BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In Re: Fuel and Purchased Power Cost Recovery Clause and Generating Performance Incentive Factor.	DOCKET NO. 930001-EI ORDER NO. PSC-93-0443-FOF-EI ISSUED: 03/23/93

The following Commissioners participated in the disposition of this matter:

THOMAS M. BEARD
SUSAN F. CLARK
J. TERRY DEASON

ORDER APPROVING PROJECTED EXPENDITURES
AND TRUE-UP AMOUNTS FOR FUEL ADJUSTMENT FACTORS;
GPIF TARGETS, RANGES, AND REWARDS;
PROJECTED EXPENDITURES AND TRUE-UP AMOUNTS
FOR OIL BACKOUT COST RECOVERY FACTORS;
AND PROJECTED EXPENDITURES AND TRUE-UP AMOUNTS
FOR CAPACITY COST RECOVERY FACTORS

BY THE COMMISSION:

As part of this Commission's continuing fuel cost recovery, oil backout cost recovery, capacity cost recovery, conservation cost recovery, and purchased gas cost recovery proceedings, hearings are held in February and August of each year. Pursuant to notice, a hearing was held in this docket and in Dockets No. 930002-EG and 930003-GU on February 17, 1993. The utilities submitted testimony and exhibits in support of their proposed fuel adjustment true-up amounts, fuel cost recovery factors, generating performance incentive factors, oil backout true-up amounts, capacity cost recovery factors and related issues.

Fuel Adjustment Factors

We find that the appropriate final fuel adjustment true-up amounts for the amounts for the period April, 1992 through September, 1992 are as follows:

FPC: $13,863,288 Underrecovery.

FPL: $13,545,567 Underrecovery.

FPUC: $170,987 Underrecovery. (Marianna)
$19,913 Overrecovery. (Fernandina Beach)

GULF: $1,732,139 Underrecovery.

TECO: $3,689,497 Underrecovery.

The estimated fuel adjustment true-up amounts for the period October, 1992 through March, 1993 are as follows:

FPC: $815,209 Underrecovery.

FPL: $30,415,048 Underrecovery.

FPUC: $186,021 Underrecovery. (Marianna)
$5,813 Underrecovery. (Fernandina Beach)

GULF: $1,199,942 Underrecovery.

TECO: $441,934 Overrecovery.

The total true-up amounts to be collected during the period April, 1993 through September, 1993 are as follows:

FPC: $14,678,497 Underrecovery.

FPL: $43,960,615 Underrecovery.

FPUC: $357,008 Underrecovery. (Marianna)
$14,100 Overrecovery. (Fernandina Beach)

GULF: $2,932,081 Underrecovery.

TECO: $3,247,563 Underrecovery

Finally, the appropriate levelized fuel cost recovery factors for the period April, 1993 through September, 1993 are as follows:

FPC: 2.171 cents per kWh - Standard rates*
2.780 cents per kWh - TOU On-Peak rates*
1.854 cents per kWh - TOU Off-Peak rates*

*Before line loss adjustment.

FPL: 2.259 cents/kwh is the levelized recovery charge for non-time differentiated rates and 2.431 cents/kwh and 2.172 cents/kwh are the levelized fuel recovery charges for the on-peak and off-peak periods, respectively, for the differentiated rates.

FPUC: 3.266 cents/kwh (Marianna).
4.422 cents/kwh (Fernandina Beach).

The factors are calculated to include true-up and revenue tax, exclude demand cost recovery, and have not been adjusted for line losses.

GULF: 2.216 cents per KWH.

TECO: 2.508 cents per KWH before application of the factors which adjust for variations in line losses.

For billing purposes, the new fuel adjustment charge, oil backout charge, conservation cost recovery charge and capacity cost recovery charge factors shall be effective beginning with the specified fuel cycle and thereafter for the period April, 1993 through September, 1993. Billing cycles may start before April 1, 1993, and the last cycle may be read after September 30, 1993, so that each customer is billed for six months regardless of when the adjustment factor became effective.

Each utility proposed fuel recovery loss multipliers to be used in calculating the fuel cost recovery factors charged to each rate class. Those multipliers are shown in Attachment A attached hereto. We find that the proposed multipliers are appropriate and should be approved. The utilities further proposed fuel cost recovery factors for each rate group, adjusted for line losses, which are also shown in Attachment A. We find that the proposed factors are appropriate and should be approved.

Florida Power and Light Company proposed that they change the frequency of coal inventory aerial surveys from quarterly to semi-annually. We considered the issue for all investor-owned electric utilities and we find the proposal to be reasonable. We therefore approve the change in the frequency of aerial coal inventory surveys from quarterly to semi-annually for a two-year period. We direct our staff to review the impact of the less frequent surveys on inventory adjustments to determine whether to recommend a permanent change.

The other fuel adjustment issues raised in this docket pertain to specific utilities and are discussed below.

Florida Power Corporation

Florida Power Corporation requested our permission to recover through the fuel adjustment clause the cost of its affiliate, Electric Fuels Corporation's, charge for a return on equity on EFC's investment in locomotives. We approve the request. Florida Power Corporation has projected that the purchase of the locomotives will result in a reduction in rail transportation costs. This reduction will provide savings to FPC's ratepayers in excess of EFC's charge for a return on equity on EFC's investment.

We also approve Florida Power Corporation request for permission to recover through the fuel adjustment clause the charges associated with gas transportation to FPC's University of Florida cogeneration project. The costs are reasonable gas transportation costs for FPC's University of Florida cogeneration project, and they are appropriately recoverable through the fuel adjustment clause.

The following issue has been deferred to the August, 1993, fuel proceeding:

> Should Florida Power Corporation be permitted to recover through the fuel adjustment clause $972,000 in payments to the Department of Energy (DOE) for costs of the decontamination and decommissioning of the DOE's uranium enrichment plants?

For this period we will permit FPC to recover its payments to DOE for the costs of the decontamination and decommissioning of the DOE's uranium enrichment plants, subject to refund pending our decision on the issue in August.

Florida Power and Light Company

Florida Power and Light Company requested that it be permitted to recover through the fuel adjustment clause $550,000. of Clean Air Act operating fees. We prefer to investigate and determine the appropriate recovery of compliance costs associated with the Clean Air Act Amendment in a generic docket, where we can fully consider the appropriate recovery for all types of compliance costs for all investor-owned utilities. We do not wish to make this determination piecemeal. Therefore, we withhold approval of FPL's recovery of those fees at this time, pending our investigation in the generic docket.

The following issue, similar to the issue for Florida Power Corporation, has been deferred to the August, 1993 fuel proceeding:

> Should Florida Power and Light Company be permitted to recover through the fuel adjustment clause $2,580,000 in payments to the Department of Energy (DOE) for costs of the decontamination and decommissioning of the DOE's uranium enrichment plants?

For this period we will permit FPL to recover its payments to DOE for the costs of the decontamination and decommissioning of the DOE's uranium enrichment plants, subject to refund pending our decision on the issue in August.

Florida Power and Light Company also requested that it be permitted to recover through the fuel adjustment clause $4,087,634 in litigation costs associated with the IMC contract arbitration. We find that the litigation costs incurred in the IMC contract dispute were reasonably related to the cost of fuel, reasonably expected to result in reduced fuel cost for the retail ratepayers, and thus appropriate for recovery through the fuel clause.

<u>Tampa Electric Company</u>

In August 1992, we deferred the following issues to this proceeding:

> What is the appropriate 1991 benchmark price for coal Tampa Electric Company purchased from its affiliate, Gatliff Coal Company, and;
>
> Has Tampa Electric Company adequately justified any costs associated with the purchase of coal from Gatliff coal Company that are in excess of the 1991 benchmark price?

At Public Counsel's request, the following issue was also scheduled to be heard in this proceeding;

Should TECO be ordered to refund the excess cost of Gatliff coal above the 1991 benchmark?

These issues relate to the market-based pricing methodology we established in Order No. 20298 (Docket No. 870001-EI-A) to measure the appropriate cost of coal TECO purchases from its affiliate, Gatliff Coal Company. The methodology we established at that time was developed by stipulation between TECO and the Office of Public Counsel.

The day before the hearing in this proceeding, TECO and the Office of Public Counsel submitted a new stipulation that revised the methodology by which the appropriateness of TECO's Gatliff coal purchases will be measured from 1993 to 1999. The new stipulation resolves all outstanding issues related to the pricing of TECO's coal purchases from Gatliff through 1992, and it provides that TECO will reduce its recoverable fuel expense by $10 million and credit that amount to its ratepayers. The adjustment will be made over the 12-month period from April, 1993 through March, 1994. Interest will be included.

The revised methodology developed by TECO and Public Counsel establishes a beginning base price of $38.00 per ton FOB Mine as of December 31, 1992. That base price will be escalated or de-escalated by the annual percentage change in the Consumer Price Index, All Urban Consumers (CPI-U). The stipulation provides that the weighted average annual price TECO pays to Gatliff will be disallowed for fuel cost recovery purposes if that price exceeds the price established by the methodology described above.

We approve the new stipulation revising the method to determine the appropriateness of the cost of TECO's coal purchases from its affiliate. The details of the revised methodology are provided in paragraphs 12 -14 of the stipulation attached to this order as Attachment B.

Generating Performance Incentive Factor (GPIF)

There was no controversy among the parties at this hearing as to either the appropriate GPIF reward or penalty for past performance or the proposed GPIF targets and ranges for performance in the upcoming period. The parties agreed to, and we approve, the following GPIF rewards for the period April, 1992 through September, 1992.

FPC: $1,211,009 reward.

FPL: $2,020,173 reward.

GULF: Reward $322,504.

TECO: Reward of $318,938.

The parties also agreed to targets and ranges for the period April, 1993 through September, 1993, which are shown on Attachment C to this order. We approve those targets and ranges.

Oil Backout Cost Recovery Factor

In accordance with the agreement of the parties, we find the proper final oil backout true-up amount for the period April, 1992 through September, 1992 period to be:

FPL: $3,636 Overrecovery.

TECO: $1,301,825 Overrecovery.

The estimated oil backup true-up amount for the period October, 1992 through March, 1993, is:

FPL: $185,325 Overrecovery.

TECO: $988,475 Overrecovery.

The total oil backout true-up amount to be collected or refunded during the period April, 1993 through September, 1993, is:

FPL: $188,961 Overrecovery.

TECO: $1,580,247 Overrecovery.

Finally, we find the proper projected oil backout cost recovery factor for the period April, 1993 through September, 1993, is:

FPL: .013 cents/kwh.

TECO: .065 cents/kwh.

Capacity Cost Recovery Factor

We approve the following the final capacity cost recovery true-up amounts for the April, 1992 through September, 1992 period:

FPC: None.

FPL: $5,781,688 Underrecovery.

GULF: None. Gulf's initial implementation of a purchased power capacity cost recovery factor occurred during the October 1992 through March 1993 recovery period. As a result, Gulf does not have a true-up amount for any periods prior to October 1992.

TECO: None. Since Tampa Electric did not have a capacity cost recovery factor in effect for the period April 1992 - September 1992, there is no true-up to consider.

We approve the following estimated capacity cost recovery true-up amounts for the period October, 1992 through March, 1993

FPC: $1,662,838 Underrecovery.

FPL: $29,006,869 Overrecovery.

GULF: $1,711,114 Underrecovery.

TECO: $2,940,455 Underrecovery.

We approve the following total capacity cost recovery true-up amounts to be collected during the period April, 1993 through September, 1993

FPC: $1,662,838 Underrecovery.

FPL: $23,225,181 Overrecovery.

GULF: $1,711,114 Underrecovery.

TECO: $2,940,455 Underrecovery.

We approve the following appropriate projected net purchased power capacity cost amount to be included in the recovery factor for the period April, 1993 through September, 1993.

FPC: $32,570,136 jurisdictional.

FPL: $152,333,871 jurisdictional.

GULF: $1,801,898 jurisdictional.

TECO: $11,536,771 jurisdictional.

We approve the following projected capacity cost recovery factors for the period April, 1993 through September, 1993.

FPC:	RS	0.289	cents per kwh
	GS-Transmission	0.196	"
	GS-Primary	0.199	"
	GS-Secondary	0.202	"
	GS-100% Load Factor	0.152	"
	GSD-Transmission	0.140	"
	GSD-Primary	0.176	"
	GSD-Secondary	0.179	"
	CS-Curtailable	0.138	"
	IS-Transmission	0.145	"
	IS-Primary	0.147	"
	LS-Lighting Service	0.057	"

FPL:

RS1	0.442	cents per kwh
GS1	0.412	"
GSD1	0.377	"
OS2	0.365	"
GSLD1/CS1	0.384	"
GSLD2/CS2	0.317	"
GSLD3/CS3	0.300	"
ISST1D	0.261	"
SST1T	0.237	"
SST1D	0.243	"
CILCD	0.264	"
CILCT	0.243	"
MET	0.337	"
OL1/SL1	0.203	"
SL2	0.279	"
TOTAL	0.405	"

GULF: See table below:

RATE CLASS	CAPACITY COST RECOVERY FACTORS ¢/KWH
RS, RST	0.048
GS, GST	0.048
GSD, GSDT	0.036
LP, LPT	0.032
PX, PXT	0.027
OSI, OSII	0.005
OSIII	0.029
OSIV	0.003
SS	0.026

TECO:

RS	.217 cents per KWH
GS, TS	.179 cents per KWH
GSD	.149 cents per KWH
GSLD, SBF	.133 cents per KWH
IS-1 & 3, SBI-1 & 3	.012 cents per KWH
SL, OL	.012 cents per KWH

The other capacity cost recovery issues raised in this docket pertain to specific utilities and are discussed below.

Company-Specific Capacity Cost Recovery Issues

Florida Power and Light Company

Florida Power and Light Company requested recovery through the capacity clause the capacity payments associated with the 1988 Unit Power Sales Agreement (UPS) with the Southern Companies. We approve recovery. The 1988 UPS Agreement is a reasonable, prudent and necessary expense that benefits FPL's customers and is not being recovered in any other manner.

In consideration of the above, it is

ORDERED by the Florida Public Service Commission that the findings and stipulations set forth in the body of this Order are hereby approved. It is further

ORDERED that investor-owned electric utilities subject to our jurisdiction are hereby authorized to apply the fuel cost recovery factors set forth herein during the period of April through September, 1993, and until such factors are modified by subsequent Order. Florida Power Corporation is authorized to apply its fuel cost recovery factors on the same date as any rate adjustment ordered in Docket No. 910890-EI. It is further

ORDERED that the estimated true-up amounts contained in the above fuel cost recovery factors are hereby authorized subject to final true-up, and further subject to proof of the reasonableness and prudence of the expenditures upon which the amounts are based. It is further

ORDERED that the Generating Performance Incentive Factor rewards and penalty stated in the body of this Order shall be applied to the projected levelized fuel adjustment factors for the period of April through September, 1993. It is further

ORDERED that the targets and ranges for the Generating Performance Incentive Factors set forth herein are hereby adopted for the period of April through September, 1993. It is further

ORDERED that the estimated true-up amounts included in the above Oil Backout Cost Recovery Factors are hereby authorized subject to final true-up, and further subject to proof of the reasonableness and prudence of the expenditures upon which the amounts are based. It is further

ORDERED that the investor-owned electric utilities are hereby authorized to apply the capacity cost recovery factors set forth herein during the period of April through September, 1993, and until such factors are modified by subsequent Order. It is further

ORDERED that the estimated true-up amounts contained in the above capacity cost recovery factors are hereby authorized subject to final true-up, and further subject to proof of the reasonableness and prudence of the expenditures upon which the amounts are based.

By ORDER of the Florida Public Service Commission this 23rd day of March, 1993.

STEVE TRIBBLE, Director
Division of Records and Reporting

(S E A L)
MCB:bmi

Commissioner Deason Dissents in Part from the decision in this Docket as follows:

I dissent from the Commission's decision to require Gulf Power to reflect the capacity revenues associated with Gulf Power's long - term non-firm schedule E contract with Florida Power Corporation in the capacity cost recovery clause. As I expressed at the time the clause was created, I have serious reservations about adding new costs/revenues to the factor if those costs/revenues are not currently included in the fuel adjustment clause. I believe that a rate case is the best time to make the determination about whether previously unrecognized items should be recovered through the CCRC.

In my view the setting of rates in a rate case recognizes that a balance is achieved between costs, investment and revenues. Once the Commission has engaged in such a balancing and set rates, these rates are deemed valid until changed. It is only when these rate making components are shown by the company or other party to be out of balance is there a need to address, either in a full - blown rate case or a more limited proceeding, a company's cost recovery. The difficulty facing the Commission in this case only underscores my belief that a rate case is the better place to undertake the comprehensive analysis that is needed.

I am only agreeing with the result reached by the majority of Commissioners with respect to denial of recovery of the IIC payments. I believe this same analysis set out above applies to those payments and would preclude recovery through the CCRC prior to a full rate case.

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 the Commission's final action in this matter may request: 1) reconsideration of the decision by filing a motion for reconsideration with the Director, Division of Records and Reporting within fifteen (15) days of the issuance of this order in the form prescribed by Rule 25-22.060, Florida Administrative Code; or 2) 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 sewer utility by filing a notice of appeal with the Director, Division of Records and Reporting and filing a copy of the notice of appeal and the filing fee with the appropriate court. This filing must be completed within thirty (30) days after the issuance of this order, pursuant to Rule 9.110, Florida Rules of Appellate Procedure. The notice of appeal must be in the form specified in Rule 9.900 (a), Florida Rules of Appellate Procedure.

ATTACHMENT A
ORDER NO. PSC-93-0443-FOF-EI
DOCKET NO. 930001-EI
PAGE 14

TOTAL FUEL COST FOR THE PERIOD: April – September 1993

DATE: 2/17/93
PAGE 1 of 10

	PROPOSED April – September 1993			PRESENT October 1992 – March 1993			DIFFERENCE				
		Cents per kwh			Cents per kwh			Cents per kwh		RESIDENTIAL LINE LOSS	PROPOSED RESIDENTIAL FUEL
COMPANY	Levelized	On/Peak	Off/Peak	Levelized	On/Peak	Off/Peak	Levelized	On/Peak	Off/Peak	MULTIPLIER	FACTOR
Fla. Power & Light	2.259	2.431	2.172	1.709	1.848	1.654	0.550	0.583	0.518	1.00145	2.262
Fla. Power Corp.	2.171	2.780	1.854	1.785	2.306	1.569	0.386	0.474	0.285	1.00270	2.177
Tampa Electric	2.508	3.275	2.146	2.358	2.584	2.281	0.150	0.691	−0.135	1.00640	2.524
Gulf Power	2.216	2.390	2.135	2.301	2.380	2.274	−0.085	0.010	−0.139	1.01228	2.243
Fla. Public											
Marianna (1)	5.290	NA	NA	4.796	NA	NA	0.494	NA	NA	1.01260	5.357
Fernandina (1)(2)	5.753	NA	NA	5.305	NA	NA	0.448	NA	NA	1.00000	5.753

COST FOR 1,000 KWH RESIDENTIAL SERVICE

PRESENT: October 1992 – March 1993

	Fla. Power & Light	Fla. Power Corp. (6)	Tampa Electric (5)	Gulf Power	Florida Public Utilities Marianna	Florida Public Utilities Fernandina
Base	47.38	46.91	49.80	43.25	17.22	19.20
Fuel (3)	17.11	17.90	23.56	23.29	48.57	53.05
Oil Backout	0.17	NA	0.96	NA	NA	NA
Energy Conservation	1.59	3.52	1.34	0.32	0.08	0.09
Capacity Recovery	8.53	1.91	0.54	1.07	NA	NA
Gross Receipts Tax (4)	0.77	1.44	1.95	0.70	0.68	0.74
Total	$75.55	$71.68	$78.15	$68.63	$66.55	$73.08

PROPOSED: April – September 1993

	Fla. Power & Light	Fla. Power Corp.	Tampa Electric (8)	Gulf Power (7)	Florida Public Utilities Marianna	Florida Public Utilities Fernandina
Base	47.38	47.41	49.80	43.25	17.22	19.20
Fuel (3)	22.62	21.77	24.51	22.43	53.57	57.53
Oil Backout	0.13	NA	0.65	NA	NA	NA
Energy Conservation	2.05	4.59	1.28	0.15	0.11	0.05
Capacity Recovery	4.42	2.89	2.17	0.48	NA	NA
Gross Receipts Tax (4)	0.79	1.97	2.01	0.68	0.73	0.79
Total	$77.39	$78.63	$80.42	$66.99	$71.63	$77.57

DIFFERENCE	Fla. Power & Light	Fla. Power Corp.	Tampa Electric	Gulf Power	Florida Public Utilities Marianna	Florida Public Utilities Fernandina
Base	0.00	0.50	0.00	0.00	0.00	0.00
Fuel (3)	5.51	3.87	0.95	−0.86	5.00	4.48
Oil Backout	−0.04	NA	−0.31	NA	NA	NA
Energy Conservation	0.46	1.07	−0.06	−0.17	0.03	−0.04
Capacity Recovery	−4.11	0.98	1.63	−0.59	NA	NA
Gross Receipts Tax (4)	0.02	0.53	0.06	−0.02	0.05	0.05
Total	1.84	6.95	2.27	−1.64	5.08	4.49

(1) Fuel costs include purchased power demand costs of 2.024 for Marianna and 1.331 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. FPC and TECO have removed all g.r.t. from rates. The entire 2.5% g.r.t. is thus shown separately for these companies effective February 3, 1993 for TECO and April, 1993 for FPC. (5) TECO base rates reflect rate change effective February, 1993, resulting from rate case, Docket No. 920324–EI. (6) FPC present base rates reflect increase effective November 1, 1992, resulting from rate case, Docket No. 910890–EI. Proposed rates reflect step increase effective April 1, 1993. (7) Present Gulf capacity factor reflects commission vote on reconsideration, effective January 5, 1993. (8) TECO fuel rates include refund factor of .073 cents/kwh attributable to stipulation of Gatliff Coal issue in the February 1993 fuel adjustment hearing.

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

DIVISION OF ELECTRIC AND GAS
DATE: 2/17/93
PAGE 2 of 10

FOR THIS PERIOD: April – September 1993

COMPANY	GROUP	RATE SCHEDULES	WITHOUT LINE LOSS MULTIPLIER Levelized	On/Peak	Off/Peak	LINE LOSS MULTIPLIER	WITH LINE LOSS MULTIPLIER Levelized	On/Peak	Off/Peak
FP&L	A	RS-1,RST-1,GST-1,GS-1,SL-2	2.259	2.431	2.172	1.00145	2.262	2.434	2.175
	A-1	SL-1,OL-1	2.214	NA	NA	1.00145	2.217	NA	NA
	B	GSD-1,GSDT-1	2.259	2.431	2.172	1.00139	2.262	2.434	2.175
	C	GSLD-1,GSLDT-1,CS-1,CST-1	2.259	2.431	2.172	1.00014	2.260	2.432	2.173
	D	[illegible]	2.259	2.431	2.172	0.99566	2.249	2.420	2.163
	E	[illegible]	2.259	2.431	2.172	0.96726	2.185	2.351	2.101
	F	CILC-1(D),ISST-1(D)		2.431	2.172	0.[illegible]9415		2.417	2.160
FPC	A	Distribution Secondary Delivery	2.171	2.780	1.854	1.00270	2.177	2.788	1.859
	A-1	OL-1,SL-1	2.028	NA	NA	1.00270	2.033	NA	NA
	B	Distribution Primary Delivery	2.171	2.780	1.854	0.98880	2.147	2.749	1.833
	C	Transmission Delivery	2.171	2.780	1.854	0.97860	2.125	2.721	1.814
TECO	A	RS,GS,TS	2.508	3.275	2.146	1.00640	2.524	3.296	2.160
	A-1	SL-1,2,3,OL-1,2	2.315	NA	NA	1.00640	2.330	NA	NA
	B	GSD,GSLD	2.508	3.275	2.146	1.00120	2.511	3.279	2.149
	C	IS-1,IS-3	2.508	3.275	2.146	0.97210	2.438	3.184	2.086
GULF	A	RS,GS,GSD,OS-III,OS-IV	2.216	2.390	2.135	1.01228	2.243	2.419	2.161
	B	LP	2.216	2.390	2.135	0.98106	2.174	2.345	2.095
	C	PX	2.216	2.390	2.135	0.96230	2.132	2.300	2.055
	D	OS-1,OS-2	2.157	NA	NA	1.01228	2.183	NA	NA
FPUC									
Fernandina	A	RS	5.753	NA	NA	1.00000	5.753	NA	NA
	B	GS	5.509	NA	NA	1.00000	5.509	NA	NA
	C	GSD	5.335	NA	NA	1.00000	5.335	NA	NA
	D	OL, OL-2, SL-2, SL-3, CSL	4.799	NA	NA	1.00000	4.799	NA	NA
	E	GSLD					4.164 (1)		
Marianna	A	RS	5.290	NA	NA	1.01260	5.357	NA	NA
	B	GS	5.034	NA	NA	0.99630	5.015	NA	NA
	C	GSD	4.609	NA	NA	0.99630	4.592	NA	NA
	D	OL, OL-2	3.266	NA	NA	1.01260	3.307	NA	NA
	E	SL-1, SL-2	3.266	NA	NA	0.98810	3.227	NA	NA

(1) Informational Purposes Only–GSLD class is billed actual fuel cost

DIVISION OF ELECTRIC AND GAS
DATE: 2/17/93
PAGE 3 of 10

PROPOSED CAPACITY COST RECOVERY FACTORS
For the Period: April – September 1993

COMPANY	RATE SCHEDULE	RECOVERY FACTOR (CENTS PER KWH)
FPL	RS1	0.442
	GS1	0.412
	GSD1	0.377
	OS2	0.365
	GSLD1/CS1	0.384
	GSLD2/CS2	0.317
	GSLD3/CS3	0.300
	ISST1D	0.261
	SST1T	0.237
	SST1D	0.243
	CILCD,CILCG	0.264
	CILCT	0.243
	MET	0.337
	OL1/SL1	0.203
	SL2	0.279
FPC	RS	0.289
	GS–Transmission	0.196
	GS–Primary	0.199
	GS–Secondary	0.202
	GS – 100% Load Factor	0.152
	GSD–Transmission	0.140
	GSD–Primary	0.176
	GSD–Secondary	0.179
	CS – Curtailable	0.138
	IS–Transmission	0.145
	IS–Primary	0.147
	LS – Lighting Service	0.057
TECO	RS	0.217
	GS,TS	0.179
	GSD	0.149
	GSLD,SBF	0.133
	IS–1 & 3,SBI–1 & 3	0.012
	SL/OL	0.012
GULF	RS,RST	0.048
	GS,GST	0.048
	GSD,GSDT	0.036
	LP,LPT	0.032
	PX,PXT	0.027
	OS–I,OS–II	0.005
	OS–III	0.029
	OS–IV	0.003
	SS	0.026

FUEL & PURCHASED POWER COST RECOVERY CLAUSE CALCULATION

DIVISION OF ELECTRIC AND GAS
DATE: 2/17/93
PAGE 4 OF 10

ESTIMATED FOR THE PERIOD: April – September 1993

FLORIDA POWER & LIGHT COMPANY

CLASSIFICATION	Classification Associated $	Classification Associated KWH	Classification Associated Cents/KWH
1.Fuel Cost of System Net Generation (E3)	569,708,111	30,990,960,000	1.83830
2.Spent NUC Fuel Disposal Cost (E2)	9,181,000	9,719,910,000 (a)	0.09446
2a. DOE Decontamination & Decommissioning Costs	2,580,000	0	0.00000
3.Coal Car Investment	192,519	0	0.00000
4. Natural Gas Pipeline Enhancements	680,379	0	0.00000
4a. Fuel Cost of Sales to FKEC	(6,982,074)	(298,706,000)	2.33744
5.TOTAL COST OF GENERATED POWER	575,359,935	30,692,254,000	1.87461
6.Fuel Cost of Purchased Power – Firm (E8)	164,126,800	8,563,900,000	1.91650
7.Energy Cost of Sch.C,X Economy Purchases (Broker) (E9)	16,417,000	850,200,000	1.93096
8.Energy Cost of Economy Purchases (Non–Broker) (E9)	27,559,700	1,212,300,000	2.27334
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)	21,097,700	1,130,500,000	1.86623
12.TOTAL COST OF PURCHASED POWER	229,201,200	11,756,900,000	1.94950
13.TOTAL AVAILABLE KWH		42,449,154,000	
14.Fuel Cost of Economy Sales (E7)	(7,144,800)	(238,900,000)	2.99071
15.Gain on Economy Sales – 80% (E7A)	(2,138,320)	(238,900,000)(a)	0.89507
16.Fuel Cost of Unit Power Sales (SL2 Partpts) (E7)	(1,226,100)	(167,500,000)	0.73200
17.Fuel Cost of Other Power Sales (E7)	(1,497,400)	(58,600,000)	2.55529
18.TOTAL FUEL COST AND GAINS OF POWER SALES	(12,006,620)	(465,000,000)	2.58207
19.Net Inadvertant Interchange (E4)	0	0	0.00000
20.TOTAL FUEL AND NET POWER TRANSACTIONS	792,554,515	41,984,154,000	1.88775
21.Net Unbilled (E4)	(19,713,456)(a)	(1,044,285,000)	–0.05224
22.Company Use (E4)	2,394,588 (a)	126,849,000	0.00635
23.T & D Losses (E4)	58,108,470 (a)	3,078,192,000	0.15399
24.Adjusted System KWH Sales	792,554,515	37,734,828,000	2.10033
25.Wholesale KWH Sales	2,396,843	114,119,000	2.10030
26.JURISDICTIONAL KWH SALES	790,157,672	37,620,709,000	2.10033
27.Jurisdictional KWH Sales Adjusted for Line Loss – 1.00034	790,426,326	37,620,709,000	0.02101
28.True–up * (derived in Attachment C)	43,960,615	37,620,709,000	0.11685
29.TOTAL JURISDICTIONAL FUEL COST	834,386,941	37,620,709,000	2.21789
30.Revenue Tax Factor			1.01609
31.Fuel Cost Adjusted for Taxes			2.25358
32.GPIF*	2,020,173	37,620,709,000	0.00537
33.Total fuel cost including GPIF	836,407,114	37,620,709,000	2.25895
34.TOTAL FUEL COST FACTOR ROUNDED TO THE NEAREST .001 CENTS PER KWH:			2.259

*Based on Jurisdictional Sales

(a) included for informational purposes only.

FUEL & PURCHASED POWER COST RECOVERY CLAUSE CALCULATION

DIVISION OF ELECTRIC AND GAS
DATE: 2/17/93
PAGE 5 OF 10

ESTIMATED FOR THE PERIOD: April – September 1993

FLORIDA POWER CORPORATION

CLASSIFICATION	Classification Associated $	Classification Associated KWH	Classification Associated cents/KWH
1.Fuel Cost of System Net Generation (E3)	258,518,390	14,579,910,000	1.77311
2.Spent NUC Fuel Disposal Cost (E3A)	2,310,746	2,471,386,000 (a)	0.09350
3.Coal Car Investment	0	0	0.00000
4.Adjustments to Fuel Cost	(4,918,000)	0	0.00000
5.TOTAL COST OF GENERATED POWER	255,911,136	14,579,910,000	1.75523
6.Energy Cost of Purchased Power – Firm (E8)	500	7,000	7.14286
7.Energy Cost of Sch.C,X Economy Purchases (Broker) (E9)	14,143,300	490,000,000	2.88639
8.Energy Cost of Economy Purchases (Non–Broker) (E9)	463,544	23,580,000	1.96584
9.Energy Cost of Sch.E Purchases (E9)	13,744,770	556,367,000	2.47045
10.Capacity Cost of Sch.E Economy Purchases (E9)	0	0 (a)	0.00000
11.Payments to Qualifying Facilities (E8A)	26,504,610	1,109,644,000	2.38857
12.TOTAL COST OF PURCHASED POWER	54,856,724	2,179,598,000	2.51683
13.TOTAL AVAILABLE KWH		16,759,508,000	
14.Fuel Cost of Economy Sales (E7)	(5,567,200)	(290,000,000)	1.91972
14a.Gain on Economy Sales – 80% (E7A)	(580,000)	(290,000,000)(a)	0.20000
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)	(4,747,800)	(296,640,000)	1.60053
18.TOTAL FUEL COST AND GAINS OF POWER SALES	(10,895,000)	(586,640,000)	1.85719
19.Net Inadvertant Interchange (E4)	0	0	
20.TOTAL FUEL AND NET POWER TRANSACTIONS	299,872,860	16,172,868,000	1.85417
21.Net Unbilled (E4)	7,518,725 (a)	(405,497,000)	0.05149
22.Company Use (E4)	1,752,219 (a)	(94,500,000)	0.01200
23.T & D Losses (E4)	19,849,508 (a)	(1,070,516,000)	0.13593
24.Adjusted System KWH Sales	299,872,860	14,602,355,000	2.05359
25.Wholesale KWH Sales(Excluding Seminole Supplemental)	(11,364,454)	(554,509,000)	2.04946
26.JURISDICTIONAL KWH SALES	288,508,406	14,047,846,000	2.05376
27.Jurisdictional KWH Sales Adjusted for Line Loss – 1.0012	288,854,616	14,047,846,000	2.05622
28.Prior Period True–Up *	14,678,497	14,047,846,000	0.10449
28a. Miscellaneous True–Up	0	0	0.00000
29.TOTAL JURISDICTIONAL FUEL COST	303,533,113	14,047,846,000	2.16071
30.Revenue Tax Factor			1.00083
31.Fuel Cost Adjusted for Taxes			2.16250
32.GPIF*	1,211,009	14,047,846,000	0.00860
33.Total fuel cost including GPIF	304,744,122	14,047,846,000	2.17110
34.TOTAL FUEL COST FACTOR ROUNDED TO THE NEAREST .001 CENTS PER KWH:			2.171

*Based on Jurisdictional Sales

(a) Included for informational purposes only.

FUEL & PURCHASED POWER COST RECOVERY CLAUSE CALCULATION

DIVISION OF ELECTRIC AND GAS
DATE: 2/17/93
PAGE 6 OF 10

ESTIMATED FOR THE PERIOD: April – September 1993

TAMPA ELECTRIC COMPANY

CLASSIFICATION	Classification Associated $	Classification Associated KWH	Classification Associated cents/KWH
1.Fuel Cost of System Net Generation (E3)	197,433,221	8,717,479,000	2.26480
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	197,433,221	8,717,479,000	2.26480
6.Fuel Cost of Purchased Power – Firm (E8)	4,222,400	93,410,000	4.52029
7.Energy Cost of Sch.C,X Economy Purchases (Broker) (E9)	1,195,500	31,489,000	3.79656
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)	3,875,400	185,496,000	2.08921
12.TOTAL COST OF PURCHASED POWER	9,293,300	310,395,000	2.99402
13.TOTAL AVAILABLE KWH		9,027,874,000	
14.Fuel Cost of Economy Sales (E7)	10,353,400	471,336,000	2.19661
15.Gain on Economy Sales – 80% (E7A)	1,973,920	471,336,000 (a)	0.41879
16.Fuel Cost of Scedule D Sales (E7)	1,242,300	52,703,000	2.35717
17. Fuel Cost of Schedule D Sales – Separated (E7)	2,796,200	185,177,000	1.51001
18.Fuel Cost Schedule D TPS Sales – Separated (E7)	3,600,300	167,062,000	2.15507
19. Fuel Cost Schedule G Sales, Juris. (E7)	0	0	0.00000
20. Fuel Cost Schedule J Sales, Juris. (E7)	8,535,800	321,984,000	2.65100
21.TOTAL FUEL COST AND GAINS OF POWER SALES	28,501,920	1,198,262,000	2.37861
22.Net Inadvertant Interchange (E4)	0	0	
23. Wheeling Rec'd. less Wheeling Delv'd.	0	0	
24. Interchange and Wheeling Losses		23,518,000	
25.TOTAL FUEL AND NET POWER TRANSACTIONS	178,224,601	7,806,094,000	2.28315
26.Net Unbilled (E4)	3,288,489 (a)	144,033,000	0.04530
27.Company Use (E4)	397,268 (a)	17,400,000	0.00547
28.T & D Losses (E4)	8,813,164 (a)	386,009,000	0.12142
29.Adjusted System KWH Sales	178,224,601	7,258,652,000	2.45534
30.Wholesale KWH Sales	(2,387,707)	(97,194,000)	2.45664
31.JURISDICTIONAL KWH SALES	175,836,894	7,161,458,000	2.45532
32.Jurisdictional Loss Multiplier			1.0005
33.Jurisdictional KWH Sales Adjusted for Line Loss	175,924,812	7,161,458,000	2.45655
34.True–up *	3,247,563	7,161,458,000	0.04535
35.TOTAL JURISDICTIONAL FUEL COST	179,172,375	7,161,458,000	2.50190
31.Revenue Tax Factor			1.00083
32.Fuel Cost Adjusted for Taxes	179,321,089		2.50397
33.GPIF * (Already adjusted for taxes)	318,938	7,161,458,000	0.00445
34.Total Fuel Cost including GPIF	179,640,027	7,161,458,000	2.50842
35.TOTAL FUEL COST FACTOR ROUNDED TO THE NEAREST .001 CENTS PER KWH:			2.508

*Based on Jurisdictional Sales

(a) Included for informational purposes only.

FUEL & PURCHASED POWER COST RECOVERY CLAUSE CALCULATION

DIVISION OF ELECTRIC AND GAS
DATE: 2/17/93
PAGE 7 OF 10

ESTIMATED FOR THE PERIOD: April – September 1993

GULF POWER COMPANY

CLASSIFICATION	Classification Associated $	Classification Associated KWH	Classification Associated cents/KWH
1.Fuel Cost of System Net Generation (E3)	112,212,493	5,632,060,000	1.9924
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	112,212,493	5,632,060,000	1.9924
5.Fuel Cost of Purchased Power – Firm (E8)	0	0	0.0000
6.Energy Cost of Sch.C,X Economy Purchases (Broker) (E9)	9,157,000	451,500,000	2.0281
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	9,157,000	451,500,000	2.0281
12.TOTAL AVAILABLE KWH (line 4 + line 11)		6,083,560,000	
13.Fuel Cost of Economy Sales (E7)	(467,000)	(23,510,000)	1.9864
14.Gain on Economy Sales – 80% (E7A)	(57,600)	0 (a)	0.0000
15.Fuel Cost of Unit Power Sales (E7)	(9,902,000)	(483,270,000)	2.0490
16.Fuel Cost of Other Power Sales (E7)	(9,695,000)	(563,063,000)	1.7218
17.TOTAL FUEL COST AND GAINS OF POWER SALES	(20,121,600)	(1,069,843,000)	1.8808
18.Net Inadvertant Interchange (E4)	0		
19.TOTAL FUEL AND NET POWER TRANSACTIONS	101,247,893	5,013,717,000	2.0194
20.Net Unbilled (E4)	0	0	0.0000
21.Company Use (E4)	194,468 (a)	9,630,000	2.0194
22.T & D Losses (E4)	6,856,711 (a)	339,542,000	2.0194
23.Adjusted System KWH Sales	101,247,893	4,664,545,000	2.1706
24.Wholesale KWH Sales	3,479,428	160,298,000	2.1706
25.JURISDICTIONAL KWH SALES	97,768,465	4,504,247,000	2.1706
26.Jurisdictional KWH Sales Adjusted for Line Loss – 1.00140	97,905,340	4,504,247,000	2.1736
27.True–up *	2,932,081	4,504,247,000	0.0651
28.Total Jurisdictional Fuel Cost	100,837,421	4,504,247,000	2.2387
29.Revenue Tax Factor			1.01609
30.Fuel Cost Adjusted for Taxes			2.2747
31.Special Contract Recovery Cost	(2,957,580)	4,504,247,000	–0.0657
32.GPIF *	322,504	4,504,247,000	0.0072
33.Total Fuel Cost including GPIF	101,159,925	4,504,247,000	2.2162
34.TOTAL FUEL COST FACTOR ROUNDED TO THE NEAREST .001 CENTS PER KWH:			2.216

*Based on Jurisdictional Sales
Effective date for billing purposes:

(a) included for informational purposes only.

FUEL & PURCHASED POWER COST RECOVERY CLAUSE CALCULATION

DIVISION OF ELECTRIC AND GAS
DATE: 2/17/93
PAGE 8 OF 10

ESTIMATED FOR THE PERIOD: April – September 1993

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)	3,008,243	145,011,000	2.07449
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)	3,088,926	145,011,000 (a)	2.13013
10a.Demand Costs of Purchased Power	2,086,500 (a)		
10b.Non–Fuel Energy & Customer Costs of Purchased Power	1,002,426 (a)		
11.Energy Payments to Qualifying Facilities (E8A)	0	0	0.00000
12.TOTAL COST OF PURCHASED POWER	6,097,169	145,011,000	4.20463
13.TOTAL AVAILABLE KWH	6,097,169	145,011,000	4.20463
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	6,097,169	145,011,000	4.20463
21.Net Unbilled (E4)	243,574 (a)	5,793,000	0.18273
22.Company Use (E4)	5,172 (a)	123,000	0.00388
23.T & D Losses (E4)	243,784 (a)	5,798,000	0.18289
24.ADJUSTED SYSTEM KWH SALES	6,097,169	133,297,000	4.57412
25.Less Total Demand Cost Recovery	2,170,093		
26.JURISDICTIONAL KWH SALES	3,927,076	133,297,000	2.94611
27.Jurisdictional KWH Sales Adjusted for Line Loss – 1.00	3,927,076	133,297,000	2.94611
28.True–up *	357,008	133,297,000	0.26783
29.TOTAL JURISDICTIONAL FUEL COST	4,284,084	133,297,000	3.21394
30.Revenue Tax Factor			1.01609
31.Fuel Cost Adjusted for Taxes	3,499,562	0	3.26565
32.GPIF *	0	133,297,000	0.00000
33.Total Fuel Cost including GPIF	4,284,084	133,297,000	3.26565
34.TOTAL FUEL COST FACTOR ROUNDED TO THE NEAREST .001 CENTS PER KWH:			3.266

*Based on Jurisdictional Sales

(a) included for informational purposes only.

FUEL & PURCHASED POWER COST RECOVERY
CLAUSE CALCULATION

DIVISION OF ELECTRIC AND GAS
DATE: 2/17/93
PAGE 9 OF 10

ESTIMATED FOR THE PERIOD: April – September 1993

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)	6,224,977	161,478,000	3.85500
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	2,260,348	161,478,000	1.39979
10a.Demand Costs of Purchased Power (E2)	2,057,000 (a)		
10b.Non Fuel Energy and Customer Costs of Purchased Power (E2)	203,348 (a)		
11.Energy Payments to Qualifying Facilities (E8A)	187,680	4,800,000	3.91000
12.TOTAL COST OF PURCHASED POWER	8,673,005	166,278,000	5.21597
13.TOTAL AVAILABLE KWH	8,673,005	166,278,000	5.21597
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	8,673,005	166,278,000	5.21597
21.Net Unbilled (E4)	21,855 (a)	419,000	0.01404
22.Company Use (E4)	9,076 (a)	174,000	0.00583
23.T & D Losses (E4)	520,397 (a)	9,977,000	0.33421
24.Adjusted System KWH Sales	8,673,005	155,708,000	5.57004
25.Wholesale KWH Sales	0	0	0.00000
26.JURISDICTIONAL KWH SALES	8,673,005	155,708,000	5.57004
27.Jurisdictional KWH Sales Adjusted for Line Loss – 1.00	8,673,005	155,708,000	5.57004
27a.GSLD KWH Sales (E11)		37,200,000	
27b.Other Classes KWH Sales (E11)		118,508,000	
27c.GSLD CP KW		108,000 (a)	
28. GPIF			
29.True-up *	(14,100)	155,708,000	-0.00906
30.TOTAL JURISDICTIONAL FUEL COST	8,658,905	155,708,000	5.56099

FUEL & PURCHASED POWER COST RECOVERY
CLAUSE CALCULATION

DIVISION OF ELECTRIC AND GAS
DATE: 2/17/93
PAGE 10 OF 10

ESTIMATED FOR THE PERIOD: April – September 1993

FLORIDA PUBLIC UTILITIES–FERNANDINA

CLASSIFICATION	Classification Associated $	Classification Associated KWH	Classification Associated cents/KWH
30a.Demand Purchased Power Costs (line 10a)	2,057,000 (a)		
30b.Non–Demand Purchased Power Costs (lines 6+10b+11)	6,616,005 (a)		
30c.True–up Over/Under Recovery (line 29)	(14,100)(a)		
APPORTIONMENT OF DEMAND COSTS			
31.Total Demand Costs	2,057,000		
32.GSLD Portion of Demand Costs Including line losses (line 27c * $4.6865)	612,360	108,000 KW	$5.67/KW
33.Balance to Other Customers	1,444,640	118,508,000	1.21902
APPORTIONMENT OF NON–DEMAND COSTS			
34.Total Non–Demand Costs (line 30b)	6,616,005		
35.Total KWH Purchased (line 12)		166,278,000	
36.Average Cost per KWH Purchased			3.97888
37.Avg. Cost Adjusted for Transmission line losses (line 36 * 1.03)			4.09825
38.GSLD Non–Demand Costs (line 27a * line 37)	1,524,543	37,200,000	0.04098
39.Balance to Other Customers	5,091,462	118,508,000	4.29630
GSLD PURCHASED POWER COST RECOVERY FACTORS			
40a.Total GSLD Demand Costs (Line 32)	612,360	108,000	$5.67
40b.Revenue Tax Factor			1.01609
40c.GSLD Demand Purchased Power factor adjusted for taxes and rounded:			$5.76
40d.Total Current GSLD Non–Demand Costs (line 38)	1,524,543	37,200,000	4.09823
40e.Total Non–Demand Costs including true–up	1,524,543	37,200,000	4.09823
40f.Revenue Tax Factor			1.01609
40g.GSLD Non–demand costs adjusted for taxes			4.164
OTHER CLASSES PURCHASED POWER COST RECOVERY FACTORS			
41a.Total Demand and Non–Demand Purchased Power Costs of other classes (lines 33 + 39)	6,536,102	118,508,000	5.51533
41b.Less: Total Demand Cost Recovery	1,364,607 (a)		
41c.Total Other Costs to be Recovered	5,171,495 (a)	118,508,000	4.36384
41d.Other Classes' Portion of True–up (line 30 C)	(14,100)	118,508,000	–0.01190
41e.Total Demand and Non–Demand Costs including True–up	5,157,395	118,508,000	4.35194
42.Revenue tax factor			1.01609
			4.42196
43.OTHER CLASSES PURCHASED POWER FACTOR ADJUSTED FOR TAXES ROUNDED TO THE NEAREST .001 CENTS PER KWH:			**4.422**

*Based on Jurisdictional Sales

(a) included for informational purposes only.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Fuel and Purchased Power Cost Recovery Clause and Generating Performance Incentive Factor.	DOCKET NO. 930001-EI FILED: February 16, 1993

STIPULATION

This Stipulation is entered into by and between Tampa Electric Company ("Tampa Electric" or "the company") and the Office of Public Counsel ("Public Counsel") on this 16th day of February 1993 as follows:

Purpose of this Stipulation

This Stipulation has been entered into by Tampa Electric and Public Counsel to establish arrangements to dispose of a continuing controversy over a proper way to judge the reasonableness of prices paid by Tampa Electric to an affiliated coal supplier, Gatliff Coal Company ("Gatliff"). It is the objective of each party to this Stipulation to establish arrangements under which fair and reasonable coal costs are reflected in prices to electric consumers. With the Commission's encouragement that parties attempt to resolve disputes amicably, Tampa Electric and Public Counsel have engaged in extensive and protracted efforts to establish arrangements consistent with that objective. The parties' focus has been to develop a means to evaluate the pricing of Gatliff coal in a way that fairly passes on the appropriate costs to Tampa Electric's Customers and at the same time provides greater understanding and certainty for the parties as to the appropriate way to proceed in the future. The proposed settlement embodied in this Stipulation, if approved by the Commission, will resolve a pending appeal in the Supreme Court of Florida, will resolve all issues related to the pricing of coal purchased by Tampa Electric from Gatliff through calendar year 1992 and will afford the Commission and the parties an agreed upon method for evaluating the reasonableness of the pricing of such purchases during 1993 through 1999. In addition, Tampa Electric's Customers will receive the benefits of a $10 million downward adjustment to Tampa Electric's recoverable fuel expenses, by virtue of a credit (as described in Paragraph 9 below) to billed fuel costs on their electric bills.

To effect the above results, Tampa Electric and Public Counsel stipulate and agree as follows:

Background

1. In 1988, in Tampa Electric's "cost plus" docket, the Commission approved the implementation of a market-based pricing and benchmark methodology to measure the appropriateness of Tampa Electric's coal purchase prices from an affiliate, Gatliff Coal Company. (Order No. 20298, Docket No. 870001-EI-A). In that docket the Commission approved a stipulation (the "1988 Stipulation") between Tampa Electric and the Office of Public Counsel describing a benchmark for evaluating the reasonableness of coal prices. The 1988 Stipulation established an initial market price of $39.44 per ton FOB Mine as of December 31, 1987 for coal

purchased from Gatliff. The 1988 Stipulation then provided that for purposes of regulatory review in the fuel docket, an adjusted price would be calculated by escalating or de-escalating the initial market price by the annual percentage change in Bureau of Mines District 8 data for coal, as reported on FERC Form 423, for the weighted average price per million BTU of contract transactions that meet agreed upon coal specifications. The adjusted price would be increased by 5% to arrive at a new benchmark price. For purposes of recovery through the fuel adjustment clause, Tampa Electric was required to justify the costs for Gatliff Coal that exceeded the market-based benchmark calculation.

2. While one of the objectives of the benchmark calculation was to reduce or eliminate controversy concerning the pricing of Gatliff coal, the determination of the regulatory benchmark price under the 1988 Stipulation has been controversial and has consumed considerable time and resources of the Commission and all of the parties to this issue.

3. In the August 1991 fuel hearings the Commission found that, while the actual per ton contract price for 1990 for Gatliff Coal exceeded the regulatory benchmark, the actual per ton contract price of Gatliff coal purchased by Tampa Electric had been justified and full recovery should be allowed. See Order No. 25148 (Commissioner Deason dissenting) issued October 1, 1991 and Order No. PSC-92-0015-FOF-EI issued on reconsideration on March 9, 1992 in Docket No. 920001-EI. These orders are currently pending on review in the Florida Supreme Court in Case No. 79,675 in a

proceeding initiated by Public Counsel.

4. On January 10, 1992, Tampa Electric filed in Docket No. 920041-EI a Petition for Clarification and Guidance on the calculation of the market based pricing methodology under the 1988 Stipulation. This Petition sought review of the appropriate method to calculate the benchmark index used to examine the reasonableness of the price paid for coal purchased by Tampa Electric from Gatliff. The testimony at the hearings centered around the interpretation of comparable data from the FERC Form 423 reports as a measure of market change. The Commission on September 23, 1992 issued Order No. PSC-92-1048-FOF-EI which affirmed the continued use of the existing market based index calculation. The Commission further stated that it would be beneficial also to analyze the market data on a contract annual average quality basis as a "sanity check."

5. The appropriate level of recovery of prices paid by Tampa Electric to Gatliff for 1991 is now pending in Docket No. 930001-EI and scheduled for hearing on February 17-19, 1993. The determination of the level of recovery of prices paid by Tampa Electric to Gatliff in 1992 would normally be considered during the fuel adjustment hearings to be conducted in August of 1993.

6. Public Counsel and Tampa Electric have met to discuss methods by which the application of market pricing to the coal transactions between Tampa Electric and Gatliff can be improved. As a result of these discussions, Public Counsel and Tampa Electric have reached the agreement embodied in this Stipulation.

7. The focus of this agreement is on the regulatory benchmark and approval methodology. The format or details of the specific contracts between Tampa Electric and its affiliates, including the pricing indices in the contracts, are not subject to this proceeding. Tampa Electric may negotiate the terms in contracts with its affiliates in any manner it deems to be fair and reasonable. Tampa Electric agrees to prudently administer the provisions of such contracts.

8. The actual prices paid by Tampa Electric to its affiliates shall be reported to this Commission in the normal course of the fuel adjustment proceedings.

Gatliff Coal Company

9. Tampa Electric agrees to make a $10 million downward adjustment to its recoverable fuel expense beginning in April 1993. The adjustment will be implemented through a credit on Customers' bills which shall be calculated by multiplying a levelized factor adjusted for line losses times the actual KWH usage during the period of the credit. The adjustment shall be spread over the 12-month period April 1993 through March 1994, plus interest on the unamortized amount of the adjustment. Such interest shall be at the thirty (30) day commercial paper rate for high grade unsecured notes sold through dealers by major corporations in multiples of $1,000 as regularly published in the Wall Street Journal. Any over- or undercollection associated with this downward adjustment will be handled as a true-up component in the normal course of fuel

cost recovery proceedings.

10. Public Counsel and Tampa Electric agree that, after the downward adjustment specified in Paragraph 9 is taken into account, the prices paid by Tampa Electric to Gatliff in 1990, 1991 and 1992 are appropriate for recovery through the fuel and purchased power cost recovery clause.

11. The parties further agree that Public Counsel's appeal of Orders Nos. 25148 and PSC-92-0015-FOF-EI, pending in Florida Supreme Court Case No. 79,675, shall be withdrawn and dismissed with prejudice forthwith on Commission approval of this Stipulation. To preserve the status quo pending the Commission's consideration of this Stipulation, Public Counsel and Tampa Electric agree to jointly file a motion with the Court, immediately after signing this Stipulation, asking the Court to stay such appeal pending the finality of the Commission's action resolving the parties' request for approval of this Stipulation.

12. In order to provide a simpler and less controversial prospective benchmark for regulatory review of the annual average price per ton paid by Tampa Electric for coal purchased from Gatliff, the new beginning benchmark price to be used for computing the benchmark for Tampa Electric's transactions with Gatliff shall be $38.00 per ton FOB Mine as of December 31, 1992.

13. For purposes of regulatory review, this base price of $38.00 per ton FOB Mine shall be escalated or de-escalated by the annual percentage change in the unadjusted all items category of the final published calculation for the Consumer Price Index, All

Urban Consumers (CPI-U), as described in Attachment A, page 1 of 2, to this Stipulation. In the event the weighted average annual price of Gatliff coal to Tampa Electric is increased by (a) the enactment or amendment of any law, regulation, order or other governmentally imposed requirement, or (b) any change in the application or enforcement of any law, regulation, order or other governmentally imposed requirement, the base price as escalated or de-escalated as provided in the first sentence of this Paragraph shall be further increased by the effect on Gatliff coal prices of matters described in (a) or (b) of this Paragraph, but only to the extent that the weighted average annual price of Gatliff coal to Tampa Electric exceeds the base price escalated or de-escalated by the CPI-U as provided in the first sentence of this Paragraph.

14. The weighted average annual price paid to Gatliff Coal Company by Tampa Electric above the price determined for purposes of regulatory review in Paragraph 13 above, shall be disallowed for fuel cost recovery purposes.

TECO Transport & Trade

15. The parties agree that the provisions for calculating the market price benchmark described in paragraphs 8, 9 and 10 and Attachment "3" of the 1988 Stipulation, relating to coal transportation cost, are hereby reaffirmed and shall remain in full force and effect.

General Provisions

16. The approval of this Stipulation and compliance with its provisions will completely resolve all of the issues concerning the prices paid by Tampa Electric to Gatliff for coal through December 31, 1992.

17. This Stipulation is based on the unique factual circumstances of this case and shall have no precedential value in any proceedings involving other utilities before this Commission. The parties to this Stipulation reserve the right to assert different positions on any of the matters contained in this Stipulation if this Stipulation is not accepted in its entirety by the Commission.

18. The parties hereto shall support the approval of this Stipulation by the Commission at the earliest possible time in order to facilitate the implementation of the downward adjustment to Tampa Electric's recoverable fuel expenses provided for herein beginning April 1, 1993. The parties hereto shall not seek reconsideration or judicial appeal of the Commission's approval of this Stipulation.

19. The parties urge that the Commission take final agency action at the earliest possible time approving this Stipulation.

20. This Stipulation shall be effective upon Commission approval. In the event that the Commission rejects or modifies the Stipulation, in whole or in part, the parties agree that this Stipulation is void unless otherwise ratified by the parties, and that each party may pursue its interests as those interests exist,

and that no party will be bound to or make reference to this Stipulation before this Commission, any court, any other administrative forum or arbitration panel.

DATED this 16th day of February, 1993.

JACK SHREVE and
JOHN ROGER HOWE
Office of Public Counsel
111 West Madison, Suite 801
Tallahassee, FL 32301
(904) 488-9330

LEE L. WILLIS and
JAMES D. BEASLEY
Ausley, McMullen, McGehee,
Carothers & Proctor
Post Office Box 391
Tallahassee, FL 32302
(904) 224-9115

and

HERBERT S. SANGER, JR.
Wagner, Myers & Sanger
1801 Plaza Tower
Post Office Box 1308
Knoxville, TN 37901-1308
(615) 525-4600

ATTORNEYS FOR TAMPA ELECTRIC
COMPANY

ATTACHMENT A
Page 1 of 2

TAMPA ELECTRIC COMPANY

BENCHMARK MARKET BASED COAL CALCULATION

The initial base price of $38.00 per ton shall be adjusted by the annual percentage change in the unadjusted all items category of the final published calculation for the Consumer Price Index, All Urban Consumers (CPI-U). The CPI-U adjusted base price for any given year will be the adjusted base price at the end of the immediately preceding year increased by the percentage change in the CPI-U for the given year.

EXAMPLE

Assumptions:

1. Base price at beginning of year one = $38.00
2. Hypothetical CPI-U percentage change from 1992 to 1993 = 3.0%, which is the percentage change in CPI-U from end of 1992 to end of 1993
3. Hypothetical CPI-U percentage change from 1993 to 1994 also equals 3.0 percent.

Calculation for first year:

$38.00 x .03 = $1.14 + $38.00 = $39.14 = benchmark price for all coal purchased in year one (1993). This calculation may be increased to the extent provided in the second sentence of Paragraph 13.

Calculation for second year under same assumptions:

$39.14 x .03 = $1.17 + $39.14 = $40.31 = benchmark price for all coal purchased in year two (1994). This calculation may be increased to the extent provided in the second sentence of Paragraph 13.

ATTACHMENT A
Page 2 of 2

PUBLIC COUNSEL'S MARKET

PRICE APPLICATION

-- Gatliff coal purchased[1]

FOB mine	$45/ton
Tons purchased	500,000
Total cost	$22,500,000

-- Market Benchmark $40/ton

-- Cost recovered through fuel clause

$40/ton x 500,000 = $20,000,000

-- Cost disallowed recovery

$20,000,000 - $22,500,000 = $2,500,000*

1. This would include the total average price of Gatliff produced coal and coal purchased and resold as Gatliff coal.

* The company would not be allowed to recover these costs under this Stipulation except to the extent provided in the second sentence of Paragraph 13.

GPIF REWARDS/PENALTIES
April 1992 to September 1992

Florida Power Corporation	$1,211,009	Reward
Florida Power and Light Company	$2,020,173	Reward
Gulf Power Company	$322,504	Reward
Tampa Electric Company	$318,938	Reward

Utility/ Plant/Unit	EAF		Heat Rate	
FPC	Target	Adj. Actual	Target	Adj. Actual
Anclote 1	90.4	93.8	9,745	9,735
Anclote 2	92.2	94.4	9,867	9,669
Crystal River 1	81.6	73.1	10,026	9,897
Crystal River 2	81.6	88.9	10,045	10,053
Crystal River 3	51.2	61.4	10,635	10,548
Crystal River 4	81.3	76.0	9,303	9,253
Crystal River 5	89.5	86.3	9,265	9,103
FPL	Target	Adj. Actual	Target	Adj. Actual
Cape Canaveral 2	92.0	95.5	9,112	9,037
Fort Myers 2	83.0	80.9	9,459	9,330
Manatee 1	61.8	61.0	9,740	9,721
Manatee 2	92.5	95.9	9,584	9,558
Martin 1	92.9	95.4	9,531	9,928
Martin 2	95.1	97.5	9,251	9,409
Port Everglades 2	95.5	92.2	9,833	9,788
Port Everglades 3	90.4	92.7	9,183	9,093
Port Everglades 4	71.6	75.6	9,186	9,169
Riviera 3	90.2	93.7	9,483	9,701
Riviera 4	88.3	92.2	9,249	9,431
Turkey Point 1	94.4	89.3	9,370	9,115
Turkey Point 2	94.9	87.3	9,424	9,190
Turkey Point 3	62.7	70.8	11,305	11,217
Turkey Point 4	76.2	97.0	11,230	11,206
St. Lucie 1	90.5	91.3	10,806	10,808
St. Lucie 2	58.7	59.0	10,805	10,718
GULF	Target	Adj. Actual	Target	Adj. Actual
Crist 6	80.2	82.1	10,372	10,090
Crist 7	77.5	72.7	10,100	9,909
Smith 1	85.2	84.5	10,283	10,076
Smith 2	86.4	85.6	10,273	10,051
Daniel 1	97.8	95.7	10,522	10,387
Daniel 2	97.5	99.1	10,492	10,138

GPIF REWARDS/PENALTIES
April 1991 to September 1991

Utility/ Plant/Unit	EAF		Heat Rate	
TECO	Target	Adj. Actual	Target	Adj. Actual
Big Bend 1	67.2	66.0	10,032	10,185
Big Bend 2	78.6	84.0	10,014	10,095
Big Bend 3	82.2	86.6	9,693	9,635
Big Bend 4	87.7	88.1	10,279	10,214
Gannon 5	85.5	89.5	10,440	10,392
Gannon 6	82.9	84.9	10,247	10,271

GPIF TARGETS
April 1993 to September 1993

Utility/ Plant/Unit	Equivalent Availability				Heat Rate	
	Company			Staff	Company	Staff
FPC	EAF	POF	EUOF			
Anclote 1	83.4	11.5	5.1	Agree	9,763	Agree
Anclote 2	94.7	0.0	5.3	Agree	9,886	Agree
Crystal River 1	84.3	0.0	15.7	Agree	9,988	Agree
Crystal River 2	78.1	7.1	14.8	Agree	9,975	Agree
Crystal River 3	72.2	15.3	12.5	Agree	10,462	Agree
Crystal River 4	83.2	12.6	4.2	Agree	9,245	Agree
Crystal River 5	94.9	0.0	5.1	Agree	9,301	Agree
FPL	EAF	POF	EUOF			
Cape Canaveral 1	83.8	10.9	5.3	Agree	9,082	Agree
Cape Canaveral 2	79.5	15.3	5.2	Agree	9,202	Agree
Ft. Myers 2	91.9	0.0	8.1	Agree	9,414	Agree
Manatee 1	83.7	0.0	16.3	Agree	9,710	Agree
Manatee 2	95.4	0.0	4.6	Agree	9,521	Agree
Martin 1	90.7	0.0	9.3	Agree	9,172	Agree
Martin 2	96.0	0.0	4.0	Agree	9,138	Agree
Port Everglades 1	94.8	0.0	5.2	Agree	9,791	Agree
Port Everglades 2	91.0	0.0	9.0	Agree	9,713	Agree
Port Everglades 3	93.9	0.0	6.1	Agree	9,301	Agree
Port Everglades 4	95.4	0.0	4.6	Agree	9,353	Agree
St. Johns River 1	97.3	0.0	2.7	Agree	9,344	Agree
St. Johns River 2	98.0	0.0	2.0	Agree	9,258	Agree
Riviera 3	91.1	0.0	8.9	Agree	9,864	Agree
Riviera 4	56.3	37.1	6.5	Agree	9,776	Agree
Sanford 4	93.8	0.0	6.2	Agree	9,979	Agree
Turkey Point 1	74.1	19.1	6.8	Agree	9,324	Agree
Turkey Point 2	82.5	0.0	17.5	Agree	9,480	Agree
Turkey Point 3	90.7	0.0	9.3	Agree	11,258	Agree
Turkey Point 4	60.1	35.0	4.9	Agree	11,216	Agree
St. Lucie 1	62.5	32.2	5.3	Agree	10,813	Agree
St. Lucie 2	93.6	0.0	6.4	Agree	10,795	Agree
GULF	EAF	POF	EUOF			
Crist 6	87.8	0.0	12.2	Agree	10,247	Agree
Crist 7	62.0	25.1	12.8	Agree	9,989	Agree
Smith 1	84.8	8.8	6.5	Agree	10,178	Agree
Smith 2	91.8	2.2	6.0	Agree	10,227	Agree
Daniel 1	98.0	0.0	2.0	Agree	10,498	Agree
Daniel 2	97.8	0.0	2.2	Agree	10,408	Agree

GPIF TARGETS
April 1993 to September 1993

Utility/ Plant/Unit	Equivalent Availability				Heat Rate	
	Company			Staff	Company	Staff
TECO	EAF	POF	EUOF			
Big Bend 1	81.0	3.8	15.2	Agree	9,994	Agree
Big Bend 2	84.0	1.1	14.9	Agree	9,984	Agree
Big Bend 3	72.6	16.4	11.0	Agree	9,634	Agree
Big Bend 4	87.0	0.0	13.0	Agree	9,914	Agree
Gannon 5	59.5	30.6	9.9	Agree	10,442	Agree
Gannon 6	81.8	0.0	18.2	Agree	10,268	Agree