BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In Re: Fuel and Purchased Power Cost Recovery Clause and Generating Performance Incentive Factor.	DOCKET NO. 910001-EI ORDER NO. 25148 ISSUED: 10-1-91

The following Commissioners participated in the disposition of this matter:

THOMAS M. BEARD, Chairman
J. TERRY DEASON
BETTY EASLEY

ORDER APPROVING PROJECTED EXPENDITURES AND TRUE-UP AMOUNTS FOR FUEL ADJUSTMENT FACTORS; GPIF TARGETS, RANGES, AND REWARDS; AND PROJECTED EXPENDITURES AND TRUE-UP AMOUNTS FOR OIL BACKOUT 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 21-23, 1991. 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, cost recovery factors and related issues.

Fuel Adjustment Factors

We find that the appropriate final fuel adjustment true-up amounts for the period October, 1990 through March, 1991 are as follows:

FPC:	$8,313,700	overrecovery	
FPL:	$4,852,416	overrecovery	
FPUC:	$ 95,466	underrecovery	(Marianna)
	$ 152,324	overrecovery	(Fernandina Beach)
GULF:	$1,618,737	overrecovery	
TECO:	$5,902,169	underrecovery	

The estimated fuel adjustment true-up amounts for the period April, 1991 through September 1991 are as follows:

FPC:	$ 5,458,007	overrecovery	
FPL:	$ 8,930,318	underrecovery	
FPUC:	$ 80,045	underrecovery	(Marianna)
	$ 149,727	underrecovery	(Fernandina Beach)
GULF:	$ 351,045	underrecovery	
TECO:	$ 7,526,601	underrecovery	

The total fuel adjustment true-up amounts to be collected during the period October, 1991 through March, 1992 are as follows:

FPC:	$13,771,707	overrecovery.	
FPL:	$ 4,077,902	underrecovery.	
FPUC:	$ 175,511	underrecovery.	(Marianna)
	$ 2,597	overrecovery.	(Fernandina Beach)
GULF:	$ 1,267,692	overrecovery.	
TECO:	$13,428,770	underrecovery.	

Finally, the appropriate levelized fuel cost recovery factors for the period October, 1991 through March, 1992, before line loss adjustment, are as follows:

FPC: 2.256 cents per kwh for non-time differentiated rates.
2.891 cents per kwh for On-Peak periods.
2.009 cents per kwh for Off-Peak periods.

FPL: 2.093 cents per kwh for non-time differentiated rates.
2.270 cents per kwh for On-Peak periods.
2.024 cents per kwh for Off-Peak periods

($4,266,000 has been removed from FPL's fuel cost recovery charge, since it is included in FPL's new capacity cost recovery factor discussed below).

FPUC: 2.876 cents per kwh excluding demand related recovery. (Marianna)
5.288 cents per kwh excluding demand related recovery. (Fernandina Beach)

GULF:	2.056 cents per kwh for non-time differentiated rates. 2.161 cents per kwh for On-Peak periods. 2.019 cents per kwh for Off-Peak periods.
TECO:	2.698 cents per kwh for non-time differentiated rates. 3.116 cents per kwh for On-Peak periods. 2.569 cents per kwh for Off-Peak periods.

The above factors should be effective beginning with the specified fuel cycle and thereafter for the period October, 1991 through March, 1992. Billing cycles may start before October 1, 1991, and the last cycle may be read after March 31, 1992, 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, which 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 & Light Company

1. Independent observation of Ashland and Shamrock Belt Scale Certification.

Staff's fuel adjustment audit Disclosure No. 2 for FPL pointed out that the CSX railroad scale personnel certify the scales for the Ashland and Shamrock coal suppliers as well as the scales at St. Johns River Power Park. The railroad also bases its charges on these same scales. While CSX administers the certification process, the actual scale adjustments are made either by a scale technician who is an employee of the scale manufacturer, or by an independent consultant such as Weighing and Control Services, Inc. On the basis of the audit disclosure, our staff raised the issue of whether FPL should be required to employ a qualified independent person to observe the biannual certification of the scales at origin and destination to ensure that they are certified according to the requirements of Handbook 44 of the U.S. Bureau of Standards.

Our staff, the Office of Public Counsel and FPL all took the position that FPL would be required to employ qualified independent personnel to observe the biannual certification of the producers' belt scales at origin for the Ashland and Shamrock coal supplies. The independent observers would determine whether or not the certification was conducted according to the requirements of Handbook 44 of the U.S. Bureau of Standards. The accuracy of the SJRPP plant scales at destination will continue to be checked and verified to be "in tolerance" at least semi-annually. "In tolerance" means weighing within plus or minus 0.25% of the reference certified weight.

We approve this position. We find that the procedure sanctioned therein will assure FPL that the certification process is accomplished appropriately.

<u>2. FPL's $900,000 Refund to the Florida Municipal Power Authority</u>

At the hearing, our staff, FPL, and the Office of Public Counsel recommended, and we agreed, that the following issue would be deferred to the February 1992 Fuel Adjustment Hearing.

> <u>ISSUE:</u> Should FPL have refunded $900,000 to the Florida Municipal Power authority (FMPA) as a settlement related to billings to the FMPA in 1987 under the Nuclear Reliability Exchange Agreement (NREA)?

<u>3. FPL's Capacity Cost Recovery Factor</u>

At our July 2, 1991, Agenda Conference in Docket No. 910580-EQ, we authorized FPL to use a separate factor (Capacity Cost Recovery Factor) to recover the capacity portion of its purchased power costs, effective October 1, 1991. In our Order No. 24840 memorializing that decision we opened a generic docket (Docket No. 910794-EQ) to consider, on an industry-wide basis, all possible alternatives for allocating purchased capacity costs. We stated that we would further evaluate FPL's proposed method of recovering the capacity portion of its purchased power costs as a specific issue in this proceeding.

We have reviewed, and we approve, FPL's proposed new capacity cost recovery factor. We find that FPL's proposed method of allocating and recovering the capacity portion of its purchased power costs is reasonable and appropriate, and we are satisfied that the change will be communicated in such a way as to avoid customer confusion.

Specifically, we find that $199,586,026 in capacity costs should be removed from FPL's Oil-Backout calculation, and $4,266,000 in capacity costs should be removed from the Fuel Cost Recovery calculation. These costs should be recovered in the Capacity Cost Recovery Factor effective October 1, 1991 for the period October 1991 through March 1992.

FPL submitted proposed capacity cost recovery factors for each rate class which are included here as attachment "B". We approve those proposed factors.

For the October 1991 through March 1992 period, FPL should calculate the true-up of its capacity costs on a system-wide basis. The net over/under recovery amount should be determined by comparing total capacity costs to actual revenue. In the subsequent period that amount would be added to total projected cost and allocated using the same methodology used for the projected cost.

4. Fuel related engineering analyses for reload design for nuclear units

Staff, FPL and Public Counsel all proposed that FPL should be allowed to recover through the Fuel Cost Recovery Clause the costs for performing fuel related engineering analyses necessary to support reload design for refueling nuclear units. We agree that the costs of using in-house personnel to perform fuel related engineering analyses should be recovered through the Fuel Cost Recovery Clause. The costs were incurred in lieu of payments that had previously been made to FPL's fabrication vendors to perform those services. Those payments have previously been recovered through the Fuel Cost Recovery Factor, and thus the costs incurred in lieu of those payments should be recovered.

FLORIDA PUBLIC UTILITIES COMPANY

1. $2,225,682 refund from Gulf Power Company

FPUC has received a refund of $2,225,682 from Gulf Power for fuel buyout costs collected from FPUC during the period January 1, 1987 through July 18, 1990. Gulf made the refund to FPUC in compliance with FERC Order No.55-61,030. In that order FERC held that Gulf would not be permitted to collect from its wholesale customers the fuel buyout costs that Gulf had incurred prior to its petition to FERC to collect those costs. Gulf has appealed the FERC order, and the question before us in this proceeding is how FPUC should manage the refund pending the outcome of Gulf's appeal.

We agree with FPUC, with Public Counsel, and with our staff that until Gulf's appeal of the FERC order is concluded FPUC shall hold the $2,225,682 in an interest bearing escrow account for the protection of its customers. When the appeal is concluded, if Gulf is unsuccessful, FPUC shall pass the $2,225,682, plus the interest accrued in the escrow account, back to FPUC's ratepayers. If the appeal succeeds, but Gulf is not authorized to recover interest from FPUC, FPUC shall refund to its customers the interest earned on the funds while in escrow. In this event, or if the appeal is concluded adversely to Gulf, FPUC shall promptly notify our staff and the Office of Public Counsel. FPUC shall also bring before us for our approval at that time a proposal outlining the timing and the manner in which the refund will be made to its customers. Gulf's appeal will be considered concluded adversely to Gulf when the funds are no longer subject to entry of any further judicial or administrative orders which could authorize Gulf to recover the funds from FPUC.

GULF POWER COMPANY

1. Re-evaluation of the recovery mechanism of Gulf Power Company's "special rate agreements" with Monsanto Company and Air Products And Chemicals, Inc. (Deferred from the February 21, 1991 hearing in this Docket)

a. The Monsanto Agreement

Upon review of the mechanism by which Gulf Power Company recovers the discounts it gives to Monsanto Company under the terms of their "special rate agreement", we find that the mechanism we originally approved in Order No. 20178 continues to be reasonable and appropriate. The recovery mechanism associated with the Monsanto agreement operates as follows: Fuel savings each period associated with the sales to this industrial customer are accounted for and subsequently recovered from the general body of customers through the fuel cost recovery charge. These savings are accumulated in an account along with the original prepayment made by Monsanto under the contract. The balance in this account at any point in time consists of these amounts plus interest, less the amount of all Annual Adjustments paid to Monsanto to date. Any positive balance in the account at the conclusion of the contract recovery period will be split between Gulf and its general body of ratepayers, 25% to Gulf and 75% to the ratepayers. Gulf Power Company has properly calculated the fuel savings attributable to retaining Monsanto Company on its system.

We agree with our staff, however, that the manner in which fuel savings are calculated when the marginal costs of serving the

Monsanto load exceeds the average cost needs improvement. In December of 1989 Gulf's marginal costs of serving the Monsanto load did exceed the average cost, and Gulf reflected the "fuel savings" for the month as zero, rather than as a reduction of fuel savings. In the future, when Gulf's ratepayers pay more for fuel due to the existence of the Monsanto load, the "fuel savings" recovered by Gulf should be reduced correspondingly.

Also, our staff has brought to our attention a possible problem with respect to the liquidation of the special account at the expiration of the contract on December 31, 1992. At that time, any remaining funds are to be divided 75-25 between the ratepayers and the company, respectively. Since the fuel savings are not deposited into the special account until one year after they are incurred, the total fuel savings will not be deposited at the time of liquidation of the account as outlined in the order approving the contract. We expect that Gulf and our staff will take the appropriate steps to resolve this problem and bring the matter to our attention in the next fuel adjustment hearing if necessary.

The Air Products Agreement

Pursuant to our Order No. 20387, which was issued in Docket No. 880647-EI (the Monsanto docket), but which discussed the terms of the orders approving both the Monsanto and Air Products contracts with Gulf, we have reviewed the Air Products agreement in this proceeding. We find that Gulf has calculated the fuel savings attributable to retaining Air Products and Chemicals, Inc. on its system in accordance with Order No. 19613 approving that agreement.

Order No. 19613 specifically directed "that the fuel savings benefits associated with the retention of Air Products' load shall be calculated as the difference between the PXT fuel cost recovery factor paid by Air Products and the cost of replacement fuel purchased in excess of contract minimum requirements", i.e., the spot-market cost of fuel. While we find that Gulf Power has properly employed this methodology "in accordance" with Order No. 19613, we agree with Gulf, the Office of Public Counsel, and with our staff that the mechanism by which Gulf Power recovers the credits given to Air Products and Chemicals, Inc. should be consistent with the mechanism by which Gulf recovers the credits given to Monsanto Co., for all prospective applications, effective April 1, 1991.

In addition, the fuel savings recovered from the ratepayers under the contract should be recovered in every six-month fuel period. Currently, a year's worth of the fuel savings are recovered in only the six-month October - March period. In order to smooth the recovery of the fuel savings, they should be recovered in both the October - March and April - September fuel periods.

TAMPA ELECTRIC COMPANY

1. Recovery of fuel contract buyout costs

On January 8, 1988, we issued Order No. 18670 approving TECO's buyout cost recovery for the buyout of its coal contracts with Pyramid Mining, Inc. In that order we did not differentiate between retail and wholesale ratepayers, and at the time the order was issued TECO did not have any wholesale customers. Because TECO did not have any wholesale customers at the time the order was issued, TECO has interpreted the order to mean that all the costs associated with the buyout should be collected from its retail ratepayers.

In March of 1990 Sebring became a wholesale customer of TECO's, and the issue before us in this fuel adjustment proceeding is whether TECO should continue to recover the costs of the Pyramid contract buyout from its retail or "jurisdictional" customers only, instead of recovering the costs from its wholesale or "nonjurisdictional" customers as well, over total kilowatt sales.

Our staff and TECO agree that on a prospective basis, beginning October 1, 1991, TECO should recover its Pyramid buyout costs over total kilowatt sales, thereby allocating the costs to all of its customers. Public Counsel argues that refunds should be made to jurisdictional ratepayers for all costs that should have been allocated to wholesale customers when Sebring became TECO's customer.

We believe that TECO's wholesale customer enjoys the benefits associated with the buyout and thus TECO's retail customers should not bear all the costs. On a prospective basis, therefore, TECO shall recover the Pyramid buyout costs over total kilowatt sales.

We will not require TECO to refund amounts already collected from jurisdictional ratepayers above their total kilowatt sales since TECO acquired its wholesale customer. Our order approving the Pyramid buyout and recovery of the costs associated with it did not contemplate the question of recovery from retail versus wholesale ratepayers, because at that time TECO did not have any wholesale customers. Under this circumstance, when TECO acquired its wholesale customer, we believe that TECO could reasonably have interpreted the buyout order to apply only to its jurisdictional customers. While we disagree with that interpretation, we see that reasonable minds could differ here.

Furthermore, as we have seen from FERC's treatment of Gulf Power Company's request to recover buyout costs from its wholesale customers, FERC will not allow recovery of those costs incurred prior to the filing of a petition with FERC. We therefore believe that the fairest resolution of the issue before us is to apply our interpretation of the method of allocation of contract buyout costs on a prospective basis.

2. TECO's recovery of coal costs above the Coal Market Price Benchmark for 1990.

In 1990 the actual prices that TECO paid for coal from its affiliate, Gatliff Coal, exceeded the benchmark established by the Commission in Order No. 20298, Docket No. 870001-EI. In that order we approved a stipulation between TECO and Public Counsel that changed the pricing methodology to be used in calculating and recovering the costs associated with TECO's affiliate transportation and coal contracts. Under the terms of the order, TECO may recover all transportation and coal costs of their affiliate contracts below the benchmark established in the stipulation. If TECO incurs coal costs in excess of the benchmark, however, in order to recover the excess costs, TECO is required to justify the reasonableness and prudence of the excess costs incurred.

In the prehearing order issued in this proceeding (Order No. 24938) the issue addressing TECO's coal costs in excess of the benchmark was stated as follows:

11b. ISSUE: Should TECO's proposed Coal Market Price and Transportation Benchmark for 1990 be adopted?

STAFF: No. TECO's benchmark for transportation, as shown in Mr. Cantrell's Document No. 1, page 1 of 2, shows a value of $24.17 per ton. Staff's calculation of the benchmark results in a figure of $22.22 per ton. While Staff agrees with TECO's Gatliff coal $39.33 per ton benchmark price of coal, Staff does not agree with TECO's calculation of a cumulative benefit for prior years. Order No. 20298, Docket No. 870001-EI does not mention or support the use of a cumulative benefit method of calculating fuel cost recovery. Each year is to be considered separately. TECO should be required to return the excess monies collected to its customers.

TECO: Yes. (Cantrell)

OPC: Agree with staff. TECO's argument that the index used in determining the Gatliff benchmark price does not appropriately track the trend in price of the low ash fusion coals is not justification to allow the excess cost incurred above the benchmark. The index used in determining the annual benchmark for the Gatliff coal was stipulated to by TECO, and accepted by Order No. 20298, 11/10/88. As long as the index produced a benchmark that was above the cost of Gatliff Coal, Teco was satisfied. Now that the index has produced a benchmark below the cost of Gatliff coal TECO wants to argue that the index is not appropriate. TECO has not justified the costs incurred for Gatliff coal above the 1990 benchmark, therefore the excess amount should be refunded to the ratepayers. TECO also argues that no refund should be made because there is a cumulative net savings. This is not a part of the stipulation. This was not the intent of the stipulation. There is already a 5% margin (zone) added to the market price. The cumulative net benefit argument should be denied. (Additionally, this was not presented in the previous years.)

In our discussion at the conclusion of the hearing, immediately before our vote on this issue, and after testimony had been heard, all parties finally acknowledged that the issue of whether the 1990 benchmark should be adopted did not sufficiently address the fact that TECO had incurred excess costs above the benchmark in 1990. Rather, the issue that should have been raised was whether TECO's excess costs above the benchmark were justified, and therefore recoverable under the fuel adjustment clause. Much of the testimony and cross-examination at the hearing did not address this issue. Thus the real issue for us to decide was obfuscated considerably by discussion about the benchmark itself, whether it should be changed, and whether the costs of the Gatliff coal contracts below the benchmark in prior years should be used in determining the calculation of the benchmark in 1990.

In future fuel adjustment hearings, when TECO has incurred costs from its coal or transportation contracts with its affiliates that exceed the established benchmark, we will expect explicit identification of the issue of whether the excess costs were justified and thus recoverable under the fuel adjustment clause.

For now, however, although we are not happy with the manner in which the issue was addressed in this hearing, we find that the evidence submitted to us supports the finding that TECO's excess Gatliff coal costs were justified, and no evidence was submitted or developed at the hearing to contravene that finding.

Mr. Cantrell testified for TECO that Gatliff is the only eastern supplier of low sulfur, low ash-fusion coal with sufficient reserves to meet TECO's long-term coal needs. Mr. Cantrell stated that Gatliff's delivered coal prices for the particular coal required by TECO's Gannon Station units are lower, if the cost of transportation is considered in determining the price, than low sulfur, low ash-fusion coal mined in the west. Mr. Cantrell also explained that the increase in production capacity for compliance coal has driven prices for compliance coal down to the point that today many coal suppliers are selling coal at their variable costs and are failing to recover their fixed costs. Mr. Cantrell explained that TECO's long term needs for low sulfur, low ash-fusion coal can not be adequately protected by the purchase of coal from suppliers selling at variable costs, because of the risk that those suppliers would not remain in business for the duration of the contracts designed to supply TECO's long term needs. Therefore, Mr. Cantrell testified, there really are no viable alternatives for acquisition of low sulfur, low ash-fusion coal available to TECO other than Gatliff coal. We believe that TECO's Gatliff coal costs that exceed the benchmark are justified for these reasons, and we will allow TECO to recover them in this proceeding.

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. Staff, the Office of Public Counsel and the utilities stipulated to the following GPIF rewards and penalty for the period October, 1990 through March, 1991:

FPC:	$1,352,447	Reward.
FPL:	$2,942,050	Reward.
GULF:	$93,473	Penalty.
TECO:	$436,181	Reward.

The parties also stipulated to targets and ranges for the period October, 1991 through March, 1992, which are shown on Appendix "B" to this order. We approve the stipulations.

Oil Backout Cost Recovery Factor

Pursuant to stipulation by the parties, we find the proper final oil backout true-up amount for the period October, 1990 through March, 1991 to be $3,483,270 underrecovery for FPL and $1,644,725 overrecovery for TECO. The estimated oil backout true-up amount for the period April through September, 1991 is $6,765,319 overrecovery for FPL, and $936,636 overrecovery for TECO.

The total oil backout true-up amount to be collected or refunded during the period October, 1991 through March, 1992 $3,282,049 overrecovery for FPL, and $2,581,362 overrecovery for TECO.

Finally, we find the proper projected oil backout cost recovery factor for the period October, 1991 through March, 1992 to be .009 cents per KWH for FPL, and .081 cents per KWH for TECO.

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, 1991 through March, 1992, 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 October, 1991 through March, 1992. 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, 1991 through March, 1992. 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.

BY ORDER of the Florida Public Service Commission, this 1st day of OCTOBER, 1991.

STEVE TRIBBLE, Director
Division of Records and Reporting

(S E A L)

by: Kay Flynn
Chief, Bureau of Records

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

I respectfully dissent from the majority's decision on Issue 11(b) to allow Tampa Electric Company to recover the cost of coal purchased from its affiliate, Gatliff Coal, which exceeds the stipulated, Commission approved benchmark. It is my understanding that the Commission's decisions in this docket are limited to the issues raised by the parties. Issue 11(b) reads as follows:

> Should TECO's proposed Coal Market Price and Transportation Benchmark for 1990 be adopted?

While this issue perhaps could have been better worded, it is clear to me that the purpose of the hearing on this issue was to calculate the benchmark as approved by the Commission in Order No. 20298 and to give the company the opportunity to justify any cost in excess of it.

The very nature of the benchmark is to incorporate market considerations into the evaluation of the prices paid for coal purchased from affiliated companies. It is not a perfect tool but is the best one we currently have. More importantly, it was stipulated to by all the parties and approved by the Commission. Since its purpose is to incorporate market considerations, it is not surprising that prices paid may be above or below the benchmark as the coal market fluctuates with changing economic conditions.[1]

When the price paid exceeds the benchmark, the benchmark does not and should not result in an automatic disallowance. However, it clearly places the burden on the Company to justify payments in excess of the benchmark. It does not place a burden on any other party to provide evidence to contravene a finding that costs above the benchmark are prudent. TECO did not meet its burden, as its evidence was directed at the benchmark itself and whether it is an appropriate tool. This evidence cannot and did not justify the costs paid in excess of the benchmark. Therefore, the excess cost should accordingly be disallowed.

I would like to express a further concern that this decision may have ominous implications for the prospect for settlements in the future. Parties to stipulations must have confidence that they can rely on agreements that have been accepted by the Commission. Absent a compelling demonstration that the previously approved stipulation is not in the public interest, all parties must remain bound by agreements that were entered into with open eyes. In this case, there was no compelling need shown to abandon the stipulation.

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

[1]It should be noted that there is a 5% factor incorporated into the benchmark which tends to cushion the impact of swings in the market.

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 1991 - March 1992

	PROPOSED October 1991 - March 1992			PRESENT April 1991 - September 1991			DIFFERENCE				
	TOTAL FUEL COST CENTS PER KWH			TOTAL FUEL COST CENTS PER KWH			TOTAL FUEL COST CENTS PER KWH			RESIDENTIAL LINE LOSS MULTIPLIER	PROPOSED RESIDENTIAL FUEL FACTOR
COMPANY	Levelized	On/Peak	Off/Peak	Levelized	On/Peak	Off/Peak	Levelized	On/Peak	Off/Peak		
Fla. Power & Light	2.093	2.270	2.024	2.088	2.238	2.015 (5)	0.005	0.032	0.009	1.00125	2.096
Fla. Power Corp.	2.256	2.891	2.009	2.421	3.320	1.995	-0.165	-0.429	0.014	1.00420	2.265
Tampa Electric	2.698	3.116	2.569	2.545	2.783	2.439	0.153	0.333	0.130	1.01470	2.738
Gulf Power	2.056	2.161	2.019	2.586	2.811	2.478	-0.530	-0.650	-0.459	1.01228	2.081
Fla. Public											
Marianna (1)	4.901	NA	NA	5.113	NA	NA	-0.212	NA	NA	1.01260	4.963
Fernandina (1)(2)	6.160	NA	NA	5.871	NA	NA	0.289	NA	NA	1.00000	6.160

COST FOR 1,000 KWH RESIDENTIAL SERVICE

PRESENT: April 1991 - September 1991

	Fla. Power & Light		Fla. Power Corp.	Tampa Electric	Gulf Power	Fla. Public Marianna	Fla. Public Fernandina
Base	46.58	(5)	44.96	50.34	42.87	17.22	19.20
Fuel (3)	20.91		24.28	25.82	26.18	51.77	58.71
Oil Backout	6.51		NA	1.36	NA	NA	NA
Energy Conservation	1.35		2.24	1.39	0.33	0.21	0.00
Gross Receipts Tax (4)	0.58		0.55	0.61	0.53	0.53	0.60
Capacity Recovery	0.00		0.00	0.00	0.00	0.00	0.00
Total	$75.93		$72.03	$79.52	$69.91	$69.73	$78.51

PROPOSED: October 1991 - March 1992

	Fla. Power & Light		Fla. Power Corp.	Tampa Electric	Gulf Power	Fla. Public Marianna	Fla. Public Fernandina
Base	47.38	(5)	44.96	50.34	42.87	17.22	19.20
Fuel (3)	20.96		22.65	27.38	20.81	49.63	61.60
Oil Backout	0.09		NA	0.81	NA	NA	NA
Energy Conservation	1.25		2.91	1.31	0.20	0.17	0.03
Gross Receipts Tax (4)	0.59		0.54	0.61	0.49	0.51	0.62
Capacity Recovery	6.69		0.00	0.00	0.00	0.00	0.00
Total	$76.96		$71.06	$80.45	$64.37	$67.53	$81.45

DIFFERENCE

	Fla. Power & Light		Fla. Power Corp.	Tampa Electric	Gulf Power	Fla. Public Marianna	Fla. Public Fernandina
Base	0.80	(5)	0.00	0.00	0.00	0.00	0.00
Fuel (3)	0.05		-1.63	1.56	-5.37	-2.14	2.89
Oil Backout	-6.42		NA	-0.55	NA	NA	NA
Energy Conservation	-0.10		0.67	-0.08	-0.13	-0.04	0.03
Gross Receipts Tax (4)	0.01		-0.01	0.00	-0.04	-0.02	0.02
Capacity Recovery	6.69		0.00	0.00	0.00	0.00	0.00
Total	1.03		-0.97	0.93	-5.54	-2.20	2.94

(1) Fuel costs include purchased power demand costs of 2.025 for Marianna and 0.872 cents/KWH for Fernandina allocated to the residential class. (2) All classes except OSLD.
(3) Adjusted for line loss. (4) Gross receipts tax increased by .25% effective 7/1/91. Total additional tax now equals .75%, in addition to the 1.5% which is already included in fuel and base rates.
(5) Present FPL base rates include ITC rate reduction of .08 cents/kwh ordered in Docket No. 890148-EI.

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

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FOR THE PERIOD: October 1991 - March 1992

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,GS-1,SL-2	2.093	2.270	2.024	1.00125	2.096	2.273	2.026
	A-1	SL-1,OL-1	2.063	NA	NA	1.00125	2.066	NA	NA
	B	GSD-1	2.093	2.270	2.024	1.00121	2.096	2.273	2.026
	C	GSLD-1,CS-1	2.093	2.270	2.024	1.00048	2.094	2.271	2.025
	D	GSLD-2,CS-2,OS-2,MET	2.093	2.270	2.024	0.99673	2.086	2.262	2.017
	E	GSLD-3,CS-3	2.093	2.270	2.024	0.97075	2.032	2.203	1.965
	F	IST-1,ISST-1		2.270	2.024	0.99442		2.257	2.013
FPC	A	Distribution Secondary Delivery	2.256	2.891	2.009	1.00420	2.265	2.903	2.017
	A-1	OL-1,SL-1	2.174	NA	NA	1.00420	2.183	NA	NA
	B	Distribution Primary Delivery	2.256	2.891	2.009	0.98240	2.216	2.840	1.974
	C	Transmission Delivery	2.256	2.891	2.009	0.97230	2.194	2.811	1.953
TECO	A	RS,GS,TS	2.698	3.116	2.569	1.01470	2.738	3.162	2.607
	A-1	SL-1,2,3,OL-1,2	2.651	NA	NA	1.01470	2.690	NA	NA
	B	GSD,GSLD	2.698	3.116	2.569	0.99750	2.691	3.108	2.563
	C	IS-1,IS-3	2.698	3.116	2.569	0.96860	2.613	3.018	2.488
GULF	A	RS,GS,GSD,OS-3	2.056	2.162	2.019	1.01228	2.081	2.188	2.044
	B	LP	2.056	2.162	2.019	0.98106	2.017	2.120	1.981
	C	PX	2.056	2.162	2.019	0.96230	1.978	2.080	1.943
	D	OS-1,OS-2	2.050	NA	NA	1.01228	2.075	NA	NA
FPUC									
Fernandina	A	RS	6.160	NA	NA	1.00000	6.160	NA	NA
	B	GS	6.000	NA	NA	1.00000	6.000	NA	NA
	C	GSD	5.886	NA	NA	1.00000	5.886	NA	NA
	D	OL, OL-2, SL-2, SL-3, CSL	5.535	NA	NA	1.00000	5.535	NA	NA
	E	GSLD				(1)	(2) 0.000		
							(2) $3.77/CP KW		
Marianna	A	RS	4.901	NA	NA	1.01260	4.963	NA	NA
	B	GS	4.644	NA	NA	0.99630	4.627	NA	NA
	C	GSD	4.220	NA	NA	0.99630	4.204	NA	NA
	D	OL, OL-2	2.876	NA	NA	1.01260	2.912	NA	NA
	E	SL-1, SL-2, SL-3	2.876	NA	NA	0.98810	2.842	NA	NA

(1) Group line losses reflected on schedule E1
(2) Informational Purposes Only-GSLD class is billed actual fuel cost

FLORIDA POWER AND LIGHT COMPANY
PROPOSED CAPACITY RECOVERY FACTORS

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Rate Class	Recovery Factor (Cents per kwh)
RS1	0.669
GS1	0.702
GSD1	0.628
OS2	0.433
GSLD1/CS1	0.578
GSLD2/CS2	0.524
GSLD3/CS3	0.473
IST1D	0.426
IST1T	0.455
ISST1D	0.508
SST1T	0.518
SST1D	0.396
CILCD	0.454
CILCT	0.384
MET	0.584
OL1/SL1	0.405
SL2	0.462

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FUEL AND PURCHASED POWER COST RECOVERY CLAUSE CALCULATION

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CLASSIFICATION	FLORIDA POWER & LIGHT COMPANY Classification Associated $	Classification Associated KWH	Classification Associated cents/KWH
1. Fuel Cost of System Net Generation (E3)	423,091,554	22,593,715,000	1.87261
2. Spent NUC Fuel Disposal Cost (E2)	9,632,000	9,133,181,000 (a)	0.10546
3. Coal Car Investment	202,576	0	0.00000
4. Adjustments to Fuel Cost	0	0	0.00000
5. TOTAL COST OF GENERATED POWER	432,926,130	22,593,715,000	1.91614
6. Fuel Cost of Purchased Power - Firm (E8)	189,948,500	10,170,400,000	1.86766
7. Energy Cost of Sch.C,X Economy Purchases (Broker) (E9)	19,800,300	886,000,000	2.23480
8. Energy Cost of Economy Purchases (Non-Broker) (E9)	7,180,700	293,900,000	2.44325
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)	20,281,600	888,500,000	2.28268
12. TOTAL COST OF PURCHASED POWER	237,211,100	12,238,800,000	1.93819
13. TOTAL AVAILABLE KWH		34,832,515,000	
14. Fuel Cost of Economy Sales (E7)	(4,071,900)	(125,000,000)	3.25752
15. Gain on Economy Sales - 80% (E7A)	(1,205,280)	(125,000,000)(a)	0.96422
16. Fuel Cost of Unit Power Sales (SL2 Partpts) (E7)	(1,253,900)	(155,400,000)	0.80689
17. Fuel Cost of Other Power Sales (E7)	(2,768,800)	(89,500,000)	3.09363
18. TOTAL FUEL COST AND GAINS OF POWER SALES	(9,299,880)	(369,900,000)	2.51416
19. Net Inadvertant Interchange (E4)	0	0	0.00000
20. TOTAL FUEL AND NET POWER TRANSACTIONS	660,837,350	34,462,615,000	1.91755
21. Net Unbilled (E4)	12,155,666 (a)	633,917,000	0.03746
22. Company Use (E4)	1,981,096 (a)	103,314,000	0.00610
23. T & D Losses (E4)	48,272,864 (a)	2,517,426,000	0.14875
24. Adjusted System KWH Sales	660,837,350	32,451,291,000	2.03640
25. Wholesale KWH Sales	7,638,883	375,116,000	2.03641
26. Jurisdictional KWH Sales	653,198,467	32,076,175,000	2.03640
27. Jurisdictional KWH Sales Adjusted for Line Loss - 1.00039	653,453,214	32,076,175,000	2.03719
28. True-up * (derived in Attachment C)	4,077,902	32,076,175,000	0.012 1
29. Total Jurisdictional Fuel Cost	657,531,116	32,076,175,000	2.04990
30. Revenue Tax Factor			1.01652
31. Fuel Cost Adjusted for Taxes			2.08380
32. GPIF*	2,942,050	32,076,175,000	0.00920
33. Total fuel cost including GPIF	660,473,166	32,076,175,000	2.09300
34. Total Fuel Cost Factor Rounded to the Nearest .001 cents per KWH (used in attachment B, pages 1 and 2 of 9)			2.093

*Based on Jurisdictional Sales (a) included for informational purposes only
Effective dates for billing purposes: October 1, 1991

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FUEL AND PURCHASED POWER COST RECOVERY CLAUSE CALCULATION

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CLASSIFICATION	FLORIDA POWER CORPORATION Classification Associated $	Classification Associated KWH	Classification Associated cents/KWH
1. Fuel Cost of System Net Generation (E3)	242,589,277	12,202,133,000	1.98809
2. Spent NUC Fuel Disposal Cost (E3A)	2,021,876	2,021,876,000 (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	244,611,153	12,202,133,000	2.00466
6. Fuel Cost of Purchased Power - Firm (E8)	907,080	11,712,000	7.74488
7. Energy Cost of Sch.C,X Economy Purchases (Broker) (E9)	15,951,280	423,825,000	3.76365
8. Energy Cost of Economy Purchases (Non-Broker) (E9)	6,871,220	193,200,000	3.55653
9. Energy Cost of Sch.E Purchases (E9)	18,442,760	852,503,000	2.16337
10. Capacity Cost of Sch.E Economy Purchases (E9)	10,800,000	852,503,000 (a)	1.26686
11. Payments to Qualifying Facilities (E8A)	19,210,049	526,908,000	3.64581
12. TOTAL COST OF PURCHASED POWER	72,182,389	2,008,148,000	3.59448
13. TOTAL AVAILABLE KWH		14,210,281,000	
14. Fuel Cost of Economy Sales (E7)	(7,608,800)	(480,006,000)	1.58515
14a. Gain on Economy Sales -80% (E7A)	(1,054,414)	(480,006,000)(a)	0.21967
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)	(424,360)	(7,910,000)	5.36485
16a. Gain on Seminole Back-up Sales (E7B)	(1,021,580)	(7,910,000)(a)	12.91504
17. Fuel Cost of Seminole Supplemental Sales (E7)	(7,952,300)	(257,775,000)	3.08498
18. TOTAL FUEL COST AND GAINS OF POWER SALES	(18,061,454)	(745,691,000)	2.42211
19. Net Inadvertant Interchange (E4)	0	0	
20. TOTAL FUEL AND NET POWER TRANSACTIONS	298,732,088	13,464,590,000	2.21865
21. Net Unbilled (E4)	(7,256,175)(a)	327,061,000	-0.05625
22. Company Use (E4)	2,030,019 (a)	(91,500,000)	0.01574
23. T & D Losses (E4)	17,762,289 (a)	(800,608,000)	0.13770
24. Adjusted System KWH Sales	298,732,088	12,899,543,000	2.31583
25. Wholesale KWH Sales(Excluding Seminole Supplemental)	(12,299,914)	(531,153,000)	2.31570
26. Jurisdictional KWH Sales	286,432,174	12,368,390,000	2.31584
27. Jurisdictional KWH Sales Adjusted for Line Loss - 1.0019	286,976,395	12,368,390,000	2.32024
28. Prior Period True-Up *	(13,771,707)	12,368,390,000	-0.11135
28a. Miscellaneous True-Up	0	0	0.00000
29. Total Jurisdictional Fuel Cost	273,204,688	12,368,390,000	2.20889
30. Revenue Tax Factor			1.01652
31. Fuel Cost Adjusted for Taxes			2.24539
32. GPIF*	1,352,447	12,368,390,000	0.01093
33. Total fuel cost including GPIF	274,557,135	12,368,390,000	2.25632
34. Total Fuel Cost Factor Rounded to the Nearest .001 cents per KWH (used in Attachment B. pages 1 and 2 of 9)			2.256

*Based on Jurisdictional Sales (a) included for informational purposes only.
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FUEL AND PURCHASED POWER COST RECOVERY CLAUSE CALCULATION

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CLASSIFICATION	TAMPA ELECTRIC COMPANY Classification Associated $	Classification Associated KWH	Classification Associated cents/KWH
1.Fuel Cost of System Net Generation (E3)	180,145,867	8,111,446,000	2.22088
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	180,145,867	8,111,446,000	2.22088
6.Fuel Cost of Purchased Power - Firm (E8)	87,100	2,331,000	3.73659
7.Energy Cost of Sch.C,X Economy Purchases (Broker) (E9)	541,300	15,009,000	3.60650
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)	7,478,800	240,297,000	3.11232
12.TOTAL COST OF PURCHASED POWER	8,107,200	257,637,000	3.14675
13.TOTAL AVAILABLE KWH		8,369,083,000	
14.Fuel Cost of Economy Sales (E7)	23,090,100	1,231,691,000	1.87467
15.Gain on Economy Sales - 80% (E7A)	4,193,840	1,231,691,000 (a)	0.34049
16.Fuel Cost of Scedule D Sales (E7)	3,143,900	168,116,000	1.87008
16a.Fuel Cost of Schedule J Sales (E7)	3,903,200	181,893,000	2.14588
17.Fuel Cost of Other Power Sales (E7)			0.00000
18.TOTAL FUEL COST AND GAINS OF POWER SALES	34,331,040	1,581,700,000	2.17052
19.Net Inadvertant Interchange (E4)	0		
19b.Interchange and Wheeling Losses		20,833,000	
20.TOTAL FUEL AND NET POWER TRANSACTIONS	153,922,027	6,766,550,000	2.27475
21.Net Unbilled (E4)	0 (a)	0	0.00000
22.Company Use (E4)	391,439 (a)	17,208,000	0.00596
23.T & D Losses (E4)	4,202,305 (a)	184,737,000	0.06401
24.Adjusted System KWH Sales	153,922,027	6,564,605,000	2.34473
25.Wholesale KWH Sales	(1,968,261)	(83,895,000)	2.34610
26.Jurisdictional KWH Sales	151,953,766	6,480,710,000	2.34471
26a. Jurisdictional Loss Multiplier			1.00050
27.Jurisdictional KWH Sales Adjusted for Line Loss	152,029,743	6,480,710,000	2.34588
28.True-up * (derived in Attachment C)	13,428,770	6,480,710,000	0.20721
29.Pyramid Coal Contract Buyout Adjustment	6,141,132	6,480,710,000	0.09476
30.Total Jurisdictional Fuel Cost	171,599,645	6,480,710,000	2.64785
31.Revenue Tax Factor			1.01652
32.Fuel Cost Adjusted for Taxes	174,434,471		2.69160
33.GPIF * (Already adjusted for taxes)	436,181	6,480,710,000	0.00673
34.Total Fuel Cost including GPIF	174,870,652	6,480,710,000	2.69833
35.Total Fuel Cost Factor Rounded to the Nearest .001 cents per KWH (used in Attachment B, pages 1 and 2 of 9)			2.698

*Based on Jurisdictional Sales (a) included for informational purposes only
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FUEL AND PURCHASED POWER COST RECOVERY CLAUSE CALCULATION

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	GULF POWER COMPANY		
CLASSIFICATION	Classification Associated $	Classification Associated KWH	Classification Associated cents/KWH
1.Fuel Cost of System Net Generation (E3)	91,570,582	4,690,090,000	1.9524
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	91,570,582	4,690,090,000	1.9524
5.Fuel Cost of Purchased Power - Firm (E8)	0	0	0.0000
6.Energy Cost of Sch.C,X Economy Purchases (Broker) (E9)	10,632,554	651,550,000	1.6319
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	0.0000
10.Payments to Qualifying Facilities (E9A)	0	0	0.0000
11.TOTAL COST OF PURCHASED POWER	10,632,554	651,550,000	1.6319
12.TOTAL AVAILABLE KWH (line 4 + line 11)		5,341,640,000	
13.Fuel Cost of Economy Sales (E7)	(2,073,000)	(103,300,000)	2.0068
14.Gain on Economy Sales - 80% (E7A)	(52,800)	(a)	
15.Fuel Cost of Unit Power Sales (E7)	(14,004,000)	(725,310,000)	1.9308
16.Fuel Cost of Other Power Sales (E7)	(11,108,000)	(596,682,000)	1.8616
17.TOTAL FUEL COST AND GAINS OF POWER SALES	(27,277,800)	(1,425,292,000)	1.9138
18.Net Inadvertant Interchange (E4)	0		
19.TOTAL FUEL AND NET POWER TRANSACTIONS	74,925,336	3,916,348,000	1.9131
20.Net Unbilled (E4)	0	0	0.0000
21.Company Use (E4)	189,531 (a)	9,907,000	1.9131
22.T & D Losses (E4)	3,978,138 (a)	207,942,000	1.9131
23.Adjusted System KWH Sales	74,925,336	3,698,499,000	2.0258
24.Wholesale KWH Sales	2,400,492	118,496,000	2.0258
25.Jurisdictional KWH Sales	72,524,844	3,580,003,000	2.0258
26.Jurisdictional KWH Sales Adjusted for Line Loss - 1.00140	72,626,379	3,580,003,000	2.0287
27.True-up *	(1,267,692)	3,580,003,000	-0.0354
28.Total Jurisdictional Fuel Cost	71,358,687	3,580,003,000	1.9933
29.Revenue Tax Factor			1.01652
30.Fuel Cost Adjusted for Taxes			2.0262
31. Special Contract Recovery Cost	1,159,067	3,580,003,000	0.0324
32.GPIF *	(93,473)	3,580,003,000	-0.0026
33.Total Fuel Cost including GPIF	71,265,214	3,500,003,000	2.0560
34.Total Fuel Cost Factor Rounded to the Nearest .001 cents per KWH (used in Attachment B, pages 1 and 2 of 9)			2.056

*Based on Jurisdictional Sales (a) included for informational purposes only.
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FUEL AND PURCHASED POWER COST RECOVERY CLAUSE CALCULATION

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CLASSIFICATION	FLORIDA PUBLIC UTILITIES (MARIANNA) Classification Associated $	Classification Associated KWH	Classification Associated cents/KWH
1.Fuel Cost of System Net Generation (E3)	0	300,000	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	300,000	0.00000
6.Fuel Cost of Purchased Power - Firm (E8)	2,295,603	117,181,000	1.95902
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)	2,442,175	117,181,000 (a)	2.08410
10a.Demand Costs of Purchased Power	1,631,500 (a)		
10b.Non-Fuel Energy & Customer Costs of Purchased Power	810,675 (a)		
11.Energy Payments to Qualifying Facilities (E8A)	0	0	0.00000
12.TOTAL COST OF PURCHASED POWER	4,737,778	117,181,000	4.04313
13.TOTAL AVAILABLE KWH	4,737,778	117,481,000	4.03280
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	4,737,778	117,481,000	4.03280
21.Net Unbilled (E4)	85,213 (a)	2,113,000	0.07703
22.Company Use (E4)	2,057 (a)	51,000	0.00186
23.T & D Losses (E4)	189,542 (a)	4,700,000	0.17135
24.Adjusted System KWH Sales	4,737,778	110,617,000	4.28305
25.Less Total Demand Cost Recovery	1,783,279	0	0.00000
26.Jurisdictional KWH Sales	2,954,499	110,617,000	2.67093
27.Jurisdictional KWH Sales Adjusted for Line Loss - 0	2,954,499	110,617,000	2.67093
28.True-up * (derived in Attachment C)	175,511	110,617,000	0.15867
29.Total Jurisdictional Fuel Cost	3,130,010	110,617,000	2.82959
30.Revenue Tax Factor			1.01652
31.Fuel Cost Adjusted for Taxes	3,499,562	110,617,000	2.87633
32.GPIF *	0	110,617,000	0.00000
33.Total Fuel Cost including GPIF	3,130,010	110,617,000	2.87633
34.Total Fuel Cost Factor Rounded to the Nearest .001 cents per KWH (used in Attachment B, pages 1 and 2 of 9)			2.876

*Based on Jurisdictional Sales (a) included for informational purposes only.
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FUEL AND PURCHASED POWER COST RECOVERY CLAUSE CALCULATION

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CLASSIFICATION	FLORIDA PUBLIC UTILITIES (FERNANDINA) 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)	5,416,816	135,420,000	4.00001
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	2,248,530	135,420,000	1.66041
10a.Demand Costs of Purchased Power (E2)	1,029,600 (a)		
10b.Non Fuel Energy and Customer Costs of Purchased Power (E2)	1,218,930 (a)		
11.Energy Payments to Qualifying Facilities (E8A)	0	0	
12.TOTAL COST OF PURCHASED POWER	7,665,346	135,420,000	5.66042
13.TOTAL AVAILABLE KWH		135,420,000	
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	7,665,346	135,420,000	5.66042
21.Net Unbilled (E4)	(104,548)(a)	(1,847,000)	-0.08100
22.Company Use (E4)	4,132 (a)	73,000	0.00320
23.T & D Losses (E4)	459,966 (a)	8,126,000	0.35637
24.Adjusted System KWH Sales	7,665,346	129,068,000	5.93900
25.Wholesale KWH Sales	0	0	0.00000
26.Jurisdictional KWH Sales	7,665,346	129,068,000	5.93900
27.Jurisdictional KWH Sales Adjusted for Line Loss - 0	7,665,346	129,068,000	5.9390
27a.GSLD KWH Sales (E11)		36,000,000	
27b.Other Classes KWH Sales (E11)		93,068,000	
27c.GSLD CP KW		84,000,000	
28. GPIF			
29.True-up *	(2,597)	129,068,000	-0.00201
30.Total Jurisdictional Fuel Cost	7,662,749	129,068,000	5.93699

FUEL AND PURCHASED POWER COST RECOVERY CLAUSE CALCULATION

ESTIMATED FOR THE PERIOD: October 1991 - March 1992

DIVISION OF ELECTRIC AND GAS
DATE: 8/21/91
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CLASSIFICATION	FLORIDA PUBLIC UTILITIES (FERNANDINA) Classification Associated $	Classification Associated KWH	Classification Associated cents/KWH
30a. Demand Purchased Power Costs (line 10a)	1,029,600 (a)		
30b. Non-Demand Purchased Power Costs (lines 6+10b+11)	6,635,746 (a)		
30c. True-up Over/Under Recovery (line 29)	(2,597)(a)		
31. Total Demand Costs	1,029,600		
32. GSLD Portion of Demand Costs Including line losses (line 27c * $3.708)	311,472	84,000 (KW)	$3.71/KW
33. Balance to Other Customers	718,128	93,068,000	0.77162
34. Total Non-Demand Costs (line 30b)	6,635,746		
35. Total KWH Purchased (line 12)		135,420,000	
36. Average Cost per KWH Purchased			4.90012
37. Avg. Cost Adjusted for Transmission line losses (line 36 * 1.03)			5.04713
38. GSLD Non-Demand Costs (line 27a * line 37)	1,816,248	36,000,000	5.04513
39. Balance to Other Customers	4,819,498	93,068,000	5.17847
40a. Total GSLD Demand Costs (Line 32)	311,472	84,000	$3.71
40b. Revenue Tax Factor			1.01652
40c. GSLD Demand Purchased Power factor adjusted for taxes and rounded			$3.77
40d. Total Current GSLD Non-Demand Costs (line 38)	1,816,248	36,000,000	4.77644
40e. Total Non-Demand Costs including true-up	1,816,248	36,000,000	4.77644
40f. Revenue Tax Factor			1.01652
40g. GSLD Non-demand costs adjusted for taxes			4.85534
41a. Total Demand and Non-Demand Purchased Power Costs of other classes (lines 33 + 39)	5,537,626	93,068,000	5.95009
41b. Less: Total Demand Cost Recovery	814,253 (a)		
41c. Total Other Costs to be Recovered	4,844,403 (a)	93,068,000	5.20523
41d. Other Classes' Portion of True-up (line 30 C)	(2,597)	93,068,000	-0.00279
41e. Total Demand and Non-Demand Costs including True-up	4,841,806	93,068,000	5.20244
42. Revenue tax factor			1.01652
			5.28838
43. Other Classes Purchased Power Factor adjusted for taxes to the Nearest .001 cents per KWH (used in Attachment B, pages 1 and 2 of 9)			5.288

*Based on Jurisdictional Sales (a) included for informational purposes only.
Effective dates for billing purposes: