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-94-0963-PHO-EI ISSUED: August 9, 1994

Pursuant to Notice, a Prehearing Conference was held on August 4, 1994, in Tallahassee, Florida, before Commissioner Susan F. Clark, as Prehearing Officer.

APPEARANCES:

JAMES A. McGEE, Esquire, Post Office Box 14042, St. Petersburg, Florida 33733-4042
On behalf of Florida Power Corporation.

MATTHEW M. CHILDS, P.A., Steel Hector & Davis, 215 South Monroe Street, Suite 601, Tallahassee, Florida 32301
On behalf of Florida Power and Light Company.

FLOYD R. SELF, Esquire, Messer, Vickers, Caparello, Madsen & Goldman, P.A., Post Office Box 1876, Tallahassee, Florida 32302-1876
On behalf of Florida Public Utilities Company.

G. EDISON HOLLAND, JR., Esquire, JEFFREY A. STONE, Esquire, and TERESA E. LILES, Esquire, Beggs & Lane, 700 Blount Building, 3 West Garden Street, Post Office Box 12950, Pensacola, Florida 32576-2950
On behalf of Gulf Power Company.

LEE L. WILLIS, Esquire and JAMES D. BEASLEY, Esquire, Macfarlane, Ausley, Ferguson & McMullen, Post Office Box 391, Tallahassee, Florida 32302
On behalf of Tampa Electric Company.

JOSEPH A. McGLOTHLIN, Esquire and VICKI GORDON KAUFMAN, Esquire, McWhirter, Reeves, McGlothlin, Davidson & Bakas, 315 South Calhoun Street, Suite 716, Tallahassee, Florida 32301
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.

JOHN ROGER HOWE, Esquire, Deputy Public Counsel, Office of Public Counsel, c/o The Florida Legislature, 111 West Madison Street, Room 812, Tallahassee, Florida 32399-1400
On behalf of the Citizens of the State of Florida.

MARTHA CARTER BROWN, Esquire, Florida Public Service Commission, 101 East Gaines Street, Tallahassee, Florida 32399-0863
On behalf of the Commission Staff.

PREHEARING ORDER

I. CASE BACKGROUND

As part of the Commission's continuing fuel cost, capacity cost, and environmental cost recovery proceedings, a hearing is set for August 11-12, 1994 in this docket and in Docket No. 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	1-9, 12-15
*William C. Micklon	FPC	10 and 11
*R. Silva	FPL	1,2,3,13,14
*D. C. Poteralski	FPL	1,2,3

Witness	Appearing For	Issues #
*B. T. Birkett	FPL	1,2,3,4,5,6,7,8,9, 15,16,17,18,19,20, 21,22,23,24a,24b
*Bachman	FPUC	1-8
M. L. Gilchrist	GULF	1,2,4,12
*M. W. Howell	GULF	1,2,4,19,20,21
*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	1,2,3,4,6,7,8,11c, 19,20,21,22,23,25a
*G. A. Keselowsky	TECO	13,14
*R. F. Tomczak and *E. A. Townes	TECO	15,16,17,18
*W. N. Cantrell	TECO	11a,11b

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 for the period October, 1994 through March, 1995 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 2.353 cents per KWH before application of factors which adjust for variation in line losses; the proposed capacity cost recovery factor of .142 cents per KWH before applying the 12 CP and 1/13 allocation methodology; a GPIF reward of $406,404; and an oil backout cost recovery factor of .096 cents per KWH.

FLORIDA INDUSTRIAL POWER USERS GROUP (FIPUG): None necessary.

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 replacement 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.

OFFICE OF PUBLIC COUNSEL (OPC): None necessary.

STAFF: Staff has no basic position in this docket. Staff's positions on specific issues 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 October, 1993 through March, 1994?

POSITION:
FPC: $5,074,211 underrecovery
FPL: $2,066,794 overrecovery
FPUC: Marianna: $ 10,735 overrecovery
Fernandina Beach: $215,029 overrecovery
GULF: $ 810,768 underrecovery, pending resolution of Issue 12.
TECO: $5,779,224 overrecovery

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

POSITION:
FPC: $26,512,241 underrecovery.
FPL: $32,451,868 overrecovery.
FPUC: Marianna: $38,323 underrecovery
Fernandina Beach: $74,042 overrecovery
GULF: $1,969,504 underrecovery, pending resolution of Issue 12.
TECO: $4,827,083 underrecovery.

STIPULATED ISSUE 3: What are the total fuel adjustment true-up amounts to be collected during the period October, 1994 through March, 1995?

POSITION:
FPC: $31,586,452 underrecovery.
FPL: $34,518,662 overrecovery.
FPUC: Marianna: $ 27,588 underrecovery.
Fernandina Beach: $289,071 overrecovery.
GULF: $2,780,272 underrecovery, pending resolution of Issue 12.
TECO: $ 952,141 overrecovery.

STIPULATED ISSUE 4: What are the appropriate levelized fuel cost recovery factors for the period October, 1994 through March, 1995?

POSITION: In cents/kWh:

FPC:	2.051
FPL:	1.567
FPUC:	Marianna: 3.009
	Fernandina Beach: 3.646
GULF:	2.179
TECO:	2.353

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 October, 1994 through March, 1995. Billing cycles may start before October 1, 1994, and the last cycle may be read after March 31, 1995, 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: The appropriate line loss multipliers are found on page 2 of 10 of Staff Attachment 2.

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

POSITION: The appropriate factors are found on page 2 of 10 of Staff Attachment 2.

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 October, 1994 through March, 1995?

POSITION:

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

COMPANY SPECIFIC FUEL ADJUSTMENT ISSUES

Florida Power and Light Company

STIPULATED DEFERRED ISSUE 9: Is FPL's proposed new methodology for allocating fuel costs to the various customer classes appropriate?

POSITION: This issue should be deferred to the February 1995 fuel hearings to allow further time to analyze FPL's proposed methodology.

Florida Power Corporation

STIPULATED ISSUE 10a: Should FPC be permitted to recover the costs associated with the accelerated purchase of locomotives?

POSITION: Yes. The company has demonstrated that the accelerated purchase of locomotives will increase the savings to its ratepayers from $10.9 million to $14.5. Therefore, the Commission should allow FPC to recover the costs associated with the accelerated purchases.

STIPULATED ISSUE 10b: Is it appropriate for FPC to differentiate fuel charges by metering voltage?

POSITION: Yes. Differentiating fuel charges in this manner will ensure consistency with the treatment of base rate charges, the ECCR and the CCR.

Tampa Electric Company

STIPULATED ISSUE 11a: Has Tampa Electric Company adequately justified any costs associated with the purchase of coal from Gatliff Coal Company that are in excess of the 1993 benchmark price?

POSITION: Yes. TECO's actual costs are below the benchmark and therefore this issue is moot.

STIPULATED ISSUE 11b: Has Tampa Electric Company adequately justified any costs associated with transportation services provided by affiliates of Tampa Electric Company that are in excess of the 1993 waterborne transportation benchmark price?

POSITION: Yes. TECO's actual costs are below the benchmark, and therefore this issue is moot.

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

POSITION: Yes. TECO has prudently administered its contract.

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?

GULF: Gulf should recover all costs associated with the Peabody contract suspension, including the suspension payment and the costs of purchasing replacement coal. These costs were prudently incurred and resulted in net fuel savings for the customers totalling approximately $14,479,865. (Gilchrist)

OPC: No position.

FIPUG: No position.

ORGULF: None.

STAFF: Gulf has provided a cost benefit analysis that demonstrates a positive savings as a result of the Peabody contract suspension. Therefore, the prudently incurred costs associated with the suspension of the Peabody Contract are appropriate for recovery.

Generic Generating Performance Incentive Factor Issues

STIPULATED ISSUE 13: What is the appropriate GPIF reward or penalty for performance achieved during the period October, 1993 through March, 1994?

POSITION:

FPC: $1,009,345 reward.
FPL: $3,107,919 reward.
GULF: $84,941 (penalty).
TECO: $406,404 (reward).

STIPULATED ISSUE 14: What should the GPIF targets/ranges be for the period October, 1994 through March, 1995?

POSITION:

FPC: As provided on page 2 of Staff Attachment 1.
FPL: As provided on page 2 of Staff Attachment 1.
GULF: As provided on page 2 of Staff Attachment 1.
TECO: As provided on page 2 of Staff Attachment 1.

Company-Specific GPIF Issues

No company-specific GPIF issues have been identified for this hearing.

Generic Oil Backout Issues

STIPULATED ISSUE 15: What is the final oil backout true-up amount for the October, 1993 through March, 1994 period?

POSITION:
FPL: $257,863 overrecovery.
TECO: $ 81,177 underrecovery.

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

POSITION:
FPL: $250,389 overrecovery.
TECO: $ 49,634 overrecovery.

STIPULATED ISSUE 17: What is the total oil backout true-up amount to be collected during the period October, 1994 through March, 1995?

POSITION:
FPL: $508,252 overrecovery.
TECO: $ 31,543 underrecovery.

STIPULATED ISSUE 18: What is the projected oil backout cost recovery factor for the period October, 1994 through March, 1995?

POSITION:
FPL: .011 cents/kwh.
TECO: .096 cents per KWH.

Company-Specific Oil Backout Issues

There are no company-specific oil backout issues for this hearing.

Generic Capacity Cost Recovery Issues

STIPULATED ISSUE 19: What is the appropriate final capacity cost recovery true-up amount for the period October, 1993 through March, 1994?

POSITION:

FPC:	$ 69,905 under-recovery.
FPL:	$8,570,760 overrecovery
GULF:	$1,135,019 underrecovery.
TECO:	$ 861,751 overrecovery.

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

POSITION:

FPC:	$4,622,826 over-recovery.
FPL:	$8,210,602 overrecovery.
GULF:	$ 56,118 over-recovery.
TECO:	$ 742,821 overrecovery

STIPULATED ISSUE 21: What is the total capacity cost recovery true-up amount to be collected during the period October, 1994 through March, 1995?

STAFF:

FPC:	$ 4,552,921 overrecovery.
FPL:	$16,781,361 overrecovery.
GULF:	$ 1,078,901 underrecovery.
TECO:	$ 1,604,572 overrecovery

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 October, 1994 through March, 1995?

POSITION:

FPC:	$ 82,945,428
FPL:	$152,074,783
GULF:	$ 6,956,372
TECO:	$ 9,181,060

STIPULATED ISSUE 23: What are the projected capacity cost recovery factors for the period October, 1994 through March, 1995?

POSITION: The appropriate capacity cost recovery factors are found on page 3 of 10 of Staff Attachment 2.

Company-Specific Capacity Cost Recovery Issues

Florida Power and Light Company

STIPULATED ISSUE 24a: Was it appropriate for FPL to change the amount of annual capacity credit associated with the St. Johns River Power Park from $63,975,761 to $56,945,592?

POSITION: Yes. The adjustment appropriately reflects all purchased power capacity revenues and costs that were included in base rates as a result of FPL's 1988 tax savings docket.

STIPULATED ISSUE 24b: How should FPL recover capacity costs from customers who take standby power?

POSITION: FPL should recover capacity costs from standby customers through the combination of a reservation charge/daily demand charge component. These charges should be calculated in a manner consistent with the methodology outlined in Order No. 17159.

Tampa Electric Company

DEFERRED ISSUE 25a: Other than economy sales and revenues from the seven entities that were separated out in TECO's last rate case, should Tampa Electric credit all nonfuel revenues from off-system sales back to the retail ratepayers through the fuel adjustment clause and the capacity cost recovery clause?

TECO: No. The level of sales and resulting revenues from long-term firm off-system sales vary subsequent to a rate case. In Docket No. 920324-EI it was determined that long-term firm off-system sales were to be treated with consistency. (Pennino)

OPC: Yes. TECO is making additional wholesale sales from "excess jurisdictional capacity." Order No. 93-0664 requires that nonfuel revenues from such sales be credited back to retail customers through the fuel clause.

FIPUG: Yes.

ORGULF: No position.

STAFF: Yes. In Order No PSC-93-0664-FOF-EI, the Commission ordered TECO to credit all nonfuel revenues from off-system sales that had not been allocated to the wholesale jurisdiction back to the retail ratepayers by including those revenues as credits in the Capacity Cost Recovery Clause and the Fuel and Purchased Power Clause. TECO has not been crediting all off-system sales to the appropriate clauses. As a result, the shareholders are receiving the benefits of these off-system sales while the retail ratepayers are bearing the costs.

VII. EXHIBIT LIST

Witness	Proffered By	I.D. No.	Description
*Wieland	FPC	(KHW-1)	True-up Variance Analysis
*Wieland	FPC	(KHW-2)	Schedules A1 through A13 (True-up)
*Wieland	FPC	(KHW-3)	Forecast Assumptions (Parts A-C), Capacity Cost Recovery Factors (Part D), and Other Supporting Information (Parts E-G)

Witness	Proffered By	I.D. No.	Description
*Wieland	FPC	(KHW-4)	Schedules E1 through E11 and H1 (Projections)
*Micklon	FPC	(WCM-1)	Standard Form GPIF Schedules (Reward/Penalty)
*Micklon	FPC	(WCM-2)	Standard Form GPIF Schedules (Targets/Ranges)
*Birkett	FPL	(BTB-1)	Appendix I/Fuel Cost Recovery True-Up Calculation
*Birkett	FPL	(BTB-2)	Appendix II/Capacity Cost Recovery True-Up Calculation
*Birkett	FPL	(BTB-3)	Appendix III/Oil Backout Cost Recovery True-Up Calculation
*Birkett	FPL	(BTB-4)	Appendix IV/A Schedules October 1993 - March 1994
*Silva	FPL	(RS-1)	Appendix I/Fuel Cost Recovery Forecast Assumptions
*Birkett	FPL	(BTB-5)	Appendix II/Fuel Cost Recovery Calculation of Factor
*Birkett	FPL	(BTB-6)	Appendix III/Fuel Cost Recovery Estimated/Actual True-Up Calculation
*Birkett	FPL	(BTB-7)	Appendix IV/Capacity Cost Recovery Calculation Of Factors

Witness	Proffered By	I.D. No.	Description
*Birkett	FPL	(BTB-8)	Appendix V/Oil Backout Cost Recovery Calculation of Factor
*Silva	FPL	(RS-2)	Document No. 1/GPIF Results
*Silva	FPL	(RS-3)	Document No. 1/GPIF Targets and Ranges
*Birkett	FPL	(BTB-9)	Fuel Cost Recovery, Calculation of Factor Revised
*Bachman	FPUC	(GMB-2)	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)
Gilchrist	GULF	(MLG-1)	Coal Suppliers Oct '93 - Mar '94
Gilchrist	GULF	(MLG-2)	Projected vs. Actual Fuel Cost; Calculation of Net Fuel Savings - Peabody Suspension Agreement
*Howell	GULF	(MWH-1)	Projected Capacity Transactions Oct.'94 - Mar '95
*Cranmer	GULF	(SDC-1)	Fuel Cost Recovery Final True-up Calculation

Witness	Proffered By	I.D. No.	Description
*Cranmer	GULF	(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, Nov '93 thru May '94; (development of fuel cost and capacity cost recovery factors)
*Fontaine	GULF	(GDF-1)	GPIF Results Schedules
*Fontaine	GULF	(GDF-2)	GPIF Targets and Ranges
*Pennino	TECO	(MJP-1)	Levelized fuel cost recovery and capacity cost recovery final true-up, October 1993 - March 1994
*Pennino	TECO	(MJP-2)	Fuel adjustment projection, October 1994 - March 1995
*Pennino	TECO	(MJP-3)	Capacity cost recovery projection, October 1994 - March 1995
*Keselowsky	TECO	(GAK-1)	Generating Performance Incentive Factor Results, October 1993 - March 1994
*Keselowsky	TECO	(GAK-2)	GPIF Targets and Ranges for October 1994 - March 1995
*Keselowsky	TECO	(GAK-3)	Estimated Unit Performance Data, October 1994 - March 1995

Witness	Proffered By	I.D. No.	Description
*Tomczak/ Townes	TECO	(RFT/EAT-1)	Schedules Supporting Oil Backout Cost Recovery Factor - Actual, October 1993 - March 1994
*Tomczak/ Townes	TECO	(RFT/EAT-2)	Schedules Supporting Oil Backout Cost Recovery Factor, October 1994 - March 1995
*Tomczak/ Townes	TECO	(RFT/EAT-3)	Gannon Conversion Project Comparison of Projected Payoff with Original Estimate as of May 1994
*Cantrell	TECO	(WNC-1)	Transportation Benchmark Calculation, FPSC Order 93-0443 -FOF-EI and FPSC Order No. 20298

VIII. PROPOSED STIPULATIONS

Issues Nos. 1-11, and 13-24b. The proposed stipulations represent the position of those parties that chose to take a position on the issue. Issue 9 and Issue 25a will be deferred until the March 1995 hearings.

IX. RULINGS

It is noted that Intervenor Tropicana Products voluntarily withdrew from participation in this docket.

It is therefore,

ORDERED by Commissioner Susan F. Clark, 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 Commissioner Susan F. Clark, as Prehearing Officer, this 9th day of August, 1994.

Susan F. Clark

SUSAN F. CLARK, Commissioner and
Prehearing Officer

(S E A L)
MCB: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.

GPIF REWARDS/PENALTIES
October 1993 to March 1994

Florida Power Corporation	$1,009,345	Reward
Florida Power and Light Company	$3,107,919	Reward
Gulf Power Company	$84,941	Penalty
Tampa Electric Company	$406,404	Reward

Utility/ Plant/Unit	EAF		Heat Rate	
FPC	Target	Adj. Actual	Target	Adj. Actual
Anclote 1	86.7	88.1	10,247	9,998
Anclote 2	82.1	83.8	9,955	9,874
Crystal River 1	73.1	81.3	10,024	9,971
Crystal River 2	50.8	47.3	9,998	9,761
Crystal River 3	88.7	99.0	10,334	10,414
Crystal River 4	95.3	91.8	9,264	9,378
Crystal River 5	80.7	79.9	9,293	9,207
FPL	Target	Adj. Actual	Target	Adj. Actual
Cape Canaveral 1	48.2	46.0	9,426	9,365
Cape Canaveral 2	94.0	89.1	9,040	9,344
Fort Myers 2	91.4	91.5	9,381	9,368
Manatee 2	94.7	99.4	9,664	9,747
Port Everglades 3	94.2	95.7	9,317	9,594
Port Everglades 4	83.5	85.6	9,171	9,173
Putnam 1	88.6	93.5	9,208	8,698
Putnam 2	95.0	94.9	8,975	8,476
Riviera 3	75.2	76.1	9,975	9,869
Riviera 4	90.4	90.5	9,840	9,890
Sanford 4	95.3	95.7	10,086	9,734
Sanford 5	93.0	96.8	9,461	9,496
Scherer 4	96.0	97.6	8,904	9,416
St. Johns River 1	81.8	82.3	9,385	9,336
St. Johns River 2	80.0	80.8	9,228	9,404
St. Lucie 1	93.1	95.8	10,741	10,894
St. Lucie 2	60.9	73.2	11,152	11,580
Turkey Point 1	88.5	93.6	9,363	8,917
Turkey Point 2	80.0	88.0	9,129	9,163
Turkey Point 3	83.6	87.7	10,881	10,887
Turkey Point 4	93.5	93.4	10,932	10,858
Gulf	Target	Adj. Actual	Target	Adj. Actual
Crist 6	68.8	73.8	10,164	10,042
Crist 7	69.0	61.7	9,945	10,026
Smith 1	64.4	68.1	10,107	10,226
Smith 2	82.6	85.9	10,109	10,302
Daniel 1	76.4	78.0	10,527	10,013
Daniel 2	74.1	74.7	10,134	10,035
TECO	Target	Adj. Actual	Target	Adj. Actual
Big Bend 1	82.0	82.2	9,834	9,990
Big Bend 2	57.2	60.6	9,821	9,966
Big Bend 3	80.0	86.8	9,536	9,589
Big Bend 4	64.7	68.5	9,927	9,974
Gannon 5	80.2	87.3	10,416	10,384
Gannon 6	77.1	81.9	10,129	10,324

Staff Attachment 1
Page 2 of 2

GPIF TARGETS
October 1994 to March 1995

Utility/ Plant/Unit	Equivalent Availability				Heat Rate	
	Company			Staff	Company	Staff
FPC	EAF	POF	EUOF			
Anclote 1	90.8	7.7	1.5	Agree	9,905	Agree
Anclote 2	96.7	0.0	3.3	Agree	9,805	Agree
Crystal River 1	73.9	15.4	10.7	Agree	10,177	Agree
Crystal River 2	70.4	15.4	14.2	Agree	9,975	Agree
Crystal River 3	92.8	0.0	7.2	Agree	10,400	Agree
Crystal River 4	94.2	0.0	5.8	Agree	9,289	Agree
Crystal River 5	72.8	23.1	4.1	Agree	9,247	Agree
FPL	EAF	POF	EUOF			
Cape Canaveral 1	92.4	0.0	7.6	Agree	9,291	Agree
Cape Canaveral 2	89.9	0.0	10.1	Agree	9,338	Agree
Fort Louderdale 4	92.6	1.7	5.7	Agree	7,225	Agree
Fort Louderdale 5	92.7	0.0	7.3	Agree	7,198	Agree
Fort Myers 2	93.3	0.0	6.7	Agree	9,294	Agree
Manatee 2	95.7	0.0	4.3	Agree	9,758	Agree
Port Everglades 3	94.5	0.0	5.5	Agree	9,307	Agree
Putnam 1	94.2	0.0	5.8	Agree	8,670	Agree
Riviera 3	90.9	0.0	9.1	Agree	9,713	Agree
Riviera 4	82.8	9.3	7.9	Agree	9,672	Agree
Sanford 4	94.6	0.0	5.4	Agree	9,755	Agree
Sanford 5	94.1	0.0	5.9	Agree	9,692	Agree
Scherer 4	84.3	12.1	3.6	Agree	9,933	Agree
St. Johns River 1	76.8	19.2	4.0	Agree	9,336	Agree
St. Johns River 2	95.1	0.0	4.9	Agree	9,375	Agree
St. Lucie 1	60.6	35.2	4.2	Agree	10,854	Agree
St. Lucie 2	91.6	0.0	8.4	Agree	10,763	Agree
Turkey Point 3	93.6	0.0	6.4	Agree	10,865	Agree
Turkey Point 4	60.6	35.2	4.2	Agree	11,002	Agree
Gulf	EAF	POF	EUOF			
Crist 6	83.6	8.8	7.6	Agree	10,410	Agree
Crist 7	69.2	8.8	22.0	Agree	10,317	Agree
Smith 1	87.7	8.8	3.5	Agree	10,137	Agree
Smith 2	84.8	12.6	2.5	Agree	10,237	Agree
Daniel 1	85.4	0.0	14.6	Agree	10,287	Agree
Daniel 2	94.8	0.0	5.2	Agree	9,923	Agree
TECO	EAF	POF	EUOF			
Big Bend 1	85.4	0.0	14.6	Agree	9,957	Agree
Big Bend 2	62.3	30.8	6.9	Agree	9,895	Agree
Big Bend 3	69.4	19.2	11.4	Agree	9,610	Agree
Big Bend 4	89.4	0.0	10.6	Agree	9,832	Agree
Gannon 5	88.1	0.0	11.9	Agree	10,454	Agree
Gannon 6	75.9	9.3	14.8	Agree	10,288	Agree

Staff Attachment 2

TOTAL FUEL COST FOR THE PERIOD: October 1994 – March 1995

DATE: 08/04/94
PAGE 1 of 10

COMPANY	PROPOSED July 1994 – September 1994 October 1994 – March 1995 Levelized	On/Peak	Off/Peak	PRESENT April 1994 – September 1994 July 19! Levelized	Cents per kwh On/Peak	Off/Peak	DIFFERENCE Levelized	Cents per kwh On/Peak	Off/Peak	RESIDENTIAL LINE LOSS MULTIPLIER	PROPOSED RESIDENTIAL FUEL FACTOR
Fla. Power & Light (5)	1.567	1.673	1.525	1.488	1.633	1.415	0.079	0.040	0.110	1.00210	1.570
Fla. Power Corp.	2.055	2.612	1.827	1.968	2.692	1.587	0.087	−0.080	0.240	1.00000	2.055
Tampa Electric	2.353	3.791	2.444	2.894	2.946	2.346	−0.541	0.845	0.098	1.00640	2.368
Gulf Power	2.179	2.226	2.164	2.158	2.253	2.113	0.021	−0.027	0.051	1.01228	2.206
Fla. Public											
Marianna (1)	4.874	NA	NA	4.658	NA	NA	−0.216	NA	NA	1.01260	4.936
Fernandina (1)(2)	5.098	NA	NA	5.308	NA	NA	−0.210	NA	NA	1.00000	5.098

COST FOR 1,000 KWH RESIDENTIAL SERVICE

PRESENT: July 1994 – September 1994

	Fla. Power & Light	Fla. Power Corp.	Tampa Electric (5)	Gulf Power (6)	Florida Public Utilities Marianna (7)	Fernandina
Base	47.38	49.05	51.92	43.25	20.43	19.20
Fuel (3)	14.90	19.75	24.89	21.85	47.17	53.08
Oil Backout	0.12	N/A	0.73	N/A	N/A	N/A
Energy Conservation	2.43	4.40	1.85	0.26	0.12	0.06
Environmental Cost Recovery	0.12	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	2.09	0.69	1.74	0.74
Total	$71.31	$80.32	$83.53	$67.84	$69.46	$73.08

PROPOSED: October 1994 – March 1995

	Fla. Power & Light	Fla. Power Corp.	Tampa Electric	Gulf Power	Florida Public Utilities Marianna	Fernandina
Base	47.38	49.05	51.92	43.25	20.43	19.20
Fuel (3)	15.70	20.55	23.68	22.06	49.36	50.98
Oil Backout	0.11	N/A	0.96	N/A	N/A	N/A
Energy Conservation	2.43	4.40	1.85	0.26	0.12	0.06
Environmental Cost Recovery	0.10	N/A	N/A	1.55	N/A	N/A
Capacity Recovery	5.17	7.47	1.93	2.24	N/A	N/A
Gross Receipts Tax (4)	0.73	2.09	2.06	0.71	1.79	0.72
Total	$71.62	$83.56	$82.40	$70.07	$71.70	$70.96

DIFFERENCE	Fla. Power & Light	Fla. Power Corp.	Tampa Electric	Gulf Power	Florida Public Utilities Marianna	Fernandina
Base	0.00	0.00	0.00	0.00	0.00	0.00
Fuel (3)	0.80	0.80	−1.21	0.21	2.19	−2.10
Oil Backout	−0.01	N/A	0.23	N/A	N/A	N/A
Energy Conservation	0.00	0.00	0.00	0.00	0.00	0.00
Environmental Cost Recovery	−0.02	N/A	N/A	0.07	N/A	N/A
Capacity Recovery	−0.47	2.36	−0.12	1.93	N/A	N/A
Gross Receipts Tax (4)	0.01	0.08	−0.03	0.02	0.05	−0.02
Total	0.31	3.24	−1.13	2.23	2.24	−2.12

(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.

Staff Attachment 2

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

DIVISION OF ELECTRIC AND GAS
DATE: 08/04/94
PAGE 2 of 10

FOR THE PERIOD: October 1994 – March 1995

COMPANY	GROUP	RATE SCHEDULES	WITHOUT LINE LOSS MULTIPLIER			LINE LOSS	WITH LINE LOSS MULTIPLIER		
			Levelized	* On/Peak	Off/Peak	MULTIPLIER	Levelized	On/Peak	Off/Peak
FP&L	A	RS-1,RST-1,GST-1,GS-1,SL-2, CILC-G,	1.567	1.673	1.525	1.00210	1.570	1.677	1.529
	A-1	SL-1,OL-1	1.549	NA	NA	1.00210	1.552	NA	NA
	B	GSD-1,GSDT-1	1.567	1.673	1.525	1.00204	1.570	1.677	1.528
	C	GSLD-1,GSLDT-1, CS-1, CST-1	1.567	1.673	1.525	1.00089	1.568	1.675	1.527
	D	GSLD-2,GSLDT-2, CS-2, CST-2	1.567	1.673	1.525	0.99443	1.558	1.664	1.517
	E	GSLD-3,GSLDT-3,CS-3,CST-3	1.567	1.673	1.525	0.96091	1.506	1.608	1.466
	F	CILC-1(D),ISST-1(D)	NA	1.673	1.525	0.99758	NA	1.669	1.522
FPC *	A	Distribution Secondary Delivery	2.055	2.612	1.827	1.00000	2.055	2.612	1.827
	A-1	OL-1,SL-1	1.974	NA	NA	1.00000	1.974	NA	NA
	B	Distribution Primary Delivery	2.055	2.612	1.827	0.99000	2.034	2.585	1.808
	C	Transmission Delivery	2.055	2.612	1.827	0.98000	2.014	2.560	1.790
TECO	A	RS,GS,TS	2.353	2.666	2.239	1.00640	2.368	2.683	2.253
	A-1	SL-1,2,3,OL-1,2	2.302	NA	NA	1.00640	2.317	NA	NA
	B	GSD,GSLD	2.353	2.666	2.239	1.00120	2.356	2.669	2.242
	C	IS-1,IS-3	2.353	2.666	2.239	0.97210	2.287	2.592	2.177
GULF	A	RS,GS,GSD,OS-III,OS-IV	2.179	2.226	2.164	1.01228	2.206	2.253	2.191
	B	LP	2.179	2.226	2.164	0.98106	2.138	2.184	2.123
	C	PX	2.179	2.226	2.164	0.96230	2.097	2.142	2.082
	D	OS-1,OS-2	2.178	NA	NA	1.01228	2.205	NA	NA
FPUC									
Fernandina	A	RS	5.098	NA	NA	1.00000	5.098	NA	NA
	B	GS	4.832	NA	NA	1.00000	4.832	NA	NA
	C	GSD	4.643	NA	NA	1.00000	4.643	NA	NA
	D	OL, OL-2, SL-2, SL-3, CSL	4.058	NA	NA	1.00000	4.058	NA	NA
	E	GSLD					4.799 (1)		
							$6.28/CP KW		
Marianna	A	RS	4.874	NA	NA	1.01260	4.936	NA	NA
	B	GS	4.721	NA	NA	0.99630	4.704	NA	NA
	C	GSD	4.346	NA	NA	0.99630	4.330	NA	NA
	D	GLSD	4.185	NA	NA	0.99630	4.170	NA	NA
	E	OL, OL-2	3.009	NA	NA	1.01260	3.047	NA	NA
	F	SL-1, SL-2	3.009	NA	NA	0.98810	2.973	NA	NA

Staff Attachment 2

PROPOSED CAPACITY COST RECOVERY FACTORS
For the Period: October 1994 – March 1995

DIVISION OF ELECTRIC AND GAS
DATE: 08/04/94
PAGE 3 of 10

COMPANY	RATE SCHEDULE	RECOVERY FACTOR (CENTS PER KWH)
FPL	RS1	0.517
	GS1	0.458
	OL1/SL1	0.135
	SL2	0.325
	OS2	0.286
		RECOVERY FACTOR (DOLLARS PER KW)
	GSD1	1.690
	GSLD1/CS1	1.760
	GSLD2/CS2	1.780
	GSLD3/CS3	1.760
	ISST1D	RDC .23, SDD .11
	SST1T	RDC .22, SDD .10
	SST1D	RDC .23, SDD .11
	CILCD,CILCG	1.680
	CILCT	1.600
	MET	1.830
		RECOVERY FACTOR (CENTS PER KWH)
FPC *	RS	0.747
	GS–Transmission	0.581
	GS–Primary	0.587
	GS–Secondary	0.593
	GS – 100% Load Factor	0.409
	GSD–Transmission	0.487
	GSD–Primary	0.491
	GSD–Secondary	0.496
	CS – Primary	0.413
	CS – Secondary	0.417
	IS–Transmission	0.409
	IS–Primary	0.413
	IS–Secondary	0.417
	LS – Lighting Service	0.149
TECO	RS	0.193
	GS,TS	0.178
	GSD	0.134
	GSLD,SBF	0.122
	IS–1 & 3,SBI–1 & 3	0.011
	SL/OL	0.011
GULF	RS,RST	0.224
	GS,GST	0.219
	GSD,GSDT	0.170
	LP,LPT	0.147
	PX,PXT	0.119
	OS–1,OS–II	0.014
	OS–III	0.132
	OS–IV	0.015
	SS	0.363

Staff Attachment 2

FUEL & PURCHASED POWER COST RECOVERY
CLAUSE CALCULATION

DIVISION OF ELECTRIC AND GAS
DATE: 08/04/94
PAGE 4 OF 10

ESTIMATED FOR THE PERIOD: October 1994 - March 1995

FLORIDA POWER & LIGHT COMPANY

CLASSIFICATION	Classification Associated $	Classification Associated KWH	Classification Associated Cents/KWH
1.Fuel Cost of System Net Generation (E3)	417,030,531	28,184,276,000	1.47966
2.Spent NUC Fuel Disposal Cost (E2)	8,958,421	9,755,442,000 (a)	0.09183
3.Fuel Related Transactions	7,069,705	0	0.00000
4. Natural Gas Pipeline Enhancements	0	0	0.00000
4a. Fuel Cost of Sales to FKEC	(7,342,607)	(379,284,000)	1.93591
5.TOTAL COST OF GENERATED POWER	425,716,050	27,804,992,000	1.53108
6.Fuel Cost of Purchased Power - Firm (E8)	79,340,740	4,757,009,000	1.66787
7.Energy Cost of Sch.C,X Economy Purchases (Broker) (E9)	7,130,110	381,899,000	1.86701
8.Energy Cost of Economy Purchases (Non-Broker) (E9)	443,200	19,909,000	2.22613
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)	42,767,956	2,415,279,000	1.77073
12.TOTAL COST OF PURCHASED POWER	129,682,006	7,574,096,000	1.71218
13.TOTAL AVAILABLE KWH		35,379,088,000	
14.Fuel Cost of Economy Sales (E7)	(6,804,040)	(279,287,000)	2.43622
15.Gain on Economy Sales - 80% (E7A)	(1,734,687)	(279,287,000)(a)	0.62111
16.Fuel Cost of Unit Power Sales (SL2 Partpts) (E7)	(717,521)	(168,528,000)	0.42576
17.Fuel Cost of Other Power Sales (E7)	0	0	0.00000
18.TOTAL FUEL COST AND GAINS OF POWER SALES	(9,256,248)	(447,815,000)	2.06698
19.Net Inadvertant Interchange (E4)	0	0	0.00000
20.TOTAL FUEL AND NET POWER TRANSACTIONS	546,141,808	34,931,273,000	1.56348
21.Net Unbilled (E4)	13,681,159 (a)	875,048,000	0.04098
22.Company Use (E4)	(1,656,221)(a)	(105,932,000)	-0.00496
23.T & D Losses (E4)	(36,326,331)(a)	(2,312,886,000)	-0.10880
24.Adjusted System KWH Sales	546,141,808	33,387,503,000	1.63577
25.Wholesale KWH Sales	1,260,987	77,089,000	1.63575
26.JURISDICTIONAL KWH SALES	544,880,821	33,310,414,000	1.63577
27.Jurisdictional KWH Sales Adjusted for Line Loss - 1.00035	545,169,608	33,310,414,000	1.63663
28.True-up * (derived in Attachment C)	(34,518,662)	33,310,414,000	-0.10363
29.TOTAL JURISDICTIONAL FUEL COST	510,650,946	33,310,414,000	1.53300
30.Revenue Tax Factor			1.01609
31.Fuel Cost Adjusted for Taxes			1.55767
32.GPIF*	3,107,919	33,310,414,000	0.00933
33.Total fuel cost including GPIF	513,758,865	33,310,414,000	1.56700
34.TOTAL FUEL COST FACTOR ROUNDED TO THE NEAREST .001 CENTS PER KWH:			1.567

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

ORDER NO. PSC-94-0963-PHO-EI
DOCKET NO. 940001-EI
PAGE 28

Staff Attachment 2

FUEL & PURCHASED POWER COST RECOVERY
CLAUSE CALCULATION

DIVISION OF ELECTRIC AND GAS
DATE: 08/04/94
PAGE 5 OF 10

ESTIMATED FOR THE PERIOD: October 1994 - March 1995

FLORIDA POWER CORPORATION

CLASSIFICATION	Classification Associated $	Classification Associated KWH	Classification Associated cents/KWH
1.Fuel Cost of System Net Generation (E3)	172,200,853	11,130,354,000	1.54713
2.Spent NUC Fuel Disposal Cost (E3A)	2,972,984	3,179,662,000 (a)	0.09350
3.Coal Car Investment	0	0	0.00000
4.Adjustments to Fuel Cost	(1,200,000)	0	0.00000
5.TOTAL COST OF GENERATED POWER	173,973,837	11,130,354,000	1.56306
6.Energy Cost of Purchased Power – Firm (E8)	11,781,150	562,578,000	2.09414
7.Energy Cost of Sch.C,X Economy Purchases (Broker) (E9)	7,176,500	220,000,000	3.26205
8.Energy Cost of Economy Purchases (Non–Broker) (E9)	423,390	18,000,000	2.35217
9.Energy Cost of Sch.E Purchases (E9)	2,308,161	118,080,000	1.95474
10.Capacity Cost of Sch.E Economy Purchases (E9)	0	0 (a)	0.00000
11.Payments to Qualifying Facilities (E8A)	71,413,950	3,077,460,000	2.32055
12.TOTAL COST OF PURCHASED POWER	93,103,151	3,996,118,000	2.32984
13.TOTAL AVAILABLE KWH		15,126,472,000	
14.Fuel Cost of Economy Sales (E7)	(6,762,000)	(360,000,000)	1.87833
14a.Gain on Economy Sales – 80% (E7A)	(866,360)	(360,000,000)(a)	0.24066
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)	(7,766,300)	(310,647,000)	2.50004
18.TOTAL FUEL COST AND GAINS OF POWER SALES	(15,394,660)	(670,647,000)	2.29549
19.Net Inadvertant Interchange (E4)	0	0	
20.TOTAL FUEL AND NET POWER TRANSACTIONS	251,682,328	14,455,825,000	1.74104
21.Net Unbilled (E4)	(6,840,232)(a)	392,891,000	–0.04905
22.Company Use (E4)	1,645,245 (a)	(94,500,000)	0.01180
23.T & D Losses (E4)	14,080,094 (a)	(808,736,000)	0.10097
24.Adjusted System KWH Sales	251,682,328	13,945,480,000	1.80476
25.Wholesale KWH Sales(Excluding Seminole Supplemental)	(8,694,040)	(484,616,000)	1.79401
26.JURISDICTIONAL KWH SALES	242,988,288	13,460,864,000	1.80515
27.Jurisdictional KWH Sales Adjusted for Line Loss – 1.0014	243,304,173	13,460,864,000	1.80749
28.Prior Period True–Up *	31,586,452	13,460,864,000	0.23451
28a. Market Price Refund for 1992	(19,637)	0	0.00000
29.TOTAL JURISDICTIONAL FUEL COST	274,870,988	13,460,864,000	2.04200
30.Revenue Tax Factor			1.00083
31.Fuel Cost Adjusted for Taxes			2.04370
32.GPIF*	1,009,347	13,460,864,000	0.00750
33.Total fuel cost including GPIF	275,880,335	13,460,864,000	2.05120
34.TOTAL FUEL COST FACTOR ROUNDED TO THE NEAREST .001 CENTS PER KWH:			2.051

*Based on Jurisdictional Sales

(a) Included for informational purposes only.

Staff Attachment 2

FUEL & PURCHASED POWER COST RECOVERY CLAUSE CALCULATION

DIVISION OF ELECTRIC AND GAS
DATE: 08/04/94
PAGE 6 OF 10

ESTIMATED FOR THE PERIOD: October 1994 – March 1995

TAMPA ELECTRIC COMPANY

CLASSIFICATION	Classification Associated $	Classification Associated KWH	Classification Associated cents/KWH
1.Fuel Cost of System Net Generation (E3)	160,682,999	7,193,453,000	2.23374
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	160,682,999	7,193,453,000	2.23374
6.Fuel Cost of Purchased Power – Firm (E8)	1,564,400	34,785,000	4.49734
7.Energy Cost of Sch.C,X Economy Purchases (Broker) (E9)	162,900	6,366,000	2.55891
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)	4,642,600	279,642,000	1.66019
12.TOTAL COST OF PURCHASED POWER	6,369,900	320,793,000	1.98567
13.TOTAL AVAILABLE KWH		7,514,246,000	
14.Fuel Cost of Economy Sales (E7)	7,656,200	468,199,000	1.63524
15.Gain on Economy Sales – 80% (E7A)	1,015,520	468,199,000 (a)	0.21690
16.Fuel Cost of Seedule D Sales (E7)	3,383,400	233,606,000	1.44834
16a.Fuel Cost of Schedule G Sales (E7)	0	0	0.00000
17.Fuel Cost Schedule J Sales (E7)	788,900	45,748,000	1.72445
17a.Fuel Cost Schedule D TPS Sales (E7)	1,426,200	71,744,000	1.98790
18.TOTAL FUEL COST AND GAINS OF POWER SALES	14,270,220	819,297,000	1.74176
19.Net Inadvertant Interchange (E4)	0	0	
19b.Interchange and Wheeling Losses	0	12,865,000	
20.TOTAL FUEL AND NET POWER TRANSACTIONS	152,782,679	6,682,084,000	2.28645
21.Net Unbilled (E4)	(2,983,406)(a)	(130,482,000)	−0.04606
22.Company Use (E4)	370,405 (a)	16,200,000	0.00572
23.T & D Losses (E4)	7,289,820 (a)	318,827,000	0.11254
24.Adjusted System KWH Sales	152,782,679	6,477,539,000	2.35865
25.Wholesale KWH Sales	(101,945)	(4,305,000)	2.36806
26.JURISDICTIONAL KWH SALES	152,680,734	6,473,234,000	2.35865
27.Jurisdictional KWH Sales Adjusted for Line Loss – 1.00005	152,757,074	6,473,234,000	2.35983
28.True–up * (derived in Attachment C)	(952,141)	6,473,234,000	−0.01471
29.Pyramid Coal Contract Buyout Adjustment	0	6,473,234,000	0.00000
30.TOTAL JURISDICTIONAL FUEL COST	151,804,933	6,473,234,000	2.34512
31.Revenue Tax Factor			1.00083
32.Fuel Cost Adjusted for Taxes	151,930,931		2.34706
33.GPIF * (Already adjusted for taxes)	406,404	6,473,234,000	0.00628
34.Total Fuel Cost including GPIF	152,337,335	6,473,234,000	2.35334
35.TOTAL FUEL COST FACTOR ROUNDED TO THE NEAREST .001 CENTS PER KWH:			2.353

*Based on Jurisdictional Sales

Effective date for billing purposes:

(a) Included for informational purposes only.

ORDER NO. PSC-94-0963-PHO-EI
DOCKET NO. 940001-EI
PAGE 30

Staff Attachment 2

FUEL & PURCHASED POWER COST RECOVERY CLAUSE CALCULATION

DIVISION OF ELECTRIC AND GAS
DATE: 08/04/94
PAGE 7 OF 10

ESTIMATED FOR THE PERIOD: October 1994 – March 1995

GULF POWER COMPANY

CLASSIFICATION	Classification Associated $	Classification Associated KWH	Classification Associated cents/KWH
1.Fuel Cost of System Net Generation (E3)	111,500,080	5,907,450,000	1.8874
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	111,500,080	5,907,450,000	1.8874
5.Fuel Cost of Purchased Power – Firm (E8)	0	0	0.0000
6.Energy Cost of Sch.C,X Economy Purchases (Broker) (E9)	2,335,000	125,150,000	1.8658
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	2,335,000	125,150,000	1.8658
12.TOTAL AVAILABLE KWH (line 4 + line 11)		6,032,600,000	
13.Fuel Cost of Economy Sales (E7)	(473,000)	(27,380,000)	1.7275
14.Gain on Economy Sales – 80% (E7A)	(65,600)	0 (a)	0.0000
15.Fuel Cost of Unit Power Sales (E7)	(12,518,000)	(698,950,000)	1.7910
16.Fuel Cost of Other Power Sales (E7)	(20,595,000)	(1,193,353,000)	1.7258
17.TOTAL FUEL COST AND GAINS OF POWER SALES	(33,651,600)	(1,919,683,000)	1.7530
18.Net Inadvertant Interchange (E4)	0		
19.TOTAL FUEL AND NET POWER TRANSACTIONS	80,183,480	4,112,917,000	1.9496
20.Net Unbilled (E4)	0	0	0.0000
21.Company Use (E4)	193,381 (a)	9,919,000	1.9496
22.T & D Losses (E4)	4,336,183 (a)	222,414,000	1.9496
23.Adjusted System KWH Sales	80,183,480	3,880,584,000	2.0663
24.Wholesale KWH Sales	2,959,438	143,224,000	2.0663
25.JURISDICTIONAL KWH SALES	77,224,042	3,737,360,000	2.0663
26.Jurisdictional KWH Sales Adjusted for Line Loss – 1.00140	77,332,156	3,737,360,000	2.0692
27.True–up *	2,780,272	3,737,360,000	0.0744
28.Total Jurisdictional Fuel Cost	80,112,428	3,737,360,000	2.1436
29.Revenue Tax Factor			1.01609
30.Fuel Cost Adjusted for Taxes			2.1781
31.Special Contract Recovery Cost	121,472	3,737,360,000	0.0033
32.GPIF *	(84,941)	3,737,360,000	–0.0023
33.Total Fuel Cost including GPIF	80,027,487	3,737,360,000	2.1791
34.TOTAL FUEL COST FACTOR ROUNDED TO THE NEAREST .001 CENTS PER KWH:			2.179

*Based on Jurisdictional Sales
Effective date for billing purposes:

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Staff Attachment 2

FUEL & PURCHASED POWER COST RECOVERY CLAUSE CALCULATION

DIVISION OF ELECTRIC AND GAS
DATE: 08/04/94
PAGE 8 OF 10

ESTIMATED FOR THE PERIOD: October 1994 – March 1995

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)	2,497,657	120,834,000	2.06702
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)	2,746,846	120,834,000 (a)	2.27324
10a.Demand Costs of Purchased Power	1,911,000 (a)		
10b.Non–Fuel Energy & Customer Costs of Purchased Power	835,846 (a)		
11.Energy Payments to Qualifying Facilities (E8A)	0	0	0.00000
12.TOTAL COST OF PURCHASED POWER	5,244,503	120,834,000	4.34025
13.TOTAL AVAILABLE KWH	5,244,503	120,834,000	4.34025
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	5,244,503	120,834,000	4.34025
21.Net Unbilled (E4)	17,708 (a)	408,000	0.01534
22.Company Use (E4)	5,339 (a)	123,000	0.00462
23.T & D Losses (E4)	239,701 (a)	4,834,000	0.20759
24.ADJUSTED SYSTEM KWH SALES	5,244,503	115,469,000	4.54191
25.Less Total Demand Cost Recovery	1,800,784		
26.JURISDICTIONAL KWH SALES	3,443,719	115,469,000	2.98238
27.Jurisdictional KWH Sales Adjusted for Line Loss – 1.00	3,443,719	115,469,000	2.98238
28.True–up *	27,588	115,469,000	0.02389
29.TOTAL JURISDICTIONAL FUEL COST	3,471,307	115,469,000	3.00627
30.Revenue Tax Factor			1.00083
31.Fuel Cost Adjusted for Taxes	3,499,562	0	3.00876
32.GPIF *	0	115,469,000	0.00000
33.Total Fuel Cost including GPIF	3,471,307	115,469,000	3.00876
34.TOTAL FUEL COST FACTOR ROUNDED TO THE NEAREST .001 CENTS PER KWH:			3.009

*Based on Jurisdictional Sales

(a) included for informational purposes only.

Staff Attachment 2

FUEL & PURCHASED POWER COST RECOVERY CLAUSE CALCULATION

DIVISION OF ELECTRIC AND GAS
DATE: 08/04/94
PAGE 9 OF 10

ESTIMATED FOR THE PERIOD: October 1994 – March 1995

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)	2,705,455	146,637,000	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	4,681,528	146,637,000	3.19260
10a.Demand Costs of Purchased Power (E2)	2,268,000 (a)		
10b.Non Fuel Energy and Customer Costs of Purchased Power (E2)	2,413,528 (a)		
11.Energy Payments to Qualifying Facilities (E8A)	0	0	0.00000
12.TOTAL COST OF PURCHASED POWER	7,386,983	146,637,000	5.03760
13.TOTAL AVAILABLE KWH	7,386,983	146,637,000	5.03760
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	7,386,983	146,637,000	5.03760
21.Net Unbilled (E4)	(229,160)(a)	(4,549,000)	−0.16113
22.Company Use (E4)	8,362 (a)	166,000	0.00588
23.T & D Losses (E4)	443,208 (a)	8,798,000	0.31163
24.Adjusted System KWH Sales	7,386,983	142,222,000	5.19398
25.Wholesale KWH Sales	0	0	0.00000
26.JURISDICTIONAL KWH SALES	7,386,983	142,222,000	5.19398
27.Jurisdictional KWH Sales Adjusted for Line Loss – 1.00	7,386,983	142,222,000	5.19398
27a.GSLD KWH Sales (E11)		42,000,000	
27b.Other Classes KWH Sales (E11)		100,222,000	
27c.GSLD CP KW		120,000 (a)	
28. GPIF			
29.True–up *	(289,071)	142,222,000	−0.20325
30.TOTAL JURISDICTIONAL FUEL COST	7,097,912	142,222,000	4.99073

Staff Attachment 2

FUEL & PURCHASED POWER COST RECOVERY CLAUSE CALCULATION

DIVISION OF ELECTRIC AND GAS
DATE: 08/04/94
PAGE 10 OF 10

ESTIMATED FOR THE PERIOD: October 1994 – March 1995

FLORIDA PUBLIC UTILITIES–FERNANDINA

CLASSIFICATION	Classification Associated $	Classification Associated KWH	Classification Associated cents/KWH
30a.Demand Purchased Power Costs (line 10a)	2,268,000 (a)		
30b.Non–Demand Purchased Power Costs (lines 6+10b+11)	5,118,983 (a)		
30c.True–up Over/Under Recovery (line 29)	(289,071)(a)		
APPORTIONMENT OF DEMAND COSTS			
31.Total Demand Costs	2,268,000		
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	1,526,400	100,222,000	1.52302
APPORTIONMENT OF NON–DEMAND COSTS			
34.Total Non–Demand Costs (line 30b)	5,118,983		
35.Total KWH Purchased (line 12)		146,637,000	
36.Average Cost per KWH Purchased			3.49092
37.Avg. Cost Adjusted for Transmission line losses (line 36 * 1.03)			3.59565
38.GSLD Non–Demand Costs (line 27a * line 37)	1,510,175	42,000,000	0.03596
39.Balance to Other Customers	3,608,808	100,222,000	3.60081
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)	1,510,175	42,000,000	3.59565
40e.Total Non–Demand Costs including true–up	1,510,175	42,000,000	3.59565
40f.Revenue Tax Factor			1.01609
40g.GSLD Non–demand costs adjusted for taxes			3.654
OTHER CLASSES PURCHASED POWER COST RECOVERY FACTORS			
41a.Total Demand and Non–Demand Purchased Power Costs of other classes (lines 33 + 39)	5,135,208	100,222,000	5.12383
41b.Less: Total Demand Cost Recovery	1,249,724 (a)		
41c.Total Other Costs to be Recovered	3,885,484 (a)	100,222,000	3.87688
41d.Other Classes' Portion of True–up (line 30 C)	(289,071)	100,222,000	–0.28843
41e.Total Demand and Non–Demand Costs including True–up	3,596,413	100,222,000	3.58845
42.Revenue tax factor			1.01609
			3.64618
43.OTHER CLASSES PURCHASED POWER FACTOR ADJUSTED FOR TAXES ROUNDED TO THE NEAREST .001 CENTS PER KWH:			3.646

*Based on Jurisdictional Sales

(a) included for informational purposes only.