BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In Re: Fuel and Purchased Power Cost Recovery Clause and Generating Performance Incentive Factor	DOCKET NO. 950001-EI ORDER NO. PSC-95-0450-FOF-EI ISSUED: April 6, 1995

The following Commissioners participated in the disposition of this matter:

J. TERRY DEASON
JULIA L. JOHNSON
DIANE K. KIESLING

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

APPEARANCES:

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On behalf of Florida Power Corporation

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On behalf of Florida Power and Light Company.

Norman H. Horton, Jr., Esquire, Messer, Vickers, Caparello, Madsen, Goldman & Metz, P. A., Post Office Box 1876, Tallahassee, FL 32302-1876
On behalf of Florida Public Utilities Company.

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On behalf of Florida Steel Corporation.

G. Edison Holland, Jr., Esquire, Jeffrey A. Stone, Esquire, and Russell A. Badders, Esquire, of Beggs & Lane, 700 Blount Building, 3 West Garden Street, P.O. Box 12950, Pensacola, FL 32576-2950
On behalf of Gulf Power Company.

Lee L. Willis, Esquire, 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, Vicki Gordon Kaufman, Esquire, McWhirter, Reeves, McGlothlin, Davidson & Bakas, 315 South Calhoun Street, Suite 716, Tallahassee, Florida 32301
On behalf of the Florida Industrial Power Users Group.

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, and Vicki D, Johnson, Esquire, Florida Public Service Commission, 101 E. Gaines Street, Tallahassee, Florida 32399-0863
On behalf of the Commission Staff.

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

BY THE COMMISSION:

CASE BACKGROUND

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 semi-annually. Pursuant to notice, a hearing was held in this docket and in Dockets No. 950002-EG and 950003-GU, and 950007-EI on March 8-9, 1995. 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. Our decision on these matters is set out below.

Generic Fuel Adjustment Issues

In accordance with the agreement of the parties, we find that the appropriate final fuel adjustment true-up amounts for the period April, 1994 through September, 1994 are as follows:

FPC: $2,284,495 underrecovery.

FPL: $6,684,993 overrecovery.

FPUC: $230,486 underrecovery. (Marianna)

$25,350 underrecovery. (Fernandina Beach)

GULF: $2,394,382 underrecovery.

TECO: $3,986,565 underrecovery.

The estimated fuel adjustment true-up amounts for the period October, 1994 through March, 1995 are as follows:

FPC: $12,575,671 overrecovery.

FPL: $21,299,545 overrecovery

FPUC: $86,548 overrecovery. (Marianna)

$162,890 overrecovery. (Fernandina Beach)

GULF: $577,273 underrecovery.

TECO: $2,455,113 underrecovery.

The total true-up amounts to be collected during the period April, 1995 through September, 1995 are as follows:

FPC: $10,291,176 overrecovery.

FPL: $14,614,552 overrecovery.

FPUC: $143,938 underrecovery. (Marianna)

$137,540 overrecovery. (Fernandina Beach)

GULF: $2,971,655 underrecovery.

TECO: $6,423,678 overrecovery.

Finally, the appropriate levelized fuel cost recovery factors, before line loss adjustment, for the period April, 1995, through September, 1995, are as follows:

FPC:	1.891 cents/KWH.	
FPL:	1.744 cents/KWH.	
FPUC:	Marianna:	3.221 cents/KWH.
	Fernandina Beach:	3.584 cents/KWH.
GULF:	2.315 cents/KWH.	
TECO:	2.386 cents/KWH.	

For billing purposes, the new fuel adjustment charge, oil backout charge, and conservation cost recovery charge shall be effective beginning with the specified fuel cycle and thereafter for the period April, 1995 through September, 1995. Billing cycles may start before April 1, 1995, and the last cycle may be read after September 30, 1995, 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. The appropriate multipliers are as follows:

FPC:

Delivery Group	Line Loss Voltage Level	Multiplier
A.	Transmission	0.9800
B.	Distribution Primary	0.9900
C.	Distribution Secondary	1.0000
D.	Lighting Service	1.0000

FPL: See FPL's loss multiplers on page 6.

FPUC: Marianna

Rate Schedule	Multiplier
RS	1.0126
GS	0.9963
GSD	0.9963
GSLD	0.9963
OL, OL-2	1.0126
SL-1, SL-2	0.9881

Fernandina Beach

All Rate Schedules 1.0000

GULF: See table below:

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

TECO:

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

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

The utilities further proposed fuel cost recovery factors for each rate group, adjusted for line losses. We find that the proposed factors are appropriate and are as follows:

FPC:

		Fuel Cost Factors (cents/kWh)		
			Time Of Use	
Group	Delivery Voltage Level	Standard	On-Peak	Off-Peak
A.	Transmission	1.856	2.376	1.583
B.	Distribution Primary	1.875	2.400	1.599
C.	Distribution Secondary	1.894	2.424	1.616
D.	Lighting Service	1.767		

FPL:

RATE SCHEDULE	PRICE MULTIPLIER	LOSS MULTIPLIER	FUEL RECOVERY FACTOR (¢/kWh)
RS-1	1.009	1.00210	1.764
GS-1	1.018	1.00210	1.779
GSD-1	0.996	1.00204	1.741
GSLD-1	0.982	1.00092	1.714
GSLD-2	0.970	0.99500	1.683
GSLD-3	0.959	0.96091	1.607
CS-1	0.990	1.00024	1.726
CS-2	0.958	0.99656	1.666
CILC-D	0.957	0.99757	1.666
CILC-G	0.972	1.00210	1.699
CILC-T	0.944	0.96091	1.582
MET	0.961	0.98063	1.643
OL-1	0.834	1.00210	1.458
SL-1	0.834	1.00210	1.457
SL-2	0.947	1.00210	1.655

RATE SCHEDULE	PRICE MULTIPLIER	LOSS MULTIPLIER	ON PEAK FUEL RECOVERY (¢/kWh)	OFF PEAK FUEL RECOVERY (¢/kWh)
RST-1	1.009	1.00210	2.000	1.650
GST-1	1.018	1.00210	2.017	1.664
GSDT-1	0.996	1.00204	1.974	1.628
GSLDT-1	0.982	1.00092	1.943	1.603
GSLDT-2	0.970	0.99500	1.908	1.574
GSLDT-3	0.959	0.96091	1.822	1.503
CST-1	0.990	1.00024	1.957	1.615
CST-2	0.958	0.99656	1.889	1.558
CILC-D	0.957	0.99757	1.889	1.558
CILC-G	0.972	1.00210	1.926	1.589
CILC-T	0.944	0.96091	1.794	1.480

FPUC: Marianna

Rate Schedule	Adjustment
RS	5.151¢/kWh
GS	4.915¢/kWh
GSD	4.541¢/kWh
GSLD	4.381¢/kWh
OL, OL-2	3.262¢/kWh
SL-1, SL-2	3.183¢/kWh

Fernandina Beach Rate Schedule	Adjustment
RS	5.036¢/kWh
GS	4.770¢/kWh
GSD	4.581¢/kWh
OL, & SL	3.996¢/kWh

GULF: See table below:

Group	Rate Schedules	Fuel Cost Factors ¢/KWH		
		Standard	Time of Use	
			On-Peak	Off-Peak
A	RS, GS, GSD, OSIII, OSIV	2.343	2.564	2.238
B	LP, SBS	2.271	2.485	2.169
C	PX, RPT, SBS	2.228	2.438	2.128
D	OSI, OSII	2.268	N/A	N/A

TECO:

	Standard	On-Peak	Off-Peak
Group A	2.401	2.844	2.154
Group A1	2.258	-	-
Group B	2.389	2.829	2.143
Group C	2.319	2.747	2.080

We further find that the appropriate revenue tax factor to be applied in calculating each company's levelized fuel factor for the projection period of April through September, 1995 is as follows:

FPC: 1.00083

FPL: 1.01609

FPUC: Marianna: 1.00083

Fernandina Beach: 1.01609

GULF: 1.01609

TECO: 1.00083

SO_2 Emission Allowances

With respect to recovery of costs and revenues associated with SO_2 emission allowances, we find that they are appropriately recovered through the Environmental Cost Recovery Clause (ECRC). If a utility is not participating in the ECRC, however, it would be appropriate to recover those dollars through the Fuel and Purchased Power Cost Recovery Clause. If a utility begins participating in the ECRC, any SO_2 emission allowance dollars shall be removed from the Fuel clause and recovered through the ECRC.

Company-Specific Fuel Adjustment Issues

Florida Power and Light Company

Florida Power and Light Company requested a new methodology for allocating fuel costs to the various customer classes. In FPL's proposal, kilowatt hours (kWhs) consumed in hours with higher loads are allocated a higher proportion of fuel costs, and vice versa. FPL suggested that this allocation method was appropriate, because it recognizes that the costs of each kWh consumed are not the same during every hour of the day, due to the differences in the prices of fuels and the efficiencies of generating units.

FPL's request is inconsistent with the way that generating plant costs are allocated to the customer classes. There is an inverse relationship between the capital costs of the generating units and the cost of fuel needed to operate the generating units. Consequently, if a customer class is assigned a larger portion of the fuel costs because it contributes relatively more to the higher peaking load hours, then that class should be allocated a smaller portion of generating unit capital costs. FPL has not proposed to allocate the capital costs of generating units in this fashion. We therefore deny approval of FPL's new methodology regarding allocation of fuel costs to the various customer classes.

FPL also requested recovery of approximately $2,754,502 for modifications made to Cape Canaveral Unit #1 and #2, Fort Myers Unit #2, Riviera Unit #3, and #4 and Sanford Unit #3, #4, and #5.

The modifications will enable the units to operate using a more economic grade of residual fuel oil. The modified units will still comply with emission constraints. FPL asked to recover the costs of the modifications through the Fuel and Purchased Power Cost Recovery Clause, because the modifications will generate significant savings due to lower fuel prices for high sulfur residual oil.

When we established comprehensive guidelines for the treatment of fossil fuel-related costs, we recognized that certain unanticipated costs may be appropriate for recovery through the fuel clause. Order No. 14546 addresses this concern by allowing fuel-related expenditures that are not being recovered through a utility's base rates to be recovered through the fuel clause. Order 14546 states:

> While it is the Commission's intent in this order to establish comprehensive guidelines for the treatment of fossil fuel related costs, it is recognized that certain unanticipated costs may have been overlooked. If any utility incurs, or will incur, a fossil fuel related cost which was not addressed in this order and the utility seeks to recover such cost through its fuel adjustment clause, the utility should present testimony justifying such recovery in an appropriate fuel adjustment hearing.

We have allowed such costs to be recovered through the fuel clause in the past when those expenditures resulted in significant savings to the utility's ratepayers. According to FPL's projections, its ratepayers will realize over $80 million in fuel savings through 1999. We find that FPL's cost for modifications fits within the policy we established in Order No. 14564. We approve recovery of the modification costs through the fuel clause. The costs should be expensed and included in the April through September 1995 period. Our staff will review FPL's adjustments in conjunction with the annual fuel audit. This will ensure that the adjustments have been properly made to remove the costs from depreciable plant balances.

Florida Steel Corporation raised an issue concerning FPL's projection of costs to be incurred during the April through September, 1995, period. Florida Steel asserted that FPL had over estimated the price of natural gas, and therefore FPL would overrecover fuel costs unnecessarily.

We find that FPL's estimation of as-burned natural gas prices for the period April through September, 1995, are reasonable for purposes of determining the appropriate fuel factor for the aforementioned period. Natural gas prices are but one element of the many components that are used to determine a utility's projected fuel factor. When we evaluate a utility's total fuel and purchased power costs, we realize that overstated fuel prices may be offset by increased sales or by lower than projected purchased power costs. Based on FPL's projections and actual, total fuel and purchased power costs incurred during October, 1994, through January, 1995, we find that FPL's fuel factor for the upcoming period is reasonable.

Generic Generating Performance Incentive Factor (GPIF)

There was no controversy among the parties regarding 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, 1994 through September, 1994:

FPC: $986,547 reward.

FPL: $3,065,156 reward.

GULF: $22,931 reward.

TECO: $146,321 reward.

We approve the parties' targets and ranges for the period April, 1995 through September, 1995. The GPIF targets and ranges are found on Staff Attachment 1, page 2 of 2.

Company-Specific GPIF

Florida Power and Light Company

We find that the forced outage hours for St. Lucie Unit 1 shall be adjusted to remove the outage hours caused by the June 6, 1994 severe thunderstorm.

The GPIF manual provides for adjustments to the Equivalent Availability Factor (EAF) of generating units under certain circumstances. Section 4.3.1 of the manual identifies several circumstances that would warrant the adjustment of the EAF including those that are "natural or externally caused disasters". The severe storm of June 6, 1994, was a naturally occurring disturbance that was responsible for the transformer trip and subsequent unit trip. The effects of the storm were the cause of the loss in unit availability, and thus those forced outage hours shall be removed before calculating the PSL1 unit EAF performance during the April, 1994, through September, 1994, period.

Generic Oil Backout Issues

In accordance with the agreement of the parties, we find the proper final oil backout true-up amount for the period April, 1994 through September, 1994 period to be:

FPL: $11,602 overrecovery.

TECO: $30,836 underrecovery.

The estimated oil backup true-up amount for the period October, 1994 through March, 1995, is:

FPL: $527,531 underrecovery.

TECO: $183,974 overrecovery.

The total oil backout true-up amount to be collected during the period April, 1995 through September, 1995, is:

FPL: $515,929 underrecovery.

TECO: $153,138 overrecovery.

Finally, we find that the proper projected oil backout cost recovery factor for the period April, 1995 through September, 1995, is:

FPL: .012 cents/kWh.

TECO: .081 cents/kWh.

Generic Capacity Cost Recovery Issues

The parties agree that the following final capacity cost recovery true-up amounts are appropriate for the April, 1994 through September, 1994 period, which we approve:

FPC: $6,943,182 overrecovery.

FPL: $2,159,836 overrecovery.

GULF: $ 221,434 overrecovery.

TECO: $ 35,650 underrecovery.

We approve the following estimated capacity cost recovery true-up amounts for the period October, 1994 through March, 1995, as follows:

FPC: $10,515,204 underrecovery.

FPL: $12,962,747 overrecovery.

GULF: $ 101,423 underrecovery.

TECO: $ 1,065,382 overrecovery.

We also approve the following total capacity cost recovery true-up amounts to be collected during the period April, 1995 through September, 1995:

FPC: $ 3,572,022 underrecovery.

FPL: $15,122,583 overrecovery.

GULF: $ 120,011 overrecovery.

TECO: $ 1,029,732 overrecovery.

We approve the following appropriate projected net purchased power capacity cost amount to be included in the recovery factor for the period April, 1995 through September, 1995:

FPC: $116,445,839.

FPL: $144,171,942

GULF: $2,672,392.

TECO: $10,827,805.

Finally we approve the projected capacity cost recovery factors for the period April, 1995 through September, 1995, they are shown on Attachment A to this order and as follows:

FPC: See page 3 of 10 of Attachment A.

FPL: RATE CLASS	**CAPACITY RECOVERY FACTOR ($/KW)**	**CAPACITY RECOVERY FACTOR ($/KWH)**
RS1	-	0.00415
GS1	-	0.00367
GSD1	1.36	-
OS2	-	0.00229
GSLD1/CS1	1.41	-
GSLD2/CS2	1.43	-
GSLD3/CS3	1.41	-
CILCD/CILCG	1.35	-
CILCT	1.29	-
MET	1.47	-
OL1/SL1	-	0.00109
SL2	-	0.00261

RATE CLASS	**CAPACITY RECOVERY FACTOR (RESERVATION DEMAND CHARGE)**	**CAPACITY RECOVERY FACTOR (SUM OF DAILY DEMAND CHARGE) ($/KW)**
ISST1D	.18	.09
SST1T	.17	.08
SST1D	.18	.09

GULF: See table below:

RATE CLASS	**CAPACITY COST RECOVERY FACTORS ¢/KWH**
RS, RST	0.070
GS, GST	0.068
GSD, GSDT, SBS	0.053
LP, LPT, SBS	0.046
PX, PXT, RPT, SBS	0.037
OSI, OSII	0.005
OSIII	0.041
OSIV	0.005

TECO: The appropriate factors are as follows, subject to adjustment pending resolution of company specific issues:

Rate Schedules	Factor
RS	.187 cents per KWH
GS, TS	.173 cents per KWH
GSD	.130 cents per KWH
GSLD, SBF	.119 cents per KWH
IS-1 & 3, SBI-1 & 3	.011 cents per KWH
SL, OL	.029 cents per KWH

Company-Specific Capacity Cost Recovery Issues

Tampa Electric Company

Tampa Electric Company received $1,106,760. for an "Option Payment" from Polk Power Partners in 1993. In return for the payment, TECO allowed Polk Power Partners to choose which of its two cogeneration facilities would serve TECO's standard offer cogeneration contract. TECO also negotiated certain other changes to the standard offer contract that were approved by the Commission in Order No. PSC-95-0038-FOF-EU, Docket No. 94155-EQ, issued January 9, 1995. TECO recorded the option payment on its books as "other electric revenues", and presented testimony in this proceeding that the amount of the payment should not be credited directly back to the ratepayers through the capacity cost recovery clause.

The option payment TECO received from Polk was possible because of the standard offer contract between the parties, for which TECO's ratepayers pay the costs and bear the risks. TECO recovers the costs of payments to the cogenerator from its ratepayers on a dollar for dollar basis through the capacity cost recovery clause. At the hearing the issue was whether the ratepayers should receive all of the benefits from the option payment directly as a credit to the capacity clause, since they are the ones that bear all the risk. The rationale was that if TECO were required to credit the option payment back to the ratepayer, the risks associated with the contract would be properly matched to the benefits associated with the contract.

We understand that TECO's customers are responsible for providing the non-fuel revenue stream to support the benefits derived from these cogeneration contracts. We also understand, however, that this is an unusual situation, and we believe that all parties, the cogenerator, the company, and the ratepayers, benefitted from the modifications to the standard offer contract and TECO's agreement to provide Polk the option. Therefore, we believe that it is appropriate to divide the option payment between the capacity cost recovery clause and TECO's other electric revenues account. The ratepayers will receive a dollar for dollar credit through the clause for half of the option payment, and the remainder will be treated as other electric revenue. The capacity cost recovery clause portion of the option payment, plus interest for the intervening time period, will be part of the true-up in the next projection period.

We find that TECO should not be required to credit the revenues it receives from long-term firm Schedule D interchange sales back to the retail ratepayers through the fuel adjustment clause and the capacity cost recovery clause. This is because at the time of TECO's last rate case the firm Schedule D interchange sales were treated as a separated (wholesale) class of customers. By separating this class of customers from the retail jurisdiction, the company and its shareholders were effectively required to carry all of the risk associated with the portion of rate base and expenses that was assigned to this wholesale class of customers. Requiring the company to credit the revenues it could receive from potential additional Schedule D sales to the retail jurisdiction, without recognizing that the company and its shareholders may also experience a shortfall in the revenues that were separated from the retail jurisdiction, would be inequitable and asymmetrical treatment.

We also find that all of the revenues that result from interchange sales other than the firm Schedule D sales shall continue to appear as credits in the appropriate adjustment clauses. TECO shall inform the Commission's Division of Electric and Gas by certified letter when additional Schedule D sales are made.

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, 1995, and until such factors are modified by subsequent Order. 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, 1995. 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, 1995. 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, 1995, 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 6th day of April, 1995.

Blanca S. Bayó

BLANCA S. BAYÓ, Director
Division of Records and Reporting

(S E A L)

MCB/LW

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.

GPIF REWARDS/PENALTIES
April 1994 to September 1994

Florida Power Corporation	$986,547	Reward
Florida Power and Light Company	$3,065,156	Reward
Gulf Power Company	$22,931	Reward
Tampa Electric Company	$146,321	Reward

Utility/ Plant/Unit	EAF		Heat Rate	
FPC	Target	Adj. Actual	Target	Adj. Actual
Anclote 1	92.6	89.2	9,634	9,584
Anclote 2	81.7	82.1	9,596	9,678
Crystal River 1	85.9	89.7	10,118	9,993
Crystal River 2	83.9	85.5	10,081	9,874
Crystal River 3	59.8	62.9	10,533	10,497
Crystal River 4	87.2	86.0	9,268	9,320
Crystal River 5	94.7	96.7	9,315	9,256
FPL	Target	Adj. Actual	Target	Adj. Actual
Cape Canaveral 1	94.7	91.7	8,978	8,824
Cape Canaveral 2	93.2	90.9	9,400	9,556
Fort Myers 1	95.2	96.1	10,054	10,057
Fort Myers 2	94.0	93.8	9,418	9,481
Manatee 1	92.7	91.9	9,658	9,635
Manatee 2	94.5	96.6	9,785	9,869
Port Everglades 1	96.0	92.9	9,960	9,969
Port Everglades 2	95.3	87.1	9,936	9,907
Port Everglades 3	95.2	87.3	9,320	9,422
Port Everglades 4	87.1	91.2	9,372	9,554
Putnam 1	89.4	95.0	8,183	8,159
Putnam 2	94.2	94.3	8,302	8,143
Riviera 3	65.4	67.5	9,691	9,434
Riviera 4	90.4	91.3	9,717	9,655
Sanford 4	94.6	98.2	9,760	9,483
Sanford 5	94.1	97.9	9,534	9,476
Scherer 4	95.9	99.7	8,855	9,689
St. Johns River 1	95.6	99.4	9,370	9,475
St. Johns River 2	95.3	98.7	9,302	9,427
St. Lucie 1	93.4	94.8	10,846	10,942
St. Lucie 2	70.3	82.1	10,796	10,902
Turkey Point 1	82.6	98.0	9,444	9,066
Turkey Point 2	87.4	96.0	9,624	9,670
Turkey Point 3	67.0	68.6	11,086	11,131
Turkey Point 4	93.6	96.0	11,216	11,220
Gulf	Target	Adj. Actual	Target	Adj. Actual
Crist 6	66.6	64.4	10,391	10,588
Crist 7	82.1	90.8	10,231	10,341
Smith 1	80.8	85.0	10,162	10,143
Smith 2	90.8	98.4	10,192	10,421
Daniel 1	86.8	84.8	10,449	10,301
Daniel 2	96.8	97.8	10,089	9,961
TECO	Target	Adj. Actual	Target	Adj. Actual
Big Bend 1	58.6	59.1	10,062	9,988
Big Bend 2	87.6	79.2	10,069	10,214
Big Bend 3	83.5	90.9	9,676	9,930
Big Bend 4	88.1	92.6	10,114	10,173
Gannon 5	82.7	83.9	10,408	10,495
Gannon 6	83.1	90.7	10,454	10,6[illegible]

GPIF TARGETS
April 1995 to September 1995

Utility/ Plant/Unit	Equivalent Availability				Heat Rate	
	Company			Staff	Company	Staff
FPC	EAF	POF	EUOF			
Anclote 1	97.1	0.0	2.9	Agree	9,268	Agree
Anclote 2	97.2	0.0	2.8	Agree	9,565	Agree
Crystal River 1	60.2	31.2	8.6	Agree	10,130	Agree
Crystal River 2	83.6	0.0	16.4	Agree	10,053	Agree
Crystal River 3	94.0	0.0	6.0	Agree	10,532	Agree
Crystal River 4	92.9	0.0	7.1	Agree	9,377	Agree
Crystal River 5	90.6	3.8	5.6	Agree	9,274	Agree
FPL	EAF	POF	EUOF			
Cape Canaveral 1	91.2	0.0	8.8	Agree	9,230	Agree
Cape Canaveral 2	89.8	0.0	10.2	Agree	9,252	Agree
Fort Lauderdale 4	89.5	5.5	5.0	Agree	7,335	Agree
Fort Lauderdale 5	95.7	0.0	4.3	Agree	7,362	Agree
Fort Myers 2	91.7	0.0	8.3	Agree	9,337	Agree
Manatee 2	96.0	0.0	4.0	Agree	9,600	Agree
Port Everglades 3	85.6	6.0	8.4	Agree	9,209	Agree
Port Everglades 4	96.0	0.0	4.0	Agree	9,313	Agree
Putnam 1	96.0	0.0	4.0	Agree	8,540	Agree
Putnam 2	84.2	11.4	4.4	Agree	8,519	Agree
Riviera 3	93.6	0.0	6.4	Agree	9,610	Agree
Riviera 4	90.9	0.0	9.1	Agree	9,805	Agree
Sanford 5	96.0	0.0	4.0	Agree	9,694	Agree
Scherer 4	96.0	0.0	4.0	Agree	9,956	Agree
St. Lucie 1	93.6	0.0	6.4	Agree	10,882	Agree
St. Lucie 2	83.3	0.0	16.7	Agree	10,877	Agree
Turkey Point 1	82.7	12.6	4.7	Agree	9,309	Agree
Turkey Point 2	95.6	0.0	4.4	Agree	9,262	Agree
Turkey Point 3	85.1	8.7	6.2	Agree	11,133	Agree
Turkey Point 4	93.1	0.0	6.9	Agree	11,218	Agree
Gulf	EAF	POF	EUOF			
Crist 6	76.6	13.1	10.3	Agree	10,804	Agree
Crist 7	76.4	8.7	14.9	Agree	10,675	Agree
Smith 1	81.4	13.1	5.5	Agree	10,147	Agree
Smith 2	87.7	4.9	7.4	Agree	10,270	Agree
Daniel 1	90.5	4.4	5.1	Agree	10,291	Agree
Daniel 2	97.5	0.0	2.5	Agree	10,107	Agree
TECO	EAF	POF	EUOF			
Big Bend 1	83.4	1.1	15.5	Agree	10,137	Agree
Big Bend 2	88.1	0.0	11.9	Agree	10,055	Agree
Big Bend 3	67.1	23.0	9.9	Agree	9,607	Agree
Big Bend 4	90.6	0.0	9.4	Agree	10,036	Agree
Gannon 5	88.7	0.0	11.3	Agree	10,052	Agree
Gannon 6	80.4	5.5	14.1	Agree	10,335	Agree

TOTAL FUEL COST FOR THE PERIOD: April 1995 - September 1995

DATE: 02/20/95

COMPANY	PROPOSED April 1995 - September 1995 Levelized	On/Peak	Off/Peak	PRESENT December 1994 - March 1995 Cents per kwh Levelized	On/Peak	Off/Peak	DIFFERENCE Cents per kwh Levelized	On/Peak	Off/Peak	RESIDENTIAL LINE LOSS MULTIPLIER	PROPOSED RESIDENTIAL FUEL FACTOR
Fla. Power & Light (5)	1.744	1.890	1.673	1.567	1.673	1.525	0.177	0.217	0.148	1.00210	1.747
Fla. Power Corp.	1.894	2.425	1.616	2.055	2.612	1.827	-0.161	-0.187	-0.211	1.00000	1.894
Tampa Electric	2.386	2.666	2.239	2.353	2.666	2.239	0.033	0.000	0.000	1.00640	2.401
Gulf Power	2.315	2.533	2.211	2.179	2.226	2.164	0.136	0.307	0.047	1.01228	2.343
Fla. Public											
Marianna (1)	5.086	NA	NA	4.874	NA	NA	0.212	NA	NA	1.01260	5.151
Fernandina (1)(2)	5.036	NA	NA	4.976	NA	NA	0.060	NA	NA	1.00000	5.036

COST FOR 1,000 KWH RESIDENTIAL SERVICE

PRESENT: December 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	49.76
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	1.54	N/A	N/A
Capacity Recovery	5.17	7.47	1.93	2.24	NA	NA
Gross Receipts Tax (4)	0.73	2.09	2.06	0.71	1.79	0.71
Total	$71.62	$83.56	$82.40	$70.06	$71.70	$69.73

PROPOSED: April 1995 - September 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)	17.47	18.94	24.01	23.43	51.51	50.36
Oil Backout	0.12	N/A	0.81	N/A	N/A	N/A
Energy Conservation	2.51	3.35	1.53	0.26	0.18	0.12
Environmental Cost Recovery	0.10	N/A	N/A	1.36	N/A	N/A
Capacity Recovery	4.15	9.18	1.87	0.70	N/A	N/A
Gross Receipts Tax (4)	0.74	2.06	2.05	0.71	1.85	0.71
Total	$72.47	$82.58	$82.19	$69.71	$73.97	$70.39

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)	1.77	-1.61	0.33	1.37	2.15	0.60
Oil Backout	0.01	N/A	-0.15	N/A	N/A	N/A
Energy Conservation	0.08	-1.05	-0.32	0.00	0.06	0.06
Environmental Cost Recovery	0.00	N/A	N/A	-0.18	N/A	N/A
Capacity Recovery	-1.02	1.71	-0.06	-1.54	N/A	N/A
Gross Receipts Tax (4)	0.01	-0.03	-0.01	0.00	0.06	0.00
Total	0.85	-0.98	-0.21	-0.35	2.27	0.66

(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.

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

DIVISION OF ELECTRIC AND GAS
DATE: 02/20/95

FOR THE PERIOD: April 1995 – September 1995

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, CILC−G	1.744	1.890	1.673	1.00210	1.747	1.894	1.677
	A−1	SL−1,OL−1	1.707	NA	NA	1.00210	1.712	NA	NA
	B	GSD−1,GSDT−1	1.744	1.890	1.673	1.00204	1.747	1.894	1.676
	C	GSLD−1,GSLDT−1, CS−1, CST−1	1.744	1.890	1.673	1.00089	1.745	1.892	1.674
	D	GSLD−2,GSLDT−2, CS−2, CST−2	1.744	1.890	1.673	0.99443	1.734	1.880	1.664
	E	GSLD−3,GSLDT−3,CS−3,CST−3	1.744	1.890	1.673	0.96091	1.676	1.816	1.608
	F	CILC−1(D),ISST−1(D)	NA	1.890	1.673	0.99758	NA	1.886	1.669
FPC *	A	Distribution Secondary Delivery	1.894	2.425	1.616	1.00000	1.894	2.424	1.616
	A−1	OL−1,SL−1	1.767	NA	NA	1.00000	1.767	NA	NA
	B	Distribution Primary Delivery	1.894	2.425	1.616	0.99000	1.875	2.400	1.599
	C	Transmission Delivery	1.894	2.425	1.616	0.98000	1.856	2.376	1.583
TECO	A	RS,GS,TS	2.386	2.826	2.140	1.00640	2.401	2.844	2.154
	A−1	SL−1,2,3,OL−1,2	2.258	NA	NA	1.00000	2.258	NA	NA
	B	GSD,GSLD	2.386	2.826	2.140	1.00120	2.389	2.829	2.143
	C	IS−1,IS−3	2.386	2.826	2.140	0.97210	2.319	2.747	2.080
GULF	A	RS,GS,GSD,OS−III,OS−IV, SBS(100 to 500 kW)	2.315	2.533	2.211	1.01228	2.343	2.564	2.238
	B	LP, SBS(Contract Demand of 500 to 7499 kW)	2.315	2.533	2.211	0.98106	2.271	2.485	2.169
	C	PX, SBS(Contract Demand above 7499 kW)	2.315	2.533	2.211	0.96230	2.228	2.438	2.128
	D	OS−1,OS−2	2.240	NA	NA	1.01228	2.268	NA	NA
FPUC									
Fernandina	A	RS	5.036	NA	NA	1.00000	5.036	NA	NA
	B	GS	4.770	NA	NA	1.00000	4.770	NA	NA
	C	GSD	4.581	NA	NA	1.00000	4.581	NA	NA
	D	OL, OL−2, SL−2, SL−3, CSL	3.996	NA	NA	1.00000	3.996	NA	NA
	E	GSLD	N/A				4.799 (1) $6.18/CP KW		
Marianna	A	RS	5.086	NA	NA	1.01260	5.151	NA	NA
	B	GS	4.933	NA	NA	0.99630	4.915	NA	NA
	C	GSD	4.558	NA	NA	0.99630	4.541	NA	NA
	D	GLSD	4.397	NA	NA	0.99630	4.381	NA	NA
	E	OL, OL−2	3.221	NA	NA	1.01260	3.262	NA	NA
	F	SL−1, SL−2	3.221	NA	NA	0.98810	3.183	NA	NA

ATTACHMENT A

PROPOSED CAPACITY COST RECOVERY FACTORS
For the Period: April 1995 – September 1995

DIVISION OF ELECTRIC AND GAS
DATE: 02/20/95
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COMPANY	RATE SCHEDULE	RECOVERY FACTOR (CENTS PER KWH)	
FPL	RS1	0.415	
	GS1	0.367	
	OL1/SL1	0.109	
	SL2	0.261	
	OS2	0.229	
		RECOVERY FACTOR (DOLLARS PER KW)	
	GSD1	$1.36	
	GSLD1/CS1	$1.41	
	GSLD2/CS2	$1.43	
	GSLD3/CS3	$1.41	
	ISST1D = RDC/SDD	$0.18	$0.09
	SST1T = RDC/SDD	$0.17	$0.08
	SST1D = RDC/SDD	$0.18	$0.09
	CILCD.CILCG	$1.35	
	CILCT	$1.29	
	MET	$1.47	
		RECOVERY FACTOR (CENTS PER KWH)	
FPC	RS	0.918	
	GS-Transmission	0.714	
	GS-Primary	0.721	
	GS-Secondary	0.728	
	GS - 100% Load Factor	0.502	
	GSD-Transmission	0.598	
	GSD-Primary	0.604	
	GSD-Secondary	0.610	
	CS - Transmission	0.501	
	CS - Primary	0.506	
	CS - Secondary	0.511	
	IS-Transmission	0.502	
	IS-Primary	0.507	
	IS-Secondary	0.512	
	LS - Lighting Service	0.183	
TECO	RS	0.187	
	GS,TS	0.173	
	GSD	0.130	
	GSLD,SBF	0.119	
	IS-1 & 3,SBI-1 & 3	0.011	
	SL/OL	0.029	
GULF	RS,RST	0.070	
	GS,GST	0.068	
	GSD,GSDT	0.053	
	LP,LPT	0.046	
	PX,PXT	0.037	
	OS-I,OS-II	0.005	
	OS-III	0.041	
	OS-VI	0.005	

FUEL & PURCHASED POWER COST RECOVERY CLAUSE CALCULATION

DIVISION OF ELECTRIC AND GAS
DATE: 02/20/95
PAGE 4 OF 10

ESTIMATED FOR THE PERIOD: April 1995 – September 1995

FLORIDA POWER & LIGHT COMPANY

CLASSIFICATION	Classification Associated $	Classification Associated KWH	Classification Associated Cents/KWH
1.Fuel Cost of System Net Generation (E3)	544,755,274	35,853,147,000	1.51941
2.Spent NUC Fuel Disposal Cost (E2)	11,153,262	11,946,509,000 (a)	0.09336
3.Fuel Related Transactions	7,034,943	0	0.00000
4. Natural Gas Pipeline Enhancements	0	0	0.00000
4a. Fuel Cost of Sales to FKEC	(8,848,014)	(448,644,000)	1.97217
5.TOTAL COST OF GENERATED POWER	554,095,465	35,404,503,000	1.56504
6.Fuel Cost of Purchased Power – Firm (E8)	90,347,195	5,217,333,000	1.73167
7.Energy Cost of Sch.C.X Economy Purchases (Broker) (E9)	9,068,200	779,060,000	1.16399
8.Energy Cost of Economy Purchases (Non–Broker) (E9)	10,344,570	598,969,000	1.72706
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)	38,925,071	2,263,095,000	1.71999
12.TOTAL COST OF PURCHASED POWER	148,685,036	8,858,457,000	1.67845
13.TOTAL AVAILABLE KWH		44,262,960,000	
14.Fuel Cost of Economy Sales (E7)	(9,131,626)	(414,750,000)	2.20172
15.Gain on Economy Sales – 80% (E7A)	(2,202,510)	(414,750,000)(a)	0.53105
16.Fuel Cost of Unit Power Sales (SL2 Partpts) (E7)	(1,120,283)	(262,154,000)	0.42734
17.Fuel Cost of Other Power Sales (E7)	0	0	0.00000
18.TOTAL FUEL COST AND GAINS OF POWER SALES	(12,454,419)	(676,904,000)	1.83991
19.Net Inadvertant Interchange (E4)	0	0	0.00000
20.TOTAL FUEL AND NET POWER TRANSACTIONS	690,326,082	43,586,056,000	1.58382
21.Net Unbilled (E4)	4,350,620 (a)	(1,000,153,000)	0.01100
22.Company Use (E4)	(2,055,280)(a)	(132,104,000)	−0.00519
23.T & D Losses (E4)	(45,079,110)(a)	(2,885,000,800)	−0.11393
24.Adjusted System KWH Sales	690,326,082	39,568,798,200	1.74462
25.Wholesale KWH Sales	3,877,976	(222,280,000)	1.74464
26.JURISDICTIONAL KWH SALES	686,448,106	39,346,518,200	1.74462
27.Jurisdictional KWH Sales Adjusted for Line Loss – 1.00035	686,811,923	39,346,518,200	1.74555
28.True–up * (derived in Attachment C)	(14,614,552)	39,346,518,200	−0.03714
29.TOTAL JURISDICTIONAL FUEL COST	672,197,371	39,346,518,200	1.70840
30.Revenue Tax Factor			1.01609
31.Fuel Cost Adjusted for Taxes			1.73589
32.GPIF*	3,065,156	39,346,518,200	0.00779
33.Total fuel cost including GPIF	675,262,527	39,346,518,200	1.74368
34.TOTAL FUEL COST FACTOR ROUNDED TO THE NEAREST .001 CENTS PER KWH:			1.744

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

ATTACHMENT A

FUEL & PURCHASED POWER COST RECOVERY CLAUSE CALCULATION

DIVISION OF ELECTRIC AND GAS
DATE: 02/20/95
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ESTIMATED FOR THE PERIOD: April 1995 – September 1995

FLORIDA POWER CORPORATION

CLASSIFICATION	Classification Associated $	Classification Associated KWH	Classification Associated cents/KWH
1.Fuel Cost of System Net Generation (E3)	201,690,909	12,617,244,000	1.59853
2.Spent NUC Fuel Disposal Cost (E3A)	2,948,649	3,153,635,000 (a)	0.09350
3.Coal Car Investment	0	0	0.00000
4.Adjustments to Fuel Cost	299,000	0	0.00000
5.TOTAL COST OF GENERATED POWER	204,938,558	12,617,244,000	1.62427
6.Energy Cost of Purchased Power – Firm (E8)	23,471,060	1,138,415,000	2.06173
7.Energy Cost of Sch.C,X Economy Purchases (Broker) (E9)	19,807,800	770,000,000	2.57244
8.Energy Cost of Economy Purchases (Non–Broker) (E9)	564,152	23,580,000	2.39250
9.Energy Cost of Sch.E Purchases (E9)	0	0	0.00000
10.Capacity Cost of Sch.E Economy Purchases (E9)	0	0 (a)	0.00000
11.Payments to Qualifying Facilities (E8A)	72,143,870	3,563,863,000	2.02432
12.TOTAL COST OF PURCHASED POWER	115,986,882	5,495,858,000	2.11044
13.TOTAL AVAILABLE KWH		18,113,102,000	
14.Fuel Cost of Economy Sales (E7)	(4,705,740)	(265,000,000)	1.77575
14a.Gain on Economy Sales –80% (E7A)	(524,000)	(265,000,000)(a)	0.19774
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)	(7,360,400)	(320,012,000)	2.30004
18.TOTAL FUEL COST AND GAINS OF POWER SALES	(12,590,140)	(585,012,000)	2.15212
19.Net Inadvertant Interchange (E4)	0	0	
20.TOTAL FUEL AND NET POWER TRANSACTIONS	308,335,300	17,528,090,000	1.75909
21.Net Unbilled (E4)	10,258,192 (a)	(583,150,000)	0.06479
22.Company Use (E4)	1,662,350 (a)	(94,500,000)	0.01050
23.T & D Losses (E4)	17,900,039 (a)	(1,017,568,000)	0.11306
24.Adjusted System KWH Sales	308,335,300	15,832,872,000	1.94744
25.Wholesale KWH Sales(Excluding Seminole Supplemental)	(10,051,165)	(516,042,000)	1.94774
26.JURISDICTIONAL KWH SALES	298,284,135	15,316,830,000	1.94743
27.Jurisdictional KWH Sales Adjusted for Line Loss – 1.0014	298,671,904	15,316,830,000	1.94996
28.Prior Period True–Up *	(10,291,176)	15,316,830,000	–0.06719
28a. Market Price Refund for 1992	0	0	0.00000
29.TOTAL JURISDICTIONAL FUEL COST	288,380,728	15,316,830,000	1.88277
30.Revenue Tax Factor			1.00083
31.Fuel Cost Adjusted for Taxes	288,620,084		1.88430
32.GPIF*	986,547	15,316,830,000	0.00640
33.Total fuel cost including GPIF	289,606,631	15,316,830,000	1.89070
34.TOTAL FUEL COST FACTOR ROUNDED TO THE NEAREST .001 CENTS PER KWH:			1.891

*Based on Jurisdictional Sales

(a) Included for informational purposes only.

ATTACHMENT A

FUEL & PURCHASED POWER COST RECOVERY CLAUSE CALCULATION

DIVISION OF ELECTRIC AND GAS
DATE: 02/20/95
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ESTIMATED FOR THE PERIOD: April 1995 – September 1995

TAMPA ELECTRIC COMPANY

CLASSIFICATION	Classification Associated $	Classification Associated KWH	Classification Associated cents/KWH
1.Fuel Cost of System Net Generation (E3)	195,434,704	8,992,142,000	2.17339
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	3,083,415	8,992,142,000	0.03429
5.TOTAL COST OF GENERATED POWER	198,518,119	8,992,142,000	2.20768
6.Fuel Cost of Purchased Power – Firm (E8)	5,520,500	150,153,000	3.67658
7.Energy Cost of Sch.C,X Economy Purchases (Broker) (E9)	624,500	18,415,000	3.39126
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)	4,577,800	234,743,000	1.95013
12.TOTAL COST OF PURCHASED POWER	10,722,800	403,311,000	2.65869
13.TOTAL AVAILABLE KWH		9,395,453,000	
14.Fuel Cost of Economy Sales (E7)	13,059,300	797,767,000	1.63698
15.Gain on Economy Sales – 80% (E7A)	2,093,040	797,767,000 (a)	0.26236
16.Fuel Cost of Scedule D Sales (Jurisdictional)(E7)	399,200	24,657,000	1.61901
16a.Fuel Cost of Schedule G Sales (E7)	0	0	0.00000
17.Fuel Cost Schedule J Sales (E7)	581,700	33,359,000	1.74376
17a.Fuel Cost Schedule D TPS and Seperated Sales (E7)	4,107,800	257,993,000	1.59221
18.TOTAL FUEL COST AND GAINS OF POWER SALES	20,241,040	1,113,776,000	1.81733
19.Net Inadvertant Interchange (E4)	0	0	
19b.Interchange and Wheeling Losses	0	19,834,000	
20.TOTAL FUEL AND NET POWER TRANSACTIONS	188,999,879	8,261,843,000	2.28762
21.Net Unbilled (E4)	3,627,868 (a)	158,587,000	0.04731
22.Company Use (E4)	384,320 (a)	16,800,000	0.00501
23.T & D Losses (E4)	9,570,647 (a)	418,367,000	0.12481
24.Adjusted System KWH Sales	188,999,879	7,668,089,000	2.46476
25.Wholesale KWH Sales	(798,126)	(32,759,000)	2.43636
26.JURISDICTIONAL KWH SALES	188,201,753	7,635,330,000	2.46488
27.Jurisdictional KWH Sales Adjusted for Line Loss – 1.00005	188,295,854	7,635,330,000	2.46611
28.True–up * (derived in Attachment C)	(6,423,678)	7,635,330,000	–0.08413
29.Pyramid Coal Contract Buyout Adjustment	0	7,635,330,000	0.00000
30.TOTAL JURISDICTIONAL FUEL COST	181,872,176	7,635,330,000	: 2.38198
31.Revenue Tax Factor			1.00083
32.Fuel Cost Adjusted for Taxes	182,023,130		2.38396
33.GPIF * (Already adjusted for taxes)	146,321	7,635,330,000	0.00192
34.Total Fuel Cost including GPIF	182,169,451	7,635,330,000	2.38588
35.TOTAL FUEL COST FACTOR ROUNDED TO THE NEAREST .001 CENTS PER KWH:			2.386

*Based on Jurisdictional Sales

Effective date for billing purposes:

(a) Included for informational purposes only.

ATTACHMENT A

FUEL & PURCHASED POWER COST RECOVERY CLAUSE CALCULATION

DIVISION OF ELECTRIC AND GAS
DATE: 02/20/95
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ESTIMATED FOR THE PERIOD: April 1995 – September 1995

GULF POWER COMPANY

CLASSIFICATION	Classification Associated $	Classification Associated KWH	Classification Associated cents/KWH
1.Fuel Cost of System Net Generation (E3)	113,193,885	5,533,480,000	2.0456
2.Net Cost of Emission Allowances	0	0	0.0000
3.Adjustments to Fuel Cost	0	0	0.0000
4.TOTAL COST OF GENERATED POWER	113,193,885	5,533,480,000	2.0456
5.Fuel Cost of Purchased Power – Firm (E8)	0	0	0.0000
6.Energy Cost of Sch.C,X Economy Purchases (Broker) (E9)	10,212,000	562,780,000	ERR
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	10,212,000	562,780,000	1.8146
12.TOTAL AVAILABLE KWH (line 4 + line 11)		6,096,260,000	
13.Fuel Cost of Economy Sales (E7)	(654,000)	(22,790,000)	2.8697
14.Gain on Economy Sales – 80% (E7A)	(55,200)	0 (a)	0.0000
15.Fuel Cost of Unit Power Sales (E7)	(12,115,000)	(688,200,000)	1.7604
16.Fuel Cost of Other Power Sales (E7)	(5,046,000)	(247,167,000)	2.0415
17.TOTAL FUEL COST AND GAINS OF POWER SALES	(17,870,200)	(958,157,000)	1.8651
18.Net Inadvertant Interchange (E4)	0		
19.TOTAL FUEL AND NET POWER TRANSACTIONS	105,535,685	5,138,103,000	2.0540
20.Net Unbilled (E4)	0	0	0.0000
21.Company Use (E4)	20,255,805 (a)	9,865,000	205.3300
22.T & D Losses (E4)	7,143,422 (a)	347,781,000	2.0540
23.Adjusted System KWH Sales	105,535,685	4,780,457,000	2.2076
24.Wholesale KWH Sales	3,774,554	170,980,000	2.2076
25.JURISDICTIONAL KWH SALES	101,761,131	4,609,477,000	2.2077
26.Jurisdictional KWH Sales Adjusted for Line Loss – 1.00140	101,903,596	4,609,477,000	2.2107
27.True–up *	2,971,655	4,609,477,000	0.0645
28.Total Jurisdictional Fuel Cost	104,875,251	4,609,477,000	2.2752
29.Revenue Tax Factor			1.01609
30.Fuel Cost Adjusted for Taxes			2.3118
31.Special Contract Recovery Cost	121,472	4,609,477,000	0.0026
32.GPIF *	22,931	4,609,477,000	0.0005
33.Total Fuel Cost including GPIF	104,898,182	4,609,477,000	2.3149
34.TOTAL FUEL COST FACTOR ROUNDED TO THE NEAREST .001 CENTS PER KWH:			2.315

*Based on Jurisdictional Sales

Effective date for billing purposes:

(a) included for informational purposes only.

ATTACHMENT A

FUEL & PURCHASED POWER COST RECOVERY CLAUSE CALCULATION

DIVISION OF ELECTRIC AND GAS
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ESTIMATED FOR THE PERIOD: April 1995 – September 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)	3,239,841	151,682,000	2.13594
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)	3,336,279	151,682,000 (a)	2.19952
10a.Demand Costs of Purchased Power	2,287,890 (a)		
10b.Non–Fuel Energy & Customer Costs of Purchased Power	1,048,389 (a)		
11.Energy Payments to Qualifying Facilities (E8A)	0	0	0.00000
12.TOTAL COST OF PURCHASED POWER	6,576,120	151,682,000	4.33546
13.TOTAL AVAILABLE KWH	6,576,120	151,682,000	4.33546
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	6,576,120	151,682,000	4.33546
21.Net Unbilled (E4)	205,544 (a)	4,741,000	0.14603
22.Company Use (E4)	4,986 (a)	115,000	0.00354
23.T & D Losses (E4)	263,032 (a)	6,067,000	0.18687
24.ADJUSTED SYSTEM KWH SALES	6,576,120	140,759,000	4.67190
25.Less Total Demand Cost Recovery	2,190,354		
26.JURISDICTIONAL KWH SALES	4,385,766	140,759,000	3.11580
27.Jurisdictional KWH Sales Adjusted for Line Loss – 1.00	4,385,766	140,759,000	3.11580
28.True–up *	143,938	140,759,000	0.10226
29.TOTAL JURISDICTIONAL FUEL COST	4,529,704	140,759,000	3.21806
30.Revenue Tax Factor			1.00083
31.Fuel Cost Adjusted for Taxes	3,499,562	0	3.22073
32.GPIF *	0	140,759,000	0.00000
33.Total Fuel Cost including GPIF	4,529,704	140,759,000	3.22073
34.TOTAL FUEL COST FACTOR ROUNDED TO THE NEAREST .001 CENTS PER KWH:			3.221

*Based on Jurisdictional Sales

(a) included for informational purposes only.

ATTACHMENT A

FUEL & PURCHASED POWER COST RECOVERY
CLAUSE CALCULATION

DIVISION OF ELECTRIC AND GAS
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ESTIMATED FOR THE PERIOD: April 1995 – September 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)	3,038,247	174,083,000	1.74529
7.Energy Cost of Sch.C,X Economy Purchases (Broker) (E9)	0	0	0.00000
8.Energy Cost of Economy Purchases (Non–Broker) (E9)	0		
9.Energy Cost of Sch.E Purchases (E9)	0	0	0.00000
10.Demand & Non Fuel Cost of Purchased Power	5,253,018	174,083,000	3.01754
10a.Demand Costs of Purchased Power (E2)	2,388,000 (a)		
10b.Non Fuel Energy and Customer Costs of Purchased Power (E2)	2,865,018 (a)		
11.Energy Payments to Qualifying Facilities (E8A)	0	0	0.00000
12.TOTAL COST OF PURCHASED POWER	8,291,265	174,083,000	4.76282
13.TOTAL AVAILABLE KWH	8,291,265	174,083,000	4.76282
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	8,291,265	174,083,000	4.76282
21.Net Unbilled (E4)	10,288 (a)	216,000	0.00630
22.Company Use (E4)	9,811 (a)	206,000	0.00601
23.T & D Losses (E4)	497,477 (a)	10,445,000	0.30480
24.Adjusted System KWH Sales	8,291,265	163,216,000	5.07993
25.Wholesale KWH Sales	0	0	0.00000
26.JURISDICTIONAL KWH SALES	8,291,265	163,216,000	5.07993
27.Jurisdictional KWH Sales Adjusted for Line Loss – 1.00	8,291,265	163,216,000	5.07993
27a.GSLD KWH Sales (E11)		36,000,000	
27b.Other Classes KWH Sales (E11)		127,216,000	
27c.GSLD CP KW		132,000 (a	
28.GPIF			
29.True–up *	(137,540)	163,216,000	–0.08427
30.TOTAL JURISDICTIONAL FUEL COST	8,153,725	163,216,000	4.99567

ATTACHMENT A

FUEL & PURCHASED POWER COST RECOVERY CLAUSE CALCULATION

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FLORIDA PUBLIC UTILITIES – FERNANDINA

CLASSIFICATION	Classification Associated $	Classification Associated KWH	Classification Associated cents KWH
30a.Demand Purchased Power Costs (line 10a)	2,388,000 (a)		
30b.Non – Demand Purchased Power Costs (lines 6 + 10b + 11)	5,903,265 (a)		
30c.True – up Over/Under Recovery (line 29)	(137,540)(a)		
APPORTIONMENT OF DEMAND COSTS			
31.Total Demand Costs	2,388,000		
32.GSLD Portion of Demand Costs Including line losses (line 27c * $3.708)	815,760	132,000 KW	$6.18
33.Balance to Other Customers	1,572,240	127,216,000	1.23588
APPORTIONMENT OF NON – DEMAND COSTS			
34.Total Non – Demand Costs (line 30b)	5,903,265		
35.Total KWH Purchased (line 12)		174,083,000	
36.Average Cost per KWH Purchased			3.39106
37.Avg. Cost Adjusted for Transmission line losses (line 36 * 1.03)			3.49280
38.GSLD Non – Demand Costs (line 27a * line 37)	1,257,303	36,000,000	0.03493
39.Balance to Other Customers	4,645,962	127,216,000	3.65203
GSLD PURCHASED POWER COST RECOVERY FACTORS			
40a.Total GSLD Demand Costs (Line 32)	815,760	132,000	$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)	1,257,303	36,000,000	3.49251
40e.Total Non – Demand Costs including true – up	1,257,303	36,000,000	3.49251
40f.Revenue Tax Factor			1.01609
40g GSLD Non – demand costs adjusted for taxes			3.549
OTHER CLASSES PURCHASED POWER COST RECOVERY FACTORS			
41a.Total Demand and Non – Demand Purchased Power Costs of other classes (lines 33 + 39)	6,218,202	127,216,000	4.88791
41b.Less: Total Demand Cost Recovery	1,593,378 (a)		
41c.Total Other Costs to be Recovered	4,624,824 (a)	127,216,000	3.63541
41d.Other Classes' Portion of True – up (line 30 C)	(137,540)	127,216,000	– 0.10812
41e.Total Demand and Non – Demand Costs including True – up	4,487,284	127,216,000	3.52730
42.Revenue tax factor			1.01609
			3.58405
43.OTHER CLASSES PURCHASED POWER FACTOR ADJUSTED FOR TAXES ROUNDED TO THE NEAREST .001 CENTS PER KWH:			**3.584**

*Based on Jurisdictional Sales

(a) included for informational purposes only.