional KWH Sales Adjusted for Line Loss – 1.00005	196,136,670	7,249,171,000	2.70564
28.True–up * (derived in Attachment C)	13,698,115	7,249,171,000	0.18896
29.Pyramid Coal Contract Buyout Adjustment	0	7,249,171,000	0.00000
30.TOTAL JURISDICTIONAL FUEL COST	209,834,785	7,249,171,000	2.89460
31.Revenue Tax Factor			1.00083
32.Fuel Cost Adjusted for Taxes	210,008,948		2.89701
33.GPIF * (Already adjusted for taxes)	(214,237)	7,249,171,000	–0.00296
34.Total Fuel Cost including GPIF	209,794,711	7,249,171,000	2.89405
35.TOTAL FUEL COST FACTOR ROUNDED TO THE NEAREST .001 CENTS PER KWH:			2.894

*Based on Jurisdictional Sales

Effective date for billing purposes:

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FUEL & PURCHASED POWER COST RECOVERY
CLAUSE CALCULATION

DIVISION OF ELECTRIC AND GAS
DATE: 03/10/94
PAGE 7 OF 10

ESTIMATED FOR THE PERIOD: April 1994 – September 1994

GULF POWER COMPANY

CLASSIFICATION	Classification Associated $	Classification Associated KWH	Classification Associated cents/KWH
1.Fuel Cost of System Net Generation (E3)	111,171,243	5,957,220,000	1.8662
2.Spent NUC Fuel Disposal Cost (E13)	0	0	0.0000
3.Adjustments to Fuel Cost	0	0	0.0000
4.TOTAL COST OF GENERATED POWER	111,171,243	5,957,220,000	1.8662
5.Fuel Cost of Purchased Power – Firm (E8)	0	0	0.0000
6.Energy Cost of Sch.C,X Economy Purchases (Broker) (E9)	5,822,000	316,750,000	1.8380
7.Energy Cost of Economy Purchases (Non–Broker) (E9)	0	0	0.0000
8.Energy Cost of Sch.E Purchases (E9)	0	0	0.0000
9.Capacity Cost of Sch.E Economy Purchases (E2)	0	0 (a)	0.0000
10.Payments to Qualifying Facilities (E9A)	0	0	0.0000
11.TOTAL COST OF PURCHASED POWER	5,822,000	316,750,000	1.8380
12.TOTAL AVAILABLE KWH (line 4 + line 11)		6,273,970,000	
13.Fuel Cost of Economy Sales (E7)	(534,000)	(22,680,000)	2.3545
14.Gain on Economy Sales – 80% (E7A)	(54,400)	0 (a)	0.0000
15.Fuel Cost of Unit Power Sales (E7)	(10,851,000)	(570,360,000)	1.9025
16.Fuel Cost of Other Power Sales (E7)	(11,336,000)	(631,726,000)	1.7944
17.TOTAL FUEL COST AND GAINS OF POWER SALES	(22,775,400)	(1,224,766,000)	1.8596
18.Net Inadvertant Interchange (E4)	0		
19.TOTAL FUEL AND NET POWER TRANSACTIONS	94,217,843	5,049,204,000	1.8660
20.Net Unbilled (E4)	0	0	0.0000
21.Company Use (E4)	180,480 (a)	9,672,000	1.8660
22.T & D Losses (E4)	6,379,742 (a)	341,894,000	1.8660
23.Adjusted System KWH Sales	94,217,843	4,697,638,000	2.0056
24.Wholesale KWH Sales	3,334,430	166,256,000	2.0056
25.JURISDICTIONAL KWH SALES	90,883,413	4,531,382,000	2.0056
26.Jurisdictional KWH Sales Adjusted for Line Loss – 1.00140	91,010,649	4,531,382,000	2.0085
27.True–up *	4,730,114	4,531,382,000	0.1044
28.Total Jurisdictional Fuel Cost	95,740,763	4,531,382,000	2.1129
29.Revenue Tax Factor			1.01609
30.Fuel Cost Adjusted for Taxes			2.1469
31.Special Contract Recovery Cost	376,902	4,531,382,000	0.0083
32.GPIF *	128,552	4,531,382,000	0.0028
33.Total Fuel Cost including GPIF	95,869,315	4,531,382,000	2.1580
34.TOTAL FUEL COST FACTOR ROUNDED TO THE NEAREST .001 CENTS PER KWH:			2.158

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Effective date for billing purposes:

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FUEL & PURCHASED POWER COST RECOVERY
CLAUSE CALCULATION

DIVISION OF ELECTRIC AND GAS
DATE: 03/10/94
PAGE 8 OF 10

ESTIMATED FOR THE PERIOD: April 1994 – September 1994

FLORIDA PUBLIC UTILITIES–MARIANNA

CLASSIFICATION	Classification Associated $	Classification Associated KWH	Classification Associated cents/KWH
1.Fuel Cost of System Net Generation (E3)	0	0	0.00000
2.Spent NUC Fuel Disposal Cost (E3A)	0	0	0.00000
3.Coal Car Investment	0	0	0.00000
4.Adjustments to Fuel Cost	0	0	0.00000
5.TOTAL COST OF GENERATED POWER	0	0	0.00000
6.Fuel Cost of Purchased Power – Firm (E8)	2,855,193	149,410,000	1.91098
7.Energy Cost of Sch.C,X Economy Purchases (Broker) (E9)	0	0	0.00000
8.Energy Cost of Economy Purchases (Non–Broker) (E9)	0	0	0.00000
9.Energy Cost of Sch.E Purchases (E9)	0	0	0.00000
10.Demand & Non Fuel Cost of Purchased Power (E2)	3,138,733	149,410,000 (a)	2.10075
10a.Demand Costs of Purchased Power	2,106,000 (a)		
10b.Non–Fuel Energy & Customer Costs of Purchased Power	1,032,733 (a)		
11.Energy Payments to Qualifying Facilities (E8A)	0	0	0.00000
12.TOTAL COST OF PURCHASED POWER	5,993,926	149,410,000	4.01173
13.TOTAL AVAILABLE KWH	5,993,926	149,410,000	4.01173
14.Fuel Cost of Economy Sales (E7)	0	0	0.00000
15.Gain on Economy Sales – 80% (E7A)	0	0	0.00000
16.Fuel Cost of Unit Power Sales (E7)	0	0	0.00000
17.Fuel Cost of Other Power Sales (E7)	0	0	0.00000
18.TOTAL FUEL COST AND GAINS OF POWER SALES	0	0	0.00000
19.Net Inadvertant Interchange (E4)	0	0	
20.TOTAL FUEL AND NET POWER TRANSACTIONS	5,993,926	149,410,000	4.01173
21.Net Unbilled (E4)	200,867 (a)	5,007,000	0.14524
22.Company Use (E4)	4,975 (a)	124,000	0.00360
23.T & D Losses (E4)	239,701 (a)	5,975,000	0.17331
24.ADJUSTED SYSTEM KWH SALES	5,993,926	138,304,000	4.33388
25.Less Total Demand Cost Recovery	2,160,481		
26.JURISDICTIONAL KWH SALES	3,833,445	138,304,000	2.77175
27.Jurisdictional KWH Sales Adjusted for Line Loss – 1.00	3,833,445	138,304,000	2.77175
28.True–up *	25,603	138,304,000	0.01851
29.TOTAL JURISDICTIONAL FUEL COST	3,859,048	138,304,000	2.79026
30.Revenue Tax Factor			1.00083
31.Fuel Cost Adjusted for Taxes	3,499,562	0	2.79258
32.GPIF *	0	138,304,000	0.00000
33.Total Fuel Cost including GPIF	3,859,048	138,304,000	2.79258
34.TOTAL FUEL COST FACTOR ROUNDED TO THE NEAREST .001 CENTS PER KWH:			2.793

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FUEL & PURCHASED POWER COST RECOVERY
CLAUSE CALCULATION

DIVISION OF ELECTRIC AND GAS
DATE: 03/10/94
PAGE 9 OF 10

ESTIMATED FOR THE PERIOD: April 1994 – September 1994

FLORIDA PUBLIC UTILITIES–FERNANDINA

CLASSIFICATION	Classification Associated $	Classification Associated KWH	Classification Associated cents/KWH
1.Fuel Cost of System Net Generation (E3)	0	0	0.00000
2.Spent NUC Fuel Disposal Cost (E2)	0	0	0.00000
3.Coal Car Investment	0	0	0.00000
4.Adjustments to Fuel Cost	0	0	0.00000
5.TOTAL COST OF GENERATED POWER	0	0	0.00000
6.Fuel Cost of Purchased Power – Firm (E8)	3,178,366	172,269,000	1.84500
7.Energy Cost of Sch.C,X Economy Purchases (Broker) (E9)	0	0	0.00000
8.Energy Cost of Economy Purchases (Non–Broker) (E9)	0		
9.Energy Cost of Sch.E Purchases (E9)	0	0	0.00000
10.Demand & Non Fuel Cost of Purchased Power	5,217,177	172,269,000	3.02851
10a.Demand Costs of Purchased Power (E2)	2,382,000 (a)		
10b.Non Fuel Energy and Customer Costs of Purchased Power (E2)	2,835,177 (a)		
11.Energy Payments to Qualifying Facilities (E8A)	0	0	0.00000
12.TOTAL COST OF PURCHASED POWER	8,395,543	172,269,000	4.87351
13.TOTAL AVAILABLE KWH	8,395,543	172,269,000	4.87351
14.Fuel Cost of Economy Sales (E7)	0	0	0.00000
15.Gain on Economy Sales – 80% (E7A)	0	0	0.00000
16.Fuel Cost of Unit Power Sales (E7)	0	0	0.00000
17.Fuel Cost of Other Power Sales (E7)	0	0	0.00000
18.TOTAL FUEL COST AND GAINS OF POWER SALES	0	0	0.00000
19.Net Inadvertant Interchange (E4)			
20.TOTAL FUEL AND NET POWER TRANSACTIONS	8,395,543	172,269,000	4.87351
21.Net Unbilled (E4)	21,541 (a)	442,000	0.01336
22.Company Use (E4)	9,552 (a)	196,000	0.00592
23.T & D Losses (E4)	503,726 (a)	10,336,000	0.31230
24.Adjusted System KWH Sales	8,395,543	161,295,000	5.20509
25.Wholesale KWH Sales	0	0	0.00000
26.JURISDICTIONAL KWH SALES	8,395,543	161,295,000	5.20509
27.Jurisdictional KWH Sales Adjusted for Line Loss – 1.00	8,395,543	161,295,000	5.20509
27a.GSLD KWH Sales (E11)		42,000,000	
27b.Other Classes KWH Sales (E11)		119,295,000	
27c.GSLD CP KW		120,000 (a)	
28. GPIF			
29.True–up *	(118,219)	161,295,000	–0.07329
30.TOTAL JURISDICTIONAL FUEL COST	8,277,324	161,295,000	5.13179

FUEL & PURCHASED POWER COST RECOVERY
CLAUSE CALCULATION

DIVISION OF ELECTRIC AND GAS
DATE: 03/10/94

ESTIMATED FOR THE PERIOD: April 1994 – September 1994

FLORIDA PUBLIC UTILITIES–FERNANDINA

CLASSIFICATION	Classification Associated $	Classification Associated KWH	Classification Associated cents/KWH
30a.Demand Purchased Power Costs (line 10a)	2,382,000 (a)		
30b.Non–Demand Purchased Power Costs (lines 6+10b+11)	6,013,543 (a)		
30c.True–up Over/Under Recovery (line 29)	(118,219)(a)		
APPORTIONMENT OF DEMAND COSTS			
31.Total Demand Costs	2,382,000		
32.GSLD Portion of Demand Costs Including line losses (line 27c * $3.708)	741,600	120,000 KW	$6.18
33.Balance to Other Customers	1,640,400	119,295,000	1.37508
APPORTIONMENT OF NON–DEMAND COSTS			
34.Total Non–Demand Costs (line 30b)	6,013,543		
35.Total KWH Purchased (line 12)		172,269,000	
36.Average Cost per KWH Purchased			3.49079
37.Avg. Cost Adjusted for Transmission line losses (line 36 * 1.03)			3.59551
38.GSLD Non–Demand Costs (line 27a * line 37)	1,510,111	42,000,000	0.03596
39.Balance to Other Customers	4,503,432	119,295,000	3.77504
GSLD PURCHASED POWER COST RECOVERY FACTORS			
40a.Total GSLD Demand Costs (Line 32)	741,600	120,000	$6.18
40b.Revenue Tax Factor			1.01609
40c.GSLD Demand Purchased Power factor adjusted for taxes and rounded:			$6.28
40d.Total Current GSLD Non–Demand Costs (line 38)	1,510,111	42,000,000	3.59550
40e.Total Non–Demand Costs including true–up	1,510,111	42,000,000	3.59550
40f.Revenue Tax Factor			1.01609
40g.GSLD Non–demand costs adjusted for taxes			3.653
OTHER CLASSES PURCHASED POWER COST RECOVERY FACTORS			
41a.Total Demand and Non–Demand Purchased Power Costs of other classes (lines 33 + 39)	6,143,832	119,295,000	5.15012
41b.Less: Total Demand Cost Recovery	1,498,638 (a)		
41c.Total Other Costs to be Recovered	4,645,194 (a)	119,295,000	3.89387
41d.Other Classes' Portion of True–up (line 30 C)	(118,219)	119,295,000	–0.09910
41e.Total Demand and Non–Demand Costs including True–up	4,526,975	119,295,000	3.79477
42.Revenue tax factor			1.01609
			3.85583
43.OTHER CLASSES PURCHASED POWER FACTOR ADJUSTED FOR TAXES ROUNDED TO THE NEAREST .001 CENTS PER KWH:			3.856

*Based on Jurisdictional Sales

(a) included for informational purposes only.