BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In Re: Fuel and Purchased Power Cost Recovery Clause and Generating Performance Incentive Factor.	DOCKET NO. 920001-EI ORDER NO. PSC-92-1001-FOF-EI ISSUED: 09/17/92

The following Commissioners participated in the disposition of this matter:

SUSAN F. CLARK
J. TERRY DEASON
BETTY EASLEY

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, conservation cost recovery, and purchased gas cost recovery proceedings, hearings are held in February and August of each year in this docket and in two related dockets. Pursuant to notice, a hearing was held in this docket and in Dockets No. 910002-EG and 910003-GU on August 12, 1992. 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 period October, 1991 through March, 1992 are as follows:

FPC:	$22,416,601	overrecovery.
FPL:	$57,265,882	overrecovery.
FPUC:	$ 52,582	underrecovery. (Marianna)
	$ 144,251	overrecovery. (Fernandina Beach)
GULF:	$ 2,705,971	underrecovery.
TECO:	$ 81,492	underrecovery.

The estimated fuel adjustment true-up amounts for the period April, 1992 through September 1992 are as follows:

FPC:	$13,094,231 overrecovery less the $22,418,369 midcourse correction being refunded during the current period for a net underrecovery of $9,324,138.
FPL:	$21,694,083 underrecovery.
FPUC:	$ 84,169 underrecovery. (Marianna)
	$ 145,678 overrecovery. (Fernandina Beach)
GULF:	$ 1,622,183 underrecovery.
TECO:	An overrecovery of $7,470,211.

The total fuel adjustment true-up amounts to be collected during the period October, 1992 through March, 1993 are as follows:

FPC:	$13,092,463 overrecovery.
FPL:	$35,571,799 overrecovery.
FPUC:	$ 136,751 underrecovery. (Marianna)
	$ 289,929 overrecovery. (Fernandina Beach)
GULF:	$ 4,328,154 underrecovery.
TECO:	$ 7,388,719 overrecovery.

Finally, the appropriate levelized fuel cost recovery factors for the period October, 1992 through March, 1993, before line loss adjustment, are as follows:

FPC:	1.785 cents per kWh non-time differentiated.
	2.306 cents per kWh - On-Peak.
	1.569 cents per kWh - Off-Peak.
FPL:	1.709 cents per kWh non-time differentiated.
	1.848 cents per kWh - On-peak.
	1.654 cents per kWh - Off-peak.
FPUC:	2.772 per kWh. (Marianna)
	4.433 per kWh. (Fernandina Beach)
GULF:	2.301 cents per kWh non-time differentiated.
	2.380 cents per kWh - On-peak.
	2.274 cents per kWh - Off-peak.
TECO:	2.358 cents per kWh non-time differentiated.
	2.584 cents per kWh - On-peak.
	2.281 cents per kWh - Off-peak.

The above factors should be effective beginning with the specified fuel cycle and thereafter for the period October, 1992 through March, 1993. Billing cycles may start before October 1, 1992, and the last cycle may be read after March 30, 1993, so that each customer is billed for six months regardless of when the adjustment factor became effective.

Florida Power Corporation will be permitted to put its new factors into effect on the same date as any rate adjustment ordered in Docket No. 910890-EI.

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 Appendix "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 Appendix "A". We find that the proposed factors are appropriate and should be approved.

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

Florida Power and Light Company

Florida Power and Light Company requested that it be allowed to recover through the Fuel Cost Recovery Clause the costs of certain gas lateral enhancements. The parties agreed that FPL should be permitted to recover those costs. The enhancement to the gas lateral is specifically related to the transportation of natural gas and, as such, serves a purpose similar to that of rail cars used to deliver coal to the utility. In our Order No. 14546, Docket No. 850001-EI-B, we authorized recovery through the Fuel Cost Recovery Clause of fuel related transportation costs. In our Order No. 18136, Docket No. 870001-EI, we approved FPL's recovery of SJRPP rail cars through the Fuel Cost Recovery Clause. Similarly, we will approve recovery of gas lateral enhancements here.

Gulf Power Company

Gulf's Special Contract with Monsanto expires on December 31, 1992. The issue before us in this proceeding was how the "fuel savings" associated with the contract that accrued as of December 31, 1992 should be recovered from the general body of ratepayers, and how the Special Account established for those "fuel savings" should be liquidated. The parties agreed on a method that we approve.

The "fuel savings" that have not yet been deposited into the Special Account at the time of its liquidation on December 31, 1992 will be recovered in the April through September 1993 fuel adjustment period. In order to properly settle the Special Account, 25% of the fuel savings that are identified in the April-December 1992 period will be returned to Gulf through an adjustment to the April-September 1993 fuel factor. This represents Gulf's share of the Special Account funds that would have been deposited had there not been a lag between the time the fuel savings were accrued and the time they were recovered.

The fuel factor for the April-September 1993 period will also be adjusted to return to the ratepayers their 75% share of the account balance at the end of the contract, as well as 75% of the fuel savings that will be recovered for the period January through March of 1993.

Tampa Electric Company

The parties agreed to defer the following issues to the February 1993 fuel hearings, because we did not rule on Tampa Electric Company's Petition for Clarification and Guidance on the Appropriate market-based Pricing Methodology for Coal Purchased from Gatliff Coal Company, Docket No. 920041-EI until after the hearing in this fuel proceeding.

***ISSUE 10a:** What is the appropriate 1991 benchmark price for coal Tampa Electric Company purchased from its affiliate, Gatliff Coal Company?

***ISSUE 10b:** 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?

No further testimony or exhibits will be filed on these issues. The testimony and exhibits that were filed in this proceeding will be transferred to the February proceeding. No further discovery will be conducted, with the exception of the previously scheduled deposition of Mr. Shea.

Two other issues related to Tampa Electric Company's fuel costs were raised in this proceeding; 1) recovery of the costs associated with the purchase of transportation services from its affiliates for the 1991 period, and 2) the appropriate treatment of interest on overstated affiliated waterborne transportation charges in September of 1991. The parties agreed that Tampa Electric Company's transportation costs were below the benchmark for the 1991 period, and therefore recovery was appropriate and no specific justification of those costs was required. The parties also agreed that Tampa Electric Company had already made the appropriate adjustment to account for the interest on the overstated charges and no further adjustment was necessary. The adjustment was included in Tampa Electric's monthly fuel filing for May, 1992. We approve the parties' agreement on those matters.

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 October, 1991 through March, 1992:

FPC:	$1,061,794	reward.
FPL:	$4,627,514	reward.
GULF:	$ 87,028	reward.
TECO:	$ 403,442	reward.

The parties also agreed to targets and ranges for the period October, 1992 through March, 1993, which are shown on Appendix "B" to this order. We approve those targets and ranges.

We will permit Florida Power Corporation to adjust the actual heat rate for Crystal River 1 and 2 to reflect the effect on the GPIF heat rate performance that may result from the Environmental Protection Agency's mandate to reduce circulating water flow. We grant this permission on a preliminary basis, subject to further review in the August 1993 fuel proceedings.

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 October, 1991 through March, 1992 to be $733,514 underrecovery for FPL and $603,095 overrecovery for TECO. The estimated oil backout true-up amount for the period April, 1992 through September, 1992 is $685,173 overrecovery for FPL and $32,642 underrecovery for TECO.

The total oil backout true-up amount to be collected or refunded during the period October, 1992 through March, 1993 is $48,341 underrecovery for FPL and an overrecovery of $737,702 for TECO.

Finally, we find the proper projected oil backout cost recovery factor for the period October, 1992 through March, 1993 is .017 cents per kWh for FPL, and .098 cents per KWH for TECO.

Capacity Cost Recovery Factor.

In February of this year we conducted a generic investigation of the proper recovery of purchased power by investor-owned electric utilities. (Docket No. 910794-EQ). At the conclusion of our investigation we required the utilities to implement a capacity payment charge to recover demand related capacity costs that were being recovered through the fuel or oil-backout adjustment charges. We also permitted the utilities to recover capacity related purchased power costs of contracts entered into since the utility's last rate case if those costs were not being recovered through the fuel or oil backout charges. In order to match costs and revenues we found that revenues from demand related capacity sales were to be netted against demand related capacity costs to determine the amount recoverable through the new capacity cost recovery factor. We directed the utilities to implement the new charges for the October 1992 fuel adjustment period in the same manner that Florida Power and Light Company had implemented the new charge for the preceeding fuel adjustment period. (See Order No. 25773, February 2, 1992).

The final capacity cost recovery true-up amount for the October, 1991 through March, 1992 period for FPL was $6,769,227 underrecovery. We approve recovery of that amount.

Gulf's initial implementation of a purchased power capacity cost recovery factor is proposed for the October, 1992 through March, 1993 recovery period, and as a result, Gulf does not have a true-up amount for the October, 1991 through March, 1992 period. Tampa Electric Company and Florida Power Corporation have not applied capacity cost recovery in prior periods, either, and there is no true-up to be considered for them for this period. For the same reasons there is no estimated capacity cost recovery true-up amount for Gulf, TECO or FPC for the period April, 1992 through September, 1992. Florida Power and Light Company's estimate is $5,879,994 underrecovery. We approve that estimate, and we approve a total capacity cost recovery true-up amount of $12,649,221 underrecovery to be collected by FPL during the period October, 1992 through March, 1993.

We approve the following amounts of projected net purchased power capacity costs to be included in the recovery factor for the period October, 1992 through March, 1993:

FPC: $18,519,715 (before gross up for gross receipts tax).
$18,817,697 (after gross up for gross receipts tax).

FPL: $246,315,293, including taxes, subject to refund, pending the resolution of the outstanding issues relating to St. John's River Power Park capacity costs.

GULF: $888,526, including taxes.

TECO: $3,106,772, including taxes.

Finally, the appropriate capacity cost recovery factors to be applied for the period October, 1992 through March, 1993 are as follows:

FPC: Recovery Factor

Rate Class	(Cents Per KWH)
RS	0.1911
GS-Transmission	0.1298
GS-Primary	0.1315
GS-Secondary	0.1338
GS-100% Load Factor	0.1008
GSD-Transmission	0.0925
GSD-Primary	0.1160
GSD-Secondary	0.1181
CS-Curtailable	0.0912
IS-Transmission	0.0958
IS-Primary	0.0971
LS-Lighting Service	0.0378

FPL: Recovery Factor

Rate Class	(Cents Per KWH)
RS1	0.8530
GS1	0.7960
GSD1	0.7280
OS2	0.7050
GSLD1/CS1	0.7420
GSLD2/CS2	0.6130
GSLD3/CS3	0.5800
ISST1D	0.5050
SST1T	0.4590
SST1D	0.4690
CILCD	0.5100
CILCT	0.4700
MET	0.6510
OL1/SL1	0.3930
SL2	0.5400

GULF:

RATE CLASS	CAPACITY COST FACTOR ¢/KWH
RS, RST	-0.030
GS, GST	-0.029
GSD, GSDT	-0.022
LP, LPT	-0.020
PX, PXT	-0.016
OS-I, OS-II	-0.003
OS-III	-0.018
OS-IV	-0.002
SS	-0.016

TECO: The appropriate factors are as follows:

Rate Schedules	Factor
RS	.055 cents per KWH
GS, TS	.051 cents per KWH
GSD	.048 cents per KWH
GSLD, SBF	.046 cents per KWH
IS-1 & 3, SBI-1 & 3	.034 cents per KWH
SL, OL	.037 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 Corporation

We find that Florida Power Corporation's methodology for calculating its capacity cost recovery factor is appropriate. FPC will be permitted to put its new factor into effect on the same date as any rate adjustment ordered in Docket No. 910890-EI.

Florida Power and Light Company

The following issue was removed from this proceeding and transferred to a new docket, Docket No. 920887-EI. A hearing on this issue and related issues will be heard by the Commission on October 9, 1992.

ISSUE 24: Are the capacity payments associated with St. Johns River Power Park (SJRPP) appropriate for recovery through the capacity cost recovery clause, as provided in Order No. 25773?

Gulf Power Company

Gulf Power Company requested recovery of the capacity costs associated with Gulf's participation in the Southern Electric System's Intercompany Interchange Contract (IIC). Gulf also requested that the revenues associated with Gulf's Long-Term Non-Firm Contract with Florida Power Corporation be considered only in connection with its recovery of the IIC costs. Our staff and the Florida Industrial Power Users Group (FIPUG) disagreed with Gulf's requests. We heard testimony on Gulf's capacity cost issues at the hearing and made our decision on them at our September 1, 1992 Agenda Conference.

Our Order No.25773 directs investor-owned utilities to implement a capacity cost recovery clause beginning in October, 1992. The order describes the capacity costs that are appropriate for inclusion in the clause. The capacity costs that the order deems appropriate for recovery fall into two categories. The first category is comprised of those purchased power capacity costs that are already being recovered through the fuel or oil backout factors. By shifting those costs to the capacity cost recovery factor, the costs are allocated to customer classes using a demand allocator, rather than an energy allocator. This reallocation is appropriate because capacity costs are a demand-related cost, and should be recovered on a demand basis, not on an energy (or per kwh) basis.

The second category of capacity costs the order identified for inclusion in the new clause were costs related to contracts entered into since the utility's last rate case that were not reflected in either fuel or oil backout charges. Those costs were addressed on page five of Order No. 25773 as follows:

> We will permit utilities to recover capacity related purchased power costs <u>not</u> currently being recovered through the fuel or oil backout charges in the calculation of a capacity recovery factor for contracts entered into since the utility's last rate case. Purchased power demand costs currently being recovered in base rates are to remain in base rates until the utility's next general rate case.

We will not allow utilities to recover capacity costs of contracts that are embedded in base rates through the capacity clause. The process is complicated, and it could lead to inequities. While we agreed in Order No. 25773 that there might be other costs appropriate for inclusion in the clause, we determined that the proper time to address their inclusion would be in the context of individual utility rate proceedings. We said on page 7 of the order:

> We recognize that our present decision to implement a change in the manner in which electric utilities recover the demand related portions of purchased capacity costs is only a first step to the full development of a capacity recovery factor. It is a relatively straightforward process to change allocation factors for costs already recovered through some type of fuel charge, or to include costs not recovered elsewhere. Determining the base rate costs which may be appropriate for recovery through such a charge, however, is more complicated. Each utility, by virtue of its operations and procedure, may have additional costs which could reasonably be removed from rate base and placed in a capacity recovery factor, but these costs should be considered on an individual basis, in the context of a specific rate case.

Gulf's request to recover its IIC contract costs through the capacity clause is inconsistent with our intent to exclude recovery of capacity costs associated with contracts previously considered in base rates and it expands the scope of the decision we made in the generic capacity cost recovery docket. Gulf's IIC contact dates from the 1940s, as witness Howell testified. A projection was made for the net of Gulf's costs and revenues under the IIC contract in Gulf's last rate case. The IIC contract is thus embedded in base rates, and costs and revenues associated with it are not appropriate for inclusion in the capacity clause at this time.

Gulf contends that it is appropriate to include in the capacity cost recovery factor those costs that are incurred under a contract that was considered in setting base rates, because the actual operation of the contract resulted in a net cost to the company, rather than the net revenue the company projected. Gulf's request to recover the capacity costs of the IIC contract is basically an effort to true up the incorrect projection they made in their last rate case. The appropriate place to do that is in Gulf's next rate proceeding.

Although Gulf maintains that the requested recovery does not conflict with Order No. 25773's prohibition against including any amounts considered in setting base rates, Gulf proposes an adjustment to base revenues to account for the dollars it wishes to recover through the capacity cost recovery clause. This adjustment would be made each six-month period until Gulf's next rate case. In calculating the amount to be recovered and accounting for the adjustment, Gulf has included not only IIC purchases since the last rate case, but also the revenue from other capacity sales that were projected and included in setting base rates but not received. This is the type of adjustment we do not want to make outside of a rate case. We do not intend to use the capacity cost recovery clause to true-up projected rate case expenses. The remedy available to Gulf, or any other utility, when actual expenses exceed rate case projections is to file a rate case. We find that the capacity costs associated with Gulf's IIC contract are not appropriate for inclusion in the capacity cost recovery clause at this time.

We find that the revenues resulting from Gulf's Long-Term Non-Firm Contract with Florida Power Corporation are appropriate for inclusion in the capacity cost recovery clause at this time. Gulf's Long-Term Non-firm Schedule E contract with Florida Power was entered into subsequent to Gulf's last rate case, and the capacity revenues associated with it are not reflected in Gulf's base rates. These contract revenues are therefore appropriate for inclusion in the capacity cost recovery clause beginning in October of 1992.

Gulf agrees that the projected capacity revenues associated with its long-term non-firm Schedule E contract with Florida Power Corporation should be included in the CCRC for the period beginning in October of 1992. The contract was entered into in 1990, and witness McMillan has testified that it was not included in the setting of base rates in Gulf's last rate case. (TR 407) The revenues from the contract are not reflected in Gulf's fuel factor either. Florida Power Corporation is including the capacity costs it is paying to Gulf under this contract for recovery in its CCRC. Gulf contends, however, that the inclusion of the non-firm schedule E contract revenues should be conditioned upon our approval of their proposal to include their IIC contract costs for recovery in October 1992 as well. Gulf states that it is inequitable to require it to credit revenues which it receives under the contract if there are no costs with which to offset the revenues.

The revenues associated with the contract with Florida Power Corporation are appropriate for inclusion in the capacity cost recovery factor at this time, because they meet both criteria set out in Order No. 25773. They are associated with a contract entered into since the last rate case and they are not being recovered in any manner. Order No. 25773 does not indicate that revenues should be excluded from the calculation of the capacity factor because there are no costs against which to net them. The treatment of capacity revenues is not tied to the treatment of capacity costs, except to the extent that the two, if they were appropriately included in the calculation of the capacity factor, would be netted against each other.

At the hearing Gulf raised this issue:

> If the Commission determines that it is appropriate for Gulf to recover the costs associated with its IIC through a capacity cost recovery clause, beginning October 1992, has Gulf made an appropriate adjustment to the total projected net purchased power capacity costs to account for the component of expected base rate revenues during the subject recovery period associated with the level of purchased power capacity costs/revenues included in present base rates?

Since we have found that it is not appropriate for Gulf to recover the capacity costs associated with its IIC contract through the new capacity cost recovery clause, it is not necessary that we answer this question. We will answer the question, though, because it demonstrates why we have been reluctant to include the costs of capacity contracts that are embedded in base rates. The answer to Gulf's question is no, the adjustment is inappropriate because the methodology Gulf used will not result in a true reflection of the amount of base rate revenues for the projection period that are attributable to purchased power capacity costs/revenues.

Gulf's methodology assumes that the amount of base rate revenues attributable to the net capacity revenues varies only with the kwh for the period, when in fact, for Gulf's demand classes, the revenues are also related to the billing demand (kw) for the period. Gulf's methodology therefore does not result in a true reflection of the base rate revenues attributable to the net capacity revenues, and underscores the inappropriateness of recovering through the capacity clause the costs of purchased capacity contracts embedded in base rates.

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 October, 1992 through March, 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 October, 1992 through March, 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 October, 1992 through March, 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 utilties are hereby authorized to apply the capacity cost recovery factors set forth herein during the period of October, 1992 through March, 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 17th day of SEPTEMBER, 1992.

STEVE TRIBBLE, Director
Division of Records and Reporting

by: Kay Flynn
Chief, Bureau of Records

(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.

TOTAL FUEL COST FOR THE PERIOD: October 1992 – March 1993

Note: FPC factors will become effective concurrent with any base rate change resulting from their rate case, Docket No. 910890–EI.

COMPANY	PROPOSED October 1992 – March 1993 Cents per kwh Levelized	On/Peak	Off/Peak	PRESENT April – September 1992 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)	1.709	1.848	1.654	1.822	1.998	1.737	−0.113	−0.150	−0.083	1.00145	1.711
Fla. Power Corp.	1.785	2.306	1.569	2.070	3.124	1.526	−0.285	−0.818	0.043	1.00270	1.790
Tampa Electric	2.358	2.584	2.281	2.663	3.133	2.517	−0.305	−0.549	−0.236	1.01470	2.393
Gulf Power	2.301	2.380	2.274	2.185	2.392	2.088	0.116	−0.012	0.186	1.01228	2.329
Fla. Public											
Marianna (1)	4.796	NA	NA	4.827	NA	NA	−0.031	NA	NA	1.01260	4.857
Fernandina (1)(2)	5.305	NA	NA	5.916	NA	NA	−0.611	NA	NA	1.00000	5.305

COST FOR 1,000 KWH RESIDENTIAL SERVICE

PRESENT: April – September 1992

	Fla. Power & Light	Fla. Power Corp. (5) (6)	Tampa Electric	Gulf Power (7)	Florida Public Utilities Marianna	Fernandina
Base	47.38	46.50	50.34	43.25	17.22	19.20
Fuel (3)	18.24	20.79	27.02	22.12	48.88	59.16
Oil Backout	−0.15	NA	1.06	NA	NA	NA
Energy Conservation	1.35	2.63	1.30	0.19	0.10	0.06
Capacity Recovery	5.90	NA	NA	NA	NA	NA
Gross Receipts Tax (4)	0.75	0.72	0.82	0.67	0.68	0.80
Total	$73.47	$70.64	$80.54	$66.23	$66.88	$79.22

PROPOSED: October 1992 – March 1993

	Fla. Power & Light	Fla. Power Corp.	Tampa Electric	Gulf Power	Florida Public Utilities Marianna	Fernandina
Base	47.38	46.50	50.34	43.25	17.22	19.20
Fuel (3)	17.11	17.90	23.93	23.29	48.57	53.05
Oil Backout	0.17	NA	0.98	NA	NA	NA
Energy Conservation	1.59	3.52	1.36	0.32	0.08	0.09
Capacity Recovery	8.53	1.91	0.55	−0.30	NA	NA
Gross Receipts Tax (4)	0.77	0.72	0.79	0.68	0.68	0.74
Total	$75.55	$70.55	$77.95	$67.24	$66.55	$73.08

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)	−1.13	−2.89	−3.09	1.17	−0.31	−6.11
Oil Backout	0.32	NA	−0.08	NA	NA	NA
Energy Conservation	0.24	0.89	0.06	0.13	−0.02	0.03
Capacity Recovery	2.63	1.91	0.55	−0.30	NA	NA
Gross Receipts Tax (4)	0.02	0.00	−0.03	0.01	0.00	−0.06
Total	2.08	−0.09	−2.59	1.01	−0.33	−6.14

(1) Fuel costs include purchased power demand costs of 2.024 for Marianna and 0.872 cents/KWH for Fernandina allocated to the residential class.
(2) All classes except GSLD. (3) Adjusted for line loss. (4) Additional gross receipts tax of 1%. Effective July 1, 1992, tax increased by .25%.
(5) Present FPC fuel rates reflect mid–course correction effective April 23, 1992. (6) FPC base rates reflect interim rate increase of 3.42% effective April 23, 1992.
(7) Gulf base rates reflect expiration of management penalty on September 13, 1992.

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

DIVISION OF ELECTRIC AND GAS
DATE: 8/5/92

FOR THE PERIOD: October 1992 - March 1993 *

			WITHOUT LINE LOSS MULTIPLIER				WITH LINE LOSS MULTIPLIER		
COMPANY	GROUP	RATE SCHEDULES	Levelized	* On/Peak	Off/Peak	LINE LOSS MULTIPLIER	Levelized	On/Peak	Off/Peak
FP&L	A	RS-1,RST-1,GST-1,GS-1,SL-2	1.709	1.848	1.654	1.00145	1.711	1.851	1.656
	A-1	SL-1,OL-1	1.685	NA	NA	1.00145	1.687	NA	NA
	B	GSD-1,GSDT-1	1.709	1.848	1.654	1.00139	1.711	1.851	1.656
	C	GSLD-1,GSLDT-1,CS-1,CST-1	1.709	1.848	1.654	1.00044	1.710	1.849	1.655
	D	GSLD-2,GSLDT-2,CS-2,CST-2,OS-2,MET	1.709	1.848	1.654	0.99566	1.701	1.840	1.647
	E	GSLD-3,CS-3,GSLDT-3,CST-3,CILC-1(T),ISST-1(T)	1.709	1.848	1.654	0.96726	1.653	1.788	1.600
	F	CILC-1(D),ISST-1(D)		1.848	1.654	0.99415		1.838	1.644
FPC *	A	Distribution Secondary Delivery	1.785	2.306	1.569	1.00270	1.790	2.312	1.573
	A-1	OL-1,SL-1	1.706	NA	NA	1.00270	1.711	NA	NA
	B	Distribution Primary Delivery	1.785	2.306	1.569	0.98880	1.765	2.280	1.551
	C	Transmission Delivery	1.785	2.306	1.569	0.97860	1.747	2.257	1.535
TECO	A	RS,GS,TS	2.358	2.584	2.281	1.01470	2.393	2.622	2.315
	A-1	SL-1,2,3,OL-1,2	2.327	NA	NA	1.01470	2.361	NA	NA
	B	GSD,GSLD	2.358	2.584	2.281	0.99750	2.352	2.578	2.275
	C	IS-1,IS-3	2.358	2.584	2.281	0.96860	2.284	2.503	2.209
GULF	A	RS,GS,GSD,OS-III,OS-IV	2.301	2.380	2.274	1.01228	2.329	2.409	2.302
	B	LP	2.301	2.380	2.274	0.98106	2.257	2.335	2.231
	C	PX	2.301	2.380	2.274	0.96230	2.214	2.290	2.188
	D	OS-1,OS-2	2.298	NA	NA	1.01228	2.326	NA	NA
FPUC									
Fernandina	A	RS	5.544	NA	NA	1.00000	5.544	NA	NA
	B	GS	5.329	NA	NA	1.00000	5.329	NA	NA
	C	GSD	5.189	NA	NA	1.00000	5.189	NA	NA
	D	OL, OL-2, SL-2, SL-3, CSL	4.746	NA	NA	1.00000	4.746	NA	NA
	E	GSLD					4.573 (1) $4.69/CP KW		
Marianna	A	RS	4.796	NA	NA	1.01260	4.857	NA	NA
	B	GS	4.540	NA	NA	0.99630	4.523	NA	NA
	C	GSD	4.115	NA	NA	0.99630	4.100	NA	NA
	D	OL, OL-2	2.772	NA	NA	1.01260	2.807	NA	NA
	E	SL-1, SL-2	2.772	NA	NA	0.98810	2.739	NA	NA

* Effective date for FPC will coincide with rate change, if any, resulting from rate case, Docket No. 910890-EI. Effective date is expected to be early November, 1992.

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

PROPOSED CAPACITY RECOVERY FACTORS
For the Period: October 1992 – March 1993 *

DIVISION OF ELECTRIC AND GAS
DATE: 8/5/92
PAGE 3 of 10

COMPANY	RATE SCHEDULE	RECOVERY FACTOR (CENTS PER KWH)
FPL	RS1	0.8530
	GS1	0.7960
	GSD1	0.7280
	OS2	0.7050
	GSLD1/CS1	0.7420
	GSLD2/CS2	0.6130
	GSLD3/CS3	0.5800
	ISST1D	0.5050
	SST1T	0.4590
	SST1D	0.4690
	CILCD	0.5100
	CILCT	0.4700
	MET	0.6510
	OL1/SL1	0.3930
	SL2	0.5400
FPC *	RS	0.1911
	GS – Transmission	0.1298
	GS – Primary	0.1315
	GS – Secondary	0.1338
	GS – 100% Load Factor	0.1008
	GSD – Transmission	0.0925
	GSD – Primary	0.1160
	GSD – Secondary	0.1181
	CS – Curtailable	0.0912
	IS – Transmission	0.0958
	IS – Primary	0.0971
	LS – Lighting Service	0.0378
TECO	RS	0.0550
	GS,TS	0.0510
	GSD	0.0480
	GSLD,SBF	0.0460
	IS – 1 & 3,SBI – 1 & 3	0.0340
	SL/OL	0.0370
GULF	RS,RST	−0.0300
	GS,GST	0.0290
	GSD,GSDT	−0.0220
	LP,LPT	−0.0200
	PX,PXT	−0.0160
	OS – I,OS – II	−0.0030
	OS – III	−0.0180
	OS – IV	−0.0020
	SS	−0.0160

* FPC effective date will coincide with rate change resulting from rate case, Docket No. 910890 – EI in early November, 1992.

FUEL & PURCHASED POWER COST RECOVERY
CLAUSE CALCULATION

DIVISION OF ELECTRIC AND GAS
DATE: 8/12/92
PAGE 4 OF 10

ESTIMATED FOR THE PERIOD: October 1992 – March 1993

FLORIDA POWER & LIGHT COMPANY

CLASSIFICATION	Classification Associated $	Classification Associated KWH	Classification Associated Cents/KWH
1.Fuel Cost of System Net Generation (E3)	356,646,944	22,877,532,000	1.55894
2.Spent NUC Fuel Disposal Cost (E2)	3,766,000	10,813,910,000 (a)	0.03483
3.Coal Car Investment	190,907	0	0.00000
4. Natural Gas Pipeline Enhancements	696,432	0	0.00000
4a. Fuel Cost of Sales to FKEC	(5,722,588)	(253,120,000)	2.26082
5.TOTAL COST OF GENERATED POWER	355,577,695	22,624,412,000	1.57165
6.Fuel Cost of Purchased Power – Firm (E8)	185,547,800	9,864,900,000	1.88089
7.Energy Cost of Sch.C,X Economy Purchases (Broker) (E9)	23,036,300	1,168,000,000	1.97229
8.Energy Cost of Economy Purchases (Non–Broker) (E9)	13,975,300	648,700,000	2.15435
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)	20,034,200	1,048,500,000	1.91075
12.TOTAL COST OF PURCHASED POWER	242,593,600	12,730,100,000	1.90567
13.TOTAL AVAILABLE KWH		35,354,512,000	
14.Fuel Cost of Economy Sales (E7)	(3,941,200)	(146,000,000)	2.69945
15.Gain on Economy Sales – 80% (E7A)	(1,406,720)	(146,000,000)(a)	0.96351
16.Fuel Cost of Unit Power Sales (SL2 Partpts) (E7)	(1,623,800)	(242,000,000)	0.67099
17.Fuel Cost of Other Power Sales (E7)	(2,588,500)	(91,000,000)	2.84451
18.TOTAL FUEL COST AND GAINS OF POWER SALES	(9,560,220)	(479,000,000)	1.99587
19.Net Inadvertant Interchange (E4)	0	0	0.00000
20.TOTAL FUEL AND NET POWER TRANSACTIONS	588,611,075	34,875,512,000	1.68775
21.Net Unbilled (E4)	16,049,783 (a)	950,958,000	0.04840
22.Company Use (E4)	1,778,651 (a)	105,386,000	0.00536
23.T & D Losses (E4)	43,161,883 (a)	2,557,364,000	0.13015
24.Adjusted System KWH Sales	588,611,075	33,163,720,000	1.77486
25.Wholesale KWH Sales	1,120,480	63,130,000	1.77488
26.JURISDICTIONAL KWH SALES	587,490,595	33,100,590,000	1.77486
27.Jurisdictional KWH Sales Adjusted for Line Loss – 1.00034	587,690,342	33,100,590,000	1.77547
28.True–up * (derived in Attachment C)	(35,571,799)	33,100,590,000	–0.10747
29.TOTAL JURISDICTIONAL FUEL COST	552,118,543	33,100,590,000	1.66800
30.Revenue Tax Factor			1.01609
31.Fuel Cost Adjusted for Taxes			1.69480
32.GPIF*	4,627,514	33,100,590,000	0.01400
33.Total fuel cost including GPIF	556,746,057	33,100,590,000	1.70880
34.TOTAL FUEL COST FACTOR ROUNDED TO THE NEAREST .001 CENTS PER KWH:			1.709

*Based on Jurisdictional Sales

(a) included for informational purposes only.

FUEL & PURCHASED POWER COST RECOVERY CLAUSE CALCULATION

DIVISION OF EL8/12/92
DATE: 8/5/92
PAGE 5 OF 10

ESTIMATED FOR THE PERIOD: October 1992–March 1993

FLORIDA POWER CORPORATION

CLASSIFICATION	Classification Associated $	Classification Associated KWH	Classification Associated cents/KWH
1.Fuel Cost of System Net Generation (E3)	207,944,093	12,053,585,000	1.72516
2.Spent NUC Fuel Disposal Cost (E3A)	2,747,385	2,747,385,000 (a)	0.10000
3.Coal Car Investment	0	0	0.00000
4.Adjustments to Fuel Cost	0	0	0.00000
5.TOTAL COST OF GENERATED POWER	210,691,478	12,053,585,000	1.74796
6.Energy Cost of Purchased Power – Firm (E8)	193,305	2,450,000	7.89000
7.Energy Cost of Sch.C,X Economy Purchases (Broker) (E9)	10,989,200	390,000,000	2.81774
8.Energy Cost of Economy Purchases (Non–Broker) (E9)	1,298,137	42,644,000	3.04413
9.Energy Cost of Sch.E Purchases (E9)	20,391,594	960,509,000	2.12300
10.Capacity Cost of Sch.E Economy Purchases (E9)	0	0 (a)	0.00000
11.Payments to Qualifying Facilities (E8A)	13,934,330	600,673,000	2.31979
12.TOTAL COST OF PURCHASED POWER	46,806,566	1,996,276,000	2.34469
13.TOTAL AVAILABLE KWH		14,049,861,000	
14.Fuel Cost of Economy Sales (E7)	(10,562,850)	(520,000,000)	2.03132
14a.Gain on Economy Sales –80% (E7A)	(976,800)	(520,000,000)(a)	0.18785
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)	(8,523,600)	(321,792,000)	2.64879
18.TOTAL FUEL COST AND GAINS OF POWER SALES	(20,063,250)	(841,792,000)	2.38340
19.Net Inadvertant Interchange (E4)	0	0	
20.TOTAL FUEL AND NET POWER TRANSACTIONS	237,434,794	13,208,069,000	1.79765
21.Net Unbilled (E4)	(6,289,695)(a)	349,894,000	–0.04918
22.Company Use (E4)	1,644,804 (a)	(91,500,000)	0.01286
23.T & D Losses (E4)	12,183,773 (a)	(677,780,000)	0.09527
24.Adjusted System KWH Sales	237,434,794	12,788,683,000	1.85660
25.Wholesale KWH Sales(Excluding Seminole Supplemental)	(9,342,560)	(501,933,000)	1.86132
26.JURISDICTIONAL KWH SALES	228,092,234	12,286,750,000	1.85641
27.Jurisdictional KWH Sales Adjusted for Line Loss – 1.0012	228,365,945	12,286,750,000	1.85864
28.Prior Period True–Up *	(13,092,463)	12,286,750,000	–0.10656
28a. Miscellaneous True–Up	(522,083)	12,286,750,000	–0.00425
29.TOTAL JURISDICTIONAL FUEL COST	214,751,399	12,286,750,000	1.74783
30.Revenue Tax Factor			1.01609
31.Fuel Cost Adjusted for Taxes			1.77600
32.GPIF*	1,061,794	12,286,750,000	0.00860
33.Total fuel cost including GPIF	215,813,193	12,286,750,000	1.78460
34.TOTAL FUEL COST FACTOR ROUNDED TO THE NEAREST .001 CENTS PER KWH:			1.785

*Based on Jurisdictional Sales

(a) Included for informational purposes only.

Effective date for billing purposes: November, 1992

FUEL & PURCHASED POWER COST RECOVERY CLAUSE CALCULATION

DIVISION OF EL8/12/92
DATE: 8/5/92
PAGE 6 OF 10

ESTIMATED FOR THE PERIOD: October 1992 - March 1993

TAMPA ELECTRIC COMPANY

CLASSIFICATION	Classification Associated $	Classification Associated KWH	Classification Associated cents/KWH
1.Fuel Cost of System Net Generation (E3)	178,997,863	7,805,907,000	2.29311
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	178,997,863	7,805,907,000	2.29311
6.Fuel Cost of Purchased Power - Firm (E8)	994,900	23,186,000	4.29095
7.Energy Cost of Sch.C,X Economy Purchases (Broker) (E9)	599,100	14,024,000	4.27196
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)	3,580,600	189,550,000	1.88900
12.TOTAL COST OF PURCHASED POWER	5,174,600	226,760,000	2.28197
13.TOTAL AVAILABLE KWH		8,032,667,000	
14.Fuel Cost of Economy Sales (E7)	12,668,400	655,842,000	1.93162
15.Gain on Economy Sales - 80% (E7A)	1,902,800	655,842,000 (a)	0.29013
16.Fuel Cost of Scedule D Sales (E7)	4,172,100	279,682,000	1.49173
16a.Fuel Cost of Schedule G Sales (E7)	1,116,200	52,512,000	2.12561
17.Fuel Cost Schedule J Sales (E7)	6,271,600	314,903,000	1.99160
17a.Fuel Cost Schedule D TPS Sales (E7)	811,700	37,704,000	2.15282
18.TOTAL FUEL COST AND GAINS OF POWER SALES	26,942,800	1,340,643,000	2.00969
19.Net Inadvertant Interchange (E4)	0	0	
19b.Interchange and Wheeling Losses	0	21,072,000	
20.TOTAL FUEL AND NET POWER TRANSACTIONS	157,229,663	6,670,952,000	2.35693
21.Net Unbilled (E4)	(3,481,869)(a)	(147,729,000)	-0.05378
22.Company Use (E4)	381,823 (a)	16,200,000	0.00590
23.T & D Losses (E4)	7,733,747 (a)	328,128,000	0.11945
24.Adjusted System KWH Sales	157,229,663	6,474,353,000	2.42850
25.Wholesale KWH Sales	(2,063,444)	(84,835,000)	2.43230
26.JURISDICTIONAL KWH SALES	155,166,219	6,389,518,000	2.42845
27.Jurisdictional KWH Sales Adjusted for Line Loss - 1.00005	155,243,802	6,389,518,000	2.42966
28.True-up * (derived in Attachment C)	(7,388,719)	6,389,518,000	-0.11564
29.Pyramid Coal Contract Buyout Adjustment	0	6,389,518,000	0.00000
30.TOTAL JURISDICTIONAL FUEL COST	147,855,083	6,389,518,000	2.31403
31.Revenue Tax Factor			1.01609
32.Fuel Cost Adjusted for Taxes	150,234,071		2.35126
33.GPIF * (Already adjusted for taxes)	403,442	6,389,518,000	0.00631
34.Total Fuel Cost including GPIF	150,637,513	6,389,518,000	2.35757
35.TOTAL FUEL COST FACTOR ROUNDED TO THE NEAREST .001 CENTS PER KWH:			2.358

*Based on Jurisdictional Sales

Effective date for billing purposes:

(a) Included for informational purposes only.

8/12/92

FUEL & PURCHASED POWER COST RECOVERY CLAUSE CALCULATION

DIVISION OF ELECTRIC AND GAS
DATE: 8/5/92
PAGE 7 OF 10

ESTIMATED FOR THE PERIOD: October 1992–March 1993

GULF POWER COMPANY

CLASSIFICATION	Classification Associated $	Classification Associated KWH	Classification Associated cents/KWH
1.Fuel Cost of System Net Generation (E3)	91,790,410	4,717,240,000	1.9458
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	91,790,410	4,717,240,000	1.9458
5.Fuel Cost of Purchased Power – Firm (E8)	0	0	0.0000
6.Energy Cost of Sch.C,X Economy Purchases (Broker) (E9)	8,732,361	443,663,000	1.9682
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	8,732,361	443,663,000	1.9682
12.TOTAL AVAILABLE KWH (line 4 + line 11)		5,160,903,000	
13.Fuel Cost of Economy Sales (E7)	(558,000)	(28,360,000)	1.9676
14.Gain on Economy Sales – 80% (E7A)	(68,000)	0 (a)	0.0000
15.Fuel Cost of Unit Power Sales (E7)	(8,211,000)	(399,620,000)	2.0547
16.Fuel Cost of Other Power Sales (E7)	(11,923,000)	(725,640,000)	1.6431
17.TOTAL FUEL COST AND GAINS OF POWER SALES	(20,760,000)	(1,153,620,000)	1.7996
18.Net Inadvertant Interchange (E4)	0		
19.TOTAL FUEL AND NET POWER TRANSACTIONS	79,762,771	4,007,283,000	1.9904
20.Net Unbilled (E4)	0	0	0.0000
21.Company Use (E4)	190,561 (a)	9,574,000	1.9904
22.T & D Losses (E4)	4,240,308 (a)	213,038,000	1.9904
23.Adjusted System KWH Sales	79,762,771	3,784,671,000	2.1075
24.Wholesale KWH Sales	2,829,003	134,235,000	2.1075
25.JURISDICTIONAL KWH SALES	76,933,768	3,650,436,000	2.1075
26.Jurisdictional KWH Sales Adjusted for Line Loss – 1.00140	77,041,476	3,650,436,000	2.1105
27.True–up *	4,328,154	3,650,436,000	0.1186
28.Total Jurisdictional Fuel Cost	81,369,630	3,650,436,000	2.2291
29.Revenue Tax Factor			1.01609
30.Fuel Cost Adjusted for Taxes			2.2650
31.Special Contract Recovery Cost	1,230,651	3,650,436,000	0.0337
32.GPIF *	87,028	3,650,436,000	0.0024
33.Total Fuel Cost including GPIF	81,456,658	3,650,436,000	2.3011
34.TOTAL FUEL COST FACTOR ROUNDED TO THE NEAREST .001 CENTS PER KWH:			2.301

*Based on Jurisdictional Sales
Effective date for billing purposes: September 29, 1992.

(a) included for informational purposes only.

8/12/92
DIVISION OF ELECTRIC AND GAS
DATE: 8/5/92
PAGE 8 OF 10

FUEL & PURCHASED POWER COST RECOVERY CLAUSE CALCULATION

ESTIMATED FOR THE PERIOD: October 1992 – March 1993

FLORIDA PUBLIC UTILITIES – MARIANNA

CLASSIFICATION	Classification Associated $	Classification Associated KWH	Classification Associated cents/KWH
1.Fuel Cost of System Net Generation (E3)	0	222,000	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	222,000	0.00000
6.Fuel Cost of Purchased Power – Firm (E8)	2,141,342	115,580,000	1.85269
7.Energy Cost of Sch.C,X Economy Purchases (Broker) (E9)	0	0	0.00000
8.Energy Cost of Economy Purchases (Non–Broker) (E9)	0	0	0.00000
9.Energy Cost of Sch.E Purchases (E9)	0	0	0.00000
10.Demand & Non Fuel Cost of Purchased Power (E2)	2,520,197	115,580,000 (a)	2.18048
10a.Demand Costs of Purchased Power	1,720,550 (a)		
10b.Non–Fuel Energy & Customer Costs of Purchased Power	799,647 (a)		
11.Energy Payments to Qualifying Facilities (E8A)	0	0	0.00000
12.TOTAL COST OF PURCHASED POWER	4,661,539	115,580,000	4.03317
13.TOTAL AVAILABLE KWH	4,661,539	115,802,000	4.02544
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	4,661,539	115,802,000	4.02544
21.Net Unbilled (E4)	34,981 (a)	869,000	0.03173
22.Company Use (E4)	2,133 (a)	53,000	0.00193
23.T & D Losses (E4)	186,458 (a)	4,632,000	0.16913
24.ADJUSTED SYSTEM KWH SALES	4,661,539	110,248,000	4.22823
25.Less Total Demand Cost Recovery	1,790,700		
26.JURISDICTIONAL KWH SALES	2,870,839	110,248,000	2.60398
27.Jurisdictional KWH Sales Adjusted for Line Loss – 1.00	2,870,839	110,248,000	2.60398
28.True–up *	136,751	110,248,000	0.12404
29.TOTAL JURISDICTIONAL FUEL COST	3,007,590	110,248,000	2.72802
30.Revenue Tax Factor			1.01609
31.Fuel Cost Adjusted for Taxes	3,499,562	0	2.77192
32.GPIF *	0	110,248,000	0.00000
33.Total Fuel Cost including GPIF	3,007,590	110,248,000	2.77192
34.TOTAL FUEL COST FACTOR ROUNDED TO THE NEAREST .001 CENTS PER KWH:			2.772

*Based on Jurisdictional Sales

(a) included for informational purposes only

8/12/92

FUEL & PURCHASED POWER COST RECOVERY CLAUSE CALCULATION

DIVISION OF ELECTRIC AND GAS
DATE: 8/5/92
PAGE 9 OF 10

ESTIMATED FOR THE PERIOD: October 1992–March 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)	5,175,417	134,252,000	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	2,170,451	134,252,000	1.61670
10a.Demand Costs of Purchased Power (E2)	1,454,500 (a)		
10b.Non Fuel Energy and Customer Costs of Purchased Power (E2)	715,951 (a)		
11.Energy Payments to Qualifying Facilities (E8A)	187,680	4,800,000	3.91000
12.TOTAL COST OF PURCHASED POWER	7,533,548	139,052,000	5.41779
13.TOTAL AVAILABLE KWH	7,533,548	139,052,000	5.41779
14.Fuel Cost of Economy Sales (E7)	0	0	0.00000
15.Gain on Economy Sales – 80% (E7A)	0	0	0.00000
16.Fuel Cost of Unit Power Sales (E7)	0	0	0.00000
17.Fuel Cost of Other Power Sales (E7)	0	0	0.00000
18.TOTAL FUEL COST AND GAINS OF POWER SALES	0	0	0.00000
19.Net Inadvertant Interchange (E4)			
20.TOTAL FUEL AND NET POWER TRANSACTIONS	7,533,548	139,052,000	5.41779
21.Net Unbilled (E4)	(102,830)(a)	(1,922,000)	–0.07761
22.Company Use (E4)	7,151 (a)	132,000	0.00540
23.T & D Losses (E4)	452,060 (a)	8,344,000	0.34118
24.Adjusted System KWH Sales	7,533,548	132,498,000	5.68578
25.Wholesale KWH Sales	0	0	0.00000
26.JURISDICTIONAL KWH SALES	7,533,548	132,498,000	5.68578
27.Jurisdictional KWH Sales Adjusted for Line Loss – 1.00	7,533,548	132,498,000	5.68578
27a.GSLD KWH Sales (E11)		37,200,000	
27b.Other Classes KWH Sales (E11)		95,298,000	
27c.GSLD CP KW		108,000 (a)	
28. GPIF			
29.True–up *	(289,929)	132,498,000	–0.21882
30.TOTAL JURISDICTIONAL FUEL COST	7,243,619	132,498,000	5.46696

8/12/92

FUEL & PURCHASED POWER COST RECOVERY CLAUSE CALCULATION

DIVISION OF ELECTRIC AND GAS
DATE: 8/5/92
PAGE 10 OF 10

ESTIMATED FOR THE PERIOD: October 1992 – March 1993

FLORIDA PUBLIC UTILITIES – FERNANDINA

CLASSIFICATION	Classification Associated $	Classification Associated KWH	Classification Associated cents/KWH
30a.Demand Purchased Power Costs (line 10a)	1,454,500 (a)		
30b.Non – Demand Purchased Power Costs (lines 6 + 10b + 11)	6,079,048 (a)		
30c.True – up Over/Under Recovery (line 29)	(289,929)(a)		
APPORTIONMENT OF DEMAND COSTS			
31.Total Demand Costs	1,454,500		
32.GSLD Portion of Demand Costs Including line losses (line 27c * $4.6865)	506,142	108,000 KW	$4.69/KW
33.Balance to Other Customers	948,358	95,298,000	0.99515
APPORTIONMENT OF NON – DEMAND COSTS			
34.Total Non – Demand Costs (line 30b)	6,079,048		
35.Total KWH Purchased (line 12)		139,052,000	
36.Average Cost per KWH Purchased			4.37178
37.Avg. Cost Adjusted for Transmission line losses (line 36 * 1.03)			4.50293
38.GSLD Non – Demand Costs (line 27a * line 37)	1,674,281	37,200,000	0.04501
39.Balance to Other Customers	4,404,767	95,298,000	4.62210
GSLD PURCHASED POWER COST RECOVERY FACTORS			
40a.Total GSLD Demand Costs (Line 32)	506,142	108,000	$4.69
40b.Revenue Tax Factor			1.01609
40c.GSLD Demand Purchased Power factor adjusted for taxes and rounded:			$4.77
40d.Total Current GSLD Non – Demand Costs (line 38)	1,674,281	37,200,000	4.50076
40e.Total Non – Demand Costs including true – up	1,674,281	37,200,000	4.50076
40f.Revenue Tax Factor			1.01609
40g.GSLD Non – demand costs adjusted for taxes			4.573
OTHER CLASSES PURCHASED POWER COST RECOVERY FACTORS			
41a.Total Demand and Non – Demand Purchased Power Costs of other classes (lines 33 + 39)	5,353,125	95,298,000	5.61725
41b.Less: Total Demand Cost Recovery	905,443 (a)		
41c.Total Other Costs to be Recovered	4,447,682 (a)	95,298,000	4.66713
41d.Other Classes' Portion of True – up (line 30 C)	(289,929)	95,298,000	– 0.30423
41e.Total Demand and Non – Demand Costs including True – up	4,157,753	95,298,000	4.36290
42.Revenue tax factor			1.01609
			4.43310
43.OTHER CLASSES PURCHASED POWER FACTOR ADJUSTED FOR TAXES ROUNDED TO THE NEAREST .001 CENTS PER KWH:			**4.433**

*Based on Jurisdictional Sales

(a) included for informational purposes only.

APPENDIX B

GPIF REWARDS/PENALTIES
October 1991 to March 1992

14-Sep-92

Florida Power Corporation	$1,061,794	Reward
Florida Power and Light Company	$4,627,514	Reward
Gulf Power Company	$87,028	Reward
Tampa Electric Company	$403,442	Reward

Utility/ Plant/Unit	EAF		Heat Rate	
FPC	Target	Adj. Actual	Target	Adj. Actual
Anclote 1	75.2	84.9	10,148	10,176
Anclote 2	66.5	68.6	10,311	10,033
Crystal River 1	71.6	71.6	10,003	9,978
Crystal River 2	65.5	76.2	9,990	9,934
Crystal River 3	62.0	66.7	10,390	10,388
Crystal River 4	96.6	94.7	9,254	9,225
Crystal River 5	80.8	81.3	9,299	9,253
FPL	Target	Adj. Actual	Target	Adj. Actual
Cape Canaveral 1	59.2	61.5	9,467	9,604
Cape Canaveral 2	81.0	81.0	9,405	9,064
Fort Myers 1	91.1	96.5	10,129	10,046
Fort Myers 2	53.8	59.6	9,480	9,333
Manatee 1	77.0	70.3	9,715	9,632
Manatee 2	72.1	74.7	9,718	9,633
Martin 1	94.7	86.6	9,779	9,607
Martin 2	71.0	75.0	9,712	9,857
Port Everglades 1	70.1	75.2	9,736	9,737
Port Everglades 2	78.5	77.6	9,585	9,555
Port Everglades 3	63.7	71.8	9,276	9,192
Port Everglades 4	82.9	89.4	9,443	9,358
Turkey Point 1	89.1	97.1	9,319	9,349
Turkey Point 2	65.7	57.2	9,401	9,506
Turkey Point 3	77.4	89.0	11,047	10,896
Turkey Point 4	60.0	69.2	10,963	10,951
St. Lucie 1	54.4	64.2	10,689	10,666
St. Lucie 2	90.0	97.9	10,740	10,663
GULF	Target	Adj. Actual	Target	Adj. Actual
Crist 6	85.0	89.2	10,384	10,373
Crist 7	76.5	76.2	10,207	10,095
Smith 1	88.2	92.0	10,280	10,269
Smith 2	89.0	90.6	10,240	10,243
Daniel 1	64.9	57.4	10,393	10,211
Daniel 2	71.3	70.1	10,731	10,312

GPIF REWARDS/PENALTIES
October 1991 to March 1992

Utility/ Plant/Unit	EAF		Heat Rate	
TECO	Target	Adj. Actual	Target	Adj. Actual
Big Bend 1	78.0	89.3	9,901	9,863
Big Bend 2	57.4	63.6	9,866	10,013
Big Bend 3	75.3	79.0	9,567	9,499
Big Bend 4	70.0	68.0	9,938	9,995
Gannon 5	83.7	84.6	10,003	9,928
Gannon 6	75.3	71.6	10,187	10,020

GPIF TARGETS
October 1992 to March 1993

Utility/ Plant/Unit	Equivalent Availability Company			Equivalent Availability Staff	Heat Rate Company	Heat Rate Staff
FPC	EAF	POF	EUOF			
Anclote 1	95.4	0.0	4.7	Agree	10,111	Agree
Anclote 2	82.7	11.5	5.8	Agree	9,971	Agree
Crystal River 1	72.3	15.4	12.3	Agree	9,938	Agree
Crystal River 2	69.6	15.4	15.0	Agree	9,964	Agree
Crystal River 3	80.0	0.0	20.0	Agree	10,534	Agree
Crystal River 4	93.6	2.8	3.7	Agree	9,255	Agree
Crystal River 5	61.5	35.7	2.7	Agree	9,321	Agree
FPL	EAF	POF	EUOF			
Cape Canaveral 1	48.0	48.9	3.1	Agree	9,676	Agree
Cape Canaveral 2	93.5	0.0	6.5	Agree	8,996	Agree
Ft. Myers 1	79.7	16.5	3.8	Agree	10,050	Agree
Ft. Myers 2	97.0	0.0	3.0	Agree	9,456	Agree
Manatee 1	82.3	0.0	17.7	Agree	9,597	Agree
Manatee 2	76.4	18.1	5.5	Agree	9,464	Agree
Martin 2	96.1	0.0	3.9	Agree	9,946	Agree
Port Everglades 2	73.3	20.3	6.4	Agree	9,622	Agree
Port Everglades 3	93.1	0.0	6.9	Agree	9,329	Agree
Port Everglades 4	93.9	0.0	6.1	Agree	9,293	Agree
Riviera 3	65.8	25.8	8.4	Agree	9,500	Agree
Turkey Point 2	86.0	0.0	14.0	Agree	9,303	Agree
Turkey Point 3	79.1	14.3	6.6	Agree	10,943	Agree
Turkey Point 4	69.2	17.6	13.2	Agree	10,965	Agree
St. Lucie 1	88.3	2.8	8.9	Agree	10,718	Agree
St. Lucie 2	93.6	0.0	6.4	Agree	10,702	Agree
GULF	EAF	POF	EUOF			
Crist 6	81.1	9.9	9.0	Agree	10,372	Agree
Crist 7	69.2	11.5	19.3	Agree	10,040	Agree
Smith 1	87.8	4.9	7.2	Agree	10,329	Agree
Smith 2	62.7	34.6	2.7	Agree	10,325	Agree
Daniel 1	76.6	20.3	3.0	Agree	10,272	Agree
Daniel 2	77.7	20.3	2.0	Agree	10,247	Agree
TECO	EAF	POF	EUOF			
Big Bend 1	80.0	4.9	15.1	Agree	9,862	Agree
Big Bend 2	81.0	3.8	15.2	Agree	9,819	Agree
Big Bend 3	69.7	19.2	11.1	Agree	9,622	Agree
Big Bend 4	84.4	3.8	11.8	Agree	9,939	Agree
Gannon 5	83.1	2.7	14.2	Agree	10,259	Agree
Gannon 6	56.5	30.8	12.7	Agree	10,252	Agree