BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Review of Florida Power Corporation's Earnings, Including Effects of Proposed Acquisition of Florida Power Corporation by Carolina Power & Light

DOCKET NO. 000824-EI

Submitted for Filing:
March 18, 2002

FLORIDA POWER CORPORATION'S REQUEST FOR OFFICIAL RECOGNITION VOLUME IV

33. *In re* earnings of Florida Public Utilities Co.'s Fernandina Beach Electric Division, Order No. 13677, Docket No. 840100-EI, 1984 Fla. PUC LEXIS 251, 84 FPSC 158 (Fla. P.S.C. September 13, 1984).

34. *In re* level of earnings of Florida Public Utilities Co.'s Fernandina Beach Electric Division, Order No. 10605, Docket No. 810271-EI, 1982 Fla. PUC LEXIS 861, 82 FPSC 206 (Fla. P.S.C. February 17, 1982).

35. *In re* 1999 earnings of Florida Public Utilities Company's Fernandina Beach Division, Order No. PSC-00-1883-PAA-EI, Docket No. 001147-EI, 2000 Fla. PUC LEXIS 1203, 00 FPSC 10:163 (Fla. P.S.C. October 16, 200).

36. In re Gulf Power Co. for increase in rates and charges, 120 P.U.R. 4th 1, 1990 Fla. PUC LEXIS 1320 (Fla. P.S.C. October 3, 1990).

37. *In re* Florida Power Corp. and City of Tallahassee, Order No. PSC-99-1741, Docket No. 990771, 1999 Fla. PUC LEXIS 1624 (Fla. P.S.C. September 3, 1999).

38. *In re* Occidental Chemical Corp. for reduction of retail electric service rates charged by Florida Power Corp., Order No. 20632, Docket No. 870220-EI, 1989 Fla. PUC LEXIS 112, 89-1 FPSC 227 (Fla. P.S.C. January 20, 1989).

39. *In re* Florida Power Corp. rate modification, Order No. 8834, Docket No. 770316-EU, 1979 Fla. PUC LEXIS 501, 5 FPSC 885 (Fla. P.S.C. April 18, 1979).

40. *In re* Florida Power & Light increase in rates and charges, Order No. 13537, Docket No. 830465, 1984 Fla. PUC LEXIS 375, 84 FPSC 136 (Fla. P.S.C. July 24, 1984).

41. *In re* cost-effective level of demand-side management credit for interruptible and curtailable rate classes of Florida Power Corp., Order No. PSC-96-0842-FOF-EI, Docket No. 950645-EI, 1996 Fla. PUC LEXIS 1010, 96 FPSC 7:31 (Fla. P.S.C July 1, 1996)

42. *In re* demand-side plan of Florida Power Corp., Order No. PSC-95-0691-FOF-EG and PSC-95-0691A & PSC-95-1344-S-EG, Docket No. 941171-EG (Fla. P.S.C. June 9, 1995).

43. *In re* increase in Gulf Power's rates and charges, 120 P.U.R. 4th 1, 1990 Fla. PUC LEXIS 1320, 90-10 FPSC 195.

In re: Review of the level of earnings of Florida Public Utilities Company's Fernandina Beach Electric Division

DOCKET NO. 840100-EI; ORDER NO. 13677

Florida Public Service Commission

1984 Fla. PUC LEXIS 251

84 FPSC 158

September 13, 1984

CORE TERMS: refund, rate of return, net operating income, earnings, immediately preceding, interest associated, plus interest, consumption, calculation, consummated, accumulated, calculated, excessive, electric, monthly, ninety

[*1]

The following Commissioners participated in the disposition of this matter: GERALD L. GUNTER, Chairman; JOSEPH P. CRESSE, JOHN R. MARKS, III, KATIE NICHOLS

ORDER APPROVING STIPULATION AND REFUND

BY THE COMMISSION:

This docket was initiated by the Florida Public Service Commission pursuant to Staff's review of Florida Public Utilities Company's (Utility or Company) 1983 financial data and monthly surveillance reports for the Fernandina Beach electric division which indicates an excessive rate of return.

In response to interrogatories propounded by the Staff, the Company submitted data concerning its rate of return for the year 1983. Following a review of this data, it was determined that the Company's earned rate of return was 10.46% based on a net operating income of $818,851 and a 13-month average rate base of $7,831,285. Utilizing the procedure for computing the required rate of return contained in Section 366.071(5)(b)(2), Florida Statutes, the high range of the required rate of return is 10.37% for 1983. A 16.14% return on common equity, with a range of +/- 1.00%, was utilized in the calculations, since this was considered as the appropriate return on equity [*2] in the Company's consolidated capital structure in Docket No. 820249-GU, Order No. 11855.

Based upon the 10.37% high required rate of return, the allowed net operating income would be $812,104 on a rate base of $7,831,285. Since the actual net operating income was $818,851, the Company had $6,747 of excessive net operating income for the 12 months ending December 31, 1983. After applying the revenue factor of 1.949318 to this amount, the resulting refund is $13,152 in operating revenues, excluding interest.

During the period that the excessive earnings have been accumulated and held, the Company has had the cost-free benefit of the use of these monies. In order to compensate the rate payers for the time value of their money that was held by the Utility, the refund is to be made with interest calculated in accordance with Florida Administrative Code Rule 25-6.109. The interest is to be accrued up to and including the month immediately preceding the month during which the refund is consummated. Because it is difficult to identify the exact amount of the excess earnings on a monthly basis, it is assumed that the $13,152 in excess earnings was accumulated in 12 equal monthly increments [*3] of $1,096, during 1983, for the purpose of calculating the interest associated with the refund. The refund amount shall be calculated by dividing the $13,152, plus interest, by the previous month's KWH consumption, and be applied to each customer's KWH consumption during the month immediately preceding the month during which the refund is consummated and be displayed as a credit on each customer's bill.

The Utility, by letter of August 29, 1984, stipulated to the refund ordered herein with interest. At this time, a revision of the Company's rates does not appear to be warranted due to the relatively small amount of the refund and a current downward trend of the Company's earned rate of return in 1984. Our Staff will continue to monitor the Company's rate of return for any indication of further excess earnings.

The Utility shall provide a written report to the Electric and Gas Department (Rate Section) upon completion of the refund indicating the actual dollar amount of the refund and a schedule showing the calculation of the interest associated with the refund. It is, therefore,

ORDERED by the Florida Public Service Commission, that Florida Public Utilities Company [*4] shall refund the amount of $13,152, plus interest, within ninety (90) days of the effective date of this order. It is further

ORDERED that the Company shall submit a preliminary refund report to the Commission Clerk within thirty (30) days after the refund is completed and again ninety (90) days thereafter. A final report shall be made after all administrative aspects of the refund are completed.

By ORDER of the Florida Public Service Commission, this 13th day of September, 1984.

In re: Review of the level of earnings for Florida Public Utilities Company's Fernandina Beach Electric Division

DOCKET NO. 810271-EU; ORDER NO. 10605

Florida Public Service Commission

1982 Fla. PUC LEXIS 861

82 FPSC 206

February 17, 1982

CORE TERMS: refund, rate of return, overearnings, ended, net operating income, customer, excessive, earnings, capital structure, month period, rate base, consolidated, consumption, calculated

[*1]

The following Commissioners participated in the disposition of this matter: GERALD L. GUNTER, SUSAN W. LEISNER

ORDER APPROVING STIPULATION AND REFUND

BY THE COMMISSION:

This docket was initiated by the Florida Public Service Commission pursuant to Staff's review of Florida Public Utilities Company's 1980 financial data and surveillance reports which indicated an achieved rate of return in excess of its last authorized rate of return. We subsequently approved a Stipulation, Commission Order No. 10501, issued January 8, 1982, between the Company and Staff which established a procedure to refund future excessive earnings generated by the Company's present rates.

In accordance with Order No. 10501, the Company submitted data concerning its rate of return for the year 1980. The Company's pro-forma rate of return was 10.24% based on net operating income of $636,345 and a rate base of $6,213,607. The appropriate midpoint of the allowed rate of return is 9.07% with a range of 8.69% to 9.46% as derived from the Company's consolidated capital structure at December 31, 1980. A 15% return on common equity, with a range of +/- 1.00%, was utilized in the calculation, since [*2] this was considered as the appropriate rate of return on equity in the Company's consolidated capital structure in Docket No. 800414-GU, Order No. 9956.

Based upon the 9.46% ceiling of the rate of return range, the allowed net operating income would be $587,807 on the rate base of $6,213,607. Since the actual net operating income was $636,345, the Company had $48,538 of excessive net operating income for the twelve months ended December 31, 1980. After applying the revenue expansion factor of 1.94571 to this amount, the resulting refund is $94,440 in operating revenues.

Prior to a prehearing conference on January 20, 1982, representatives of the Company met with Staff and agreed that there were no unresolved issues with reference to a refund of excessive earnings for 1980. A Stipulation was accordingly executed whereupon it was agreed:

1. That Florida Public Utilities Company experienced overearnings of $94,440 for the twelve months ended December 31, 1980.

2. That the $94,440 of overearnings should be refunded, as a one time refund, to all of its jurisdictional customers, thirty (30) days after the date of the order approving this Stipulation is issued.

3. That no reduction [*3] in rates will be imposed as a result of the $94,440 overearnings for the twelve month period ended December 31, 1980.

4. That the Commission retains jurisdiction over any Fernandina Beach Division overearnings for the twelve month period ended December 31, 1981, and for any other appropriate purpose in this docket.

5. That the data necessary to evaluate whether any overearnings occurred during the twelve months ended December 31, 1981 shall be submitted by March 1, 1982.

We have reviewed the Company's earnings for 1980, considered other actions which may be available to us under Florida Statutes and conclude and find that the acceptance of the Stipulation would be in the best interest of the ratepayers of Florida Public Utilities Company.

The refund amount shall be calculated by dividing the $94,440 by the previous month's KWH consumption, and be applied to each customer's KWH consumption during the month immediately preceding the month during which a refund is consummated, and be displayed as a credit on each customer's bill. The Company shall provide a written report to our Electric and Gas Department (Rate Section) upon completion of the refund indicating the actual [*4] dollar amount of the refund. It is, further

ORDERED by the Florida Public Service Commission, that the Stipulation dated January 20, 1982, entered into by Florida Public Utilities Company and Florida Public Service Commission Staff, and attached hereto, is hereby accepted and approved. It is further

ORDERED that Florida Public Utilities Company refund the amount of $94,440 as calculated herein. It is, further

ORDERED that the Company shall submit a report to the Commission Clerk showing the aggregate refunds made and the amount per customer class within sixty (60) days from the date this Order is issued.

By ORDER of the Florida Public Service Commission, this 17th day of February 1982.

In re: Investigation into 1999 earnings of Florida Public Utilities Company - Fernandina Beach Division

DOCKET NO. 001147-EI; ORDER NO. PSC-00-1883-PAA-EI

Florida Public Service Commission

2000 Fla. PUC LEXIS 1203

00 FPSC 10:163

October 16, 2000

CORE TERMS: earnings, accrual, customer, ceiling, deposit, annual, working capital, effective, rate base, storm, plant, overearnings, calculation, electric, rate case, surveillance, water, net operating income, rate of return, capital structure, accounts payable, flexibility, decrease, updated, yearly, charitable contributions, gross distribution, provision account, commercial paper, interest expense

[*1] The following Commissioners participated in the disposition of this matter: J. TERRY DEASON, Chairman, E. LEON JACOBS, JR., LILA A. JABER, BRAULIO L. BAEZ

NOTICE OF PROPOSED AGENCY ACTION ORDER DETERMINING AND DISPOSING OF EXCESS EARNINGS FOR 1999

BY THE COMMISSION:

NOTICE is hereby given by the Florida Public Service Commission that the action discussed herein is preliminary in nature and will become final unless a person whose interests are substantially affected files a petition for a formal proceeding, pursuant to Rule 25-22.029, Florida Administrative Code.

Pursuant to this Commission's continuing earnings surveillance program, we noted that the 1999 earnings of the Florida Public Utilities Company - Fernandina Beach Division (FPUC-FB or the Company) were in excess of the maximum authorized return on equity (ROE) of 12.60%. As a result, an earnings audit of the Company's books and records was performed, and the audit report was issued on June 19, 2000.

By letter dated February 17, 2000, the Company agreed to cap its 1999 earnings at a 12.60% ROE. The Commission was to use its discretion to dispose of any excess earnings. The Company, however, did reserve [*2] the right to request alternative disposition such as additional contributions to its Storm Damage Reserve or the reduction of any depreciation reserve deficiencies. On July 20, 2000, the Company submitted a letter requesting that the 1999 overearnings be applied to the Fernandina Beach Storm Damage Reserve.

At the end of 1999, Florida Public Utilities-Fernandina Beach Division served approximately 12,800 customers on Amelia Island in Nassau County. This included approximately 11,445 residential, 1,340 commercial accounts, and two industrial accounts.

Jurisdiction over the subject matter of this docket is vested in the Commission pursuant to Sections 366.04, 366.05, and 366.06, Florida Statutes.

Rate Base

In its 1999 Earnings Surveillance Report (ESR), the Company reported a total "FPSC Adjusted" rate base of $ 16,132,575. Based on the adjustments discussed below, we find that the appropriate rate base is $ 16,170,276. These adjustments and calculations are shown in Attachment A to this Order, which is incorporated herein by reference.

Common Plant Allocations - According to Audit Exception 1, the Company used amounts determined in 1998 to allocate common plant between the [*3] electric and water divisions. However, these amounts should have been updated to reflect the current amounts as of December 31, 1999. Based on a recalculation using the updated amounts, the following increases to FPUC-FB should be made: $ 99,661 to Plant in Service and $ 20,786 to Accumulated Depreciation; and a decrease of $ 1,720 to Depreciation Expense.

Application of 1998 Overearnings to the Storm Damage Reserve - Included in working capital is $ 94,800 on a 13-month average basis related to the 1998 excess earnings of $ 139,228. In the review of 1998 earnings, in Order No. PSC-99-2119-PAA-EI, issued October 25, 1999, we stated, "...the 1998 excess earnings [$ 139,228] of FPUC-FB shall be applied to the FPUC-FB's Storm Damage Reserve" effective January 1, 1999. Based on the Order, the Storm Damage Reserve should be increased by $ 44,428 ($ 139,228-$ 94,800). Because this account is a working capital liability, the change reduces working capital. Therefore, working capital should be reduced by $ 44,428.

Working Capital - Allocation of Accounts Payable - In computing the allowance for working capital, the Company used 1998 base revenue allocation factors of 18.5% instead [*4] of 1999 factors of 18.1% to allocate other accounts payable (accounts payable not directly associated with a specific division) to the Fernandina Beach Electric Division. The application of the updated allocation factors decreases FPUC-FB's accounts payable and thereby increases its working capital by $ 3,254.

Rate of Return

After making the following adjustments, we find that the appropriate overall rate of return for FPUC-FB is 8.96% based on the ROE cap of 12.60% and a 13-month average capital structure for the period ending December 31, 1999. These adjustments and calculations are shown on Attachment B to this Order, which is incorporated herein by reference.

In making these adjustments, we begin with the 13-month average capital structure from the Company's earnings surveillance report (ESR) for the period ending December 31, 1999. In its ESR, the Company removed its investment in Flo-Gas entirely from common equity in a manner consistent with previous cases. The Company specifically identified deferred taxes, investment tax credits and customer deposits.

We find that a specific adjustment should be made in the amount of $ 101,467. This amount represents our calculation [*5] of the 13-month average balance of excess earnings for 1999. This amount was included as a separate line item in the capital structure and was assigned an effective cost rate of 5.06%. The cost rate on excess earnings is based on a 12-month average of the 30-day commercial paper rate. The 30-day commercial paper rate is applied as per Rule 25-6.109, Florida Administrative Code. The treatment of excess earnings as an item in the capital structure is consistent with the treatment of excess earnings in the previous earnings review of FPUC-FB (see Order No. PSC-99-2119-PAA-EI, issued October 25, 1999).

We find that a specific adjustment should be made to reduce customer deposits by $ 132,186. The customer deposit account in the Fernandina Beach Division includes both water and electric customers. The amount included in the cost of capital schedule is allocated to the electric division based on a revenue factor. The factor of 94.7% is the factor used in the 1995 Fernandina Beach Water rate case to separate water and electric customer deposits.

In the 1999 Fernandina Beach Water rate case for the historical test year ended December 31, 1998, the Company used a revenue factor of 24.5% for [*6] the water customers. Conversely, the factor for the electric customers should be 75.5%. We believe that the customer deposits should be allocated using the factor from the most recent Fernandina Beach Water rate case. Our calculations comparing the 94.7% and the 75.5% show that customer deposits should be reduced by $ 132,186.

The Company calculated an effective customer deposit cost rate of 6.57%, by using interest expense for 1999, which included an estimated interest expense for the month of May, and a 13-month average balance of customer deposits. Using actual interest expenses for the year and the 13-month average balance of customer deposits, we calculate an effective cost rate of 6.35% for customer deposits. We find that using actual interest expenses in determining the cost rate is appropriate.

We find that the remaining adjustments to rate base should be reconciled on a pro rata basis over investor-supplied sources of capital. The Commission established the return on common equity for FPUC-FB as 11.60% with a range from 10.60% to 12.60% (see Order No. PSC-94-0983-FOF-EI, issued August 12, 1994) Using the top of the range of 12.60%, we find that the weighted average [*7] cost of capital as 8.96%. This is the rate of return to be used to measure excess earnings.

Net Operating Income

In its December 1999 Earnings Surveillance Report, the Company reported an "FPSC Adjusted" net operating income of $ 1,565,836. Based on the adjustments discussed below, we find that the appropriate net operating income is $ 1,573,213.

Out of Period Expenses - The Company included an adjustment increasing operation and maintenance expenses that were incurred in December 1999 but not accrued until January 2000. However, these expenses in the amount of $ 6,575 were already in the December 1999 general ledger. Therefore, we find that an adjustment of $ 6,575 should be made to remove the duplicate expenses from 1999 expenses.

Charitable Contributions and Institutional/Goodwill Advertising - The Company recorded expenses for charitable contributions, which the Commission has a general policy of disallowing. In addition, one of these expenses was recorded twice. Therefore, we find that an adjustment of $ 3,403 should be made to remove these expenses from NOI. Also, the Company included advertising expenses in the amount of $ 597 in Account 115.4010.9301, Institutional/Goodwill [*8] Advertising. These ads were Thanksgiving and Christmas greetings from the Company and did not promote either safety or conservation related themes. Therefore, we find that an adjustment of $ 597 to reduce 1999 expenses should be made, resulting in a total decrease of $ 4,000 to Operation & Maintenance Expenses - Other.

Tax Effect of Other Adjustments - The tax effect of our adjustments to NOI results in a $ 4,918 increase in income taxes.

Interest Reconciliation and ITC Interest Synchronization - This adjustment is based on the reconciliation of the rate base and the capital structure due to adjustments to rate base. In this instance, income taxes should be increased by $ 292.

Excess Earnings

Based on our findings above, we find that FPUC-FB's excess earnings for 1999 are $ 199,380 plus interest of $ 5,290, for a total of $ 204,670. This represents an achieved ROE of 14.73% which exceeds the maximum ROE of 12.60%. Our calculation of the excess earnings, including interest, is shown in Attachment C to this Order, which is incorporated herein by reference.

Disposition of Excess Earnings

The Commission, by Order Nos. PSC-97-0135-FOF-EI, issued February 10, 1997, [*9] and PSC-97-1505-FOF-EI, issued November 25, 1997, found that FPUC-FB's excess earnings for 1995 and 1996 should be applied to the Storm Damage Reserve.

The Commission approved, by Order No. PSC-94-0170-FOF-EI, issued February 10, 1994, an annual accrual of $ 100,000 to establish a $ 1 million storm damage reserve over 10 years for the Company's Marianna Division. The reserve balance at June 30, 2000, was $ 588,661 for the Marianna Division. For the Fernandina Beach Division, the Commission approved, by Order No. 22224, issued November 27, 1989, an annual accrual of $ 21,625; no target amount for the reserve was discussed in the order. The reserve balance at June 30, 2000, was $ 732,511 for the Fernandina Beach Division.

By letter dated July 20, 2000, the Company requested that the 1999 overearnings for FPUC-FB be applied to the Storm Damage Reserve. The Company believes that the reserve is deficient based on the greater potential for loss due to a larger gross plant investment for Fernandina Beach than Marianna and a more vulnerable coastal location. The gross plant investment in Fernandina Beach exceeds that of Marianna by approximately 24%. In the 1988 Fernandina Beach rate case, [*10] the Commission recognized the need for the accrual to be 25% greater than that of Marianna based on size and location.

We agree with the Company's belief that there continues to be a deficiency in the Storm Damage Reserve for the Fernandina Beach Division even after contributing overearnings from prior years. Therefore, we find that the 1999 overearnings should be applied to the reserve.

Since the excess earnings occurred during 1999 and interest has only been calculated for that year, we find that the increase to the reserve be made effective as of January 1, 2000, for all regulatory purposes. This eliminates the need for the calculation of any additional amounts of interest and includes the increased reserve in the determination of earnings for 2000. This treatment is consistent with Order Nos. PSC-97-0135-FOF-EI, PSC-97-1505-FOF-EI, PSC-99-0022-FOF-EI, and PSC-99-2119-PAA-EI in the prior FPUC-FB earnings dockets.

Establishment of Storm Damage Reserve Ceiling

The first storm damage accrual for the FPUC-FB was authorized in 1989 in Docket 881056-EI, Order No. 22224, issued November 27, 1989. It stated, "...we feel that it is appropriate to normalize expenses caused by unusual [*11] events, such as storms, and therefore will allow the utility to establish this account. However...we will allow an annual accrual of $ 21,625, which is 25% larger than that allowed in the Marianna rate case." Earlier in 1989, the Commission approved a Storm Damage accrual of $ 17,300 yearly for the Marianna Division.

After Hurricane Andrew did extensive damage to South Florida and Louisiana in 1992, the Company found it increasingly difficult to purchase storm-related insurance for either of its electric divisions. When the Company filed for a rate increase for the Marianna Division in 1993, it requested an increase in the Storm Damage Reserve from the original $ 17,300 per year approved in 1989, to an increase to $ 200,000 yearly until the requested ceiling of $ 1,000,000 was reached. The Commission approved the ceiling of $ 1,000,000, but felt that an annual accrual of $ 100,000 would result in lesser pressure on rates. The approved ceiling and annual accrual are still in effect for the Marianna Division.

The Fernandina Beach Division has not had a full rate case since the original establishment of its reserve in 1989, and in spite of the insurance difficulties caused [*12] by Hurricane Andrew, the Company has not requested an increase in its accrual or the establishment of a ceiling for the reserve. For several years, however, the FPUC-FB has experienced rapid growth due to Amelia Island's development as a resort area. This rapid growth resulted in several years of overearnings. The Commission, at the Company's request, has ordered these overearnings placed in the Storm Damage Reserve. As of June 30, 2000, the reserve amount is $ 732,511, or slightly less than half of the recommended ceiling.

We find that a ceiling should be established in conjunction with the finding below to grant the Company the flexibility to increase its annual accrual to the Reserve whenever it feels earnings will justify such increases. Additionally, we find that the ceiling should be set higher than the ceiling set for Marianna since the Fernandina Beach Division has approximately 10% more in gross distribution plant. For these reasons, we find that a ceiling should be established for the Storm Damage Reserve at $ 1,500,000.

Increase in Annual Accrual for Storm Damage Reserve

As noted, the Fernandina Beach Division's Storm Damage Reserve account has a relatively low balance [*13] of $ 732,511 as of June 30, compared to the approved ceiling of $ 1,500,000. At the current accrual amount of $ 21,625 annually, it will take over 35 years to reach the target level, assuming no storm damage. The present amount of the storm damage reserve would be sufficient to replace only approximately 3 1/2% of gross distribution plant in the event of a major storm.

We find that the Company should be given the flexibility to increase its annual accrual to the accumulated provision account, when the Company believes it is in a position from an earnings standpoint to do so, up to the ceiling of $

1,500,000. This is similar flexibility that the Commission granted Gulf Power Company in Order No. PSC-96-0023-FOF-EI, issued January 19, 1996. Florida Public Utilities is still required to record an annual accrual to the Fernandina Beach Storm Damage Reserve of at least $ 21,625 until the Reserve reaches $ 1,500,000. Also, the Company shall provide a statement on its future earnings surveillance report when the adjustment is made to increase the amount charged to expense.

Based on the foregoing, it is

ORDERED by the Florida Public Service Commission that the Florida Public Utilities Company [*14] - Fernandina Beach Division achieved excess earnings for 1999 which, together with applicable interest, total $ 204,670, as discussed in the body of this Order. It is further

ORDERED that the Florida Public Utilities Company - Fernandina Beach Division shall apply its total 1999 excess earnings of $ 204,670 to its Storm Damage Reserve, effective January 1, 2000, for ratemaking, earnings surveillance, and earnings review purposes. It is further

ORDERED that the Storm Damage Reserve ceiling for Florida Public Utilities Company - Fernandina Beach Division be established at $ 1,500,000. It is further

ORDERED that Florida Public Utilities - Fernandina Beach Division may increase its annual accrual in the Storm Damage Reserve above the present $ 21,625 yearly accrual until the accumulated provision account balance reaches $ 1,500,000. It is further

ORDERED that the provisions of this Order, issued as proposed agency action, shall become final and effective upon the issuance of a Consummating Order unless an appropriate petition, in the form provided by Rule 28-106.201, Florida Administrative Code, is received by the Director, Division of Records and Reporting, 2540 Shumard Oak [*15] Boulevard, Tallahassee, Florida 32399-0850, by the close of business on the date set forth in the "Notice of Further Proceedings" attached hereto. It is further

ORDERED that in the event this Order becomes final, this docket shall be closed.

By ORDER of the Florida Public Service Commission this 16th day of October, 2000.

BLANCA S. BAYO, Director

Division of Records and Reporting

FLORIDA PUBLIC UTILITIES COMPANY

FERNANDINA BEACH ELECTRIC DIVISION

DOCKET NO. 001147-EI

REVIEW OF 1999 EARNINGS

ATTACHMENT A

	As Filed FPSC Adjusted Basis	Common Plant Allocations	Application of 1998 Overearnings to Storm Damage Reserve
RATE BASE			
Plant in Service	$ 27,588,624	$ 99,661	
Accumulated Depreciation	10,718,104	20,786	
Net Plant in Service	16,870,420	78,875	
Property Held for Future Use	0		
Construction Work in Progress	234,788	0	
Net Utility Plant	17,105,208	78,875	
Working Capital	(972,833)		(44,428)
Total Rate Base	$ 18,132,575	$ 78,875	($ 44,428)
INCOME STATEMENT			
Operating Revenues	$ 6,457,338		
Operating Expenses:			
Operation & Maintenance - Fuel	0		
Operation & Maintenance - Othe	1,951,810		
Depreciation & Amortization	1,026,552	(1,720)	
Taxes Other Than Income	1,435,448		
Income Taxes - Current	490,604	647	
Deferred Income Taxes (Net)	24,116		
Investment Tax Credit (Net)	(37,027)		
(Gain)/Loss on Disposition	0		
Total Operating Expenses	4,891,503	(1,073)	
Net Operating Income	$ 1,565,838	$ 1,073	$ 0
EQUITY RATIO	45.07%		
OVERALL RATE OF RETURN	9.71%		
RETURN ON EQUITY	14.88%		

[*16]

	Working Capital Allocation of A/P	Out of Period Expenses	Charitable Contributions Advertising Expense
RATE BASE			
Plant in Service			
Accumulated Depreciation			
Net Plant in Service			
Property Held for Future Use			
Construction Work in Progress			
Net Utility Plant			
Working Capital	3,254		
Total Rate Base	$ 3,254		
INCOME STATEMENT			
Operating Revenues			

Operating Expenses:			
Operation & Maintenance - Fuel			
Operation & Maintenance - Othe		(6,575)	(4,000)
Depreciation & Amortization			
Taxes Other Than Income			
Income Taxes - Current		2,474	1,505
Deferred Income Taxes (Net)			
Investment Tax Credit (Net)			
(Gain)/Loss on Disposition			
Total Operating Expenses		(4,101)	(2,495)
Net Operating Income	$ 0	$ 4,101	$ 2,495
EQUITY RATIO			
OVERALL RATE OF RETURN			
RETURN ON EQUITY			

	Interest Reconciliation/ ITC Synchronization	Total Adjustments	Total Adjusted Rate Base
RATE BASE			
Plant in Service		$ 99,681	$ 27,688,185
Accumulated Depreciation		20,785	10,738,890
Net Plant in Service		78,875	16,949,295
Property Held for Future Use		0	0
Construction Work in Progress		0	234,788
Net Utility Plant		78,875	17,184,083
Working Capital		(41,174)	(1,013,607)
Total Rate Base		$ 37,701	$ 16,170,276
INCOME STATEMENT			
Operating Revenues		$ 0	$ 6,457,339
Operating Expenses:			
Operation & Maintenance - Fuel		0	0
Operation & Maintenance - Othe		(10,575)	1,941,235
Depreciation & Amortization		(1,720)	1,024,532
Taxes Other Than Income		0	1,435,448
Income Taxes - Current	292	4,918	495,522
Deferred Income Taxes (Net)		0	24,116
Investment Tax Credit (Net)		0	(37,027)
(Gain)/Loss on Disposition		0	0
Total Operating Expenses	292	(7,377)	4,884,126
Net Operating Income	($ 292)	$ 7,377	$ 1,573,213
EQUITY RATIO		0.00%	45.07%
OVERALL RATE OF RETURN		0.02%	9.73%
RETURN ON EQUITY		0.05%	14.73%

[*17]

ORDER NO. PSC-00-1883-PAA-EI

FLORIDA PUBLIC UTILITIES COMPANY

FERNANDINA BEACH ELECTRIC DIVISION

DOCKET NO. 001147-EI

REVIEW OF 1999 EARNINGS

ATTACHMENT B

CAPITAL STRUCTURE AS FILED - FPSC ADJUSTED	Amount	Ratio	Cost Rate	Weighted Cost
Long Term Debt	$ 5,141,971	31.87%	9.93%	3.17%
Short Term Debt	1,930,043	11.86%	5.56%	0.67%
Preferred Stock	135,143	0.84%	4.75%	0.04%
Customer Deposits	651,980	4.04%	6.57%	0.27%
Common Equity	5,913,464	36.68%	12.60%	4.62%
Deferred Income Taxes	2,036,649	12.62%	0.00%	0.00%
Tax Credits - Zero Cost	1,719	0.01%	0.00%	0.00%
Tax Credits - Weighted Cost	321,606	1.99%	10.44%	0.21%
Total	$ 16,132,575	100.00%		8.96%

		Adjustments		Adjusted
ADJUSTED	Amount	Specific	Pro Rate	Total
Long Term Debt	$ 5,141,971		$ 28,814	$ 5,168,785
Short Term Debt	1,930,043		10,065	1,940,108
Preferred Stock	135,143		705	135,848
Customers Deposits	851,980	(132,186)		519,794
1999 Excess Earnings	0	101,467		101,487
Common Equity	5,913,464		30,837	5,944,301
Deferred Income Taxes	2,036,649			2,036,649
Tax Credits - Zero Cost	1,719			1,719
Tax Credits - Weighted Cost	321,606			321,606
Total	$ 16,132,575	($ 30,719)	$ 68,420	$ 16,170,276

[*18]

ADJUSTED	Ratio	Cost Rate	Weighted Cost
Long Term Debt	31.96%	9.93%	3.17%
Short Term Debt	12.00%	5.56%	0.67%
Preferred Stock	0.84%	4.75%	0.04%
Customers Deposits	3.21%	8.35%	0.20%
1999 Excess Earnings	0.63%	5.06%	0.03%
Common Equity	36.76%	12.60%	4.63%
Deferred Income Taxes	12.60%	0.00%	0.00%
Tax Credits - Zero Cost	0.01%	0.00%	0.00%
Tax Credits - Weighted Cost	1.99%	10.44%	0.21%
Total	100.00%		8.96%

FLORIDA PUBLIC UTILITIES COMPANY

FERNANDINA BEACH ELECTRIC DIVISION

DOCKET NO. 001147-EI

REVIEW OF 1999 EARNINGS

ATTACHMENT C

Adjusted Rate Base		$ 16,170,276
ROR @ 12.60% ROE	x	8.96%
Maximum allowed Net Operating Income		1,448,857
Achieved Net Operating Income		1,573,213
Excess Net Operating Income		124,356
Revenue Expansion Factor	x	1,6033
Excess Revenues		199,380
Interest		5,290
TOTAL 1999 EXCESS REVENUE		$ 204,670

In re: Petition of Gulf Power Company for an increase in its rates and charges

DOCKET NO. 891345-EI; ORDER NO. 23573

Florida Public Service Commission

1990 Fla. PUC LEXIS 1320; 120 P.U.R.4th 1

90-10 FPSC 195

October 3, 1990

CORE TERMS: customer, rate base, energy, standby, plant, outage, rate case, load, allocated, kwh, projected, working capital, rate of return, load factor, methodology, reduction, billing, net operating income, classified, fuel, appliance, budgeted, peak, demand-related, mismanagement, ratepayers, billed, rider, customer-related, maximum

G. EDISON HOLLAND, JR. and JEFFREY A. STONE, Esquires, Beggs and Lane, P.O. Box 12950, Pensacola, Florida 32576, on behalf of Gulf Power Company

JACK SHREVE and STEPHEN C. BURGESS, Esquires, Office of the Public Counsel, c/o The Florida Legislature, 111 West Madison Street, Room 812, Tallahassee, Florida 32399-1400, On behalf of the Citizens of the State of Florida

GARY A. ENDERS, Major, USAF, HQ USAF/ULT, Stop 21, Tyndall AFB, Florida 32403-6001, On behalf of the Federal Executive Agencies

JOSEPH A. McGLOTHLIN and JOHN W. McWHIRTER, JR., Esquires, Lawson, McWhirter, Grandoff & Reeves, 522 East Park Avenue, Suite 200, Tallahassee, Florida 32301, on behalf of the Industrial Intervenors

RONALD C. LaFACE and WILLIAM L. HYDE, Esquires, Roberts, Baggett, LaFace and Richard, P.O. Drawer 1838, Tallahassee, Florida 32302, On behalf of the Florida Retail Federation

ROBERT VANDIVER, MARSHA RULE and MICHAEL PALECKI, Esquires, Legal Division, Florida Public Service Commission, 101 East Gaines Street, Tallahassee, Florida 32399-0850, On [*2] behalf of the Staff of the Florida Public Service Commission

PRENTICE P. PRUITT, Esquire, Office of the General Counsel, Florida Public Service Commission, 101 East Gaines Street, Tallahassee, Florida 32399-0850, On behalf of the Commissioners

[*1]

The following Commissioners participated in the disposition of this matter: MICHAEL McK. WILSON, Chairman; THOMAS M. BEARD; BETTY EASLEY; GERALD L. GUNTER

Pursuant to duly given notice, the Florida Public Service Commission held public hearings in this docket on April 5, 1990, in Panama City, Florida; April 4, 1990, in Pensacola, Florida; and June 11 through June 21, 1990, in Tallahassee, Florida. Having considered the record herein, the Commission now enters its final order.

ORDER GRANTING CERTAIN INCREASES

BY THE COMMISSION:

On December 15, 1989, Gulf Power Company (Gulf or Company) filed its petition for permanent and interim increases to its rates and charges. In its petition, Gulf requested a permanent increase in its rates and charges designed to generate an additional in its rates and charges designed to generate an additional $ 26,295,000 of gross annual revenues. This request was based upon a projected 1990 test year and a 13-month average jurisdictional rate base of $ 923,562,000. Gulf requested an overall rate of return of 8.34%, which assumed an allowed rate of return on common [*3] equity of 13.00%. The most significant basis for the requested increase, according to Gulf, was the commitment of over 500 MW of additional capacity from its Plants Daniel and Scherer to territorial service and the O&M expenses associated with this capacity. Additionally, the utility claimed an increase in net operating income resulting from substantial capital additions in the transmission, distribution, and general plant areas as well as increased O&M expenses.

Pursuant to Section 366.06(3), Florida Statutes, Order No. 22681, issued on March 13, 1990, suspended Gulf's permanent rate schedules and granted Gulf an interim rate increase of $ 5,751,000 in annual revenues.

The Federal Executive Agencies (FEA), and Industrial Intervenors (II) were granted intervention status in this docket by Orders Nos. 22363 and 22878, respectively. Order No. 22953, issued on May 18, 1990, granted intervention status to the Florida Retail Federation (FRF). The Office of the Public Counsel (OPC) is a party to this docket pursuant to Section 350.0611, Florida Statutes.

I. SUMMARY OF DECISION

We authorize Gulf an increase in gross annual revenues of $ 11,838,000 for two years beginning September [*4] 13, 1990. Thereafter, we authorize Gulf an increase in gross annual revenues of $ 14,131,000.

We have set the rate of return on common equity capital at 12.55%. The reduced increase in gross annual revenues for the two years beginning September 13, 1990, reflects a 50 basis point penalty on return on equity imposed for mismanagement.

II. REVENUE REQUIREMENTS DETERMINATION

The revenue requirements of a utility are derived by establishing its rate base, net operating income (NOI) and fair rate of return. A test year of operations, traditionally based upon one year of operations, is used to derive these factors. Multiplying the rate base by the fair rate of return provides the net operating income the utility is permitted to earn. Comparing the permitted net operating income with the test year net operating income determines the net operating income deficiency or excess. The total test year revenue deficiency or excess is determined by adjusting the deficiency or excess by the revenue expansion factor.

III. THE TEST YEAR

The test year in a rate case provides a set period of utility operations that may be analyzed so the Commission can set reasonable rates for the period [*5] the rates will be in effect. A test period may be based upon an historic test year, adjusted to reflect typical conditions in the immediate future, which should make it reasonably representative of expected future operations. Alternatively, a test period may be based upon a projected test period which, if appropriately developed and adjusted, may reasonably represent expected future operations. We approved Gulf's choice of calendar year 1990 as a projected test year.

IV. TEST YEAR RATE BASE

To establish the Company's overall revenue requirements, we must determine its rate base. The rate base represents that investment on which the Company is entitled to earn a reasonable return. A utility's rate base is comprised of various components. These include: 1) net utility plant-in-service, which is comprised of plant-in-service less accumulated depreciation and amortization; 2) total net utility plant, which is comprised of net utility plant-in-service, Construction Work in Progress (CWIP) (where appropriate) and plant held for future use; and 3) working capital.

Gulf has submitted a proposed jurisdictional rate base of $ 923,562,000. Evidence developed during the course of the [*6] proceedings has led us to reduce that amount to $ 861,159,000. Our adjustments are set forth as follows:

1990 Rate Base
Jurisdictional (000's)

		GULF	ADJUSTMENTS	ADJUSTED RATE BASE
A.	Utility Plant-in-Service	$ 1,275,624	($ 57,337)	$ 1,218,287
B.	Accumulated Depreciation	(454,964)	(6,913)	(448,051)
C.	Net Plant-in-Service	820,660	(50,424)	770,236
D.	Construction Work in Progress	14,949	- 0 -	14,949
E.	Property Held for Future Use	3,925	(135)	3,790
F.	Acquisition Adjustment	2,317	(2,317)	- 0 -
G.	Net Utility Plant	841,851	(52,876)	788,975
H.	Working Capital	81,711	(9,527)	72,184
I.	Total Rate Base	$ 923,562	($ 62,403)	$ 861,159

A. Plant-In-Service

The amount of plant-in-service proposed by Gulf was $ 1,275,624,000. We have made certain adjustments, described below, which reduce plant-in-service to $ 1,218,287,000.

	(000s)
Plant-In-Service per Gulf	$ 1,275,624
Adjustments:	
1. New Corporate Headquarters	(3,892)
2. Navy House	(23)
3. Appliance Division	(214)
4. Tallahassee Office	(24)
5. Leisure Lakes	(142)
6. Plant Scherer	(52,987)
7. Misc. Plant-In-Service	(55)
Total Adjustments	(57,337)
Adjusted Plant-In-Service	$ 1,218,287

[*7]

1. New Corporate Headquarters

Gulf's new corporate office building occupies 17.42 acres on Bayfront Parkway overlooking Pensacola Bay. The building is five stories tall and each floor has approximately 50,000 square feet of space. A level below the building is for parking company vehicles. The building was occupied March 31, 1987.

The total building area is 308,634 square feet and consists of 149,945 square feet of office space, 57,057 square feet of parking garage, 41,237 square feet for specialty areas, and 8,832 square feet for the equipment room. The specialty areas are the mailroom and duplicating, cafeteria, system control and ready room, auditorium, MIS computer center, communications, and the like. In addition to the square footage described above, 51,563 square feet on the third floor is presently unfinished and used as a temporary storage and maintenance area.

We believe that the cost of the third floor of $ 3,840,807 should be removed from plant-in-service. Evidence developed during the course of the proceedings indicates that Gulf has adequate space for storage and maintenance functions at other locations. We find that the ratepayers of Gulf receive no benefit [*8] from Gulf's use of the third floor for storage and maintenance and therefore disallow $ 3,840,807. Gulf is allowed, however, to earn a deferred return on this plant investment and related expenses equal to the allowance for funds used in construction (AFUDC).

The Business Development Center occupies 495 square feet on the first floor of the Corporate Headquarters Building. The room was designed and furnished for presentations to representatives of businesses that are interested in moving to Northwest Florida, and for press conferences relating to weather-related emergencies. The Center is equipped with laser disk players, color monitors, and VCR's that allow prospective business customers to view various areas, industrial parks, and cities in Northwest Florida with an eye toward relocation to this area. The purpose of the laser disk players and VCR's is their use in economic development efforts. The investment capitalized for the Business Development Center in 1987 was $ 51,548. There has been no capital investment since 1987 and none is projected for 1990. We believe that $ 51,548 should be removed from rate base for the Business Development Center since the recruitment of [*9] business and industry to Florida is not a responsibility of a regulated public utility. The Chamber of Commerce and the Florida Department of Commerce perform that function. The total disallowance for the new corporate headquarters is $ 3,892,355.

2. Navy House

The Navy House is a former residence which became the property of the company when it purchased land needed to install a transmission line from the company's Bayou Chico Substation to serve the Pensacola Naval Air Station. The initial purchase price of the land and the home on the land was $ 110,000. We have no reason to believe the price paid was not proper; this amount is not at issue. In addition to the purchase price, however, the company completely renovated the residence to serve as additional training space for its employees. There appears to be ample training space at Gulf's Chase Street facility and at the new corporate headquarters. We therefore find that rate base should be reduced by $ 23,257 and that 1990 operating expenses for the Navy House be reduced by $ 7,516.

3. Appliance Division

Gulf has an appliance sales and service operation which is operated out of Gulf buildings which are included in rate [*10] base. A portion of this investment has been removed from rate base based on usage studies performed by Gulf. In several instances, the appliance operation has its own buildings which are recorded in non-utility plant.

Gulf made an error in allocating the plant investment to the appliance operation. Therefore, it would be proper to correct the error by reducing plant, accumulated depreciation and depreciation expense $ 214,000, $ 7,000 and $ 12,000, respectively.

4. Tallahassee Office

Gulf maintains an office in Tallahassee for use by its lobbyist, PSC liaison and other Pensacola-based employees while conducting business in Tallahassee. The office space is leased while the office furniture has been capitalized by the company and included in rate base. In addition, Gulf's lobbyist has a company car which is also included in rate base.

Gulf has agreed that 25% of the office investment which is used for lobbying activity should be removed from rate base. In addition Gulf agrees that 100% of the lobbyist's car should be removed. We believe these percentages are reasonable and make the following adjustments:

Reduce Plant-In-Service	$ 23,860
Accumulated Depreciation	11,193
Depreciation Expense	1,217

[*11]

5. Leisure Lakes Subdivision (Greenhead Substation)

On October 18, 1984, in Docket No. 830484-EU, Gulf Coast Electric Cooperative, Inc. (Gulf Coast) petitioned the Commission for resolution of a territorial dispute between itself and Gulf Power Company. The dispute involved the Leisure Lakes Subdivision, which consists of approximately 2,300 acres divided into approximately 750 lots. The dispute arose when Gulf Power constructed 2.2 miles of distribution line from its transmission line to the subdivision along a graded county road. After Gulf Coast's petition was filed, and with knowledge of the Commission's jurisdiction over the matter, Gulf Power also constructed the Greenhead substation near the site. In Order No. 13668 we determined that Gulf Coast was entitled to provide electric service to the disputed area. It was also ordered that Gulf Power is prohibited from serving, either temporarily or permanently, the disputed area. In our order we encouraged Gulf Power to sell the facilities they built to serve Leisure Lakes to Gulf Coast, should Gulf Coast desire to purchase them.

Gulf subsequently sold all of its facilities built to serve Leisure Lakes and has no facilities [*12] in that area except the Greenhead substation. The book value of the facilities Gulf built to serve Leisure Lakes Subdivision was approximately $ 131,000 and the sale price to Gulf Coast was $ 130,353. The Greenhead Substation was not needed to serve load since neither the Sunny Hills or Vernon Substations have reached peak capacity. Therefore, the investment made by Gulf to serve Leisure Lakes subdivision should not be included in rate base. We reduce plant-in-service by $ 142,000 and depreciation expense by $ 5,000.

6. Plant Scherer

Gulf acquired 25 percent of Plant Scherer 3 in 1984 and it came in line in January 1987. Since Plant Scherer came on line after Gulf's last rate case, this is the first time Gulf has requested that a portion of Plant Scherer be included in rate base. Of Gulf's 212 MW share of Scherer 3, 63 MW is available to serve Gulf's territorial customers in 1990 and 149 MW is dedicated to unit power sales. The 63 MW of Scherer 3 that Gulf is requesting to be included in rate base includes 44 MW that would have been sold to Gulf States Utilities if they had not defaulted on a unit power sales contract. Gulf is requesting that 63 megawatts of its 212 megawatt [*13] share of Plant Scherer 3 be included in its rate base.

Gulf's reserves are reasonable with or without Scherer. Without Scherer, Gulf's reserves are 21.9 percent and with 63 megawatts of Scherer, Gulf's reserves are 25.5 percent. Gulf's parent corporation, Southern Company, maintains reserves which are 19.9 percent without Scherer and 20.1 percent with Scherer. It appears that with or without Plant Scherer, Gulf is well able to achieve its target reserves of 20 to 25 percent.

Gulf will be selling increasing amounts of Scherer's capacity as unit power sales starting in 1992. The following table shows the amount of Scherer dedicated to Gulf's territorial customers from the year 1990 to the year 2010.

Time	Capacity Available to Retail Customers
January 1990 - May 1992	63 megawatts
June 1992 - December 1992	11 megawatts
January 1993 - May 1993	37 megawatts
June 1993 - December 1993	16 megawatts
January 1994 - May 1994	17 megawatts
June 1994 - May 1995	35 megawatts
June 1995 - May 2010	0 megawatts

As shown above, Gulf is scheduled to sell increasing amounts of Scherer 3 under unit power sales agreements starting in 1992. By 1995, none of Scherer 3 will be available [*14] to serve Gulf's territorial customers. This capacity will not be available to serve Gulf's territorial customers until the year 2010. Since Gulf is dedicating this unit to unit power sales in years that Gulf's territorial load is expected to be greater than it is in 1990, it would appear that Gulf does not need the unit in 1990 for its territorial customers.

Under Southern's contract with Gulf States Utilities, Gulf had committed to sell 44 MW of Scherer 3 to Gulf States Utilities during the test year 1990 through May, 1992. Gulf States Utilities failed to perform its contractual obligations and on July 1, 1988, FERC ruled that Southern no longer had to perform under the contract. It is clear that Gulf would not have requested 63 MW of Scherer to be in rate base had Gulf States Utilities not defaulted on their contracts. When Gulf made the decision to purchase 25 percent of Scherer 3 it was aware of the potential that their contract with Gulf States Utilities might not be honored. Since the profits from the unit power sales go to Gulf's stockholder, they should bear the risk of default, and not Gulf's ratepayers. Therefore, we remove all of Plant Scherer from rate base. All [*15] profits and losses derived from unit power sales of Scherer, and any costs or benefits accruing from any settlement with Gulf States Utilities are to go to the stockholders of Gulf Power Company. Gulf's ratepayers, who will not see the profits from Gulf's unit power sales contracts, should not be required to pay when such a contract falls through.

As a result of our exclusion of Scherer 3 from rate base, we make the following rate base and Net Operating Income adjustments:

Plant-in-Service	$ 52,987,000
Accumulated Depreciation	6,557,000
Acquisition Adjustment	2,317,000
Working Capital	2,187,000
O&M - Expenses	722,000
Depreciation Expense	1,701,000
Amortization of Plant Acquisition Adjustment	73,000
Amortization of ITC	(96,000)
Other Taxes	245,000
IIC Offset	(4,792,000)

7. Miscellaneous Plant-In-Service

We have made miscellaneous plant-in-service adjustments in the amount of $ 55,000. This resulted from discovery of two work orders that were completed and ready for service but were not immediately transferred to Account 106 (completed construction not classified). As a result, Gulf over-accrued allowance for funds used in construction (AFUDC) [*16] by $ 55,000. We therefore reduce plant-in-service by this amount.

B. Accumulated Depreciation and Amortization

The amount of accumulated depreciation and amortization proposed by Gulf was $ 454,964,000. Our previously discussed adjustments to plant-in-service require a net reduction to accumulated depreciation and amortization of $ 6,913,000. Approved accumulated depreciation and amortization is $ 448,051,000, as follows:

(000s)	
Accumulated Depreciation per Gulf	$ 454,964
Adjustments:	
Appliance Division	(7)

Tallahassee Office	(11)
Plant Scherer	(6,557)
New Corporate Headquarters	(338)
Total Adjustments	(6,913)
Adjusted Depreciation	$ 448,051

C. Net Utility Plant-In-Service

Net utility plant-in-service is comprised of utility plant-in-service, less accumulated depreciation and amortization. We find that the appropriate amount of net utility plant-in-service for test year 1990 is $ 770,236,000.

D. Construction Work in Progress (CWIP)

The company has included $ 14,949,000 of construction work in progress in rate base. We believe this amount is appropriate.

E. Property Held for Future Use

Gulf has included in its rate base the [*17] sum of $ 3,925,000 in plant held for future use. We believe this is appropriate except for the 10% of Gulf's Caryville site which is allocated to the sod farm. The sod farm, known as "Southern Sod Company", occupies approximately 200 acres of property at Gulf's Caryville site, or 10% of the Caryville acreage. Southern Sod leases this acreage from Gulf. This is a non-utility operation and we therefore find that 10% of the value of the Caryville Site included in rate base ($ 135,000) should be removed. We therefore reduce plant held for future use by $ 135,000 to $ 3,790,000. We also remove from "other revenues" the $ 3,450 in lease payments received from Southern Sod.

F. Acquisition Adjustment

As a result of its purchase of a portion of the common facilities at Plant Scherer, Gulf requested an acquisition adjustment of $ 2,317,000. Since we have not allowed Plant Scherer in rate base, no adjustment for its acquisition will be allowed in rate base. We therefore reduce rate base by $ 2,317,000.

G. Net Utility Plant

Based upon the adjustments discussed above, total net utility plant for test year 1990 is $ 788,975,000.

H. Working Capital

The company has included $ 81,711,000 [*18] of working capital in rate base. We have made certain adjustments described below, which reduce working capital to $ 72,184,000.

(000's)	
Working Capital per Gulf	$ 81,711
Adjustments:	
1. Rate Case Expenses	(765)
2. Temporary Cash Investments	0
3. Heavy Oil Inventory	(576)
4. Light Oil Inventory	(123)
5. Coal Inventory	(6,017)

6. Plant Scherer	(2,187)
7. Caryville Subsurface Study	(28)
8. PIP	169
Total Adjustments	(9,527)
Total Working Capital	$ 72,184

1. Unamortized Rate Case Expense

The company has included $ 765,385 in working capital for unamortized rate case expense. Commission policy is to exclude unamortized rate case expense from working capital. We therefore reduce working capital by the entire $ 765,385.

2. Temporary Cash Investments

Gulf, in its rebuttal testimony, has requested $ 6,045,000 in working capital for temporary cash investments. The appropriate regulatory treatment of either continuing cash balances or temporary cash investments should depend upon their prudency. If the utility can demonstrate, through competent evidence, that their cash balances or temporary cash investments are necessary for the [*19] provision of regulated utility service, they should remain in rate base and earn at the utility's overall rate of return. Any earnings generated by these funds should then be used to offset revenue requirements. The burden of proof however is on the Company to demonstrate through competent evidence that their temporary cash investments are necessary for the provision of utility service.

Gulf gave the following reason that temporary cash investments are necessary for its provision of utility service:

The test year amount for Temporary Cash Investments (13-month average amount) of $ 6,399,000 is approximately 10 percent of the average monthly disbursements. In addition we are projecting to borrow funds during five months of the test year. The Company again maintains that these funds are required and necessary in providing utility services for our customers. (Ex. 439)

During cross-examination Gulf's witness stated:

". . . we don't know of any other way to pay our bills than to have cash available. Either you are going to have temporary cash, cash, or short-term debt, one of the three, because if you -- once you stop paying your bills, you're going into bankruptcy at that stage, [*20] and you'll be shut down. You've got to have liquid assets . . ." (TR 793)

While we agree that a company needs to maintain a certain degree of liquidity to operate, we note that Gulf maintains substantial liquidity through short-term debt.

The Company has budgeted to pay $ 60,000 in 1990, for access to lines of credit totalling $ 42 million. In addition, the Company continues to keep compensating balances of $ 436,900 for additional lines of credit totalling approximately $ 6.2 million. Thus, the Company has access to approximately $ 48.2 million through lines of credit.

We do not dispute that the Company needs to maintain a certain degree of liquidity to operate. We believe, however, that the burden is on the Company to demonstrate that the additional liquidity provided by holding $ 6,045,000 in temporary cash investments is necessary. In our opinion the Company has not provided this proof. Statements such as, "its all our available cash" or "temporary cash investments represent less than 10 percent total monthly expenditures" do not constitute competent evidence. We therefore deny Gulf's request that $ 6,045,000 be included in working capital for temporary cash investment. [*21] It is not necessary for us to make an adjustment to working capital since Gulf has already removed temporary cash investments from its filing, consistent with our treatment of this matter in Gulf's last rate case.

3. Heavy Oil Inventory

Gulf has overcalculated the amount of heavy oil inventory necessary for standby fuel at Plant Crist Units 1, 2 and 3. Heavy oil inventory should be reduced to a level equal to seven days burn at 100% capacity factor.

A seven-day supply of heavy oil for Crist Units 1, 2 and 3 operating at 100% of their demonstrated capability would equal 32,774 barrels. Gulf Power has requested a heavy oil inventory of 78,533 barrels with an average price of $ 13.603 per barrel and valued at $ 1,042,000 (system). We will allow a heavy oil inventory level of 32,774 barrels at an average price of $ 13.603 per barrel. We reduce working capital by $ 596,178 (system), or by $ 576,462 (jurisdictional).

4. Light Oil Inventory

Gulf has requested that 650,895 gallons of light fuel oil (system) be included in working capital. We are of the opinion that Gulf has failed to justify its request for light oil inventory. We will allow a level equal to 30 days burn at [*22] the highest average monthly rate which calculates to 383,210 gallons. This would require a reduction in working capital of $ 125,339.

5. Coal Inventory

Gulf has requested a coal inventory level equal to 105 days projected burn. We are of the opinion that Gulf has failed to justify this request and will allow a level equal to 90 days projected burn or the amount actually maintained in the test year at each plant site, whichever is less. In Gulf's system this would amount to a total of 784,887 tons valued at $ 37,000,502 (system). This reduces working capital by $ 6,222,498 (system) or $ 6,016,717 (jurisdictional).

6. Plant Scherer

As previously discussed, our exclusion of Plant Scherer from rate base will result in an adjustment of $ 2,187,000 to working capital.

7. Caryville Subsurface Study

The subsurface study was a geological study of the Caryville site to determine if the land could support the weight of a power plant and supporting facilities. As pointed out in the company's brief, the results of the study are obviously still valid. Such a study would be necessary before any major construction of this type could be done on any site. Therefore, costs associated [*23] with the study should be considered together with the Caryville site itself. Since Caryville remains in Rate Base, the cost of the study or $ 568,000 should be allowed, however we will require that this amount be amortized to expense over a 10 year period. This necessitates a $ 28,000 reduction in working capital.

8. Productivity Improvement Plan (PIP)

The Productivity Improvement Plan (PIP) is a part of the total compensation plan for the top 11 employees of the company. Due to a change in the design of the PIP program after the budgeting process was completed, the company feels a reduction in the program is in order. The original amount for this program was $ 438,473. The company's new amount is $ 99,066. Since it appears that Gulf's overall salary and benefits program is not excessive, and this plan was allowed in the last rate case, the expenses in the amount of $ 99,066 for this program will be allowed. Therefore, expenses should be reduced $ 339,000.

Since this adjustment reduces Accounts Payable, a current liability in working capital, the 13-month average of working capital will be increased by $ 169,187.

I. Total Rate Base

Gulf has submitted a proposed jurisdictional [*24] rate base of $ 923,562,000. Based upon the above described adjustments we have reduced rate base by $ 62,403,000 to $ 861,159,000. See Attachment 1 for a complete breakdown of rate base.

V. FAIR RATE OF RETURN

The Commission must establish the rate of return which the Company should be given an opportunity to earn on its investment in rate base. The fair rate of return should be established so as to maintain the Company's financial integrity and to enable it to acquire needed capital at a reasonable cost.

A. Capital Structure

The ultimate goal of providing a fair rate of return is to allow the utility an appropriate return on its investment in rate base. Because all sources of capital cannot be clearly associated with specific utility property, the Commission has traditionally considered all sources of capital (with appropriate adjustments) in establishing a fair rate of return.

The establishment of a utility's capital structure serves to identify the sources of the capital employed by a utility, as well as the amounts and cost rates associated with each. After establishing the sources of capital, all capital costs, including the cost of equity capital, are weighted according [*25] to their relative proportion to total capital. The weighted components are then added to provide a composite or overall cost of capital. The weighted cost of capital multiplied by the net utility rate base produces an appropriate return on rate base, including a return on equity capital invested in rate base.

B. Cost of Common Equity Capital

To arrive at a fair overall rate of return, it is necessary that we utilize our judgement to establish an allowable rate of return on common equity capital.

This issue was the subject of prefiled testimony by several witnesses. By stipulation of all the parties, their testimony was inserted into the record as though read and the witnesses presence and cross-examination were waived.

The following three witnesses presented testimony on the appropriate cost of equity capital:

Dr. Roger A. Morin, Professor of Finance at the College of Business Administration, Georgia State University and Professor of Finance for Regulated

Industry at the Center for the Study of Regulated Industry at Georgia State University. (On behalf of Gulf Power) Dr. Morin recommends the adoption of a return on common equity of 13.5%.

Mr. James A. Rothschild, President, [*26] Rothschild Financial Consulting. (On behalf of the Citizens of the State of Florida) Mr. Rothschild recommends that the proper calculated return on equity for Gulf Power is 11.75%.

Mr. Scott A. Seery, Regulatory Analyst, Bureau of Finance, Division of Auditing and Financial Analysis, Florida Public Service Commission (On behalf of the Florida Public Service Commission Staff) Mr. Seery recommends the adoption of a return on common equity of 12.25%.

The witnesses used three different equity costing methodologies to arrive at their estimates of Gulf's cost of equity. Witness Morin used the risk premium, discounted cash flow (DCF) and capital asset pricing model (CAPM) methodologies. Witness Rothschild relied primarily on the DCF method. Witness Seery used the DCF and risk premium methods.

When analyzing the cost of equity one should realize that it is a subjective process. Based on the evidence in the record and a review of the equity costing methodologies presented, we find that a reasonable allowed rate of return on common equity capital for Gulf is 12.55%. This rate of return on common equity will allow Gulf the opportunity to raise capital on fair and reasonable terms and [*27] to maintain its financial integrity.

We believe a 12.55% cost of common equity is well supported by the evidence presented and represents the best estimate of the Company's cost of equity. To put this finding in perspective, at the time revised testimony was filed by these witnesses, the average yield on long-term treasuries was 8.74% and the yield on A-rated utility bonds was 9.92% for April 1990. The average yield for June 1990 was 8.60% for long-term treasuries and 9.80% for A-rated utility bonds as reported by Moody's Bond Survey, July 16, 1990.

C. Capital Structure Reconciliation

We require that there be a reconciliation of the rate base and the capital components which support the rate base. In order to determine the appropriate overall cost of capital for which the utility will be allowed to earn a return, several adjustments must be made to the capital structure as presented by the utility in its minimum filing requirements. First, as all parties agree, the preferred stock balance is to be presented net of discounts, premiums, and issuance expenses. The effect on capital structure is to reduce the preferred stock balance by $ 948,000 and to increase the common equity [*28] balance by $ 948,000.

Next, we believe all non-utility investment should be removed directly from equity when reconciling the capital structure to rate base unless the utility can show, through competent evidence, that to do otherwise would result in a more equitable determination of the cost of capital for regulatory purposes. In the case of Gulf, we believe that the non-utility investments should be removed from equity. This will recognize that non-utility investments will almost certainly increase a utility's cost of capital since there are very few investments that a utility can make that are of equal or lower risk. Removing non-utility investments directly from equity recognizes their higher risks, prevents cost of capital cross-subsidies, and sends a clear signal to utilities that ratepayers will not subsidize non-utility related costs.

We believe that specific adjustments should be made to the tax components of the capital structure. We have specifically identified the effects of the rate base adjustments for the navy house, the Tallahassee office, Leisure Lakes, unamortized rate case expense, and Plant Scherer, including the plant acquisition adjustment, and have decreased [*29] the average balance of accumulated deferred income taxes by $ 5,877,000 and of investment tax credits by $ 2,402,000. The remaining amount of these rate base adjustments are then reconciled over all investor sources and customer deposits.

All other adjustments to rate base are on a pro rata basis over all sources of capital. We believe the remaining adjustments should be removed at the company's overall cost of capital.

Based upon the rate base/capital structure reconciliation that we discussed above and our review of the record of the cost rates and capital components, the appropriate capital structure for Gulf Power is as follows:

COMPONENT	AMOUNT	PERCENT OF TOTAL CAPITAL	COST RATE	WEIGHTED COST
Long Term Debt	311,950	36.22%	8.72%	3.16%
Short Term Debt	3,971	0.46%	8.00%	0.04%
Preferred Stock	51,358	5.96%	7.75%	0.46%
Customer deposits	14,134	1.64%	7.65%	0.13%
Common Equity	264,857	30.76%	12.55%	3.86%
Accumulated Deferred Income Taxes Deferred	175,796	20.41%	0.00%	0.00%
ITC-Zero Cost	823	0.10%	0.00%	0.00%
Deferred ITC-Weighted Cost	38,270	4.44%	10.26%	0.46%
	861,159	100.00%		8.10%

For a complete breakdown of Gulf's [*30] 13-month average capital structure see Attachment 2.

VI. MISMANAGEMENT

The record is clear: Gulf Power Company admitted that corrupt practices took place at Gulf Power Company from the early 1980s through 1988, including but not limited to theft of company property, use of company employees on company time to perform services for management personnel, utility executives accepting appliances without payment, and political contributions made by third parties and charged back to Gulf Power Company. The majority of the unethical/illegal activities involved Jacob Horton, the Senior Vice President of Gulf Power Company. Mr. Horton was killed in a plane crash on April 10, 1989.

The question then becomes whether the management of the power company knew or should have known of the illegal and/or unethical conduct that was taking place. At this point it is incumbent upon the Commission to note that there is no record evidence to indicate that Mr. Douglas McCrary, President of Gulf Power Company from May of 1983 through the present, knew that illegal or unethical conduct was taking place as it happened. Mr. McCrary testified under oath as to his lack of contemporaneous knowledge of the [*31] activities.

We do believe that Gulf Power's senior management should have known of some of these activities and should have acted sooner and with sterner measures with regard to Mr. Horton's activities. This inaction constitutes mismanagement. As a totally independent ground, the activities of Mr. Horton and his subordinates as Senior Vice President alone constitute mismanagement. This recommendation is premised upon the structure of Gulf Power management with four vice presidents reporting to the president. As one of those vice presidents, Mr. Horton's actions are those of Gulf Power management.

We believe that there were many early warning signals which indicated that illegal or unethical conduct was present. In December of 1983 Mr. McCrary received anonymous letters concerning employee misappropriation of goods. Mr. McCrary commissioned an independent investigation by security personnel from a sister company to avoid one peer investigating another. The result of this investigation was the "Baker-Childers report", which was Exhibit 391 at the hearing. This report focused on warehouse thefts directed by Kyle Croft. Also contained in this report were allegations of company [*32] personnel performing personal services for Gulf Power executives, including Mr. Horton, on company time with company materials. When Mr. Horton was asked about these allegations, Mr. Horton denied them, and no further action was taken. (R169) This incident did, however, raise suspicions about Mr. Horton. (R168)

With regard to the principal allegations contained within the Baker-Childers report, Mr. Croft was fired on a Sunday morning in late January 1984. However, Mr. Horton intervened and persuaded the president to rescind the firing decision and allow Mr. Croft to resign. Unknown to others in senior management at the time, Mr. Horton arranged for Mr. Croft's attorneys fees and health insurance to be paid and billed back to Gulf Power. Gulf's senior management learned of this payment in 1988. (R197) As part of Mr. Croft resigning from Gulf Power, Mr. Croft executed a promissory note for $ 15,986.62 to Gulf Power Company. This represented an estimate of the property Mr. Croft had stolen from Gulf Power. Concurrent with the execution of this note, Mr. Horton stated that Gulf Power would not enforce the note, and Mr. Horton executed a note payable to Mr. Croft for the same [*33] amount. (Ex. 396 at p. 55) This was done to protect Mr. Croft if Gulf Power decided to enforce the note. When the senior management learned of Mr. Horton's note in 1986 it also heightened suspicion of Mr. Horton. (R199)

In June of 1984 it was learned that Gulf Power had delivered approximately $ 10,000 worth of appliances to Mr. Ed Addison, former president of Gulf Power Company and now head of the Southern Company, the parent company of Gulf Power. Mr. Addison was not billed for these goods, and it was the intent of Gulf Power employees to give the appliances to Mr. Addison. (R183) The president learned of this arrangement and discussed the matter with Mr. Addison. Mr. Addison was billed and then promptly paid for the appliances. (R184) The employees involved reported to Mr. Horton which again raised suspicion concerning Mr. Horton. (R186) No further investigation of the appliance division was made. (R187)

In July of 1984 Mr. Horton instructed a Gulf Power employee to solicit a $ 1,000 political contribution from a local architect that worked with Gulf Power Company. The president learned of this several days later. (R223) He spoke to Mr. Horton and "reemphasized" that [*34] pressure would not be placed on vendors to make political contributions. (R223) Mr. McCrary conceded that he was very much suspicious about Mr. Horton by July of 1984. (R225) Unknown to the president at the time was the fact that Gulf Power in fact reimbursed the architect for the political contribution. (Ex. 396 at p. 21) In the fall of 1986, the president learned that Gulf Power had reimbursed Mr. Graves (the architect), and had Mr. Graves reimburse Gulf Power Company, and then had Mr.

Horton reimburse Mr. Graves. Any suspicion created in 1984 by this situation should have been greatly increased by the 1986 transactions.

On October 31, 1989 Gulf Power Company entered guilty pleas to two felony counts in the United States District Court for the Northern District of Georgia, Atlanta Division. Gulf Power paid a $ 500,000 fine for these crimes. (Ex. 413) This negotiated plea agreement grew out of Gulf Power activities from 1981-1988. Over 120 counts were detailed in Exhibit 413. Basically Gulf Power management, through Mr. Horton and his subordinates, "systematically, repeatedly and willfully instructed its outside vendors, such as its advertising agencies, to submit false [*35] or inflated invoices to Gulf Power Company for payment by Gulf Power Company in order to reimburse those vendors for payments they had made to political candidates and others at the direction of Gulf Power Company." (Ex. 413 at p. 13) These illegal acts were not isolated cases and are factually indistinguishable from the Graves contribution which the senior management knew of 1984 and learned more about in 1986.

We believe that the explicit warnings the senior management received concerning Mr. Horton, coupled with the Baker Childers Report in early 1984, the Addison appliances in June of 1984, the Graves contribution in July of 1984, the 1986 Kyle Croft lawsuit revealing more information concerning Mr. Croft's resignation and the subsequent information in 1986 regarding the 1984 Graves contribution all indicate that Gulf's senior management should have been aware of Mr. Horton's activities. This is especially true in light of the close business relationship between the two senior executives (CR 219; 231; 236; 245, 246). An investigation of Mr. Horton's activities was clearly indicated by 1986.

In the fall of 1988 senior management became aware of the Appleyard ledgers. It was [*36] known at that time that violations of the law were involved. (R244) These accounts were handled by the organization reporting to Mr. Horton. Mr. Horton was informed that he was to be separated from the company on April 10, 1989. (R4192) As of May 1, 1989, the company had not undertaken an investigation of Mr. Horton, despite the events described above. See Exhibit 382 at p. 16A. We believe that the lack of action regarding Mr. Horton constitutes mismanagement because management should have been aware of Mr. Horton's activities or started an investigation into Mr. Horton's activities based on the events discussed above.

Not only did management fail to initiate an investigation of Mr. Horton, but Mr. Horton has never received a written reprimand. (R4186-87) This lack of written reprimands is troubling considering management's subsequent knowledge of Mr. Horton's promissory note, the Graves Contribution, and paying Mr. Croft's legal and insurance costs. In one case (the Graves situation) Mr. Horton lied to the president in 1984 and the president knew he lied in 1986. In another case (paying the legal and insurance costs for Mr. Croft) Mr. Horton directly disobeyed the president's [*37] explicit instructions. (R197) Mr. Horton also received Productivity Improvement Program payments for his job performance in 1983, 1984, 1985, 1986, and 1988 and his base salary rise each year from 1983-1988. (Ex. 547)

Although we believe Gulf's lack of action regarding Mr. Horton constitutes mismanagement, we believe that given Mr. Horton's position, his actions alone constitute mismanagement regardless of senior management's inaction. Gulf Power has over 1600 employees. Mr. McCrary is the leader of these employees, and four executives reported directly to him, as well as the director of Public Relations. (See R192; Ex. 414) Thus all policy decisions and supervision of all Gulf Power personnel are vested in this management team. We do not use the term "management team" loosely. The president expressed it this way:

I did that [consulted the vice-presidents on the decision to fire Mr. Croft] because we operate that company on a -- in a manner such that all very important decisions that we make, we try to do as a group, so that all vice presidents are satisfied that they have had their input and they agree with the decision.

(R193; See R217; 3050)

Given this management philosophy [*38] and practice, we believe it totally appropriate to find Mr. Horton's actions as those of Gulf Power management. Mr. Horton was one of the five people who management Gulf Power. In carrying out his duties as Senior Vice President, he committed illegal and unethical acts on behalf of the utility. Therefore, Gulf Power Company was guilty of mismanagement.

In terms of the scope of the corruption taking place at Gulf Power Company, several company programs were initiated to deal with the problem. Among these programs were adoption of a company Code of Ethics in August of 1984 and the implementation of an amnesty program around the same time. The Code of Ethics was adopted in response to the "myriad of things that had been going on in the early 1980s." (R204) The president agreed that every large well run utility should have a Code of Ethics and he couldn't say why Gulf Power lacked a Code of Ethics prior to that time. (Id.) All existing and new employees were required to sign a compliance statement. To implement the Code, Gulf Power had a series of meetings to explain the Code and the reason for it. The president was unable to point to anything Gulf Power did to further implement [*39] the Code from August of 1984 through January 5, 1989. On January 5, 1989, the Audit Committee of the Gulf Power Board of Directors adopted a resolution to reiterate the Code of Ethics and ordered management to take certain actions to implement the Code. (R206) The president explained the action as follows:

We thought it was in -- that what we should do is to reemphasize the Code of Ethics; to have an educational program; to have a program of ethics awareness, and to generally have employees focus on the Code of Ethics being a real and living document. (R206)

The Code of Ethics was adopted in 1984 to combat the embezzlement of Gulf Power property and by 1989 different sorts of ethical violations were apparent, indicating that some employees ignored the Code or failed to take it seriously. (R214-15) We believe the 1989 measures should have been in effect in 1984 and there was haphazard enforcement of the Code from 1984 to 1988.

Gulf Power's amnesty program was initiated in the summer of 1984. This program was implemented in response to numerous allegations against Gulf Power personnel in the Baker-Childers Report. (R128) An outside law firm administered the program in order [*40] to shield the identity of the participants from the company. (Ex. 396 at p. 40-41) The program was designed to allow company employees that had improperly obtained goods or services from the company to make restitution to the company and then be subject to no further action. (R128) Gulf Power had no way of knowing whether the amounts collected under the amnesty program were correct. (R136; 140) A total of $ 13,124.23 was collected pursuant to this program. Of this amount, $ 10,500 (80%) came from two individuals in leadership positions at Gulf Power Company. (R138; 201; See Ex. 414)

On January 1, 1988, one of the persons who reported directly to the president was involved in three automobile accidents while driving a company vehicle. He was charged with D.U.I. and a number of traffic violations at the scene of the third accident. The president believed it would be very damaging to Gulf Power if the incident were reported in the media and he made a conscious decision not to have the accident reported as required by company procedures. (Ex. 396 at p. 66) Although this activity constituted a violation of the Code of Ethics, the individual involved received no written reprimand. [*41] (R180) He was orally reprimanded, although it is not clear by whom. (R181) Two points concerning this incident appear relevant to our analysis. First, it would appear that this incident supports the lack of commitment to enforcement of the Code of Ethics from 1984 to 1988. Second, it also raises the issue of Gulf Power treating executives differently concerning ethical violations than other employees. This is buttressed by the lack of investigation of allegations concerning personal use of company materials involving an ex-president of the Southern Company. (R134) Discriminatory enforcement is further indicated by considering that a lower-level employee was fired for stealing a gallon of gas and certain other unspecified violations. (R107; 128; 182)

Gulf Power also did business in 1983 with Scott Addison, the son of Ed Addison, the Chief Executive Officer of the Southern Company. Although this specific transaction does appear prudent in and of itself, we do question the propriety of doing business with relatives of the parent company personnel. This is especially true when the transaction was not handled in the normal manner and Gulf Power conceded that absent the family [*42] connection, the person would probably not have received the same treatment. (See R3841-3844)

To summarize, we believe the events described above support a finding of mismanagement on the part of Gulf Power Company. The finding of mismanagement is premised on the activities of Mr. Horton, the president's lack of knowledge of those activities despite the incidents discussed above, the lack of investigation of Mr. Horton, the lack of written reprimands to Mr. Horton, the circumstances relating to the readoption of the Code of Ethics, the uneven enforcement of same, the various executives accepting goods or services without payment and the other factors discussed above. These factual circumstances as well as the fact that the illegal activity continued for at least eight years, lead us to agree with Ms. Bass, "that the corporate culture was such that employees believed these types of illegal activities were, at the least, condoned by top management." (R2994; See Ex. 391 at p. 10; 28; 33) This is particularly true when one considers that illegal activity continued for at least eight years.

Given the foregoing discussion, the issue becomes what action the Commission should take. Gulf [*43] Power argues that the commission lacks authority to lower the return on equity in absence of a demonstrable impact on rates or service from the mismanagement. (Gulf Power Brief at 110; See Id. at 107-138) In United Telephone Co. of Florida v. Mann, 403 So.2d 962, 966 (Fla. 1981), the court stated that after the rate of return is calculated, "the commission can make further adjustments to account for such things as accretion, attrition, inflation and management efficiency." (Emphasis supplied) We believe this case, in conjunction with the fact that public utility regulation is an exercise of the police power (See Section 366.01, Florida Statutes) and other statutory provisions (See Sections 350.117, 366.041, 366.07, and 366.075, Florida Statutes) grant this Commission ample authority to take management efficiency into account in setting rates.

The statutory provisions cited above give the Commission authority to consider management efficiency in setting rates. In consideration of relative efficiency, the Commission should reward the more efficient and give less relief to those operating in a less efficient manner. As the court stated in Deltona Corp. v. Florida Public Service Commission, [*44] 220 So.2d 905, 907 (Fla. 1969):

A statutory grant of power or right carries with it by implication everything necessary to carry out the power or right and make it effectual and complete.

We believe the proper method of dealing with mismanagement is through the return on equity. The New Hampshire Public Utilities Commission has acted in conformity with this principle:

The method of addressing managerial inefficiency which is most soundly rooted in proper regulatory principles and is most appropriate to the instant situation is a reduction in the allowed return on common equity. Re: Public Service Commission of New Hampshire, 57 P.U.R.4th 563, 594

In the instant case there were various ongoing criminal conspiracies reaching to the highest levels of management. These events, widely reported in the media, have hurt the company's relationship with its customers, as was made clear from the testimony customers gave at the service hearings. It is axiomatic that the involvement of managerial personnel in criminal activities lessened the efficiency of management in providing electric service.

As previously discussed, expert testimony of record established that a fair rate of return [*45] on equity (ROE) for this utility lies between 11.75% and 13.50%. Analysis of the cost of equity is a subjective process and an exact figure is impossible to measure precisely. The Commission must evaluate the testimony presented and then utilize its expertise to arrive at a fair rate of return for the particular utility at issue. As previously discussed, we believe the appropriate ROE for Gulf Power Company to be 12.55%. Were the previous pages recounting Gulf Power mismanagement not in the record of this proceeding, we could stop there. This record reflects a disregard for the ratepayers and public service, however. Accordingly, we will reduce Gulf Power Company's ROE by fifty (50) basis points for a two year period. This results in a final ROE of 12.05%.

This final ROE is well within the parameters established as fair and reasonable by expert testimony of record. This reduction in the authorized ROE for a two year period is meant as a message to management that the kind of conduct discussed above, which was endemic for at least eight years at this company, will not be tolerated for public utilities which operate in Florida. We have limited the reduction to a two year period [*46] to reflect our belief that Gulf Power has turned the corner on dealing with the extensive and long-standing illegal/unethical behavior within the company.

VII. NET OPERATING INCOME (NOI)

Having established the Company's rate base, and fair rate of return, the next step in the revenue requirements determination is to ascertain the net operating income (NOI) applicable to the test period. The formula for determining NOI is Operating Revenues less Operating Expenses equals NOI.

The Company has proposed a net operating income of $ 60,910,000. Evidence developed during these proceedings has led us to increase this amount to $ 61,085,000. Our adjustments are set forth as follows:

JURISDICTIONAL NET OPERATING INCOME

(000's)

	Gulf	Adjustments	As Adjusted
VIII. Operating Revenues *	$ 255,580	108	$ 255,688
IX. Operating Expenses *			
A. O&M	113,382	762	114,144
B. Deprec. & Amort.	47,701	(1,893)	45,808
C. Taxes - Other	20,822	(274)	20,548
D. Current Income Taxes	13,185	529	13,714
E. Def.Income Taxes (net)	1,621	712	2,333
F. ITC (net)	(2,041)	96	(1,945)
G. Total Oper. Exp.	194,670	(67)	194,603
H. Net Operating Income	$ 60,910	175	61,085

[*47]

* Operating Revenues and Expenses are net of fuel and conservation.

VIII. OPERATING REVENUES

The Company proposed an operating revenue for test year 1990 of $ 255,580,000. We have made adjustments increasing operating revenues for 1990 by a total of $ 108,000 to $ 255,688,000. Our adjustments to revenues are as follows:

(000's)

Company Test Year Revenues	$ 255,580
Adjustments:	
A. PXT misbilling:	16
B. Non-utility electric billing:	35
C. Sod Farm revenues	(3)
D. Appliance division-use of logo	-0-
E. Revision of OS-I and OS-II Revenue	66
F. Revision of OS-III and OS-IV Revenue	(6)
Total Adjustments	$ 108
Adjusted Operating Revenue	$ 255,688

A. PXT Misbilling

A PXT customer experienced a forced outage during September 2 and 3 of 1989, and took standby power of 7959 KW during that outage. The PXT customer had taken a generator off line for maintenance to repair the boiler during the period in question. Nonetheless, the customer was not billed for standby power as it should have been (see Commission Order No. 17159).

Additional revenues of $ 16,325 should therefore be imputed for 1990 as the customer should properly have been billed for standby [*48] power of 7959 KW.

B. Non Utility Electric Billing

The company has several non-utility operations including the sod farm, vision design, and the appliance sales and service. In the past and currently, Gulf has allocated the cost of the metered electric consumption to these operations at the actual cost of generation.

We believe that these non-utility operations are being subsidized in part by paying less for electricity than they would have if their consumption had been billed-out at the appropriate tariff rate. It is therefore appropriate to increase revenues by $ 34,913.

C. Sod Farm Revenues

We have previously ruled that the percentage of the Caryville site devoted to the sod farm (10%) be excluded from rate base. Therefore, it is appropriate to remove from other operating revenues $ 3,450 in rental revenues received from the sod farm operations.

D. Appliance Division - Use of Logo

After considering the briefs of the parties on this issue we have decided that the value of the Gulf logo to the non-utility appliance sales division should be recognized. It follows that an appropriate allowance for the use of the logo should be credited to the company as revenue above the [*49] line.

In the record before us however, we find no evidence concerning the dollar value of Gulf's corporate logo to the appliance division. In the absence of a record basis, we therefore make zero ($ 0) adjustment.

E. Adjustment to OS-I and OS-II

The company failed to use the revenues shown on their most recently revised MFR Schedule E-16 for these classes. It is, therefore, appropriate to increase revenues by $ 66,000.

F. Adjustment to OS-III and OS-IV

The company failed to correctly transfer revenues from MFR Schedule E-16d to E-16a. This resulted in the utility overstating its current revenues. We therefore decrease revenues by $ 6,000.

IX. OPERATING EXPENSES

Gulf has requested total operating expenses of $ 194,670,000. We have made additional adjustments reducing total operating expenses by $ 67,000 to $ 194,603,000.

A. Operating and Maintenance Expense (O&M)

Gulf has proposed total O&M expense of $ 113,382,000. We have determined that this amount should be increased by $ 762,000 to $ 114,144,000 as follows:

(000's)	
Operating and Maintenance Expenses	
Per Company	$ 113,382
Adjustments:	
1. Navy House	(8)
2. Plant Scherer-Net of IIC Offset	4,070
3. Out-of-Period, Non-Recurring, etc.	(190)
4. Industry Association Dues	(20)
5. Current Rate Case Expenses	(250)
6. Cogeneration & Industrial Programs	(426)
7. Good Cents Incentive Program	(50)
8. Presentation/Seminars Program	(55)

9. Shine Against Crime	(	92)
10. Economic Development	(	687)
11. Lobbying Expenses	(	264)
12. IRS, Grand Jury, etc.	(	5)
13. Research & Development Projects	(	32)
14. Transmission Rents	(	423)
15. Labor Complement Vacancies	(	403)
16. Productivity Improvement Plan	(	339)
17. Employee Relocation & Development Programs	(	56)
18. Management Perks	(	65)
19. Caryville Subsurface Study		57
20. Pension Expense		0
21. Retirement Medical and Life Insurance		0
Total Adjustments	$	762
Adjusted O&M Expenses	$	114,144

[*50]

1. Navy House

As discussed earlier, we find that 1990 operating expenses for the Navy House should be reduced by $ 7,516.

2. Plant Scherer - Net of IIC Offset

The Intercompany Interexchange Contract (IIC) is a methodology for equalizing the capacity reserves among the various operating companies of the Southern Company. Since Plant Scherer is being excluded from the rate base, it is also appropriate to exclude the $ 4,792,000 capacity payment that Gulf would receive for the Plant Scherer capacity. This would have the effect of increasing operating and maintenance expenses by $ 4,792,000.

On the other hand, the exclusion of Plant Scherer from rate base would also have the opposite effect of reducing operating and maintenance expenses by $ 722,000 (the cost of operating and maintaining the plant). The net of these two adjustments results in an increase in operating and maintenance expenses of $ 4,070,000.

3. Out of Period, Non Recurring or Non Utility

For 1990, Gulf budgeted $ 1,663,247 for other non-recurring expenses compared to a 5-year average of actual expenses of $ 1,473,407 or a difference of $ 189,840. Gulf did not offer any explanation as to what activities were [*51] projected for 1990 in support of the $ 1,663,247 non-recurring expenses. Since these expenses affect all functional categories of expenses, the adjustment has been included in the O&M benchmark schedule as a single adjustment to total O&M expenses. We have therefore reduced O&M expenses by $ 189,840.

4. Industry Association Dues

We have adjusted the company's budgeted industry association dues from $ 167,193 to $ 147,172. This includes a disallowance of $ 19,378 for that portion of the Edison Electric Institute Dues which is used for lobbying (1/3 of $ 58,133 total dues), and $ 643 associated with miscellaneous organizations that were not identified by the company except as "Organization to be joined in 1990."

5. Current Rate Case Expenses

The company projected rate case expense at $ 1,000,000. This amount is not contested and consists of:

Outside Consultants	$ 248,000
Legal Services	164,000
Meals and Travel	37,000
Paid Overtime	7,000
Other Expenses*	544,000
Total	$ 1,000,000

*Includes SCS expenses, postal charges, printing costs and transcripts.

At issue is the amortization period over which the expense will be spread. Commission policy is to amortize [*52] rate case expense over a period of time because a rate case benefits not only the current period, but future periods as well. In Gulf's last rate case, in Order No. 14030, we allowed a two year amortization period. In Gulf's 1982 rate case, in Order No. 10557, we allowed a three year period. In the FPUC-Fernandina Beach Division rate case, we approved a 5 year amortization period since it had been approximately 15 years since the company's last rate case. (Order No. 22224, Docket No. 881056-EI).

Gulf's witness testified that a two year amortization period was appropriate because over the past ten years Gulf has had five rate cases for an average of one rate case every two years.

It has been six years since Gulf's last rate case. Pursuant to Chapter 366, Florida Statutes, Gulf must file Modified Minimum Filing Requirements (MMFRs) in 1994. We believe that the amortization period should be greater than the two years ordered in Gulf's last rate case but less than the six years between cases, since the company must file MMFRs in four years. Therefore, rate case expense will be amortized over four years. Expenses should be reduced by $ 250,000.

6. Cogeneration and Industrial [*53] Programs

We do not believe that expenses related to Gulf's Industrial Customer Activities Cogeneration Program should be allowed. From the record in this docket, this program appears to be little more than a load retention program for large industrial customers.

As justification for this expense, Gulf states that this program provides benefits to the general body of ratepayers by preserving revenues. This presents us with the age old question of the benefits of high load factor customers to the general body of ratepayers.

Gulf contends that the retention of high load factor customers benefits all customers. On the other hand, in this rate proceeding the company has requested that additional plant be placed in base rates. From this record it cannot be concluded that high load factor customers have necessarily benefitted Gulf's general body of ratepayers.

In addition, Gulf has proposed an Energy Audit and Technical Assistance Program as part of its overall conservation plan. This program not only addresses conservation measures, but cogeneration applications, and appears to duplicate the Industrial Customer Activities Cogeneration Program in several respects. We therefore [*54] find that the amount budgeted for the Industrial Customer Activities Cogeneration Program ($ 426,464) should be disallowed.

7. Good Cents Incentive Program

The Good Cents Incentive program offers merchandise and travel packages to contractors for the installation of energy efficient appliances. It also offers these incentives for the retrofit of gas furnaces to electric heat pumps. The provision of these appliances does not require the use of an incentive. The general public, as well as the real estate community, is well aware of the benefits of having an energy efficient home. In fact, energy efficiency has become a major selling point as customers have come to demand energy efficient homes.

Since the provision of incentives to contractors is not necessary, we believe that the $ 50,000 budgeted by Gulf for the Good Cents Incentive Program should be disallowed.

8. Presentation/Seminar Program

Gulf had budgeted $ 55,429 for its Presentation/Seminar Program. Gulf contends that this program provides presentations to local contractors about the energy efficiency of electric appliances. This appears to be a duplication of the company's Education and Good Cents programs. Today's [*55] contractors are well aware of the importance of an energy efficient home. While these presentations and seminars do foster a better relationship between Gulf and the local contractors, we do not see any additional benefits accruing to the general body of ratepayers. We therefore disallow the $ 55,429 budgeted for this program.

9. Shine Against Crime

The Shine Against Crime program is simply an outdoor lighting program. These types of programs have been in existence for some time mainly to replace inefficient lighting with more efficient high pressure sodium lighting. This practice reduces kwh consumption and conserves resources. In addition to this purpose however, Gulf's program promotes the installation of new outdoor fixtures.

Section 366.80-.85 of the Florida Statutes, also known as the Florida Energy Efficiency and Conservation Act (FEECA), mandates that utilities control energy growth. While the replacement of inefficient outdoor fixtures helps to reduce energy requirements, the promotion of "new" outdoor installations increases energy requirements. It is this facet of the Shine Against Crime program that we take exception with. The promotion of off-peak load does [*56] not contribute to reducing energy requirements and may be contrary to FEECA. The company's witness stated that approximately 35 to 37% of the expenses for this program are attributable to changeouts of existing fixtures. This means that 63% of the expenses, or $ 91,761, is attributable to new installations and the promotion of off-peak sales. We therefore disallow $ 91,761 of the $ 145,652 Gulf has budgeted for this program.

10. Economic Development

Gulf contends that its well-being is directly related to that of the community, and that it has a direct stake in the community's overall development. As a result, Gulf has developed a marketing and promotional campaign designed to attract new businesses to the area.

It appears that Gulf has assumed some of the responsibilities of local chambers of commerce or development boards. Traditionally, those organizations have been in the forefront of attracting businesses to expand and relocate in their area. Gulf is duplicating these efforts. The company admits that it has "assumed a leadership role in furthering the capability of communities in its service territory to attract and/or expand the industrial base." In seeking to expand [*57] industry or business activity in general, Gulf is actively attempting to increase sales of electricity.

This type of marketing expense might be expected of a company operating in a non-regulated environment. A desire to increase sales or market share against the competition is normal and healthy when there is competition. Gulf however, has no competitors supplying electrical power in the same geographic area it serves.

We do not believe that this expense should be passed on to Gulf's ratepayers. We therefore disallow the entire $ 687,000 Gulf has budgeted for economic development.

11. Lobbying Expenses

We have removed $ 263,534 used for lobbying and lobbying-related activities from operating expenses. This adjustment removes $ 96,643 for SCS expenses for Outside Consultants and $ 119,923 for expenses incurred by Gulf's registered lobbyist and 25% of the office rent on the Tallahassee office. In addition, 10% of the expenses of Gulf's Regulatory Matters Coordinator or $ 5,375 should also be removed. This is consistent with Gulf's book treatment of these expenses in 1989.

Further adjustments are necessary to remove 25% of the expenses allocated to Gulf for the Governmental [*58] Affairs office in Atlanta and Washington or $ 41,593. Because of the similarities between these Governmental Affairs offices and the Tallahassee office it is appropriate to make this adjustment (TR 3855-3856).

12. IRS, Grand Jury Expenses

At the time of its filing, Gulf identified $ 615,000 in expenses related to grand jury and IRS investigations which it agreed to remove from its 1990 test year budget. Since its filing Gulf discovered an additional $ 5,000 used for a presentation made by Gulf's outside auditors to its Board of Directors. Gulf has stipulated to the removal of this amount and we therefore disallow $ 5,000.

13. Research and Development Projects

Gulf has budgeted $ 210,000 in O&M expenses for research and development. Of this amount, the $ 31,813 Gulf has budgeted for the Acid Rain Monitoring Program is an extension of a previous acid rain program and not a new research and development program. In removing this amount from Gulf's proposed 1990 budget, we are not disallowing funds for acid rain research. Rather, we find that Gulf has failed to sustain its burden of proof in justifying this variance from the 1990 benchmark.

14. Transmission Rents

Transmission [*59] rents, or facilities charges, are a cost effective alternative to Gulf building its own transmission lines to receive power from Plants Daniel and Scherer, which are physically located outside the State of Florida.

Since we have removed Plant Scherer from Gulf's rate base it is also appropriate that we remove the associated transmission expenses. We therefore remove $ 423,000 in transmission rents from Gulf's O&M budget.

15. Labor Complement Vacancies

An adjustment in O&M expenses is necessary to remove the effect of vacancies on the labor complement. On the average there were fifty (50) vacant positions in Gulf's labor complement over the twelve month period ending May, 1990. Four positions were eliminated however in Gulf's 1990 budget, leaving a net average vacancy rate of 46 positions. We therefore reduce O&M expenses by $ 403,222 and payroll taxes of $ 29,982 to remove the effect of vacancies on the labor complement. This adjustment is in addition to adjustments made by Gulf recognizing vacant positions.

16. Productivity Improvement Plan

As previously discussed, the Productivity Improvement Plan (PIP) is part of the total compensation plan for Gulf's top 11 employees. [*60] Due to a change in the design of the PIP program after the budgeting process was completed, a reduction in O&M expenses is in order.

The original amount budgeted for this program was $ 438,473, whereas the amount now budgeted is $ 99,066. We therefore reduce O&M expenses by $ 339,407.

17. Employee Relocation

Gulf's employee relocation plan covers a variety of costs involved in moving an employee and his family. These costs include appraisals, inspections, insurance, closing costs, broker expenses, moving expenses, and living expenses until a new home is purchased.

Relocation expenses cannot be neatly extrapolated from year to year. Unlike salaries or plant maintenance relocation expenses vary, as shown below:

Year	Actual Amount
1984	$ 263,066
1985	121,536
1986	113,552
1987	285,361
1988	205,287
1989	468,246

Relocation expense increased in 1989 primarily due to company reorganization. Gulf budgeted $ 324,100 for test year 1990. We believe that $ 324,100 is too high because of the extensive changes which occurred in 1989 are unlikely to recur soon. We believe a more reasonable approach is to allow $ 268,112, the amount of the 1986-1989 average yearly expense [*61] for relocation. Therefore, Gulf's 1990 budget for relocation expense should be reduced by $ 55,988 from $ 324,100 to $ 268,112.

18. Management Perks

Gulf's ratepayers should not pay for tax services and fitness programs for executives. These expenses should be borne by the stockholders. Expenses are reduced by $ 65,100.

19. Caryville Subsurface Study

As we have previously discussed, the subsurface study was a geological study of the Caryville site to determine if the land could support the weight of a power plant and supporting facilities. Since Caryville remains in Rate Base, this study ($ 568,000) should be allowed, however we will require that this amount be amortized to expense over a 10 year period. Amortization of the subsurface study over ten years results in a $ 57,000 increase in O&M expense. In addition, we have previously made a $ 28,000 adjustment in working capital for 1/2 year in 1990.

20. Pension Expense

Gulf presented three projections for pension expense in 1990. First, the company budgeted $ 0 for pension expense and included this in its petition for a rate increase.

The second amount presented by Gulf was on MFR Schedule C-66, Pension Cost. This [*62] MFR reports projected net periodic pension cost to be ($ 11,020). This is an early projection of pension cost under SFAS 87.

The third amount presented by Gulf to project pension expense for 1990 is a letter dated June 1, 1990, from the actuary retained by Southern Company. The letter indicates that the revised estimate of pension cost under SFAS 87 for 1990 is $ 199,000.

Historically, Gulf's pension expense has been on the decline for the past three years. For 1987, 1988, and 1989; Gulf's pension expense was $ 1,538,000, $ 1,385,000, and $ 47,000, respectively. These are the amounts recorded under SFAS 87.

Consistent with the utility's treatment of pension expense for 1987-1989, we believe that pension expense should be recorded under SFAS 87; however, the estimates of pension cost vary from ($ 11,020) to $ 199,000. Although the $ 199,000 is the most current estimate available, it is not supported by a full actuarial valuation. Because of the new estimate provided, we believe that the pension cost will probably be greater than ($ 11,020). Since the 1990 pension costs are still estimates and the 1987-1989 trend of pension expense is downward, we approve a pension expense [*63] of $ 0 as originally filed by Gulf. We are not approving $ 0 because we are certain that Gulf won't contribute to the pension fund. Rather, $ 0 is our estimate of what pension expense will be under SFAS 87, based upon the three different projections submitted by Gulf.

21. Post Retirement Medical and Life Insurance

We made no adjustments to Gulf's budgeted post retirement medical and life insurance benefits. However, we will require that Gulf's retirement medical and life insurance benefits be recognized using the accrual basis of accounting. Accrual accounting more accurately charges the cost of providing service to the customer who is receiving service. At this time, we do not believe that Gulf should be required to follow the exposure draft for accounting for post retirement benefits that has been released by the Financial Accounting Standards Board. The exposure draft will not be implemented until some future date.

B. Depreciation and Amortization

The Company has proposed test year depreciation expense of $ 47,701,000. As a result of our adjustments we have reduced depreciation and amortization expense by $ 1,893,000 to an approved amount of $ 45,808,000 as follows: [*64]

(000's)	
Depreciation and Amortization Expense Per Company	$ 47,701
Adjustments:	
1. Appliance Division	(12)
2. Tallahassee Office	(1)
3. Leisure Lakes	(5)
4. Plant Scherer	(1,774)
5. New Corporate Headquarters	(101)
Total Adjustments	(1,893)
Adjusted Depreciation & Amortization Expense	$ 45,808

C. Taxes Other than Income Taxes

Gulf has projected taxes other than income taxes to be $ 20,822,000 for test year 1990. We have made adjustments of $ 274,000 and reduced taxes other than income to $ 20,548,000.

The exclusion of Plant Scherer from rate base will result in a reduction of $ 245,000 in taxes other than income. In addition, a reduction in taxes other than income of $ 30,000 must be made to remove the effect of vacancies in Gulf's labor complement. Finally, an increase in taxes other than income in the amount of $ 1,000 should be made as a result of the additional revenue imputed for 1990 due to a PXT customer being misbilled by Gulf (as previously discussed in the rate base section of this order). These adjustments total $ 274,000 and reduce taxes other than income to $ 20,548,000 as set forth above.

D. Income Taxes Currently [*65] Payable

We have decreased current income tax expense by $ 143,000 for the net tax effect of other adjustments we have made to net operating income. We made a combined interest reconciliation adjustment and investment tax credit interest synchronization adjustment, increasing income tax expense by $ 672,000. The effect of these adjustments results in an increase of $ 529,000 in income taxes currently payable.

E. Deferred Federal Income Taxes (Net)

The company has projected $ 1,621,000 in deferred Federal Income Tax expense for test year 1990. Our elimination of Plant Scherer from rate base increases deferred Federal Income Taxes by $ 668,000. In addition, our previous adjustment to depreciation for test year 1990 increases deferred Federal Income Taxes by $ 45,000. These two adjustments totalling $ 712,000 result in total deferred Federal Income Tax expense of $ 2,333,000.

F. Investment Tax Credit

Gulf's budgeted investment tax credit amortization for test year 1990 was $ 2,041,000. As a result of our exclusion of Plant Scherer 3 from rate base we have decreased this by $ 96,000, resulting in a remaining amortization of $ 1,945,000.

G. Total Operating Expenses

Total [*66] operating expenses, as adjusted are $ 194,603,000.

H. Total Net Operating Income

The net operating income is determined by subtracting total operating expenses from operating revenues. For 1990 Gulf's net operating income is $ 61,085,000 ($ 255,688,000 - $ 194,603,000). For a complete breakdown of Gulf's net operating income see Attachment 3.

X. REVENUE EXPANSION FACTOR

The purpose of the revenue expansion factor (NOI multiplier) is to gross up or expand the Company's net operating income deficiency to compensate for income taxes and revenue taxes that the Company will incur as the result of any revenue increase. All parties agree that the appropriate revenue expansion factor in this case is 1.631699 developed as follows:

Revenue Requirement	100.000000
Uncollectible Accounts	(0.113300)
Gross Receipts Tax	(1.500000)
Regulatory Assessment Fee	(0.125000)
Net Before Income Taxes	98.261700
State Income Tax Rate	5.5000%
State Income Tax	5.404394
Net Before Federal Income Taxes	92.857307
Federal Tax Rate	34.000%
Federal Income Tax	31.571484
Net Operating Income	61.285822
Net Operating Income Multiplier	1.631699

XI. REVENUE REQUIREMENTS

Having determined [*67] the Company's rate base, the net operating income applicable to the test period, and the overall fair rate of return, it is possible to calculate any excess/deficiency of revenues. Multiplying the rate base value for 1990 of $ 861,159,000 by the fair overall rate of 8.10% yields an NOI requirement for 1990 of $ 69,746,000. The adjusted net operating income for the test year amounted to $ 61,085,000 resulting in an NOI deficiency of $ 8,660,000. Applying the appropriate NOI multiplier of 1.631699 to this figure yields a deficiency of $ 14,131,000 in gross annual revenues.

As discussed earlier, we have reduced Gulf's return on equity by fifty (50) basis points for a two year period as a penalty for corporate mismanagement. After applying the fifty basis point penalty, Gulf's authorized annual revenue increase is reduced to $ 11,838,000 the calculation of which is detailed below:

(000s)

		After 50 Basis Point Reduction
Adjusted Jurisdictional Rate Base	$ 861,159	$ 861,159
Required Rate of Return	8.10%	7.94%
Required Net Operating Income	69,746	68,341
Adjusted Achieved Test Year Jurisdictional Net Operating Income	61,085	61,085
Jurisdictional NOI Deficiency	8,660	7,255
Revenue Expansion Factor	1.631699	1.631699
Revenue Increase	14,131	11,838

[*68]

In view of the above, we authorize Gulf an increase in gross annual revenues of $ 11,838,000 for two years beginning September 13, 1990. Thereafter, we authorize Gulf an increase in gross annual revenues of $ 14,131,000.

XII. INTERIM INCREASE

Order No. 22681 issued on March 13, 1990, granted Gulf an interim rate increase of $ 5,751,000 pursuant to Section 366.071, Florida Statutes. The interim increase was calculated based on a test year consisting of the twelve (12) month period ending September 1989 (October 1988 - September 1989). We approved the interim rate increase for collection, subject to refund, pending the outcome of further evaluation of the Company's request for permanent rates. Now that the evaluation is complete, the appropriate level of interim relief must be calculated.

Under Section 366.071, Florida Statutes, a refund of interim rates should be ordered if it is necessary to reduce the utility's rate of return during the pendency of the rate case proceedings to the level of the newly authorized rate of return which is found fair and reasonable on a prospective basis.

In this docket, the interim increase was calculated using an 8.26% rate of return, which [*69] is higher than the 8.10% rate of return approved herein. Therefore, we will require a refund of $ 2,052,000 on an annual basis, the calculation of which is detailed below:

	(000s) Interim at 8.26% Rate of Return	Interim at 8.10% Rate of Return	Amount to be Refunded
Jurisdictional Adjusted Rate Base	$ 785,912	$ 785,912	
Required Rate of Return	8.26%	* 8.10%	
Required Net Operating Income	64,916	63,659	
Jurisdictional Adjusted NOI	61,392	61,392	
NOI Deficiency (Excess)	3,524	2,267	
NOI Multiplier	1.631699	1.631699	
Revenue Deficiency (Excess)	5,751	3,699	$ 2,052
Required Return on Equity	13.00%	12.55%	

* Without 50 Basis Point ROE Reduction

XIII. FUEL NEUTRALITY

A. Top Gun Video

The "Top Gun" video was produced in 1987 and shown to a group of contractors and builders at Gulf's annual awards seminar. The video shows fighter aircraft shooting gas appliances out of the air and indicates that the contractors could be top guns in their areas. One has to wonder at the overall intent of not only the video but Gulf's entire seminar presentations.

Our fuel neutrality policy can be summarized by stating that a utility should not [*70] promote its product by showing a competitive fuel in a bad light. This policy objective is set forth in Order Nos. 9974 and 12179 which were issued in 1981 and 1983.

Gulf's Top Gun video is clearly in violation of our fuel neutrality policy, and Gulf's management should be held accountable for its production and distribution.

B. Gas Busters "T" Shirt

A total of 559 of the tee-shirts in question were distributed in 1985 to Gulf Power employees. Gulf states that "[t]he shirts were made available to employees during a series of meetings during 1985 and were intended to explain and gain commitment to the Company's strategic marketing plan titled EMPACT (employee action). The shirts themselves were an inappropriate reaction to the promotional efforts of other energy suppliers that was very much in the public focus during this timeframe."

The production and distribution of these shirts having a "Gas Busters" logo, was contrary to our policy regarding fuel neutrality.

C. Good Cents Incentive

The Good Cents Incentive programs were in existence during 1987 through 1989. These programs were specifically tailored to reward customers for the replacement of gas furnaces with heat pumps. [*71] The contractors were paid anywhere from $ 25 to $ 100, in cash or merchandise, for each installation. In addition "electropoints" were awarded to contractors which were redeemable for trips, awards, and merchandise.

These programs not only provided incentives for the replacement of gas heat but also increased the Company's winter peak demand and annual energy. The good cents incentive programs clearly promoted electric over gas appliances and were contrary to our policy regarding fuel neutrality.

D. Withholding Good Cents Certification

In 1987, a commercial building received energy awards from both the U.S. Department of Energy and the Governor's Energy Office yet did not receive Good Cents certification because of a small amount of backup gas power. This practice was contrary to the Commission's policy regarding fuel neutrality.

Gulf has contended all along that the Good Cents logo is synonymous with energy efficiency. Why then wouldn't a highly efficient building that received other awards be granted Good Cents certification? Gulf is not practicing what it preaches; the promotion of the most energy efficient building for its ratepayers.

E. Misleading Advertising

Gulf [*72] ran a series of advertisements in which it compared the energy efficiency of its all electric "Good Cents" home to other homes which contained gas appliances. According to the ads, the "Good Cents" homes were consistently more energy efficient. The ads did not point out however that the homes had different levels of insulation and sizes of equipment. Both of these attributes will affect the energy usage of the home that is modeled, yet the advertisements did not mention this fact. If the general public were to read these ads, they would believe that the homes were identical. This is misleading to Gulf's general body of ratepayers.

The Company's justification for these ads is that they were responding to advertising by local gas companies that Gulf thought was misleading. We do not find this justification acceptable.

We believe that the preceding five subsections demonstrate that Gulf has consistently and blatantly violated our policy regarding fuel neutrality. Although at this time we will not make an adjustment based on these violations, we warn Gulf and other utilities under our jurisdiction that in the future such violations will not be tolerated.

XIV. COST OF SERVICE [*73] AND RATE DESIGN

Having ascertained the Company's revenue requirement and the amount of revenue increase necessary, we now turn our attention to rate design. We must determine the rate of return currently earned by each rate class, the increase in revenue requirement to be allocated to such class, and how each class's revenue responsibility will be spread between the customer, energy, and demand charges. In this rate proceeding, we have also reviewed the continued appropriateness of several aspects of the company's rate structure. We begin first with the cost of service studies presented in this case.

A. Cost of Service Methodology

Several methodologies were put forth for consideration as follows:

Gulf Power - 12 month Coincident Peak and 1/13 Energy Methodology; Public Counsel - Equivalent Peaker Cost Methodology; and Industrial Intervenors - Near Peak Methodology. The equivalent peaker methodology implies a refined knowledge of costs which is misleading, particularly as to the allocation of plant costs to hours past the break-even point. The near peak method includes too narrow a spread of peak hours in our view. We heard extensive testimony on each of these methodologies [*74] and believe that the Gulf Power proposed methodology is appropriate with the following revisions:

1) All of Account 364 will be classified as demand-related and allocated on class NCP.

Commission policy has been that no distribution system costs other than service drops (Account 369) and meters should be classified as customer-related. In addition, for customers served at primary or higher voltage only the meter is classified as customer-related. (O'Sheasy, TR 1863-1864) Therefore, we believe it was inequitable to the secondary voltage customers to classify secondary wire in Account 364 as customer-related when there was no similar classification of wire for higher voltage customers.

2) Uncollectable expense will be allocated to all classes on the basis of revenue and be classified as revenue-related. It will not be classified as customer-related or included in the customer charge.

3) Fuel inventory (stock) should be allocated on energy and classified as energy-related.

4) The coincident and noncoincident demands should be developed using the same methodology used for all other rate classes. The SEP KWH should not be excluded in the development of the CP KW and NCP KW.

5) [*75] The revenues, billing determinants and development of the 12 CP and NCP demands for the Standby Service Class will be based on the assumption that the PXT customer that is not migrating from PXT has a Standby Service Capacity of 7959 KW for the test year.

6) Service drops will be allocated to the OS classes for at least recreational lighting and advertisement or billboard customers. Meter costs, which reflect the current level of metering will be allocated to the recreational lights.

All the recreational lights have meters. (Exhibit 508) There are probably service drops for each of these installations. (O'Sheasy 1858-1860) Therefore, the cost will be allocated to the class for these customers.

7) The rate base for additional facilities for OS-I/OS-II and the expenses [associated] with these facilities will be allocated to OS-I/OS-II.

In his prefiled testimony on how a cost of service study is performed, Mr. O'Sheasy stated that "Certain costs are directly associated with one particular group of customers and are, therefore, assigned to that group." (TR 1807) This assignment was not done with respect to the additional facilities for OS-I/OS-II. The class has been credited with [*76] revenues of $ 424,653 but the rate base and expenses associated with the facilities except for those booked in Account 373 were not assigned to the class. (See TR 1861 and Exhibits 500, 231 and 501.) The rate of return in the revised study is 5.96 percent compared to 7.43 percent in the company's study in Exhibit 231. We believe the expenses should be matched with the costs so that the class' rate of return will not be significantly overstated to the detriment of the other rate classes.

8) Expenses for maintenance of cooling towers and coal pulverizers (grinding mills) will be allocated on energy and classified as energy-related.

The company has changed the classification of some O&M expenses from energy to demand in the cost of service study compared to that of Docket No. 840086-EI. In Docket No. 881167-EI, Mr. Haskins stated that maintenance for both coal grinding mills and cooling towers vary with the KWH to be generated. (TR 1763) In response to cross examination Mr. Lee agreed that operation and maintenance expenses for coal pulverizers and the operation expenses for cooling towers vary with KWH generated but that the amount of maintenance varies little with KWH. (TR 1468) [*77]

9) The test year expenses for the four conservation (Good Cents New Home, Good Cents Improved Home, and Commercial Presentations/Energy Education Seminars) programs which were denied conservation cost recovery by the Commission on May 2, 1989 will be classified as energy-related and allocated on energy to the rate classes in the revenue class to which the cost has been assigned by Gulf Power.

The test year expenses for these programs have been classified as customer-related by the company and included in the customer unit costs. Thus, the same amount of program cost is allocated to and recovered from a small RS customer as a large RS customer. (O'Sheasy, TR 1861-1863) Therefore, we believe it is more equitable to continue to recover these costs on a per KWH basis rather than on a per customer basis. Demand-related costs are collected through the energy charge for the residential class. Therefore, if there is less demand-related cost allocated to the class due to demand reductions from class participation, the customers with large usage will benefit more from the conservation program than customers with small bills.

Unfortunately we do not have a 12 CP and 1/13th cost study [*78] incorporating this combination of revisions. Because two of these problems significantly impact the rate of return of the rate classes directly involved, the company's 12 CP and 1/13th cost study (no migration study Ex. 231) has been adjusted for the two problems. One problem is the crediting of the revenues for additional facilities without the assignment of the cost for some of these facilities for OS-I and II. The second is the exclusion of the SE KWH in developing the 12 CP demands of the PXT and LPT classes. For example, a comparison of the rates of return in column 1 of Schedule 1 to those in column 3 shows that there is a 1.47 percentage point difference (7.43 percent versus 5.96 percent) for OS-III.

For the PXT and LP/LPT classes, rate base was increased by 6.84 percent ($ 2,778,000) and .79 percent ($ 592,000), respectively, of the transmission and demand-related production net plant and the demand-related production materials and supplies. The NOI for these classes was reduced by 6.84 percent ($ 316,000) and .79 percent ($ 68,000), respectively, of the total transmission and demand-related production O&M expenses, production plant A&G expenses and transmission and demand-related [*79] depreciation expenses. These are the major items allocated on the 12 CP KW. For OS-1/OS-II, the rate base and NOI from the staff-requested 12 CP and 1/13th cost of service study (Exhibit 501), which reflect the assignment of the cost to the class for all its additional facilities, was substituted for the values in Exhibit 231. All classes' rate base and NOI were adjusted proportionately to equal the company's filed levels of rate base and NOI.

1. Distribution System Costs

Our policy since the early 1980s has been to classify only the service drop and meter portion of the distribution system as customer-related. The Industrial Intervenors (II) and the utility advocate classifying a significant portion of the remainder of the distribution system, including poles, conductors, and transformers, as customer-related. This method is often referred to as the Minimum Distribution System concept. There is a fundamental flaw in this proposal in that only part of the distribution system is classified as customer-related. None of the subtransmission and transmission system would be classified as customer-related. Hence, customers served at primary voltage through dedicated substations, [*80] and customers served at higher voltages would not pay for any of this network path.

We believe this minimum distribution system approach should be rejected because it is inequitable and inconsistent to apply the concept to only those customers served at secondary voltage or at primary voltage through common substations when the network path must be there to serve each and every customer.

In our opinion distribution facilities that function as service drops or dedicated tap lines should be directly assigned to the classes whose members the facilities serve. No distribution costs other than service drops and meters should be classified as customer-related. Demand-related cost should be allocated on a demand allocator, and customer-related cost on a customer allocator.

2. Uncollectible Expense

The company assigned uncollectible accounts expense to the RS, GS and GSD classes on average number of customers and classified the expense as customer-related. The result of this classification and assignment or allocation of uncollectible accounts expense is that the expense is included in the customer charge unit cost. If the customer charges for these classes have been and are set [*81] at or near unit cost, all customers in the RS, GS and GSD rate classes pay an equal amount for uncollectible expense each month, regardless of the size of their bills. Commission policy has been to allocate uncollectible expense on revenues and not include it in the customer unit cost.

Our policy of not classifying uncollectible expense as customer-related should be continued. The company's classification of the cost as customer-related is inequitable because it results in a small customer paying as much uncollectible expense as a large customer (within and between the RS, GS and GSD classes), if customer charges are set at unit cost. However, if the account of a customer becomes uncollectible, a customer with a large bill would cause the company to incur much more uncollectible expense than a customer with a small bill.

Uncollectibles should be classified as revenue-related so that cost responsibility for uncollectible expense would be proportional to the size of a customer's bill.

3. Fuel Stock

The company has allocated fuel inventory in rate base on the 12 CP and 1/13th average demand, the same allocator they have used to allocate production plant investment. Thus, 12/13ths [*82] or 92.3 percent of the inventory has been classified as demand-related and allocated on each class's estimated demands during the system's 12 monthly peak hours. The other 7.7 percent has been classified as energy-related and allocated on energy.

In the company's last rate case we approved projected daily burn for 107.5 days as the basis for the calculation of the appropriate level of fuel inventory to be included in working capital. Since projected average daily burn is a function of KWH projected to be generated and used in the test year, fuel stock should be classified as energy-related and thus allocated on energy. The energy classification and allocation of fuel more closely track cost causation than the company's 92.3 percent allocation on 12 CP demands.

Since we have based the level of fuel stock allowed in rate base on a specific number of days burn which is a function of the KWH projected to be generated in the test year, fuel stock should be classified as energy-related and allocated on energy.

4. Estimate of CP and NCP Demands

The twelve monthly coincident peak hour demands (12 CP) are used to allocate demand-related production plant and transmission plant costs [*83] in all but the near-peak cost of service study. These demands must be estimated for all classes when using a projected test year. The 12 CP and class peak demands were estimated by class by dividing the 1990 KWH by 1987 KWH and multiplying that ratio times the 1987 12 CP for rate classes RS, GS and GSD. Under this method each class' 12 CP KW for the test year are increased over the historic load research data by the same percentage their KWH are projected to increase in the same time period, i.e., each class's 12 CP load factor is assumed to be the same as it was in the year of the historic load research data. Thus, each class's demand or use in the 12 monthly coincident peak hours relative to total KWH usage is projected to be the same in the test year as the historic load research year.

For those customers taking service on the SE rider, "supplemental energy" KWH were excluded from this calculation. The resulting 12 CP demand of 104,728 KW for the PXT class would have been 6.8 percent higher if the KWH had been included (111,893 KW). The effect on the estimated demands of the LP/LPT class was insignificant (.79 percent) because the LP/LPT customers' response to the SE rider [*84] was minimal. The 104,728 KW represents a 12 CP load factor of 107 percent in the test year for PXT. Thus, the PXT class would have been allocated about 6.8% more demand related production and transmission plant cost if these KWH had not been excluded. The effect of this adjustment or methodology is to reduce the costs allocated to the PXT class and thereby avoid or reduce a rate increase by inflating the class's rate of return.

The company's reason for excluding these KWH apparently is that it expects the SE customers to have a higher 12 CP load factor in the test year, i.e., to use less energy in the 12 monthly peak hours relative to their total usage. However, the data below shows the 12 CP load factor for 1989 for the three groupings of PXT customers decreases instead of increases in 1989. The significant decrease from 101 percent to 91 percent for PX/PXT customers on the SE rider was inconsistent with the company's assumed increased load factor for the class.

12 CP LOAD FACTORS

	Actual 1987	Actual 1989	Projected 1990
PXT Class as a whole	101	95	107
PX/PXT Customers on the SE Rider	101	91	
PX/PXT Customers not on the SE Rider	100	97	
LP/LPT Class as a whole	83	83	84
LP/LPT Customers on the SE Rider	80	83	
LP/LPT Customers not on the SE Rider	84	84	

[*85]

If the company's projection of a 107 percent 12 CP load factor for PXT due to an assumed changing usage pattern of SE customers is to be realistic or representative of 1990, it is only reasonable to expect the load factor for the PX/PXT SE customers would have been higher in 1989 than 1987.

Other data indicating that it is unreasonable to expect the 12 CP load factor for the PXT class to increase from 95 percent in 1989 to 107 percent in 1990 includes:

(1) The number of supplemental energy KWH projected for 1990 is 20 percent less than 1989. (Exhibit 486)

(2) The number of hours projected to be designated as SE hours in 1990 is less than either 1988 or 1987. (Exhibit 487)

(3) The SE rider has been in effect since 1985 without revision. (Order No. 17568)

Therefore, one would not expect a markedly different response to the rider in 1990 than in 1989.

The company has not presented any data or evidence supporting the use of a load factor higher than the historic value. All of the PX/PXT customers have time-recording meters so that their 12 CP values are actual metered numbers and not estimates. Therefore, the company had the 12 CP load factor data for the first four or five [*86] months of 1990 and could have entered it into the record during the hearing as evidence supporting the increased load resulting from their methodology. The company did not enter the data. It is reasonable to assume that the data would have been entered if it corroborated the assumptions behind their methodology.

It was also unreasonable to use 104,728 12 CP KW for 1990 for PXT because the 1989 actual (not estimated) value was 119,448 KW and the PXT KWH were projected to decrease only 1% from 1989 to 1990. (Data on Exhibits 488 and 209)

We are concerned about Gulf's departure from the policy (MFR Schedule E-14) of using the load characteristics determined from the load research collected pursuant to the Commission's Rule 25-6.0437 Cost of Service Load Research in developing various peak demands by class for the test year. The policy assumes the load characteristics, including load factor, are the same in the test year as the historic load research year. The primary purpose of the rule is "to require that load research that supports cost of service studies used in ratemaking procedures is of sufficient precision to reasonably assure that tariffs are equitable and reflect the [*87] true costs of serving each class of customers." The utilities have spent large amounts of money to collect the load research required by this rule. Gulf's departure from the use of historical load characteristics for the PXT class undermines the purpose of the Commission's Cost of Service Load Research Rule. It is inequitable and should not be allowed.

The company's exclusion of "supplemental energy" KWH in the development of the 12 monthly coincident peak hour demands and the class noncoincident peak demand for PX/PXT and LP/LPT underestimated these demands and resulted in an underallocation of production and transmission cost to the two classes. The PXT 12 CP KW should have been 6.8 percent higher and the LP/LPT's .79 percent higher. The exclusion of these KWH was inappropriate. The method employed by the company to develop its estimates by class of the 12 monthly coincident peak hour demands and the class noncoincident peak hour demands is inappropriate and Gulf's use of the methodology is denied.

B. Allocation of Revenue Increase

The revenue increases that we have authorized should be spread among the rate classes in a manner that moves class rate of return indices closer [*88] to parity. In so allocating the revenue increases we adhere to the following guidelines:

No class will receive an increase greater than 1 and 1/2 times the system percentage increase of 2.79 percent with adjustments.

The classes below parity will be given the maximum increase (RS and OS-II).

The GS class will be brought to 1.45 times parity. The approved reduction to the GS class is $ 1,655,000.

The OS-III class will be brought down to 2.34 times parity.

The balance of the increase will be spread across the remaining classes to retain as closely as possible their existing relationships.

Attachment 4 sets forth the approved spread of revenue increase by class. Attachment 5 provides the approved rates by class.

C. Seasonal Rates

The company currently has seasonal rates for the RS and GS rate classes. These seasonal rates do not track the company's cost of capacity when Gulf buys power from the Southern pool. These costs represent a significant portion of Gulf's cost of service during those hours Gulf buys power. Thus, the price signal sent by the present seasonal differential under the RS and GS rate classes may not represent the true cost to the ultimate consumer on [*89] Gulf's system, thereby tempering the reduction in peak-related costs, improvement of system load factor, and conservation of summer consumption sought by the seasonal design. A flat charge per KWH based on average costs for the RS and GS classes may produce a clearer price signal than the seasonal rate design proposed by the company.

We therefore eliminate seasonal rates for the RS and GS classes because the seasonal pricing differential does not appear to be cost-based and may not be sending the appropriate price signal during the hours Gulf buys power from the Southern pool.

D. Customer Charges

Customer charges are designed to recover costs associated with the number of customers served. These costs include primarily the costs of billing and metering and customer service. Given that costs are properly allocated to the customer component, the charge for each class should reflect the cost to provide such services. The customer charges are set as follows:

Rate Class	Unit Cost	Current Charges	Approved Charges
RS	$ 7.94	$ 6.25	$ 8.00
RST		9.25	11.00
GS	17.34	7.00	10.00
GST		10.00	13.00
GSD	41.47	27.00	40.00
GSDT		32.40	45.40
LP/LPT	447.83	51.00	225.00
PX/PXT	1,222.21	146.00	570.00

[*90]

E. Transformation Ownership Discounts

Gulf currently offers a discount to customers who own their transformation equipment and for the losses absorbed by the customer metered at primary or transmission level. Gulf proposed adjusting these credits by any variance of the demand and energy charges from unit costs. FEA proposed substantial increases in the transformation discounts to include the costs of poles, overhead/underground conductors, lines, and transformers.

We agree with staff that such a large discount could encourage uneconomic duplication of facilities to the detriment of the general body of ratepayers. Further, we agree that the adjustment for variance from unit costs proposed by Gulf is an unnecessary complication. Therefore we approve a transformer ownership credit for primary level customers of $ 0.35/KW/Month for GSD/GSDT and $ 0.42/KW/Month for LP/LPT. The transformer ownership credit for transmission level customers should be set at $ 0.41/KW/Month for GSD/GSDT, $ 0.52/KW/Month for LP/LPT, and $ 0.11/KW/Month for PX/PXT customers.

Such transformation credits should also be applied to the SS and ISS classes and should be based on 100 percent ratcheted billing [*91] demand in order to match the calculation of the local facilities demand charge applicable to standby service. Metering voltage discounts should be set equal to the otherwise applicable rate schedule for SS and ISS customers and apply to both the KW and KWH charges.

F. Time of Use Rates

Two methodologies were presented at the hearing for the design of time of use rates. Gulf's testimony supports use of the load factor methodology approved by the Commission in the company's last three rate cases. We believe that the major drawback to the load factor methodology is that it does not track costs as well as the time of use methodology (TOU) proposed by OPC.

OPC supports the use of a methodology which would recover distribution-related plant costs from the maximum demand charge; production and transmission-related demand costs through the on-peak demand charge; and energy-related production plant and operations and maintenance expenses through the energy charge. This approach also includes a ratchet for recovery of local distribution plant costs. We believe the rate design for the maximum demand charge should be based on actual metered demand and not ratcheted KW as proposed by [*92] OPC.

We therefore calculate time of use rates as follows:

1) The on-peak and off-peak non-fuel energy charges would be set equal to the energy unit cost from the cost study. (This would include the energy-related production plant and operations and maintenance expenses).

2) The maximum billing demand charge (which is applied to the customer's maximum demand whenever it occurs) would be equal to the distribution plant unit cost.

3) The on-peak demand charge would be an amount sufficient to recover the remaining revenue requirement including the transmission plant and the demand-related production plant.

G. Standby Service

1. Determination of Daily Standby Service Billing Demand

The following formula is Gulf's current formula for calculating daily standby service demand on Gulf's firm standby service (SS) tariff:

Daily Standby Service (KW) =

Maximum totalized customer generation output occurring in any interval between the end of the prior outage and the beginning of the current outage.

Minus the customer's daily generation output (KW) occurring during the on-peak period of the current outage.

Minus the daily on-peak load reduction (KW) that is a direct result of the customer's [*93] current generation outage.

The customer's daily generation output (KW) and daily on-peak period load reduction (KW) that are used in the formula must occur during the same 15 minute interval as the daily Standby Service (KW) that is used for billing purposes.

The language in the above formula for calculating daily standby service demand should be changed from:

Maximized totalized customer generation output occurring in any interval between the end of the prior outage and the beginning of the current outage

to:

The amount of load in KW ordinarily supplied by the customer's generation.

This change would satisfy the Industrial Intervenors' request for adjustment for seasonal variation in generation output in calculating daily standby service demand. It would also ensure that self-generating customers (SGCs) are not billed for standby power when they reduce generation for purely economic reasons. We believe that this change in the formula will result in a more accurate determination of standby power used.

The Industrial Intervenors proposed formula would result in standby power used by SE rider customers not being properly billed as standby power.

The language in the formula [*94] in the interruptible standby service (ISS) should be replaced with the language in the formula we are approving herein for firm standby service.

2. Design of Standby Service Charges

The present standby service rates are based on system and class unit costs from Docket No. 840086-EI. We believe the standby rate schedule (SS and ISS) charges should be adjusted to reflect unit costs from the compliance cost of service study for this rate case and the 1990 IIC capacity charge rates.

The SS charges should be designed using this compliance cost of service study and the rate design specified in Order No. 17159. The forced outage rate to be used to calculate the reservation charge would be that approved herein. If the resulting charges generate either more or less revenue than the class' revenue responsibility as approved herein, all charges except the customer charge should be decreased or increased by the (same) percentage required to generate the class' revenue requirement. The ISS charges should be the same as the SS charges except for the reservation and daily demand charges. The sum of the CP KW transmission unit cost plus an average IIC monthly charge rate of $ 6.69 should [*95] be used as the unit cost to develop these charges. Having decided herein to bill SE customers for distribution system costs on their maximum metered KW whenever it occurs, the billing KW in Exhibit 510 should be used to calculate the local facilities charges.

The customer charge should be the LP/LPT customer charge plus $ 25 except for those standby customers taking service on PX/PXT for whom the charge should be the PX/PXT charge plus $ 25.

The company should provide the staff a compliance cost of service study and the SS rates calculated in accordance with this decision. A spread sheet of component costs by function (retail revenue requirements) for the compliance study should also be provided.

With respect to the definition of the capacity used to determine the applicable local facilities and fuel charges, we are denying Gulf's proposed changes because they are not in conformance with the terms and conditions prescribed in Order No. 17159 for standby service.

3. SS Rate Forced Outage Factor

In the Standby Order No. 17159, a 10 percent forced outage rate was specified as the outage rate to be used in the calculation of the Reservation Charge. The overall reliability of the [*96] forced outage data in the record is questionable, however, in that the company was apparently accepting without review the forced outage data provided by self-generating customers (SGCs) and the SGCs may not have understood they were to report these outages, even if they signed up for zero standby power. Additionally, data was provided by only three of the four SGCS.

While we are tempted to rule that the assumed 10 percent forced outage rate should not be continued, there appears to be no practical alternative in the absence of sound, reliable data to support an alternative value for the forced outage rate.

Therefore, in the absence of reliable data to support a different value for the forced outage rate used to develop the reservation charge, the 10 percent forced outage rate prescribed in Order No. 17159 should continue to be used.

4. SE Rider Availability in Lieu of Standby Service

This issue is whether self-generating customers who are experiencing a forced outage or an outage for scheduled maintenance of their generating system can be billed on the SE rider rather than the standby service rate for standby power taken during the outage if the customer has another generator [*97] with which he could generate but chooses not to use for economic reasons. In other words, the issue is whether a self-generating customer can have standby power billed under a different rate tariff than the standby service if he has additional generating capacity available but which is less economic. Under the current standby service rate schedules, self-generating customers may reduce generation for economic reasons and take additional capacity and energy as supplementary service, including supplementary service with the SE rider applied.

Order No. 17159 at page 6, in addressing the issue of whether non QF standby customers would be entitled to the same service as QFs, requires the standby tariff resulting from that proceeding to be mandatory for all self-generating customers unless there is evidence to demonstrate that their load characteristics resemble those of normal full requirements customers. To allow such a customer to choose a different rate because it would result in a lower bill would allow that customer to escape costs properly assigned to him.

There is also a basic cost recovery problem if standby service is allowed to be billed on the provisions of the SE rider. [*98] The standby service rates have been developed by dividing the utility's full demand-related production and transmission unit cost per coincident peak kilowatt of demand by the average number of days per month that contain on-peak hours (21). Using this rate requires a standby customer who imposes load every day to pay the full demand-related unit cost per coincident peak KW because it is virtually certain that his load was on at the time of the system's peak.

The average number of days in 1988 and 1989 for which a self-generating customer would be billed daily demand charges if standby power was taken and billed pursuant to the SE rider is six. Thus, if a customer were using standby power for maintenance every day in a given month, the customer would be paying, on average, 6/21ths of the full demand-related unit cost per coincident peak KW even though it was virtually certain that his load was on at the time of the system's peak. In this scenario, the rates for standby service should be recovering the full demand-related unit cost.

Additionally, to allow standby power to be taken under the terms and conditions of the SE rider if the customer had generating capacity available [*99] but less economic would discriminate against self-generating customers with only one generator versus those with multiple generators.

KWH and capacity purchased to replace energy and capacity normally generated by a customer's generator which is experiencing a forced outage or an outage for scheduled maintenance, is clearly standby power and should be billed as standby power. However, to ensure that power taken to replace reduced generation for purely economic reasons is billed as supplemental power, the definitions of backup service and maintenance service should be more specific. Two sentences should be added to the definition (in the tariff) of backup service and maintenance service, the two forms of standby service, to indicate more clearly what constitutes scheduled and unscheduled outages. In the definition of backup service, an unscheduled outage should be defined as the loss or reduction of generation output due to equipment failure(s) or other condition(s) beyond the control of the customer. Similarly, under maintenance service a scheduled outage should be defined as the loss or reduction due to maintenance activities of any portion of a customer's generating system. [*100]

5. Waiver of Ratchet Provision for Reservation Charge

All demands registered during any maintenance outage of a self-generating customer, regardless of whether the maintenance outage is fully coordinated with Gulf, should be subject to the ratchet provision of the SS rate for the local facilities charge. The ratchet provision is appropriate because the scheduling of the outage does not affect the capacity of the local facilities to serve the customer. Scheduling the outage will not enable Gulf to avoid local facilities cost as the capacity of the local facilities, particularly dedicated substations, must be sufficient to serve the customer's maximum demand whenever it occurs. An increase in demand should properly result in an increase in the billing demand for the local facilities charge.

The Company should excuse demands registered during such periods from the ratchet provision applicable to the reservation charge if (1) the maintenance outage is usefully coordinated with Gulf and (2) the maintenance is used in hours that do not include a peak hour(s) that determines Gulf's IIC payments or revenues. The ratchet provision should not be waived for maintenance power used during [*101] the peak hours that determine Gulf's IIC payments or revenues because the cost impact continues for three years.

H. Supplemental Energy (SE) Rider

1. No Separate SE Rate Class

Order No. 17568, Docket No. 850102-EI, approved the experimental Supplemental Energy (SE) (Optional) Rider as a permanent rate schedule on the condition that it become a separate rate class in the company's next rate case. In this docket however, Gulf has not provided separate cost of service analyses for the two rate classes employing the SE Rider, LPT-SE and PXT-SE.

The necessity for a separate rate class depends on the differences between billing KW and peak demand KW characteristics of SE customers, as opposed to these in the general LP/LPT and PX/PXT classes and considerations of local facilities costs. From the record in this docket it appears that there is a large dissimilarity in the ratios of billing KW to 12 CP KW and maximum metered KW between PXT-SE and LPT-SE classes and that these customers should not be grouped into a single class. The data implies that to put all SE customers into one class would create a serious cost recovery problem between the LPT-SE and the PXT-SE customers. Therefore, [*102] a separate rate class consisting of LPT and PXT customers on the SE rider should not be implemented in this rate class.

It does, however, appear that there may be sufficient dissimilarity between the ratios of billing KW and 12 CP KW and maximum metered KW to warrant separate rate classes for the LP/LPT SE customers and for the PX/PXT-SE customers. Since we do not have a cost of service study with LP/LPT-SE and PX/PXT-SE each as a separate rate class, the question of whether a separate rate class(es) should be implemented for either PX/PXT-SE or LP/LPT-SE customers should be considered in the next rate case. Gulf is instructed to file its cost of service study in that case with LP/LPT and PX/PXT each broken into SE and non-SE classes and with totals for LP/LPT and PX/PXT.

2. Distribution System Costs for SE Customers

The SE rider presently provides forgiveness of the demands incurred during SE periods both with respect to on-peak and off-peak billing KW. Five of the six SE customers have dedicated substations (Exhibit 517). The sum of the average billing KW for the three SE customers for whom dedicated substations were built in 1989 is only 53 percent of the capacity of these [*103] substations. However, the PXT-SE customers are billed on only 59 percent of their maximum metered KW. Therefore, to ensure that the SE customers pay for the dedicated facilities that have been sized to serve their maximum demands whenever they occur, SE customers should be billed for distribution system costs on their maximum metered demand whenever it occurs. The provision of the SE rider for forgiveness of demand in the SE period would continue to apply to on-peak demand.

Therefore, Gulf shall bill SE customers for distribution system costs on their maximum metered KW whenever it occurs as per these guidelines.

I. Applicability Clause, GSD, LP and PX Classes

The applicability clause of the three demand classes (GSD, LP and PX) is stated in terms of the amount of KW demand for which the customer contracts. This is not an appropriate basis for determining applicability.

In the past, contracts have not been required of all these customers, and contract demand often bears little relationship to actual measured demand. As a part of this docket, tariffs should be modified to state that the applicability for both demand and the PX/PXT 75 percent load factor should be based on [*104] measured maximum billing demand. For SE customers, this would be the actual measured billing demand in non-SE periods. Customers whose annual load factor is less than 75 percent should not be allowed to opt for PXT because the PX/PXT rate is based on the costs of high load factor customers.

J. Minimum Charge Provisions for GSD/GSDT and LP/LPT

The current GSD/GSDT and LP/LPT rate schedules have minimum charges equal to the customer charge plus the demand charge for the minimum KW to take service on the rate schedule for customers opting for the rate schedule. This minimum charge provision is not appropriate. This provision unduly penalizes customers who opt for this higher rate class because they pay for the minimum KW to qualify for the class even if their usage falls below this level. Customers who meet the class minimum even once in every 12 month period, do not pay a minimum but pay only for their actual demand, even if it falls below the minimum.

We therefore eliminate the minimum charge provisions of the GSD/GSDT and LP/LPT rate schedules.

K. No Local Facilities Charge

The company proposed the implementation of a local facilities demand charge for LP/LPT and PX/PXT [*105] customers, which would be applied when the customer's actual demand does not reach at least 80 percent of the Capacity Required to be Maintained (CRM) specified in the Contract for Electric Power. We are denying the implementation of this charge because it is inequitable to apply the charge to the contract capacity because the contract demand for many customers bears little relationship to measured demand. Furthermore, it is an ineffective charge because no customers would have to pay the charge in the test year.

L. Service Charges

The following service charges are approved:

Initial Service	$ 20.00
Reconnect a subsequent subscriber	16.00
Reconnect of existing customer after disconnect for Cause	16.00
Collection Fee	6.00
Installing and Removing Temporary Service	60.00
Minimum Investigation Fee	55.00

M. Outdoor Service (OS)

1. Elimination of OS General Provisions

The company proposes to eliminate the general provisions pertaining to replacement of lighting systems on the Outdoor Service Rate Schedule (OS). We believe this is appropriate and that the present general provisions relating to the replacement of mercury vapor lighting fixtures with [*106] high pressure sodium fixtures should be removed.

The current provisions pertaining to replacement of lighting systems on the OS schedule are deleted as proposed by the company and no new provisions are adopted.

2. Street and Outdoor Lighting Rate

We approve the methodology used in developing the Street (OS-I) and Outdoor (OS-II) lighting rates. This entails setting the energy charges at levels which will collect the total non-fuel energy, demand, and customer-related costs at the class-approved rate of return. Maintenance charges were set so as to recover the total maintenance and administrative and general expenses allocated to OS-I and II in the cost of service study. The fixture charges were set at a level to collect the remaining revenue requirement after subtracting the energy, maintenance and additional facilities revenues. Attachment 6 sets forth the approved street and outdoor lighting rates for Gulf.

Gulf at present does not have records indicating the number of poles and other facilities in place which are dedicated to additional facilities. Because of this, it was not possible to develop cost-based rates for additional facilities in this rate case. We are directing [*107] Gulf to take the steps necessary to obtain this information so that cost-based additional facilities charges can be developed when the next rate case is filed.

3. Applicability of OS-III

The language in the OS-III (Other Outdoor Service) tariff will be modified to reflect that only customers with fixed wattage loads operating continuously throughout the billing period, such as traffic signals, cable TV amplifiers and gas transmission substations, will be allowed to take service on the OS-III rate.

N. Sports Fields Rate

Since the company's last rate case, sports fields taking service on Rate Schedules GS and GSD were allowed to transfer to the OS-III rate schedule. The company has now proposed an OS-IV rate for sports fields.

In deriving the 12 CP and NCP allocators for OS-IV, the company assumed that all recreational lighting customers would require service at a constant rate every day of the year from sunset to 10:00 p.m. A review of the customer accounting memo sheets for the sports fields customers indicates that approximately 36% of the billing months showed zero kwh usage. The company has no load data for sports fields, and does not intend to obtain such data using [*108] load research meters. The OS-IV rate was thus designed in the absence of reliable load research data.

In 1981 and 1982 the Commission eliminated special rates for sports fields, poultry farms and other uses. Addition of a special rate for sports fields is philosophically at odds with these past actions.

In spite of these problems, we will allow the rate design for OS-IV to be implemented. This is because the estimated OS-IV kilowatt hours have not been broken down into summer and winter components, and thus cannot be added to the kilowatt hours for GS and GSD to determine an accurate energy rate for those classes. In addition, the OS-IV as designed will not vary significantly from the GS rate. However, when the company files its next rate case they will be required to transfer their sports field customers to the appropriate GS or GSD rate schedules.

XV. CONCLUSIONS OF LAW

1) Gulf Power Company is a public utility within the meaning of Section 366.02, Florida Statutes, and is subject to the jurisdiction of the Commission.

2) This Commission has the legal authority to approve and use a projected test period for ratemaking purposes. Calendar year 1990 is an appropriate base [*109] test period.

3) The adjustments to rate base made herein are reasonable and proper. The value of the Company's 1990 rate base for ratemaking purposes is $ 861,159,000.

4) The adjustments made to the calculation of net operating income are proper and appropriate. For ratemaking purposes, Gulf's net operating income for 1990 is $ 61,085,000.

5) The fair rate of return on the equity capital of Gulf is 12.55%.

6) As a result of our finding of corporate mismanagement, Gulf's return on equity has been reduced by fifty (50) basis points for a two year period. This results in a return on equity of 12.05% for two years beginning September 13, 1990.

7) Gulf Power Company should be authorized to increase its rates and charges by $ 11,838,000 in annual gross revenues effective September 13, 1990. Gulf Power Company should be authorized to increase its rates and charges by $ 14,131,000 beginning September 13, 1992.

8) The rate schedules prescribed and approved herein are fair, just and reasonable within the meaning of Chapter 366, Florida Statutes.

9) The new rate schedules shall be reflected upon billings rendered for meter readings taken on or after September 13, 1990.

Accordingly, [*110] it is

ORDERED by the Florida Public Service Commission that the findings of fact and conclusions of law set forth herein are approved. It is further

ORDERED that the petition of Gulf Power Company for authority to increase its rates and charges is granted to the extent delineated herein. It is further

ORDERED that Gulf Power Company is hereby authorized to submit revised rate schedules consistent herewith designed to generate $ 11,838,000 in additional gross revenues annually for two years beginning September 13, 1990. The Company shall include with the revised rate schedules all calculations and workpapers used in deriving the revised rates and charges. It is further

ORDERED that the revised schedules authorized herein for the $ 11,838,000 revenue increase shall be reflected upon billings rendered for meter readings taken on or after September 13, 1990. It is further

ORDERED that Gulf Power Company is hereby authorized to submit revised rate schedules consistent herewith designed to generate $ 14,131,000 in additional gross revenues annually for two years beginning September 13, 1992. The Company shall include with the revised rate schedules all calculations and workpapers [*111] used in deriving the revised rates and charges. It is further

ORDERED that the revised schedules authorized herein for the $ 14,131,000 revenue increase shall be reflected upon billings rendered for meter readings taken on or after September 13, 1992. It is further

ORDERED that Gulf Power Company shall return to its ratepayers on a "per KWH basis" that portion of its interim increase set forth in the body of this order. It is further

ORDERED that Gulf Power Company shall include in each customer's bill, in the first billing of which the increase is effective, a bill stuffer explaining the nature of the increase, average level of the increase, a summary of tariff charges, and the reasons therefore. The bill stuffers shall be submitted to the Division of Electric and Gas of the Florida Public Service Commission for approval before implementation. It is further

ORDERED that in its next rate case Gulf Power Company shall file a cost of service study with LP/LPT and PXT each broken into SE and non-SE classes, with totals calculated for LP/LPT and PX/PXT. It is further

ORDERED that when Gulf Power Company files its next rate case that it transfer its sports fields customers from [*112] the OS-IV rate to the appropriate GS or GSD rate schedules. It is further

ORDERED, Gulf shall take the steps necessary to determine the quantity of street and outdoor lighting facilities dedicated to additional facilities prior to the filing of the next rate case, in order that cost-based rates can be developed for these facilities.

ORDERED that this docket be closed should no petition for reconsideration or notice of appeal be timely filed.

By ORDER of the Florida Public Service Commission, this 3rd day of OCTOBER, 1990.

ATTACHMENT 1

SCHEDULE 1

COMPANY: GULF POWER COMPANY

TEST YEAR: DECEMBER 31, 1990

COMPARATIVE RATE BASES

LINE NO.	CO. ADJ. NO.	ISSUE NO.	DESCRIPTION	COMPANY FILING SYSTEM PER BOOKS	COMPANY FILING JURISDICTIONAL PER BOOKS
1			PLANT IN SERVICE		$ 1,275,624
2		2	PLANT IN SERVICE		
3		3	SCHERER TAX ADDER ADJUSTMENT		
4		4	SCHERER ACQUISITION ADJUSTMENT		
5		5	NEW CORPORATE HEADQUARTERS		
6		7	NAVY HOUSE		
7		8	APPLIANCE DIVISION		
8		9	TALLAHASSEE OFFICE		
9		10	BONIFAY/GRACEVILLE		
10		12	LEISURE LAKES		
11		16	UNIT POWER SALES		
12		25	PLANT DANIEL		
13		27	PLANT SCHERER		
14		29	REBUILDS & RENOVATIONS		
15		30	NETWORK PROTECTORS		
16					

17		Total plant in service	0		1,275,624
18					
19					
20		ACCUMULATED DEPRECIATION		454,964	
21	3	SCHERER TAX ADDER ADJUSTMENT			
22	5	NEW CORPORATE HEADQUARTERS			
23	8	APPLIANCE DIVISION			
24	9	TALLAHASSEE OFFICE			
25	11	JDITC UNDERSTATEMENT			
26	16	UNIT POWER SALES			
27	25	PLANT DANIEL			
28	27	PLANT SCHERER			
29	29	REBUILDS & RENOVATIONS			
30	30	NETWORK PROTECTORS			
31					
32		Total depreciation reserve	0		454,964
33					
34		Net plant in service	0		820,660
35					
36					
37		CONSTRUCTION WORK IN PROGRESS		14,949	
38	13	LEVEL OF CWIP			
39	14	NON-AFUDC CWIP			
40					
41		Total CWIP	0		14,949
42					
43					
43					
44		PROPERTY HELD FOR FUTURE USE		3,925	
45	6	CARYVILLE SOD FARM			
46	15	LEVEL OF PHFFU			
47					
48		Total prop. held for future use	0		3,925
49					
50					
51					
52		ACQUISITION ADJUSTMENT		2,317	
53	4	SCHERER ACQUISITION ADJUSTMENT			
54					
55		Total acquisition adjustment	0		2,317
56					
57					
58		Net utility plant	0		841,851
59					
60					
61		WORKING CAPITAL		81,711	
62	16	UNIT POWER SALES			
63	18	PREPAID PENSIONS			
64	19	RATE CASE EXPENSES			
65	20	FUEL/CONSERVATION OVERRECOVERIES			
66	21	TEMPORARY CASH INVESTMENTS			
67	22	HEAVY OIL INVENTORY			

68		23	LIGHT OIL INVENTORY		
69		24	COAL INVENTORY		
70		25	PLANT DANIEL		
71		27	PLANT SCHERER		
72		28	CANCELED SCS BUILDING		
73		31	OTHER INVESTMENTS		
74		32	OTHER ACCOUNTS RECEIVABLE		
75		33	MATERIALS & SUPPLIES		
76		34	OTHER CURR. ASSETS & MISC. DEF. DEBITS		
77		35	CARYVILLE SUBSURFACE STUDY		
78		36	EXPENSE ADJUSTMENTS		
79					
80					
81			Total working capital	0	81,711
82					
83					
84			TOTAL RATE BASE	0	923,562

[*113]

LINE NO.	CO. ADJ. NO.	ISSUE NO.	DESCRIPTION	COMPANY FILING ADJUSTMENTS	JURISDICTIONAL ADJUSTED
1			PLANT IN SERVICE		
2		2	PLANT IN SERVICE		
3		3	SCHERER TAX ADDER ADJUSTMENT		
4		4	SCHERER ACQUISITION ADJUSTMENT		
5		5	NEW CORPORATE HEADQUARTERS		
6		7	NAVY HOUSE		
7		8	APPLIANCE DIVISION		
8		9	TALLAHASSEE OFFICE		
9		10	BONIFAY/GRACEVILLE		
10		12	LEISURE LAKES		
11		16	UNIT POWER SALES		
12		25	PLANT DANIEL		
13		27	PLANT SCHERER		
14		29	REBUILDS & RENOVATIONS		
15		30	NETWORK PROTECTORS		
16					
17			Total plant in service	0	1,275,624
18					
19					
20			ACCUMULATED DEPRECIATION		
21		3	SCHERER TAX ADDER ADJUSTMENT		
22		5	NEW CORPORATE HEADQUARTERS		
23		8	APPLIANCE DIVISION		
24		9	TALLAHASSEE OFFICE		
25		11	JDITC UNDERSTATEMENT		
26		16	UNIT POWER SALES		
27		25	PLANT DANIEL		
28		27	PLANT SCHERER		
29		29	REBUILDS & RENOVATIONS		
30		30	NETWORK PROTECTORS		

31				
32		Total depreciation reserve	0	454,964
33				
34		Net plant in service	0	820,660
35				
36				
37		CONSTRUCTION WORK IN PROGRESS		
38	13	LEVEL OF CWIP		
39	14	NON-AFUDC CWIP		
40				
41		Total CWIP	0	14,949
42				
43				
43				
44		PROPERTY HELD FOR FUTURE USE		
45	6	CARYVILLE SOD FARM		
46	15	LEVEL OF PHFFU		
47				
48		Total prop. held for future use	0	3,925
49				
50				
51				
52		ACQUISITION ADJUSTMENT		
53	4	SCHERER ACQUISITION ADJUSTMENT		
54				
55		Total acquisition adjustment	0	2,317
56				
57				
58		Net utility plant	0	841,851
59				
60				
61		WORKING CAPITAL		
62	16	UNIT POWER SALES		
63	18	PREPAID PENSIONS		
64	19	RATE CASE EXPENSES		
65	20	FUEL/CONSERVATION OVERRECOVERIES		
66	21	TEMPORARY CASH INVESTMENTS		
67	22	HEAVY OIL INVENTORY		
68	23	LIGHT OIL INVENTORY		
69	24	COAL INVENTORY		
70	25	PLANT DANIEL		
71	27	PLANT SCHERER		
72	28	CANCELED SCS BUILDING		
73	31	OTHER INVESTMENTS		
74	32	OTHER ACCOUNTS RECEIVABLE		
75	33	MATERIALS & SUPPLIES		
76	34	OTHER CURR. ASSETS & MISC. DEF. DEBITS		
77	35	CARYVILLE SUBSURFACE STUDY		
78	36	EXPENSE ADJUSTMENTS		
79				
80				

81			Total working capital	0	81,711
82					
83					
84			TOTAL RATE BASE	0	923,562

[*114]

				COMMISSION VOTE	
LINE NO.	CO. ADJ. NO.	ISSUE NO.	DESCRIPTION	ADJUSTMENTS	JURISDICTIONAL ADJUSTED
1			PLANT IN SERVICE		
2		2	PLANT IN SERVICE	(55)	
3		3	SCHERER TAX ADDER ADJUSTMENT	0	
4		4	SCHERER ACQUISITION ADJUSTMENT	0	
5		5	NEW CORPORATE HEADQUARTERS	(3,892)	
6		7	NAVY HOUSE	(23)	
7		8	APPLIANCE DIVISION	(214)	
8		9	TALLAHASSEE OFFICE	(24)	
9		10	BONIFAY/GRACEVILLE	0	
10		12	LEISURE LAKES	(142)	
11		16	UNIT POWER SALES	0	
12		25	PLANT DANIEL	0	
13		27	PLANT SCHERER	(52,987)	
14		29	REBUILDS & RENOVATIONS	0	
15		30	NETWORK PROTECTORS	0	
16					
17			Total plant in service	(57,337)	1,218,287
18					
19					
20			ACCUMULATED DEPRECIATION		
21		3	SCHERER TAX ADDER ADJUSTMENT	0	
22		5	NEW CORPORATE HEADQUARTERS	(338)	
23		8	APPLIANCE DIVISION	(7)	
24		9	TALLAHASSEE OFFICE	(11)	
25		11	JDITC UNDERSTATEMENT	0	
26		16	UNIT POWER SALES	0	
27		25	PLANT DANIEL	0	
28		27	PLANT SCHERER	(6,557)	
29		29	REBUILDS & RENOVATIONS	0	
30		30	NETWORK PROTECTORS	0	
31					
32			Total depreciation reserve	(6,913)	448,051
33					
34			Net plant in service	(50,424)	770,236
35					
36					
37			CONSTRUCTION WORK IN PROGRESS		
38		13	LEVEL OF CWIP	0	
39		14	NON-AFUDC CWIP	0	
40					
41			Total CWIP	0	14,949
42					
43					
43					

44		PROPERTY HELD FOR FUTURE USE		
45	6	CARYVILLE SOD FARM	(135)	(135)
46	15	LEVEL OF PHFFU	0	0
47				
48		Total prop. held for future use	(135)	3,790
49				
50				
51				
52		ACQUISITION ADJUSTMENT		
53	4	SCHERER ACQUISITION ADJUSTMENT	(2,317)	
54				
55		Total acquisition adjustment	(2,317)	0
56				
57				
58		Net utility plant	(52,876)	788,975
59				
60				
61		WORKING CAPITAL		
62	16	UNIT POWER SALES	0	
63	18	PREPAID PENSIONS	0	
64	19	RATE CASE EXPENSES	(765)	
65	20	FUEL/CONSERVATION	0	
		OVERRECOVERIES	0	
66	21	TEMPORARY CASH INVESTMENTS	(576)	
67	22	HEAVY OIL INVENTORY	(123)	
68	23	LIGHT OIL INVENTORY	(6,017)	
69	24	COAL INVENTORY	0	
70	25	PLANT DANIEL	(2,187)	
71	27	PLANT SCHERER	0	
72	28	CANCELED SCS BUILDING	0	
73	31	OTHER INVESTMENTS	0	
74	32	OTHER ACCOUNTS RECEIVABLE	0	
75	33	MATERIALS & SUPPLIES	0	
76	34	OTHER CURR. ASSETS & MISC. DEF. DEBITS	0	
77	35	CARYVILLE SUBSURFACE STUDY	(28)	
78	36	EXPENSE ADJUSTMENTS	169	
79				
80				
81		Total working capital	(9,527)	72,184
82				
83				
84		TOTAL RATE BASE	(62,403)	861,159

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ATTACHMENT 2

13-Month Average Capital Structure

Test Year Ending 12/31/90

COMMISSION VOTE	LONG TERM DEBT	LONG TERM NOTE	SHORT TERM DEBT	PREFERRED STOCK
Company Per Book	439,734	42,089	4,432	67,432

Company Adjustments (Specific)	(98,837)	(42,089)		(10,278)
Subtotal	340,897	0	4,432	57,154
Commission Adjustments (Specific)	7,282	0	0	169
Subtotal	348,179	0	4,432	57,323
Prorata (Other Sources) n1	(23,159)	0	(295)	(3,813)
Subtotal	325,020	0	4,137	53,510
Prorata Adjustments	(13,070)	0	(166)	(2,152)
TOTAL	311,950	0	3,971	51,358
Ratio	36.22%	0.00%	0.46%	5.96%
Cost Rate	8.72%	0.00%	8.00%	7.75%
Weighted Cost	3.16%	0.00%	0.04%	0.46%
50 basis pt reduction to equity	8.72%	0.00%	8.00%	7.75%
Weighted Cost With Reduction	3.16%	0.00%	0.04%	0.46%

COMMISSION VOTE

	COMMON EQUITY	CUSTOMER DEPOSITS	DEFERRED TAXES	ITC's Zero Cost
Company Per Book	367,404	15,775	203,823	858
Company Adjustments (Specific)	(63,994)		(14,785)	
Subtotal	303,410	15,775	189,038	858
Commission Adjustments (Specific)	(7,793)	0	(5,877)	0
Subtotal	295,617	15,775	183,161	858
Prorata (Other Sources) n1	(19,663)	(1,049)	0	0
Subtotal	275,954	14,726	183,161	858
Prorata Adjustments	(11,097)	(592)	(7,365)	(35)
TOTAL	264,857	14,134	175,796	823
Ratio	30.76%	1.64%	20.41%	0.10%
Cost Rate	12.55%	7.65%	0.00%	0.00%
Weighted Cost	3.86%	0.13%	0.00%	0.00%
50 basis pt reduction to equity	12.05%	7.65%	0.00%	0.00%
Weighted Cost With Reduction	3.71%	0.13%	0.00%	0.00%

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COMMISSION VOTE

	ITC's Wtd. Cost	TOTAL
Company Per Book	48,068	1,189,615
Company Adjustments (Specific)	(5,793)	(235,776)
Subtotal	42,275	953,839
Commission Adjustments (Specific)	(2,402)	(8,621)
Subtotal	39,873	945,218
Prorata (Other Sources) n1	0	(47,979)
Subtotal	39,873	897,239
Prorata Adjustments	(1,603)	(36,080)
TOTAL	38,270	861,159
Ratio	4.44%	100.00%
Cost Rate	10.26%	
Weighted Cost	0.46%	8.10%
50 basis pt reduction to equity	10.04%	
Weighted Cost With Reduction	0.45%	7.94%

n1 Deferred taxes and ITCs have been specifically identified for these items.

Calculation of JDIC Rate

Capital Components	Adjusted Amount	Ratio	Cost Rate	Wtd. Cost
Common Equity	264,857	42.16%	12.55%	5.29%
Preferred Stock	51,358	8.18%	7.75%	0.63%
Long-Term Debt	311,950	49.66%	8.72%	4.33%
Total	628,166	100.00%		10.26%

Calculation of JDIC Rate with 50 basis pt reduction on the equity cost rate.

Capital Components	Adjusted Amount	Ratio	Cost Rate	Wtd. Cost
Common Equity	264,857	42.16%	12.05%	5.08%
Preferred Stock	51,358	8.18%	7.75%	0.63%
Long-Term Debt	311,950	49.66%	8.72%	4.33%
Total	628,166	100.00%		10.04%

[*117]

ATTACHMENT 3

SCHEDULE 3

COMPARATIVE NET OPERATING INCOME

LINE NO.	CO. ADJ. NO.	ISSUE NO.	DESCRIPTION	COMPANY FILING SYSTEM PER BOOKS	COMPANY FILING JURISDICTIONAL PER BOOKS
1			REVENUE FROM SALES OF ELECTRICITY		249,813
2		48	PXT / STANDBY RATES		
3		49	NON-UTILITY ELECTRIC BILLINGS		
4					
5			Total sales of electricity	0	249,813
6					
7					
8			OTHER OPERATING REVENUES		5,767
9		6	CARYVILLE SOD FARM		
10		47	APPLIANCE DIVISION - USE OF LOGO		
11					
12			Total other operating revenues	0	5,767
13					
14					
15			Total operating revenues	0	255,580
16					
17					
18			OPERATING EXPENSES:		
19			OPERATION & MAINTENANCE		113,382
20		7	NAVY HOUSE		
21		27	PLANT SCHERER - NET OF IIC OFFSET		
22		29	REBUILDS & RENOVATIONS		
23		30	NETWORK PROTECTORS		
24		35	CARYVILLE SUBSURFACE STUDY		
25		50	SALARIES & BENEFITS		
26		51	BAD DEBT EXPENSE		
27		52	FUEL REVENUE & EXPENSES		

28	53	CONSERVATION REVENUE & EXPENSES
29	54	OUT-OF-PERIOD, NON-RECURRING, etc.
30	55	INDUSTRY ASSOCIATION DUES
31	56	CURRENT RATE CASE EXPENSES
32	57	881167-EI RATE CASE EXPENSES
33	58	BANK FEES & LINES OF CREDIT
34	59	OUTSIDE SERVICES
35	60	CUSTOMER ACCOUNTS
36	61	COGENERATION & INDUSTRIAL PROGRAMS
37	62	GOOD CENTS INCENTIVE PROGRAM
38	63	GOOD CENTS IMPROVED & NEW HOME PROGRAMS
39	64	ESSENTIAL CUSTOMER SERVICE PROGRAM
40	65	ENERGY EDUCATION PROGRAM
41	66	PRESENTATION / SEMINARS PROGRAM
42	67	SHINE AGAINST CRIME
43	68	ECONOMIC DEVELOPMENT
44	69	PRODUCTION RELATED A&G
45	70	OTHER A&G
46	71	LOBBYING EXPENSES
47	73	SCS EXPENSES
48	74	IRS, GRAND JURY, etc.
49	75	PENSION EXPENSE
50	76	STEAM PRODUCTION PERSONNEL
51	77	RESEARCH & DEVELOPMENT PROJECTS
52	78	EPRI / SCS DOUBLE COUNTING
53	79	PLANT DANIEL ASH HAULING
54	80	TRANSMISSION RENTS
55	81	PUBLIC SAFETY INSPECTION & MAINT.
56	86	EMPLOYEE RELATIONS PLANNING UNIT
57	87	LABOR COMPLEMENT VACANCIES
58	88	TURBINE & BOILER INSPECTIONS
59	89	PLANT DANIEL
60	90	1989 UNCOLLECTIBLES CREDIT
61	91	EMPLOYEE SAVINGS PLAN
62	92	PRODUCTIVITY IMPROVEMENT PLAN
63	93	PERFORMANCE PAY PLAN
64	94	EPRI NUCLEAR RESEARCH
65	95	PLANT SMITH ASH HAULING
66	96	EMPLOYEE RELOCATION & DEVELOPMENT PROGRAMS
67	97	OBSOLETE MATERIAL
68	98	MANAGEMENT PERKS
69	99	DUCT & FAN REPAIRS
70	100	CUSTOMER SERVICES &

		INFORMATION				
71	101	MARKETING EXPENSES				
72	102	O&M BENCHMARK				
73						
74						
75						
76						
77		Total operation & maintenance		0		113,382
78						
79						
80		DEPRECIATION AND AMORTIZATION			47,701	
81	3	SCHERER TAX ADDER ADJUSTMENT				
82	4	SCHERER ACQUISITION ADJUSTMENT				
83	5	NEW CORPORATE HEADQUARTERS				
84	8	APPLIANCE DIVISION				
85	9	TALLAHASSEE OFFICE				
86	12	LEISURE LAKES				
87	27	PLANT SCHERER				
88	82	REASONABLENESS				
89						
90		Total depreciation and amortization		0		47,701
91						
98		TAXES OTHER THAN INCOME			20,822	
99	27	PLANT SCHERER				
100	48	PXT / STANDBY RATES				
101	83	REASONABLENESS				
102	87	LABOR COMPLEMENT VACANCIES				
103						
104						
105		Total taxes other than income		0		20,822
106						
107						
108		INCOME TAXES CURRENTLY PAYABLE	0		13,185	
109	84	REASONABLENESS				
110	85	Interest expense reconciliation				
111	N/A	Effect of other adjustments				
112						
113		Total income taxes - current		0		13,185
114						
115						
116		DEFERRED INCOME TAXES (NET)	0		1,621	
117	N/A	EFFECT OF ADJS. TO DEPRECIATION				
118	27	PLANT SCHERER				
119						
120						
121						
122						
123		Total deferred income taxes (net)		0		1,621
124						
125						
126						

127			INVESTMENT TAX CREDIT (NET)		(2,041)	
128		27	PLANT SCHERER			
129						
130						
131			Total investment tax credit (net)		0	(2,041)
132						
133						
134			(GAIN)/LOSS ON SALE		0	
135						
136						
137			Total (gain)/loss on sale		0	0
138						
139						
140			TOTAL OPERATING EXPENSES	0	194,670	
141						
142						
143			NET OPERATING INCOME	0	60,910	
144						

[*118]

LINE NO.	CO. ADJ. NO.	ISSUE NO.	DESCRIPTION	COMPANY FILING ADJUSTMENTS	JURISDICTIONAL ADJUSTED
1			REVENUE FROM SALES OF ELECTRICITY		
2		48	PXT / STANDBY RATES		
3		49	NON-UTILITY ELECTRIC BILLINGS		
4					
5			Total sales of electricity	0	249,813
6					
7					
8			OTHER OPERATING REVENUES		
9		6	CARYVILLE SOD FARM		
10		47	APPLIANCE DIVISION - USE OF LOGO		
11					
12			Total other operating revenues	0	5,767
13					
14					
15			Total operating revenues	0	255,580
16					
17					
18			OPERATING EXPENSES:		
19			OPERATION & MAINTENANCE		
20		7	NAVY HOUSE		
21		27	PLANT SCHERER - NET OF IIC OFFSET		
22		29	REBUILDS & RENOVATIONS		
23		30	NETWORK PROTECTORS		
24		35	CARYVILLE SUBSURFACE STUDY		
25		50	SALARIES & BENEFITS		
26		51	BAD DEBT EXPENSE		
27		52	FUEL REVENUE & EXPENSES		

28	53	CONSERVATION REVENUE & EXPENSES
29	54	OUT-OF-PERIOD, NON-RECURRING, etc.
30	55	INDUSTRY ASSOCIATION DUES
31	56	CURRENT RATE CASE EXPENSES
32	57	881167-EI RATE CASE EXPENSES
33	58	BANK FEES & LINES OF CREDIT
34	59	OUTSIDE SERVICES
35	60	CUSTOMER ACCOUNTS
36	61	COGENERATION & INDUSTRIAL PROGRAMS
37	62	GOOD CENTS INCENTIVE PROGRAM
38	63	GOOD CENTS IMPROVED & NEW HOME PROGRAMS
39	64	ESSENTIAL CUSTOMER SERVICE PROGRAM
40	65	ENERGY EDUCATION PROGRAM
41	66	PRESENTATION / SEMINARS PROGRAM
42	67	SHINE AGAINST CRIME
43	68	ECONOMIC DEVELOPMENT
44	69	PRODUCTION RELATED A&G
45	70	OTHER A&G
46	71	LOBBYING EXPENSES
47	73	SCS EXPENSES
48	74	IRS, GRAND JURY, etc.
49	75	PENSION EXPENSE
50	76	STEAM PRODUCTION PERSONNEL
51	77	RESEARCH & DEVELOPMENT PROJECTS
52	78	EPRI / SCS DOUBLE COUNTING
53	79	PLANT DANIEL ASH HAULING
54	80	TRANSMISSION RENTS
55	81	PUBLIC SAFETY INSPECTION & MAINT.
56	86	EMPLOYEE RELATIONS PLANNING UNIT
57	87	LABOR COMPLEMENT VACANCIES
58	88	TURBINE & BOILER INSPECTIONS
59	89	PLANT DANIEL
60	90	1989 UNCOLLECTIBLES CREDIT
61	91	EMPLOYEE SAVINGS PLAN
62	92	PRODUCTIVITY IMPROVEMENT PLAN
63	93	PERFORMANCE PAY PLAN
64	94	EPRI NUCLEAR RESEARCH
65	95	PLANT SMITH ASH HAULING
66	96	EMPLOYEE RELOCATION & DEVELOPMENT PROGRAMS
67	97	OBSOLETE MATERIAL
68	98	MANAGEMENT PERKS
69	99	DUCT & FAN REPAIRS
70	100	CUSTOMER SERVICES &

		INFORMATION		
71	101	MARKETING EXPENSES		
72	102	O&M BENCHMARK		
73				
74				
75				
76				
77		Total operation & maintenance	0	113,382
78				
79				
80		DEPRECIATION AND AMORTIZATION		
81	3	SCHERER TAX ADDER ADJUSTMENT		
82	4	SCHERER ACQUISITION ADJUSTMENT		
83	5	NEW CORPORATE HEADQUARTERS		
84	8	APPLIANCE DIVISION		
85	9	TALLAHASSEE OFFICE		
86	12	LEISURE LAKES		
87	27	PLANT SCHERER		
88	82	REASONABLENESS		
89				
90		Total depreciation and amortization	0	47,701
91				
98		TAXES OTHER THAN INCOME		
99	27	PLANT SCHERER		
100	48	PXT / STANDBY RATES		
101	83	REASONABLENESS		
102	87	LABOR COMPLEMENT VACANCIES		
103				
104				
105		Total taxes other than income	0	20,822
106				
107				
108		INCOME TAXES CURRENTLY PAYABLE		
109	84	REASONABLENESS		
110	85	Interest expense reconciliation		
111	N/A	Effect of other adjustments		
112				
113		Total income taxes - current	0	13,185
114				
115				
116		DEFERRED INCOME TAXES (NET)		
117	N/A	EFFECT OF ADJS. TO DEPRECIATION		
118	27	PLANT SCHERER		
119				
120				
121				
122				
123		Total deferred income taxes (net)	0	1,621
124				
125				
126				

127		INVESTMENT TAX CREDIT (NET)				
128	27	PLANT SCHERER				
129						
130						
131		Total investment tax credit (net)		0		(2,041)
132						
133						
134		(GAIN)/LOSS ON SALE				
135						
136						
137		Total (gain)/loss on sale		0		0
138						
139						
140		TOTAL OPERATING EXPENSES	0		194,670	
141						
142						
143		NET OPERATING INCOME	0		60,910	
144						

[*119]

LINE NO.	CO. ADJ. NO.	ISSUE NO.	DESCRIPTION	COMMISSION VOTE ADJUSTMENTS	COMMISSION VOTE JURISDICTIONAL ADJUSTED
1			REVENUE FROM SALES OF ELECTRICITY		
2		48	PXT / STANDBY RATES	16	
3		49	NON-UTILITY ELECTRIC BILLINGS	95	
4					
5			Total sales of electricity	111	249,924
6					
7					
8			OTHER OPERATING REVENUES		
9		6	CARYVILLE SOD FARM	(3)	
10		47	APPLIANCE DIVISION - USE OF LOGO	0	
11					
12			Total other operating revenues	(3)	5,764
13					
14					
15			Total operating revenues	108	255,688
16					
17					
18			OPERATING EXPENSES:		
19			OPERATION & MAINTENANCE		
20		7	NAVY HOUSE	(8)	
21		27	PLANT SCHERER - NET OF IIC OFFSET	4,070	
22		29	REBUILDS & RENOVATIONS	0	
23		30	NETWORK PROTECTORS	0	
24		35	CARYVILLE SUBSURFACE STUDY	57	
25		50	SALARIES & BENEFITS	0	
26		51	BAD DEBT EXPENSE	0	
27		52	FUEL REVENUE & EXPENSES	0	

28	53	CONSERVATION REVENUE & EXPENSES	0
29	54	OUT-OF-PERIOD, NON-RECURRING, etc.	(190)
30	55	INDUSTRY ASSOCIATION DUES	(20)
31	56	CURRENT RATE CASE EXPENSES	(250)
32	57	881167-EI RATE CASE EXPENSES	0
33	58	BANK FEES & LINES OF CREDIT	0
34	59	OUTSIDE SERVICES	0
35	60	CUSTOMER ACCOUNTS	0
36	61	COGENERATION & INDUSTRIAL PROGRAMS	(426)
37	62	GOOD CENTS INCENTIVE PROGRAM	(50)
38	63	GOOD CENTS IMPROVED & NEW HOME PROGRAMS	0
39	64	ESSENTIAL CUSTOMER SERVICE PROGRAM	0
40	65	ENERGY EDUCATION PROGRAM	0
41	66	PRESENTATION / SEMINARS PROGRAM	(55)
42	67	SHINE AGAINST CRIME	(92)
43	68	ECONOMIC DEVELOPMENT	(687)
44	69	PRODUCTION RELATED A&G	0
45	70	OTHER A&G	0
46	71	LOBBYING EXPENSES	(264)
47	73	SCS EXPENSES	0
48	74	IRS, GRAND JURY, etc.	(5)
49	75	PENSION EXPENSE	0
50	76	STEAM PRODUCTION PERSONNEL	0
51	77	RESEARCH & DEVELOPMENT PROJECTS	(32)
52	78	EPRI / SCS DOUBLE COUNTING	0
53	79	PLANT DANIEL ASH HAULING	0
54	80	TRANSMISSION RENTS	(423)
55	81	PUBLIC SAFETY INSPECTION & MAINT.	0
56	86	EMPLOYEE RELATIONS PLANNING UNIT	0
57	87	LABOR COMPLEMENT VACANCIES	(403)
58	88	TURBINE & BOILER INSPECTIONS	0
59	89	PLANT DANIEL	0
60	90	1989 UNCOLLECTIBLES CREDIT	0
61	91	EMPLOYEE SAVINGS PLAN	0
62	92	PRODUCTIVITY IMPROVEMENT PLAN	(339)
63	93	PERFORMANCE PAY PLAN	0
64	94	EPRI NUCLEAR RESEARCH	0
65	95	PLANT SMITH ASH HAULING	0
66	96	EMPLOYEE RELOCATION & DEVELOPMENT PROGRAMS	(56)
67	97	OBSOLETE MATERIAL	0
68	98	MANAGEMENT PERKS	(65)
69	99	DUCT & FAN REPAIRS	0
70	100	CUSTOMER SERVICES &	

		INFORMATION	0	
71	101	MARKETING EXPENSES	0	
72	102	O&M BENCHMARK	0	
73				
74				
75				
76				
77		Total operation & maintenance	762	114,144
78				
79				
80		DEPRECIATION AND AMORTIZATION		
81	3	SCHERER TAX ADDER ADJUSTMENT	0	
82	4	SCHERER ACQUISITION ADJUSTMENT	0	
83	5	NEW CORPORATE HEADQUARTERS	(101)	
84	8	APPLIANCE DIVISION	(12)	
85	9	TALLAHASSEE OFFICE	(1)	
86	12	LEISURE LAKES	(5)	
87	27	PLANT SCHERER	(1,774)	
88	82	REASONABLENESS	0	
89				
90		Total depreciation and amortization	(1,893)	45,808
91				
98		TAXES OTHER THAN INCOME		
99	27	PLANT SCHERER	(245)	
100	48	PXT / STANDBY RATES	1	
101	83	REASONABLENESS	0	
102	87	LABOR COMPLEMENT VACANCIES	(30)	
103				
104				
105		Total taxes other than income	(274)	20,548
106				
107				
108		INCOME TAXES CURRENTLY PAYABLE		
109	84	REASONABLENESS	0	
110	85	Interest expense reconciliation	672	
111	N/A	Effect of other adjustments	(143)	
112				
113		Total income taxes - current	529	13,714
114				
115				
116		DEFERRED INCOME TAXES (NET)		
117	N/A	EFFECT OF ADJS. TO DEPRECIATION	45	
118	27	PLANT SCHERER	668	
119				
120				
121				
122				
123		Total deferred income taxes (net)	712	2,333
124				
125				
126				

127		INVESTMENT TAX CREDIT (NET)				
128	27	PLANT SCHERER		96		
129						
130						
131		Total investment tax credit (net)		96		(1,945)
132						
133						
134		(GAIN)/LOSS ON SALE				
135						
136						
137		Total (gain)/loss on sale		0		0
138						
139						
140		TOTAL OPERATING EXPENSES	(67)		194,603	
141						
142						
143		NET OPERATING INCOME	175		61,085	
144						

[*120]

ATTACHMENT 4

AUGUST 10, 1990

APPROVED REVENUE INCREASE BY CLASS

BASED ON COMPANY'S 12 CP AND 1/13TH COST OF SERVICE STUDY

SUMMARY OF CLASS ROR'S AND % INCREASE (000 DOLLARS)

(1) RATE CODE	(2) APPROVED RATE BASE	(3) APPROVED PRES.NOI	(4) PRESENT ROR/ INDEX	(5) INCREASE FROM SERVICE CHARGES	(6) INCREASE FROM SALES OF ELECTRICITY	(7) TOTAL INCREASE IN REVENUE
RS	$ 475,918	$ 29,345	6.17% / 0.87	$ 47	$ 8,652	$ 8,699
GS	$ 33,448	$ 4,835	14.46% / 2.04	$ 47	($ 1,655)	($ 1,608)
RS-GS	$ 509,366	$ 34,180	6.71% / 0.95	$ 94	$ 6,997	$ 7,091
GSD	$ 176,009	$ 13,846	7.87% / 1.11	$ 1	$ 1,817	$ 1,818
LP/LPT	$ 104,427	$ 7,435	7.12% / 1.00	$ 0	$ 2,351	$ 2,351
PX/PXT	$ 54,208	$ 4,363	8.05% / 1.13	$ 0	$ 395	$ 395
OSI-II	$ 13,431	$ 872	6.49% / 0.92	$ 0	$ 202	$ 202
OS-III	$ 613	$ 143	23.33% / 3.29	$ 0	($ 48)	($ 48)
SS	$ 3,105	$ 246	7.92% / 1.12	$ 0	$ 29	$ 29
TOT.RET	$ 861,159	$ 61,085	7.09% / 1.00	$ 95	$ 11,743	$ 11,838

(1) RATE CODE	(8) REQUIRED NOI	(9) RECOMMENDED ROR/ INDEX	(10) % INCREASE IN REV FROM SALES OF ELEC W/ADJ	BASE
RS	$ 34,676	7.29% / 0.92	4.19%	6.58%
GS	$ 3,850	11.51% / 1.45	-8.39%	-11.04%
RS-GS	$ 38,526	7.56% / 0.95	3.10%	4.77%
GSD	$ 14,960	8.50% / 1.07	2.00%	3.50%

LP/LPT	$ 8,876	8.50% / 1.07	3.91%	8.06%
PX/PXT	$ 4,605	8.50% / 1.07	1.03%	2.41%
OSI-II	$ 996	7.42% / 0.93	4.19%	5.38%
OS-III	$ 114	18.60% / 2.34	-9.58%	-14.29%
SS	$ 264	8.50% / 1.07	3.30%	3.68%
TOT.RET	$ 68,340	7.94% / 1.00	2.79%	4.72%

[*121]

ATTACHMENT 5

PROPOSED RATES FOR GULF POWER COMPANY

	CURRENT RATES	COMPANY PROPOSED
INCREASE IN REVENUES		$ 26,137,000
RATE CLASS		
RESIDENTIAL		
CUSTOMER CHARGE	$ 6.25	$ 8.00
ENERGY		
Oct - May	$ 0.03148	$ 0.03489
June - Sept	$ 0.03716	$ 0.04114
NON SEASONAL		
RESIDENTIAL TOU		
CUSTOMER CHARGE	$ 9.25	$ 11.00
ENERGY		
ON PEAK	$ 0.07797	$ 0.08623
OFF PEAK	$ 0.01378	$ 0.01608
GENERAL SERVICE		
CUSTOMER CHARGE	$ 7.00	$ 10.00
ENERGY		
Oct - May	$ 0.06174	$ 0.05441
June - Sept	$ 0.06348	$ 0.06423
NON SEASONAL		
GENERAL SERVICE TOU		
CUSTOMER	$ 10.00	$ 13.00
ENERGY		
ON PEAK	$ 0.14727	$ 0.14324
OFF PEAK	$ 0.02296	$ 0.02188
GS-DEMAND		
CUSTOMER CHARGE	$ 27.00	$ 40.00
KW DEMAND	$ 6.25	$ 4.52
ENERGY	$ 0.00641	$ 0.01424
GS DEMAND TOU		
CUSTOMER	$ 32.40	$ 45.40
KW DEMAND		
MAXIMUM	$ 2.96	$ 2.17
ON PEAK	$ 3.42	$ 2.44

ENERGY		
ON PEAK	$ 0.01395	$ 0.03269
OFF PEAK	$ 0.00302	$ 0.00692
LP		
CUSTOMER CHARGE	$ 51.00	$ 225.00
KW DEMAND	$ 6.25	$ 8.52
SE MAXIMUM CHARGE		
ENERGY	$ 0.00861	$ 0.00568
LP TOU		
CUSTOMER CHARGE	$ 51.00	$ 225.00
KW DEMAND		
MAXIMUM	$ 2.97	$ 4.15
ON PEAK	$ 3.35	$ 4.52
ENERGY		
ON PEAK	$ 0.01928	$ 0.01211
OFF PEAK	$ 0.00390	$ 0.00300
PX		
CUSTOMER CHARGE	$ 146.00	$ 570.00
KW DEMAND	$ 7.50	$ 8.25
SE MAXIMUM CHARGE		
ENERGY	$ 0.00521	$ 0.00445
PX TOU		
CUSTOMER CHARGE	$ 146.00	$ 570.00
KW DEMAND		
MAXIMUM	$ 3.56	$ 3.97
ON PEAK	$ 3.99	$ 4.32
ENERGY		
ON PEAK	$ 0.01299	$ 0.00984
OFF PEAK	$ 0.00242	$ 0.00262

[*122]

	COMMISSION VOTE	AFTER EXPIRATION OF MANAGEMENT PENALTY
INCREASE IN REVENUES	$ 11,838,000	
RATE CLASS		
RESIDENTIAL		
CUSTOMER CHARGE	$ 8.00	$ 8.07
ENERGY		
Oct - May		
June - Sept		
NON SEASONAL	$ 0.03487	$ 0.03518
RESIDENTIAL TOU		
CUSTOMER CHARGE	$ 11.00	$ 11.10
ENERGY		
ON PEAK	$ 0.10218	$ 0.10308
OFF PEAK	$ 0.00529	$ 0.00534

GENERAL SERVICE		
CUSTOMER CHARGE	$ 10.00	$ 10.09
ENERGY		
Oct - May		
June - Sept		
NON SEASONAL	$ 0.05086	$ 0.05131
GENERAL SERVICE TOU		
CUSTOMER	$ 13.00	$ 13.11
ENERGY		
ON PEAK	$ 0.15711	$ 0.15849
OFF PEAK	$ 0.00511	$ 0.00515
GS-DEMAND		
CUSTOMER CHARGE	$ 40.00	$ 40.35
KW DEMAND	$ 4.52	$ 4.56
ENERGY	$ 0.01289	$ 0.01300
GS DEMAND TOU		
CUSTOMER	$ 45.40	$ 45.80
KW DEMAND		
MAXIMUM	$ 2.15	$ 2.17
ON PEAK	$ 4.97	$ 5.01
ENERGY		
ON PEAK	$ 0.00445	$ 0.00449
OFF PEAK	$ 0.00445	$ 0.00449
LP		
CUSTOMER CHARGE	$ 225.00	$ 226.98
KW DEMAND	$ 8.50	$ 8.57
SE MAXIMUM CHARGE	$ 1.81	$ 1.83
ENERGY	$ 0.00528	$ 0.00533
LP TOU		
CUSTOMER CHARGE	$ 225.00	$ 226.98
KW DEMAND		
MAXIMUM	$ 1.81	$ 1.83
ON PEAK	$ 7.21	$ 7.27
ENERGY		
ON PEAK	$ 0.00417	$ 0.00421
OFF PEAK	$ 0.00417	$ 0.00421
PX		
CUSTOMER CHARGE	$ 570.00	$ 575.01
KW DEMAND	$ 8.25	$ 8.32
SE MAXIMUM CHARGE	$ 0.68	$ 0.69
ENERGY	$ 0.00409	$ 0.00413
PX TOU		
CUSTOMER CHARGE	$ 570.00	$ 575.01
KW DEMAND		
MAXIMUM	$ 0.68	$ 0.69

ON PEAK	$ 7.66	$ 7.73
ENERGY		
ON PEAK	$ 0.00406	$ 0.00410
OFF PEAK	$ 0.00406	$ 0.00410

[*123]

ATTACHMENT 6

APPROVED STREET AND OUTDOOR LIGHTING RATES

TYPE OF FACILITY	FIXTURE CHARGE	MAINTENANCE CHARGE	ENERGY CHARGE	TOTAL MONTHLY CHARGE
HIGH PRESSURE SODIUM (OS-I)				
5,400 LUMEN	$ 1.95	$ 1.34	$ 0.74	$ 4.03
8,800 LUMEN	$ 1.96	$ 1.06	$ 1.05	$ 4.07
20,000 LUMEN	$ 2.26	$ 1.56	$ 2.13	$ 5.95
25,000 LUMEN	$ 2.81	$ 2.03	$ 2.68	$ 7.52
46,000 LUMEN	$ 3.17	$ 1.61	$ 4.24	$ 9.02
20,000 LUMEN *	$ 4.31	$ 1.79	$ 2.13	$ 8.23
46,000 LUMEN **	$ 9.09	$ 2.00	$ 4.24	$ 15.33
20,000 LUMEN **	$ 10.79	$ 1.79	$ 2.13	$ 14.71
8,800 LUMEN ***	$ 6.14	$ 1.56	$ 1.05	$ 8.75
MERCURY VAPOR (OS-I)				
3,200 LUMEN	$ 1.44	$ 1.40	$ 1.03	$ 3.87
7,000 LUMEN	$ 1.43	$ 1.04	$ 1.76	$ 4.23
9,400 LUMEN	$ 1.91	$ 1.66	$ 2.50	$ 6.07
17,000 LUMEN	$ 2.22	$ 1.73	$ 4.00	$ 7.95
48,000 LUMEN	$ 6.03	$ 3.16	$ 9.79	$ 18.98
HIGH PRESSURE SODIUM (OS-II)				
5,400 LUMEN	$ 1.95	$ 0.84	$ 0.74	$ 3.53
8,800 LUMEN	$ 1.75	$ 0.79	$ 1.05	$ 3.59
20,000 LUMEN	$ 2.26	$ 1.05	$ 2.13	$ 5.44
25,000 LUMEN	$ 2.80	$ 1.50	$ 2.68	$ 6.98
46,000 LUMEN	$ 3.17	$ 1.10	$ 4.24	$ 8.51
20,000 LUMEN #	$ 4.27	$ 1.92	$ 2.21	$ 8.40
46,000 LUMEN #	$ 3.81	$ 1.79	$ 4.39	$ 9.99
8,800 LUMEN ***	$ 6.15	$ 0.76	$ 1.05	$ 7.96
MERCURY VAPOR (OS-II)				
7,000 LUMEN	$ 1.41	$ 0.65	$ 1.76	$ 3.82
17,000 LUMEN	$ 2.21	$ 1.29	$ 4.00	$ 7.50
17,000 LUMEN #	$ 4.11	$ 1.84	$ 4.29	$ 10.24

[*124]

* NEW OFFERING, DIRECTIONAL, COASTAL

** NEW OFFERING, DIRECTIONAL

*** NEW OFFERING, DECORATIVE

DIRECTIONAL

APPROVED STREET AND OUTDOOR LIGHTING RATES

ENERGY RATES ($ PER KWH)

RATE CLASS	RATE
OS-I AND OS-II	$ 0.02631
OS-III	$ 0.03751
OS-IV	$ 0.03711
OS-IV CUSTOMER CHARGE:	$ 10.00
ADDITIONAL FACILITIES CHARGES	
30-FOOT WOOD POLE	$ 2.00
30-FOOT CONCRETE POLE	$ 4.50

DISSENTBY: BEARD; WILSON; EASLEY; GUNTER

DISSENTING VOTES

Commissioner Beard dissented as follows:

1) From the Commission's allowance of the total cost of Gulf's Bonifay and Graceville Offices in rate base.

2) From the Commission's allowance of 90% of the Caryville site as land held for future use. Commissioner Beard would have disallowed the amount budgeted for the Caryville site because there are no plans to use the site for 20 years.

3) From the Commission's approval of $ 457,390 for the Good Cents Improved and $ 1,023,995 for the Good Cents New Home Programs. Commissioner Beard would have disallowed these expenses as an unnecessary cost to ratepayers to assure compliance with the state building code.

4) I respectfully dissent from the majority opinion on the mismanagement issue. My disagreement [*125] stems from a different interpretation of evidence before the Commission. This interpretation results in my belief that the reduction to the return on equity should have been greater than fifty basis points. I would reduce the return on equity to 11.75%, the minimum amount necessary for Gulf Power Company to achieve a fair rate of return according to the record.

At page 19, the majority states that there is no record evidence to indicate that the president of Gulf Power knew that illegal or unethical conduct was taking place as it happened. (Emphasis in original) The Order then goes into various incidents from 1983 through 1988 involving the president and Mr. Jacob Horton, Executive Vice President of Gulf Power. There is no need to recount those incidents again here. Suffice to say that in this case repeated instances of unethical/illegal activity over the years by a close business associate give rise to knowledge in my view. This is particularly true in light of the warnings Mr. McCrary had received concerning Mr. Horton's mode of operation and the repeated warnings given by Mr. McCrary to Mr. Horton. I also have serious reservations concerning disparate disciplinary treatment [*126] between executives and lower-level employees. See majority opinion at pages 23-24.

The unfortunate pattern of conduct present in this case should not be analyzed in terms of legal abstractions, but rather how a utility conducts its business in the real world. In my mind, the proper analysis holds Gulf Power management responsible for the activities here and then reduces the return on equity in conformity with that responsibility. I would set the return on equity at 11.75%.

Commissioner Wilson dissented as follows:

1) From the Commission's approval of Gulf's 1990 material and supply level. Commissioner Wilson would leave materials and supplies at the 1989 level.

2) From the Commission's approval of a 12.55% return on equity. Commissioner Wilson favored a 12.8% ROE.

3) From the Commission's reduction of the GS class to 1.45 times parity. Commissioner Wilson favored a greater reduction.

4) From the Commission's vote to eliminate seasonal rates for the RS and GS rate classes. Commissioner Wilson favored retaining seasonal rates.

Commissioner Easley dissented as follows:

1) From the Commission's vote setting the coal inventory as the lesser of 90 days burn or the [*127] amount maintained at the plant.

2) From the Commission's classification of fuel stock as energy-related. Commissioner Easley would classify fuel stocks as demand-related.

Commissioner Gunter dissented as follows:

1) From the Commission's disallowance of $ 31,813 for acid rain research.

In re: Petition by Florida Power Corporation for approval of regulatory treatment associated with the sale of replacement capacity and energy to the City of Tallahassee

DOCKET NO. 990771-EI; ORDER NO. PSC-99-1741-PAA-EI

Florida Public Service Commission

1999 Fla. PUC LEXIS 1624

99 FPSC 9:77

September 3, 1999

CORE TERMS: energy, retail, wholesale, fuel, incremental, capacity factor, assign, supplemental, ratepayers, customer, decommissioning, output, hourly, replacement, reporting, nuclear, general applicability, operating expenses, remaining life, nuclear fuel, book value, jurisdictional, newly-acquired, transmission, as-available, acquisition, qualifying, generating, accounting, generation

[*1] The following Commissioners participated in the disposition of this matter: JOE GARCIA, Chairman, J. TERRY DEASON, SUSAN F. CLARK, JULIA L. JOHNSON, E. LEON JACOBS, JR.

NOTICE OF PROPOSED AGENCY ACTION ORDER APPROVING REGULATORY TREATMENT FOR SALE OF REPLACEMENT CAPACITY AND ASSOCIATED ENERGY

BY THE COMMISSION:

NOTICE is hereby given by the Florida Public Service Commission that the action discussed herein is preliminary in nature and will become final unless a person whose interests are substantially affected files a petition for a formal proceeding, pursuant to Rule 25-22.029, Florida Administrative Code.

A. Background

The City of Tallahassee ("City") currently owns a 1.3333 percent undivided interest in Crystal River Unit 3 ("CR-3") as a tenant in common with Florida Power Corporation ("Florida Power"), Seminole Electric Cooperative, and eight other municipal electric utilities. CR-3 is an 859 MW nuclear steam electric generating unit located in Citrus County, Florida. As a party to the CR-3 Participation Agreement, the City currently receives 1.3333 percent of CR-3's actual output. However, on December 9, 1998, Florida Power agreed to acquire the City's interest in [*2] CR-3 (approximately 11.4 MW) for a nominal cost and assume responsibility for all associated future costs, including decommissioning costs ("Agreement to Acquire the City of Tallahassee's Interest in the Crystal River Nuclear Plant"). Concurrently, Florida Power agreed to replace the same amount of capacity that the City previously received as its share of CR-3

("Power Sale Agreement By and Between Florida Power Corporation and the City of Tallahassee").

For regulatory purposes, Florida Power proposes that this Commission treat the sale of capacity and associated energy to the City as a unit power sale. Thus, Florida Power would assign all costs of the "unit" (i.e., 1.3333 percent of CR-3) to the wholesale jurisdiction. When the unit does not operate at a 100 percent capacity factor, Florida Power would assign all costs of providing supplemental capacity and associated energy to the wholesale jurisdiction.

B. Applicable Law and Policy

In Order No. PSC-97-0262-FOF-EI, issued March 11, 1997, in Docket No. 970001-EI ("Order No. 97-0262"), we restated our criteria for separated wholesale sales. This Commission has traditionally required a utility to separate a wholesale sale if [*3] it is a long-term firm sale (greater than one year) that commits production capacity to a wholesale customer. We separate wholesale sales to remove the production plant and associated operating expenses from the retail jurisdiction. We use average embedded costs for production plant and operating expenses to assign costs to both jurisdictions and have required the utility to credit its fuel clause with its average system fuel cost. This treatment is intended to avoid any cross-subsidies between the wholesale and retail jurisdictions.

On behalf of Florida Power in Docket 960001-EI, Mr. Karl Wieland testified n1:

..Florida Power believes that any sale, either retail or wholesale, should be priced at the average cost of the generation resources used to make the sale. In other words, sales from the utility's system should be based on system average fuel costs, and sales from a single generating unit (e.g., a Unit Power Sales arrangement) or from a combination of units (e.g., a "stratified" sales arrangement) should be based on the average cost of the particular unit or units involved with the sale. Following this approach will ensure that retail customers do not subsidize wholesale [*4] sales...

n1 Direct testimony of Karl H. Wieland in Docket No. 960001-EI, filed June 24, 1996, page 12

In Order No. 97-0262, we stated that a utility may propose a deviation from our policy if the utility proves, on a case-by-case basis, that each new sale provides overall benefits to its retail ratepayers. Florida Power seeks approval of its proposed regulatory treatment because the treatment is a deviation from our policy as stated in Order No. 97-0262. Further, our approval of the proposed regulatory treatment is necessary for Florida Power and the City to complete the aforementioned agreements.

We acknowledge that Chapter 120, Florida Statutes, generally requires an agency to adopt as rules any agency statement of general applicability that prescribes law or policy. However, Section 120.80(13)(a), Florida Statutes, specifically exempts from this requirement agency statements relating to cost recovery clauses and mechanisms implemented pursuant to Chapter 366, Florida Statutes. Order No. 97-0262 was issued as part of this Commission's fuel and purchased power cost recovery clause. Thus, although that Order contains an agency statement of general applicability that prescribes [*5] policy, the agency statement is exempt from the rulemaking requirements of Chapter 120, Florida Statutes.

C. Provisions of "Power Sale Agreement By and Between Florida Power Corporation and the City of Tallahassee"

Florida Power will sell capacity and associated energy to the City until the expiration of CR-3's operating license on December 3, 2016. The power sales agreement between Florida Power and the City includes the following details:

1. Florida Power will deliver 11.4 MW of firm capacity to the City at a 100 percent capacity factor.

2. The City will pay Florida Power an all-inclusive charge of $ 42 per MWH, which includes energy, capacity, and transmission charges, until December 31, 2007. After that date, the amount will increase annually by the rate of change in the Consumer Price Index until December 3, 2016.

3. Florida Power will provide the capacity and associated energy to the City at a priority level equivalent to Florida Power's firm native load. To the extent that Florida Power eliminates bundled service for its native load, the capacity and associated energy will be provided at a priority equal to Florida Power's highest service obligation of its generation [*6] division.

4. Pursuant to Florida Power's Open Access Transmission Tariff, the City will maintain a valid, binding, and enforceable agreement for firm transmission and related ancillary services.

D. Proposed Regulatory Treatment

With respect to acquiring the City's interest in CR-3, Florida Power's proposed regulatory treatment would affect its jurisdictional cost separations and surveillance reporting as follows:

1. Capital cost. In accordance with the Uniform System of Accounts (USoA), the City's gross investment and accumulated depreciation in its share of CR-3 would be recorded on Florida Power's records. The difference between the acquisition price and the net book value of this share would be recorded as a credit to "Electric Plant Acquisition Adjustments", because the net book value is greater than the purchase price. The USoA requires that any company that intends to record credit amounts to this account must receive this Commission's approval. The credit would then be amortized to "Amortization of Electric Plant Acquisition Adjustments" over the remaining life of the investment. This would not increase retail ratebase or depreciation expense. Therefore, no cost [*7] separation is necessary.

2. Decommissioning costs. Florida Power would assign the continued funding of decommissioning costs for the newly acquired share to the wholesale jurisdiction.

3. Operation and maintenance costs. Florida Power would assign 1.3333 percent of the costs to operate and maintain CR-3, as well as all other costs of the unit,

such as insurance and property taxes, to the wholesale jurisdiction on an average cost basis.

4. Capital additions. Florida Power would assign 1.3333 percent of capital additions related to CR-3's existing capacity to the wholesale jurisdiction. However, Florida Power would allocate the associated costs of a capacity increase to CR-3 on a jurisdictional basis between the retail and wholesale jurisdictions.

Florida Power proposes that all transactions related to the purchase, including the acquisition adjustment, be assigned to the wholesale jurisdiction. We find that the proposed accounting treatment to amortize the acquisition adjustment over the remaining life of CR-3 is proper and will not impact retail ratepayers. Therefore, we find that Florida Power's proposed accounting treatment is appropriate.

With respect to the sale [*8] of replacement capacity and associated energy to the City, Florida Power's proposed treatment would affect its retail fuel and capacity cost recovery clauses as follows:

1. Nuclear fuel costs. Florida Power would credit 1.3333 percent of the average cost of nuclear fuel to the fuel clause.

2. Spent fuel disposal costs. Florida Power would credit $ 1.00 per MWH generated with the newly-acquired share of CR-3 to the fuel clause.

3. Nuclear decommissioning and dismantlement (D&D) charges. Florida Power would assign 1.3333 percent of CR-3's nuclear D&D charges to the wholesale jurisdiction.

4. Supplemental power costs. Florida Power would calculate the cost of providing supplemental power, during periods when CR-3 is operating at less than a 100 percent capacity factor, under the pricing provisions of Florida Power's standard Schedule B interchange tariff approved by FERC. Florida Power uses Schedule B to sell capacity and associated energy to other utilities to replace the output of a unit on a forced or maintenance outage. Its pricing provisions consist of an incremental energy charge and a capacity charge calculated as follows:

a) Calculation of incremental [*9] energy costs. Florida Power proposes to utilize the hourly incremental cost used to price as-available energy payments to qualifying facilities to represent incremental energy costs. Florida Power would multiply the hourly difference between the 11.4 MW sale to the City and 1.3333 percent of the actual output of CR-3 by the incremental energy cost for that hour. Then, Florida Power would credit the sum of these hourly amounts to the retail fuel clause.

b) Calculation of capacity costs. Capacity costs are based on average embedded costs and are expressed on an energy basis for billing purposes. The capacity charge under the current Schedule B tariff is $ 5.53 per MWH. Florida Power would credit the product of this capacity charge and the amount of supplemental energy to the capacity cost recovery clause.

E. Effects on Retail Ratepayers

We find that the proposed regulatory treatment will have a nominally positive effect on Florida Power's retail customers. First, the retail customers will not bear any fixed costs, non-fuel variable costs, or fuel costs associated with the newly-acquired share of CR-3. Also, the retail customers will not bear any of Florida Power's energy costs [*10] to provide supplemental power to the City when CR-3 operates at less than a 100 percent capacity factor.

Second, when CR-3 operates at less than a 100 percent capacity factor, Florida Power will assign the revenue received ($ 5.53 per MWH) from the City for supplemental capacity to the retail customers. If Florida Power has sufficient capacity on its system to satisfy its obligation to the City, its retail ratepayers will not bear the cost of this capacity. Absent its agreement to sell replacement capacity and associated energy to the City, Florida Power's retail ratepayers would have borne the cost of this capacity. However, because Florida Power will credit these revenues to the capacity cost recovery clause, the retail ratepayers will benefit through a reduction in rates. We recognize that Florida Power may need to purchase additional capacity on rare occasions, due to lack of capacity on its system, to meet its obligations to the City. Depending upon the specific circumstances, Florida Power may be required to pay more than $ 5.53 per MWH for the additional capacity. Our staff will monitor the occurrence of these transactions so that we may ensure Florida Power's retail ratepayers [*11] will not suffer a detriment due to the proposed regulatory treatment.

Third, under the proposed regulatory treatment, when CR-3 operates at a 100 percent capacity factor, there will be no change in the amount of electricity that the City receives from Florida Power. Under this scenario, the proposed regulatory treatment will make the transaction transparent to Florida Power's retail customers. However, when CR-3 operates at less than a 100 percent capacity factor, the City will continue to receive 11.4 MW from Florida Power. Under this scenario, Florida Power will credit the incremental energy costs to the fuel clause for the difference between 1.3333 percent of CR-3's actual output and 11.4 MW.

We note that the proposed regulatory treatment of Florida Power's supplemental power costs is analogous to the regulatory treatment prescribed by this Commission in Order No. PSC-97-1273-FOF-EU, issued October 15, 1997, in Docket No. 970171-EU. In that docket, we ordered Tampa Electric Company to credit its fuel clause with system incremental fuel cost associated with wholesale sales to FMPA and the City of Lakeland. In a similar fashion, when the capacity factor of CR-3 is less than 100 percent, [*12] Florida Power will utilize the hourly incremental cost used to price as-available energy payments to qualifying facilities to represent incremental energy costs.

F. Conclusion

In summary, after reviewing the two agreements between Florida Power and the City, we find that the regulatory treatment proposed by Florida Power will provide a nominally positive benefit to Florida Power's retail ratepayers. Therefore, under the applicable standard set forth in Order No. 97-0262, we approve Florida Power's proposed regulatory treatment.

Based on the foregoing, it is

ORDERED by the Florida Public Service Commission that Florida Power Corporation's petition for approval of proposed regulatory treatment associated with the sale of replacement capacity and associated energy to the City of Tallahassee is granted. It is further

ORDERED that the provisions of this Order, issued as proposed agency action, shall become final and effective upon the issuance of a Consummating Order unless an appropriate petition, in the form provided by Rule 28-106.201, Florida Administrative Code, is received by the Director, Division of Records and Reporting, 2540 Shumard Oak Boulevard, Tallahassee, Florida 32399-0850, [*13] by the close of business on the date set forth in the "Notice of Further Proceedings" attached hereto. It is further

ORDERED that in the event this Order becomes final, this Docket shall be closed.

By ORDER of the Florida Public Service Commission this 3rd day of September, 1999.

BLANCA S. BAYO, Director

Division of Records and Reporting

*1989 Fla. PUC LEXIS 112, **

In re: Request by Occidental Chemical Corporation for reduction of retail electric service rates charged by Florida Power Corporation

DOCKET NO. 870220-EI; ORDER NO. 20632

Florida Public Service Commission

1989 Fla. PUC LEXIS 112

89-1 FPSC 227

January 20, 1989

CORE TERMS: billing, unprotected, effective, annual, base rate, decommissioning, deferred income, nuclear, revised, judicial review, depreciation, flowthrough, permanent, reduction, protest, notice of appeal, notice, annually, monthly, Florida Rules, administrative hearing, adversely affected, formal proceeding, revenue increase, letter ruling, total amount, pro forma, normalization, calculation, annualizing

[*1]

The following Commissioners participated in the disposition of this matter: KATIE NICHOLS, Chairman; THOMAS M. BEARD, GERALD L. GUNTER, JOHN T. HERNDON, MICHAEL McK. WILSON

NOTICE OF PROPOSED AGENCY ACTION ORDER GRANTING INCREASED RATES

BY THE COMMISSION:

NOTICE is hereby given by the Florida Public Service Commission that the action discussed herein is preliminary in nature and will become final unless a person whose interests are adversely affected files a petition for a formal proceeding, pursuant to Rule 25-22.029, Florida Administrative Code.

As is more fully explained in Order No. 18627, issued in this docket on January 4, 1988, we approved a stipulated settlement (Stipulation) amongst the parties to this docket which provided for a permanent annual base rate reduction of $121,500,000, beginning January 1, 1988. Additionally, the Stipulation provided that monthly billing credits were to be applied during 1988 for a total annual amount of $18,500,000 to certain "unprotected" excess deferred income taxes. Thus, the total 1988 revenue reduction was $140,000,000. The Stipulation also addressed the possibility of increasing FPC's 1989 rates based upon adjustments respecting **[*2]** its depreciation rates, nuclear decommissioning costs and deferred income taxes.

As provided for in the Stipulation, FPC, on November 4, 1988, filed its Petition in this docket requesting our approval of revised rate schedules designed to increase its annual revenues by a total of $17,290,000. Having examined FPC's request, we find that it is consistent with the Stipulation, reasonable and necessary and should, therefore, be approved. A discussion of the several components of the revenue increase follows.

DEPRECIATION AND NUCLEAR DECOMMISSIONING

Paragraph 3 of the Stipulation provides that effective January 1, 1989, EPC's depreciation rates shall be increased by an amount equal to $6.2 million annually and that the level of funding of its reserve for the cost of nuclear decommissioning shall be increased by $4.3 million annually. The Stipulation further provides that, to the extent the above adjustments do not cause FPC's earned return on common equity to exceed 13.6%, as determined by its September, 1988 Surveillance Report, it would be entitled to a corresponding adjustment in its base rates, effective January 1, 1989.

Pursuant to the Stipulation, FPC prepared and served **[*3]** on all parties its September, 1988 Surveillance Report, which showed that the utility's earned return on equity for the twelve months ended September 30, 1988, prior to any annualizing or pro forma adjustments, was 14.07%. However, when the annualizing and pro forma adjustments shown on Attachment A to this Order are made, the earned return on equity is 12.41%. As per the Stipulation, FPC is entitled to an increase in its annual revenue requirement in the total amount of $10,669,000 ($6,300,000 for depreciation + $4,369,000 for nuclear decommissioning) to the extent that such an increase does not cause its earned return on common equity to exceed 13.6%.

Our analysis (Attachment B) shows that increasing FPC's rates by $10,669,000 will have the effect of increasing its earned return on common equity to 13.12%. Inasmuch as 13.12% is less than 13.6%, we find that FPC is entitled to increase its base rates so as to recover an additional $10,669,000 of revenues on an annual basis. Both the additional $6,200,000 of annual depreciation expense and $4,300,000 of additional annual nuclear decommissioning expense shall be included in FPC's cost of service for ratemaking purposes.

UNPROTECTED **[*4]** EXCESS DEFERRED TAXES

Paragraph 2(a) of the Stipulation provides for monthly billing credits during 1988 in the total annual amount of $18.5 million to accomplish an immediate one-year flowthrough of excess deferred income taxes which were "unprotected," i.e., not subject to the normalization requirements in Section 203(e) of the Tax Reform Act of 1986. This base rate adjustment was implemented in conjunction with the permanent reduction of $121.5 million and will expire after the last billing cycle in December, 1988.

Paragraph 2(b) provides a procedure for implementing a second year of monthly billing credits in 1989 of up to $16.65 million as a flowthrough of additional excess deferred income taxes, dependent upon the response of the Internal Revenue Service (IRS) to a private letter ruling request from FPC, which was prepared in concert with our Staff and the other parties and approved by us in Order No. 19091.

On August 3, 1988, the IRS issued the requested private letter ruling, which was filed with the Commission and served on all parties August 29, 1988. Based on the IRS ruling and the calculation methodology specified in paragraph 2(b) of the Stipulation, the total **[*5]** amount of the billing credit related to the flowthrough of additional unprotected deferred income taxes in 1989 is $11.879 million. The development of this amount is shown in Attachment C to this Order. Specifically, the IRS found that the two items in question, the repair allowance and nuclear decommissioning expense, were both "unprotected". The $16.65 million maximum billing credits would have resulted from a finding that only the repair allowance was unprotected.

Any difference between the total billing credit of $30.379 million (18.5 + $11.879) and the amount actually provided to FPC's customers in 1988 and 1989 is subject to true-up in the fuel adjustment proceedings pursuant to Paragraph 2(c) of the Stipulation. This provision is necessary to prevent the possibility of flowing through any more than the "unprotected" amount of excess deferred taxes, which would violate IRS normalization requirements applicable to "unprotected" amounts. FPC shall include a true-up reconciliation of the total billing credit in its 1990 fuel adjustment filings.

SUMMARY

The combined net effect of the adjustments to base rates pursuant to the Stipulation shows an increase during 1989 **[*6]** of $6,621,000 from the credit for the flowthrough of deferred taxes, and a permanent increase of $10,669,000 from increased depreciation and decommissioning expense, for a total base rate increase of $17,290,000, or 2.4% over 1988 base rates.

Allocation of Rate Increase

We have determined that, pursuant to the terms of the Stipulation approved in Order No. 18627, the 1989 increase (which in reality is merely a reduction in the $121.5 million rate decrease imposed by the Stipulation for 1988) shall be allocated through the application of a uniform percentage factor to FPC's currently authorized permanent base rate charge under each of its rate schedules. Accordingly, FPC shall file rate schedules allocating the authorized increase on a uniform percentage factor of 2.4% to all base rate charges under each of its rate schedules.

The new rate schedules shall be effective beginning with Cycle 1 billings for January, 1989. The increase in rates shall be collected subject to refund until either the time to protest this Order has expired, or if the Order is protested, until the protest is resolved.

Based on the above, it is

ORDERED by the Florida Public Service Commission that **[*7]** the petition of Florida Power Corporation for authority to increase its rates and charges is granted to the extent delineated herein. It is further

ORDERED that Florida Power Corporation is hereby authorized to submit revised rate schedules consistent herewith designed to generate $17,290,000 in additional gross revenues annually. The Company shall include with the revised rate schedules all calculations and workpapers used in deriving the revised rates and charges. It is further

ORDERED that the revised schedules authorized herein for the revenue increase shall be effective on January 1, 1989. It is further

ORDERED that the Company provide to each of its customers a bill stuffer describing the nature of the base rate increase. A copy of the bill stuffer shall be provided to the Commission's Electric and Gas Department for review prior to its use. It is further

ORDERED that the provisions of this Order, issued as proposed agency action, shall become final unless an appropriate petition in the form prescribed in Rule 25-22.036, Florida Administrative Code, is received by the Director, Division of Records and Reporting, at his office located at 101 East Gaines Street, Tallahassee, **[*8]** Florida 32399-0870, by the close of business on February 9, 1988.

By ORDER of the Florida Public Service Commission, this 20th day of JANUARY, 1989.

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.

The action proposed herein is preliminary in nature and will not become effective or final, except as provided by Rule 25-22.029, Florida Administrative Code. Any person whose substantial interests are affected by the action proposed by this order may file a petition for a formal proceeding, as provided by Rule 25-22.029(4), Florida Administrative Code, in the form provided by Rule 25-22.036(7)(a) and (f), Florida Administrative Code. This petition must be received by the Director, Division of Records and Reporting at his office **[*9]** at 101 East Gaines Street, Tallahassee, Florida 32399-0870, by the close of business on February 9, 1989. In the absence of such a petition, this order shall become effective February 10, 1989, as provided by Rule 25-22.029(6), Florida Administrative Code, and as reflected in a subsequent order.

Any objection or protest filed in this docket before the issuance date of this order is considered abandoned unless it satisfies the foregoing conditions and is renewed within the specified protest period.

If this order becomes final and effective on February 10, 1989, any party adversely affected may request judicial review by the Florida Supreme Court in the case of an electric, gas or telephone utility or by 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 of the effective date 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 **[*10]** Appellate Procedure.

In re: Petition of Florida Power Corporation to modify its rates

DOCKET NO. 770316-EU; ORDER NO. 8834

Florida Public Service Commission

1979 Fla. PUC LEXIS 501

5 FPSC 885

April 18, 1979

CORE TERMS: interim, presently, rate of return, customer, rate case, nuclear, monthly, savings, notice, fuel, subject to refund, commission staff, kilowatt hour, rate base, surveillance, calculations, industrial, initiated, collected, annually, earnings, refund

[*1]

The following Commissioners participated in the disposition of this matter: ROBERT T. MANN, Chairman; WILLIAM T. MAYO, GERALD L. GUNTER, JOSEPH P. CRESSE, JOHN R. MARKS, III

ORDER

BY THE COMMISSION:

This docket was initiated by a petition submitted by Florida Power Corporation on April 7, 1977. The petition, which was accompanied by rate schedules designed to generate additional revenues of $62,325,262 annually, stated that this amount was necessary to compensate the company for the fixed costs associated with the company's Crystal River No. 3 nuclear generating facility, which was placed into commercial service on March 13, 1977. The petition further averred that the proposed increase in base rates designed to recognize the fixed costs of owning the plant would be offset by reduced expenditures for fuel incurred in the generation of electricity, due to the substantial differential between the cost per kilowatt hour of nuclear fuel and the higher costing fossil fuel which it would displace. (The concept of the higher base rates being justified by offsetting fuel cost benefits has been described in this docket as the company's "net savings theory".) The scope of [*2] the case as filed was thus limited to a consideration of the costs and associated benefits of the nuclear unit.

Within the 30 day period provided by Section 366.06(4), ES, we suspended in Order No. 7791, the operation of the rate schedules submitted by the company, but authorized an interim increase in the amount of $60,767,961 to become effective, subject to refund, pending the results of public hearing.

During the initial months of operation, the unit's performance did not produce the savings projected by the company. On September 1, 1977, we determined that the interim increase should be terminated pending the results of the hearing. That decision was incorporated in Order No. 7957, dated September 9, 1977. The company immediately appealed the decision, which was stayed by the Supreme Court of Florida. Ultimately, the Court held that this action was improper, and Order No. 7957 did not become operative. Florida Power Corporation v. Hawkins, 367 So. 2d 1011 (Fla. 1979).

Eight days of public hearings on the company's petitions were held in November of 1977. A voluminous record was compiled, which included the testimony of expert witnesses in addition to the company's [*3] presentation. On February 2, 1978, we entered Order No. 8160, in which we concluded that the company had demonstrated that it was entitled to an increase in the amount of $59,468,468 annually. In that order, we commented upon the unique nature of the company's filing, and expressed our preference for a comprehensive review of a company's entire system when fixing rates.

Throughout this case, the manner in which the increase sought by the company should be spread among the classes of customers has been at issue. The original rates filed by the company were based upon a 1974 cost of service study. However, in authorizing the initial interim increase, we directed the company to increase each rate schedule by the same amount per kilowatt hour, recognizing that any reduction in fuel expense resulting from operation of the nuclear unit would impact equally upon all customers. Certain industrial customers contended, both in response to the initial interim order and during the hearings held in this docket, that the method chosen by the Commission unreasonably increased the base rates of industrial classes by a percentage greater than that for residential consumers, without [*4] due regard for the cost to serve each class. After evaluating the record, we determined in Order 8160 that the method of revenue allocation to each class of customer which we had chosen for purposes of fashioning the initial interim increase was reasonable and valid, and should be applied to the $59 million increase as well.

Several parties filed petitions for reconsideration to Order No. 8160. Prior to the time that Order became final, a serious failure within the unit caused Crystal River No. 3 to be lost from service for a then unknown period of time. Taking official notice of this circumstance, we determined that the "net savings" theory no longer had any efficacy, and would not be accepted as justification for the base rate increase. Accordingly, in Order No. 8260, dated April 13, 1978, we stated that the company could continue to collect the $59 million increase, but that it would be subject to refund pending the results of a determination, within the existing docket, of the company's full revenue requirements (as determined by an analysis of the company's rate base expenses, and appropriate rate of return). Again the company sought review by the Supreme Court of Florida. [*5] The Court stayed that portion of Order No. 8260 which compelled the company to file the data requirements preparatory to a full revenue requirements proceeding.

On December 11, 1978, the Court issued an opinion which upheld our action in expanding the docket. As a result, we issued Order No. 8694 on January 26, 1979, which established calendar year 1978 as the test year for the expanded proceeding and fixed deadlines for the filing of certain rate case data.

Subsequent to the issuance of Order No. 8694, the Commission staff brought to our attention the results of the most recent financial reports of the company, which indicate that the earned rate of return - based upon calculations which include the interim increase - is substantially lower than that presently authorized by the Commission. In addition, Mobil Chemical Company intervened in the case for the purpose of filing a Motion to Terminate Proceedings. This Motion was joined in by Honeywell, Inc., an intervener herein. The thrust of the Motion is that the Commission should not compel the company to proceed with a full revenue requirements case under circumstances which indicate that the end result may well be an actual [*6] increase in rates charged by the company. Oral argument was held on the Motion on March 26, 1979, and while we denied the Motion at that time, we directed the Commission staff to make a further recommendation after assessing all information available.

Order No. 8260 stated our objective of testing the reasonableness of the increase originally authorized by Order No. 8160 by reference to the performance of the company's entire system, as opposed to a consideration of a single unit.

This Commission maintains a continuous surveillance of the earnings performance of utility companies subject to its jurisdiction. The program includes a requirement that such companies file financial data relating to their operations in a form prescribed by the Commission on a monthly basis.

The monthly financial reports submitted by the Company in compliance with the Commission's continuing surveillance review program for the months of December, 1978, January and February, 1979, of which we take official notice, reflect that Florida Power Corporation during those months achieved earned rates of return of 8.18%, 8.02% and 7.98% respectively, as compared to its presently authorized rate of return of [*7] 8.66%. While it reasonably could be assumed that the extensive evaluation of the company's performance which takes place in a rate case setting could result in some adjustments to the bases for such calculations, including a determination of the appropriate cost of capital to the company, the disparity between the earnings performance depicted by the monthly financial reports and the presently authorized return indicates strongly that the rates presently in effect do not produce a return that is unreasonably high at the present time. While we of course do not prejudge the results of a full case, we do recognize the possibility that the company under present circumstances could justify, not only the interim increase, but the requirement of additional revenues as well. Under such circumstances, we believe that the tremendous expense - in terms of time and money - associated with a major rate case, which of course is ultimately borne by ratepayers, would be unproductive and unwarranted. Accordingly, we have decided to terminate this docket.

In doing so, we wish to reiterate that we do not look with favor upon limited petitions such as the one which initiated this proceeding. [*8] Further, by taking official notice of the recent monthly statements of the company, we make no findings as to the propriety of any item of expense or rate base included within such reports. Our action in this case is of course without prejudice to the power and ability of the Commission to determine the value of the property of the company used and useful in serving the public, the expenses prudently incurred in operating the company, and the cost of capital to the company during the company's next rate proceeding.

And, while we affirm and approve the revenue allocation presently in effect, for the reasons stated in Order Nos. 8160 and 8260, which reasons we hereby adopt, our action in this case will in no way preclude a reexamination of the company's rate structure in future proceedings.

In summary, we find that the rate schedules which were first authorized by Order No. 8160, and which were converted into interim rates by Order No. 8260, are just and reasonable. We further find that said rates do not produce a rate of return that is higher than that presently authorized by the Commission, and that the company thus is entitled to keep those revenues which have been collected [*9] subject to the refund provision of Order No. 8260. Accordingly, it is

ORDERED by the Florida Public Service Commission that the rate schedules first authorized by Order No. 8160 continue in effect on a permanent basis. It is further

ORDERED that Florida Power Corporation is authorized to retain those revenues collected on an interim basis by virtue of the refund provision of Order No. 8260. It is further

ORDERED that this docket be and the same is hereby closed.

By Order of the Florida Public Service Commission, this 18th day of April 1979.

*1984 Fla. PUC LEXIS 375, **

In re: Petition of FLORIDA POWER AND LIGHT COMPANY for an increase in its rates and charges

DOCKET NO. **830465**-EI; ORDER NO. 13537

Florida Public Service Commission

1984 Fla. PUC LEXIS 375

84 FPSC 136

July 24, 1984

CORE TERMS: customer, rate base, working capital, fuel, forecast, plant, projected, barrel, load, rate case, inventory, benchmark, staff, approve, jurisdictional, energy, depreciation, electric, dividend, rate of return, inclusion, ratepayer, billing, capital structure, fixture, on-peak, annual, salary, projection, inflation

MATTHEW M. CHILDS, Esquire, JOHN T. BUTLER, Esquire, and CHARLES GUYTON, Esquire, Steel, Hector and Davis, Suite 320, Barnett Bank Building, 315 South Calhoun Street, Tallahassee, Florida 32301, and MORRIS SHELKOFSKY, Esquire, 9250 West Flagler Street, Miami, Florida 33152, for Florida Power and Light Company

JACK SHREVE, Esquire, Public Counsel, STEVE BURGESS, Esquire, CAROLYN OLIVE, Esquire, and STEPHEN FOGEL, Esquire, Office of Public Counsel, Room 4, Holland Building, Tallahassee, Florida 32301, for the Citizens of the State of Florida

THOMAS F. WOODS, Esquire, Woods & Carlson, 1030 East Lafayette Street, Suite 112, Tallahassee, Florida 32301, for Florida Hotel & Motel Association

GEORGE B. STALLINGS, JR., Esquire, P.O. Box 13, Ortega Station, 5411 Ortega Boulevard, Jacksonville, Florida 32210, for Florida Retail Federation

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MARK H. RICHARD, Esquire, **[*2]** Law Offices of Neil Chonin, P.A., 304 Palermo Avenue, Coral Gables, Florida 33134, for Floridians United for Safe Energy, Inc.

IRA DANIEL TOKAYER, Esquire, 1626 Dade County Courthouse, 73 West Flagler Street, Miami, Florida 33130, for Metropolitan Dade County

JOHN W. MCWHIRTER, JR., Esquire, and JOSEPH A. MCGLOTHLIN, Esquire, Lawson, McWhirter, Grandoff & Reeves, 201 East Kennedy Boulevard, Suite 821, P.O. Box 3350, Tampa, Florida 33601, for Florida Industrial Power Users Group

ROBERT D. ZAHNER, Esquire, City Hall - 405 Biltmore Way, Coral Gables, Florida 33134, for City of Coral Gables

MICHAEL B. TWOMEY, Esquire, J. ROGER HOWE, Esquire, CARRIE J. HIGHTMAN, Esquire, and JOSE DIEZ-ARGUELLES, Esquire, 101 East Gaines Street, Tallahassee, Florida 32301, for the Commission Staff

PRENTICE P. PRUITT, Esquire, 101 East Gaines Street, Tallahassee, Florida 32301, counsel to the Commissioners

[*1]

The following Commissioners participated in the disposition of this matter: GERALD L. GUNTER, Chairman; JOSEPH P. CRESSE, JOHN R. MARKS, III, KATIE NICHOLS, SUSAN W. LEISNER

Pursuant to duly given Notice, the Florida Public Service Commission held public hearings in this docket on January 30, 1984, in Miami, Florida; February 3, 1984 in Fort Lauderdale, Florida; February 13, 1984, in Sarasota, Florida; February 16, 1984, in Daytona Beach, Florida; February 20, **[*3]** 1984, in Fort Myers, Florida; March 30, 1984, in Palm Beach Gardens, Florida, and in Tallahassee, Florida, on April 9-13, 16, and 18-20, 1984. Having considered the record herein, the Commission now enters its final order.

ORDER AUTHORIZING CERTAIN INCREASES

BY THE COMMISSION:

SUMMARY OF DECISION

In this Order, we have determined that Florida Power and Light Company (FPL, the Utility or the Company) should be authorized an increase in gross revenues of $81,464,000 for the test year 1984 and $114,984,000 for the 1985 "subsequent year" adjustment. In reaching this decision, we have concluded that FPL should have an opportunity to earn 15.6% on its common equity capital. Construction Work in Progress (CWIP) included in rate base has been reduced from the $267,631,000 authorized in FPL's last rate case to zero. We have disallowed in excess of $84 million of FPL's projected 1984 Operating and Maintenance (O&M) expenses because the Company failed to carry its burden of proving the expenses projected were to be reasonably and prudently incurred and necessary to the provision of electric service to its customers. In the rate design area, we have eliminated mandatory **[*4]** time-of-use rates to allow customers additional freedom of choice. An index to this order appears on Appendix A and summary statements of our adjustments are set forth on Appendices B and C.

BACKGROUND

This proceeding was commenced on November 23, 1983 by the filing of FPL's petition for a rate increase designed to produce $335,274,000 in additional annual revenues in 1984 and $120,279,000 in additional revenues in 1985. We suspended the proposed rates on January 23, 1984 by the issuance of Order No. 12919. As also noted in Order No. 12919, we denied FPL's alternative requests for interim rate relief.

Extensive public hearings have been held on FPL's rate request. These hearings extended over 15 days and resulted in a record comprising over 4,000 pages of transcript and over 145 exhibits. We have had the active participation of numerous parties, including the Public Counsel, other representatives of the public, governmental agencies and large industrial customers.

THE PARTIES

Florida Power and Light Company

Florida Power and Light Company has been engaged in the electric utility business since 1925. It operates in 35 counties in the State of Florida, serving **[*5]** an area of approximately 27,650 square miles with an estimated population of 5.6 million. As of year end 1983, FPL served approximately 2.5 million customers in some 700 communities. For the 12 months ended December 31, 1983 52.5% of FPL's operating revenues were derived from residential sales, 34.6% from commercial sales and 12.9% from other sources.

FPL generates its power from 28 steam turbines, 2 combined cycle units, 48 gas turbines and

10 diesel units. Four of the Company's steam turbine units are nuclear-fueled, while the remainder are either oil or oil/gas fired. FPL's total net summer generating capability is 13,470 megawatts (MW). FPL has interconnections and/or interchange agreements with numerous Florida electric utilities, and purchases "coal-by-wire" from Georgia Power Company and Southern Services, Inc. FPL reached its 60-minute net peak of 10,676 MW on July 25, 1983. The generated or purchased power reaches the utility's customers through 4,565 miles of transmission line and some 42,042 miles of distribution line.

FPL's last full rate case was in 1982 (Order No. 11437, Docket No. 820097-EU, issued 12/22/82). In that case, we authorized a gross annual **[*6]** revenue increase of $100,805,000 out of the $281,000,000 requested. Additionally, we determined that FPL's fair rate of return on equity fell within the range of 14.85% - 16.85% and utilized 15.85% in establishing FPL's overall rate of return of 10.83%. We denied FPL's Nuclear Power Plant Cost Recovery Factor, which was related to its then uncompleted St. Lucie Unit No. 2, but retained jurisdiction to consider the inclusion of that unit in rate base at a later date.

In 1983, we held additional hearings on the inclusion of St. Lucie 2 in rate base and on August 9, 1983, we issued Order No. 12348, which authorized FPL to increase its rates so as to generate additional gross annual revenues of $237,816,000. These revised rates became effective 30 days after the unit was placed into commercial operation and consisted of an annual incremental rate base revenue requirement of $121,169,000 for the then $1.1 billion plant and an incremental operating expenses revenue requirement of $116,647,000 related to the plant. FPL witnesses testified that St. Lucie 2 was expected to realize $179 million in fuel savings compared to the oil-fired generation it displaced during its first year of operation. **[*7]** Although we reduced FPL's oil inventory working capital allowance by over $39,000,000 and established a special Generating Performance Incentive Factor (GPIF) for the unit, we left its overall rate of return at the previously authorized 10.83% and did not otherwise modify the rates approved in 1982.

By its present petition, FPL has requested gross annual revenue increases of $335,274,000 and $120,279,000 for 1984 and 1985, respectively. These increases, according to the Company, are necessary to provide it with the opportunity to earn an overall rate of return of 11.18%, which it alleges is fair and reasonable under prevailing conditions and which would allow for a rate of return on common equity of 17.35%.

Public Counsel

Pursuant to Section 350.061, Florida Statutes, the Public Counsel is appointed by the Joint Legislature Auditing Committee to represent the general public of Florida before the Florida Public Service Commission.

The Office of Public Counsel (Public Counsel) presented the testimony of two witnesses during this proceeding. Public Counsel proposed that the Commission establish an average rate base of $5,674,890,000, a return on equity of 14.5%, and an **[*8]** overall rate of return of 9.80%, for 1984. This results in a net revenue decrease of $113,071,000 for 1984. For 1985, Public Counsel alleged that the Company should get a revenue increase of $24,468,000.

Florida Industrial Power Users Group

Several industrial customers of FPL who are members of the Florida Industrial Power Users Group (FIPUG) intervened in this proceeding. FIPUG presented the testimony of four witnesses in the areas of cost of service and rate design. FIPUG advocated the use of the average of the summer and winter peaks cost of service methodology. Additionally, FIPUG sought the elimination of mandatory time-of-use rates.

Florida Retail Federation, Inc.

The Florida Retail Federation, Inc. (FRF) is a not-for-profit corporation representing numerous retail establishments, some of whom are customers of FPL. The FRF intervened in this proceeding and presented the testimony of one witness in the area of rate structure.

Metropolitan Dade County Consumer Advocate

The Consumer Advocate of Metropolitan Dade County is a charged with the responsibility of representing the "public interest" of the Citizens of Dade County. Although he was granted **[*9]** intervenor status, the Dade Consumer Advocate did not appear at the hearings in this case.

Floridians United for Safe Energy

Floridians United for Safe Energy (FUSE) intervened in this proceeding. FUSE presented no witnesses, but cross-examined several witnesses and took positions on several issues, including rate base and net operating income.

The Commission Staff

The Commission Staff participated in the proceedings and presented the testimony of five witnesses dealing with comparative Utility statistics, accounting and financial matters, cost of captial, rate design, and customer complaints.

DENIAL OF FPL'S MOTION FOR RECONSIDERATION OF ORDER NO. 12919, WHICH DENIED INTERIM RATE RELIEF

By Order No. 12919, issued January 23, 1984, we suspended FPL's rate schedules designed to produce $335,274,000 in additional annual revenues in 1984 and $120,279,000 in additional revenues in 1985 and denied FPL's alternative requests for interim rate relief. FPL's interim request for $227,000,000, pursuant to Section 366.06(3), Florida Statutes, was denied because a proper analysis of that request would require the rapid resolution of several issues raised in the permanent **[*10]** request, which we determined would require a hearing. The Company's alternative interim request for $63,905,000, made pursuant to Section 366.071, Florida Statutes, (the Interim Statute) was denied because the Utility was not entitled to interim relief after the Commission made several adjustments to FPL's calculation. The most significant adjustments were:

1. Reducing FPL's requested CWIP of $294,193,000 by $26,562,000 to the $267,631,000 of CWIP allowed in rate base in FPL's last rate case;

2. The disallowance of $47,566,000 of O&M expense over and above the Consumer Price Index (CPI) and customer growth level approved in FPL's last rate case because the Utility did not offer persuasive justification for the increase despite the fact that they were specifically put on notice in the last rate case of our concern with the rapidly rising O&M costs; and

3. The inclusion in net income of $119,276,000 related to the inclusion of St. Lucie 2 in rate base.

By its Motion for Reconsideration, FPL asks that we reconsider the above-mentioned adjustments. Specifically, FPL argues:

1. The $47,566,000 of disallowed non-fuel O&M expenses were actually incurred by FPL during **[*11]** the interim test year. The rate order in FPL's last case did not make an "adjustment" limiting FPL's growth in O&M expenses to CPI and customer growth and, thus, the Commission's disallowance was not an "adjustment" permitted by Section 366.071, Florida Statutes. The effect of this disallowance is to apply "non-rule policy" not noticed, decided or supported by the record in any case. FPL also argues that it met the statutory requirement of making a prima facie case and that it was entitled to interim relief because these expenses were prudent.

2. FPL says that the St. Lucie 2 adjustment was not an adjustment consistent with the most recent rate case and was not proper because it adjusted the "required rate of return" when the statute only makes provision for adjustments to "achieved rate of return." FPL believes that neither the adjustment to the required nor the achieved rates of return are allowed under the interim statute. Even if these types of adjustments were allowed under the interim statute, FPL says that they are unfair because they only address revenues attributed to St. Lucie 2 and not significant increases in plant-in-service and O&M expenses related to that **[*12]** plant.

3. FPL states that its calculation of $294,193,000 of CWIP was consistent with the way CWIP was calculated in its last case and, thus, its request should have been allowed.

In its response to FPL's motion, Public Counsel addressed FPL's arguments as follows:

1. The Commission adequately warned FPL in its last rate order that it might hold the Utility to its stated goal of keeping increases in non-fuel O&M expenses at or below CPI and customer growth. The Commission is now merely holding the Utility to that test of reasonableness and, thus, the disallowance of $47 million was appropriate.

2. With regard to the St. Lucie 2 adjustment, Public Counsel states that FPL received the benefit of a favorable departure from traditional ratesetting procedures and, thus, was granted an opportunity to earn 15.85% on its equity in St. Lucie 2. Under these circumstances, Public Counsel argues that the Commission wisely and correctly imputed the earnings on St. Lucie 2 in the interim test year.

3. Public Counsel argues that the Commission allowed a constant dollar amount of CWIP ($267 million) in rate base in order to ensure the Utility's financial integrity. Accordingly, Public **[*13]** Counsel urges the Commission not to modify its decision on CWIP.

For the reasons that follow, we deny FPL's Motion for Reconsideration:

Disallowance of Non-Fuel O&M Expenses Exceeding CPI and Customer Growth

As noted by Public Counsel, we adequately placed FPL on notice that we might hold it to its stated company policy of limiting non-fuel O&M to CPI and customer growth. We merely carried out our announced intention. As will be discussed more fully in a later section of this order, FPL has failed to support, and we have disallowed as unreasonable, over $82,000,000 of O&M expenses which exceeded the CPI and customer growth standard in 1984 and over $85,000,000 of similar O&M expenses in 1985.

We believe that our $47,566,000 disallowance of non-fuel O&M expense was an appropriate adjustment consistent with those used in the Utility's last rate case and that, therefore, it is a legally acceptable and logical method of interpreting the interim statute. Accordingly, we decline to modify our decision on this point.

The St. Lucie 2 Adjustment

As described earlier in this order, we, by Order No. 12348, issued August 9, 1983, included in FPL's rate base a jurisdictional **[*14]** incremental rate base addition related to the Company's St. Lucie No. 2 nuclear unit in the amount of $1,101,351,000. This limited proceeding resulted in a jurisdictional incremental rate base revenue requirement related to St. Lucie 2 in the amount of $121,169,000 and a jurisdictional incremental operating expenses revenue requirement of $116,647,000 for a total increase in gross annual revenues of $237,816,000. The new rates were to be effective upon the placement of St. Lucie 2 into commercial service and applicable to meter readings 30 days later. St. Lucie 2 was later placed into commercial service and the new rates became effective on September 7, 1983, and applicable to billings on October 7, 1983.

On November 23, 1983, after the new St. Lucie 2 rates became effective, FPL filed its petition in this docket utilizing calendar year 1984 as the test year. The Company's interim rate request pursuant to Section 366.071, Florida Statutes, (the Interim Statute) was based upon a test year ending July 31, 1983. Thus, whether by design or chance, FPL's interim test year included no portion of the additional $237,816,000 in gross annual revenues it had already begun collecting pursuant **[*15]** to Order No. 12348. Stated in simple terms, FPL asked us to calculate their interim rates, and wanted us, in doing so, to ignore the reality that they were already collecting rates designed to recover over $237 million more annually than authorized in its last full rate case.

FPL's major argument is that the Commission should, for the purposes of calculating interim rates, ignore the effects of placing St. Lucie 2 in rate base because the resulting adjustment is "not an adjustment consistent with that used in the most recent rate case." Such an argument suggests that the interim statute requires that we ignore the reality of our 1983 inclusion of almost $1.5 billion of plant-in-service in rate base and the approval in rates of the associated O&M costs concurrently with that unit being placed into commercial service. FPL praised the Commission's progressive procedures with regard to the inclusion of that plant, but now rejects a construction of the interim statute which is not only supported by logic and reason but which also benefits the Utility's ratepayers. We believe that our adjustments to both the achieved and required rates of return related to the inclusion of **[*16]** St. Lucie 2 are appropriate and consistent with our discretion pursuant to Chapter 366, Florida Statutes, and in the public interest. Accordingly, we decline to modify our decision on this point.

The Exclusion of a Portion of the Requested CWIP

In our calculation of whether FPL was entitled to any interim rate relief in this proceeding, we included some 267 million of CWIP in rate base, which was the identical amount included in FPL's last full rate case. In doing so, we declined to include the total amount of $294,193,000 requested, which FPL stated was calculated in a manner consistent with the way the $267 million had previously been calculated.

As is more fully discussed in a later section of this order, we have reaffirmed our policy of including CWIP in rate base only when necessary to maintain the financial integrity of the Utility. When we approved the inclusion of some $267 million of CWIP in FPL's rate base in 1982, the Company had over $1 billion of its investment in St. Lucie 2 accruing a non-cash, AFUDC return. In 1982 FPL needed $267 million of CWIP in rate base to preserve its financial integrity and we authorized its inclusion. However, by the time we **[*17]** considered FPL's interim request in this case, we had included almost $1.5 billion of plant in service related to St. Lucie 2 in rate base, thereby profoundly reducing the percentage of FPL's investment earning an AFUDC return and significantly enhancing the Company's financial integrity. Whether we should have included up to $267 million of CWIP in rate base when calculating FPL's entitlement to interim rate relief may be debatable, but whether we should have included more is, in our opinion, not. For the reasons given, we deny FPL's Motion for Reconsideration of Order No. 12919 in its entirety.

REVENUE REQUIREMENTS DETERMINATION

The revenue requirements of a utility are derived by establishing its rate base, net operating income and fair rate of return. A test period of operations, traditionally based upon one year of operations, is used to derive these factors. Multiplying the rate base by the fair rate of return provides the net operating income the utility is permitted to earn. Comparing the permitted net operating income with the test year net operating income determines the net operating deficiency or excess. The total test year revenue deficiency or excess is determined **[*18]** by adjusting the deficiency or excess by the revenue expansion factor.

THE TEST YEAR

The function of a test year in a rate case is to provide a set period of utility operations that may be analyzed so as to allow the Commission to set reasonable rates for the period the rates will be in effect. A test period may be based upon an historic test year with such adjustments as will make it reflect typical conditions in the immediate future, and make it reasonably representative of expected future operations. Alternatively, a test period may be based upon a projected test year which, if appropriately developed and adjusted, may reasonably represent expected future operations.

As in other recent major electric utility rate cases, this case is predicated upon projected test years. FPL proposed to use calendar year 1984 as its base test year and calendar year 1985 as its "subsequent year" test year and received preliminary approval of these test years at the outset of the proceedings. Having considered the record herein, we affirm the appropriateness of these test years for the purposes of this case. As adjusted herein, we believe the test periods reasonably represent **[*19]** expected operations during the periods the approved rates will be in effect.

Minimum filing requirements (MFRs) Schedule F-15 provides an overview of the assumptions used by the Company in projecting its test years. Differing from its most recent rate cases, the Company's base test year was predicated on its normal budget for the prior year, 1983.

The Company's requests were based upon projected data from the following processes:

A. Energy Management Planning

The Energy Management Planning Department projects, in the regular course of business, customers, net energy for load, energy sales (KWH), and peak load. It also prepares inflation and economic forecasts.

B. System Planning

The System Planning Department projects, in the regular course of business, the generation expansion plan to meet the peak load and the bulk transmission system needed for the generation expansion plan. The net energy for load data, along with fuel prices, heat rates, plant outage schedules and interchange projections, is entered into PROMOD, which calculates fuel expense.

C. O&M Expense Forecast

The Operation and Maintenance (O&M) forecasts were prepared using the Integrated Planning **[*20]** and Control (IPC) process. The IPC process consists of two general phases. In the first phase, a manager examines his current level of operation, estimates the actual expenses for the year and then makes adjustments to that estimate for inflation, customer growth and other non-controllable factors. After identifying those items over which the manager cannot exercise control, the next step is to eliminate non-recurring events or completed projects.

The manager then adds the impact of new actions started in the prior year. The difference between a fully operational program and the first year start-up effort is called, "Management Action Carry Over". Thus, a manager completes the first of the two phases and establishes a preliminary planning base.

The second phase is used to clearly highlight to the Budget Committee any new actions that are being proposed for the ensuing year. New actions may range from inspecting, repairing or overhauling a power plant to a request for an additional employee.

The IPC process as described was executed in several discrete steps. First, various responsibility areas in the Company were requested to supply the assumptions necessary for the forecast. **[*21]** These assumptions included projections of the CPI increase, customer growth, postage, telephone rates, etc.

Next a letter was sent to all department heads and division vice presidents requesting that they prepare O&M forecasts for 1984 and 1985 for their responsibility areas.

When the items described above were complete, the Management Control Department (Management Control) received the IPC packages from each department or division.

The information was then taken to the Budget Committee for their review and approval, however, the operating budget is not approved by the Board of Directors.

D. Capital Expenditures Forecast

Florida Power and Light Company utilizes both an annual capital expenditures budgeting system and a five-year forecast of capital expenditures. The budget is prepared and revised as appropriate. The five-year forecast is also updated throughout the year as recognized changes to the Company's plans occur.

When the departments and divisions were requested to prepare a new forecast of O&M expenses for the Rate of Return Model, they were also asked to review and update the Five-Year Capital Expenditures Forecast. They were further requested to **[*22]** document any project with expenditures of at least $5,000,000 that would be in process during 1984 or 1985. New month-by-month projections of expenditures through the end of 1985 were prepared and, if the project extended beyond that date, annual projections were made through the project's expected completion date. The total Five-Year Capital Expenditures

Forecast was subsequently reviewed and approved by the Budget Committee.

E. Rate of Return Model

There are two parts to the Rate of Return Model - the property module and the financial module.

The property module input is the data from the capital expenditures forecast, plus information on plant in-service dates, projected retirements and AFUDC rates. It then calculates, by month, balances for plant in service, construction work in progress, future use property, accumulated depreciation and accumulated amortization, and depreciation expense and AFUDC.

The financial module uses the output from the property module, the forecast of operation and maintenance expense, PROMOD, and certain other information and constructs an income statement and rate base.

The output of the Rate of Return Model is combined with other information **[*23]** to develop balance sheets for each month. This data is then used to determine working capital requirements.

In developing data for 1984 and 1985, actual data for the four months ended April 30, 1983 was used as a starting point. Projected data for the last eight months of 1983 and for all of 1984 and 1985 was then developed. Prior year (1983) data included in any presentation consisted of actual 1983 data through April 30, 1983 and projected data for the May through December 1983 period. The results of the Rate of Return Model, as described above, were used to develop the 1984 and 1985 requests after certain Company and Commission adjustments from the last rate case, along with jurisdictionalization.

On the basis of the foregoing, we find that the Company's rate base, net operating income and capital structure are generally based upon reasonable projections and assumptions and that the methodology employed by the Company in preparing its case also appears to be reasonable. There are, however, certain areas where we question the reasonableness of specific projections and assumptions and we shall identify and address these specific areas as they appear throughout the **[*24]** order. Except for these specific areas, the evidence presented demonstrates that the assumptions and projections relied upon by the Company in presenting its 1984 test year data are reasonable and may be relied upon as a basis for setting rates. As will be more fully discussed in a later section on the subsequent year adjustment, the accuracy of the 1985 projections and assumptions may be subject to additional review.

RATE BASE

To establish the Company's overall revenue requirements, we must determine the value of its "rate base," which represents the investment on which the Company is entitled to earn a reasonable return. A utility's rate base is comprised of various components. These include: (1) net utility plant-in-service, which is comprised of plant-in-service less accumulated depreciation and amortization, (2) total net utility plant, which is comprised of net utility plant-in-service, CWIP (where appropriate, plant held for future use, and nuclear fuel, and (3) working capital.

FPL has submitted a proposed jurisdictional rate base of $6,372,388,000 for 1984 and $6,725,149,000 for 1985. Evidence developed during the course of these proceedings has led us to reduce **[*25]** the 1984 amount to $5,813,566,000 and the 1985 amount to $6,184,410,000. Our adjustments are set forth as follows:

	1984		
	Per Company	Adjustments	As Adjusted
A. Utility Plant-in-Service	$7,312,411,000	$ (69,690,000)	$7,242,721,000
B. Accumulated Depreciation and Amortization	(1,677,294,000)	(9,952,000)	(1,687,246,000)
C. Net Utility plant-in-Service	5,635,117,000	(79,642,000)	5,555,475,000
D. Construction Work in Progress	331,951,000	(331,951,000)	
E. Property Held for Future Use	37,393,000	(393,000)	37,000,000
F. Nuclear Fuel (Net)	166,066,000	(65,215,000)	100,851,000
G. Net Utility Plant	6,170,527,000	(477,201,000)	5,693,326,000
H. Working Capital	201,861,000	(81,621,000)	120,240,000
I. Total Rate Base	$6,372,388,000	$ (558,822,000)	$5,813,566,000

	1985		
	Per Company	Adjustments	As Adjusted
A. Utility Plant in Service	$7,875,045,000	$ (21,668,000)	$7,853,377,000
B. Accumulated Depreciation and Amortization	(1,939,193,000)	(37,467,000)	(1,976,660,000)
C. Net Utility Plant in Service	5,935,852,000	(59,135,000)	5,876,717,000
D. Construction Work in Progress	339,911,000	(339,911,000)	
E. Property Held for Future Use	38,717,000	(92,000)	38,625,000
F. Nuclear Fuel (Net)	219,923,000	(63,576,000)	156,347,000
G. Net Utility Plant	6,534,403,000	(462,714,000)	6,071,689,000
H. Working Capital	190,746,000	(78,025,000)	112,721,000
I. Total Rate Base	$6,725,149,000	$ (540,739,000)	$6,184,410,000

[*26]

A. Utility Plant in Service

The amount of utility plant in service originally proposed by the Company was $7,312,411,000 for 1984 and $7,875,045,000 for 1985. We have made certain adjustments, described below, which reduce utility plant in service to $7,242,721,000 for 1984 and $7,853,377,000 for 1985.

1. Masonary Wall Repairs

Subsequent to its filing, the Company identified an error concerning the recording of certain masonary wall repairs at its nuclear plants. The repairs were properly charged to O&M expenses but they were also mistakenly capitalized and included in plant-in-service. The appropriate adjustments to correct the error are to reduce plant in service by $3,463,000 in 1984 and $4,922,000 in 1985.

2. Litigation Items

As is more fully described in Orders Nos. 10306 and 11437, we have in FPL's last two rate cases made certain decisions involving the so-called "Litigation Items": the Martin Dam, the Expanded Fuel Storage Facilities at Turkey Point, and the Steam Generator Repairs at Turkey Point. Consistent with those previous orders, FPL has removed from plant-in-service the amounts associated with the litigation items. However, subsequent to its **[*27]** filing in this case, FPL received settlement proceeds of $12,231,387 related to the first reracking of the spent fuel nuclear fuel pits at Turkey Point. This settlement, received on June 1, 1984, consists of $9,473,242 of principal plus $2,758,145 of court-awarded interest. As of June 1, 1984, the Company's investment in the reracking was $12,704,420 less accumulated depreciation of $2,911,066. In addition, the Company had deferred carrying charges of $3,457,037 and deferred depreciation expense of $610,573, which are working capital items, the treatment of which will be addressed in a later section.

Since the litigation concerning this item appears to be concluded, we shall allow the Company to include the net plant-in-service balance of $3,231,178 ($12,704,420-$9,473,242) and the accumulated depreciation of $2,911,066 in rate base as of June 1, 1984. On a 13-month average basis, the resulting jurisdictional increases in plant-in-service are $1,639,000 for 1984 and $3,141,000 for 1985. In addition, accumulated depreciation will increase by $1,479,000 and $2,843,000 for 1984 and 1985, respectively, on a jurisdictional basis.

In its projections, the Company also included **[*28]** the cost of the second reracking of the Turkey Point Expanded Fuel Storage Facilities in plant in service as of June 1985. Per Mr. Hudiburg's Exhibit No. 1-A, the Court ruled that Westinghouse would be responsible for the second reracking of the storage facilities. Since Westinghouse will bear the cost of the second reracking, there will not be any additional plant-in-service, in terms of dollars, upon which the ratepayer would be required to provide a return. We have determined, therefore, that the cost of the second reracking should be excluded from rate base. This results in a $4,250,000 decrease in plant in service, and a $51,000 reduction in accumulated depreciation for the year 1985.

3. Jurisdictional Separation Factors

As is more fully explained in the "Jurisdictional Separation" portion of this order, we decline to accept FPL's proposed separation factors based upon the Company's July 1983 forecast and instead utilized separation factors based upon the Company's December 1983 forecast. The resulting adjustments to reflect the approved separation factors are to reduce plant in service by $67,866,000 in 1984 and by $15,637,000 in 1985.

B. Accumulated Depreciation **[*29]** and Amortization

The amount of accumulated depreciation and amortization originally proposed by the Company was $1,677,294,000 for 1984 and $1,939,193,000 for 1985. The net adjustment to this account is an increase of $9,952,000 in 1984 and an increase of $37,467,000 in 1985.

	1984	1985
Amount Requested	$ (1,677,294,000)	$ (1,939,193,000)
Adjustments:		
1. Masonary Wall Repair	50,000	220,000
2. Turkey Point - Rerack No. 1	(1,479,000)	(2,843,000)
3. Turkey Point - Rerack No. 2		51,000
4. Separation Factors	13,363,000	3,471,000)
5. Turkey point - Cost of Removal	(14,395,000)	(14,942,000)
6. Depreciation Rates	(7,491,000)	(23,424,000)
Total Adjustments	(9,952,000)	(37,467,000)
Adjusted Accum. Depre. & Amort.	$ (1,687,246,000)	$ (1,976,660,000)

Adjustments No. 1, No. 2, No. 3, and No. 4 represent the effects on accumulated depreciation as a result of the previous adjustments made to plant-in-service.

1. Turkey Point Cost of Removal

In another matter related to the "Litigation Items," witness H. Williams testified that an error had been made in the original filing concerning the exclusion of all items subject to pending **[*30]** litigation. This error is related to the cost of removal of the Turkey Point steam generators that was included in accumulated depreciation in the jurisdictional amounts of $14,395,000 and $14,942,000 for 1984 and 1985, respectively. In our opinion, these amounts should be removed from accumulated depreciation until the pending litigation is concluded. This adjustment increases accumulated depreciation and results in a decrease in rate base for 1984 and 1985.

2. Depreciation Rates

The Company's filing reflected a level of accumulated depreciation based on revised depreciation rates submitted in Docket No. 830328-EU. In that docket, however, the Commission denied the Company's request to revise its depreciation rates and ordered that the Company continue to use its existing depreciation rates. As a result, the accumulated depreciation, as filed by the Company, is understated by $7,491,000 for 1984 and by $23,424,000 for 1985 on a jurisdictional basis. We find that this adjustment is appropriate to reflect the proper levels of accumulated depreciation for 1984 and 1985. As result of this decision, it is also necessary to increase the depreciation expense in the income **[*31]** statement by $10,366,000 and $11,013,000 for 1984 and 1985, respectively.

C. Net Utility Plant-in-Service

Net utility plant-in-service is comprised of utility plant-in-service, less accumulated depreciation and amortization. We find that the appropriate amount of net utility plant-in-service for test year 1984 is $5,555,475,000 and $5,876,717,000 for test year 1985.

D. Construction Work in Progress (CWIP)

The Company's investment in plant under construction can be accounted for by either of two methods. An Allowance for Funds Used During Construction (AFUDC) may be applied to the balance to be capitalized and later recovered through depreciation charges once the plant is placed in service. When this mehtod is chosen, the financial statements of the Company reflect income "credits" associated with AFUDC, but the Utility realizes no current cash earnings from the investment in CWIP. Alternatively, CWIP may be included as a portion of rate base. Where this treatment is allowed, CWIP generates cash earnings, which provide cash flow and an increase in coverage ratios. Of course, no AFUDC is taken on that portion of CWIP which is included in rate base.

In recent **[*32]** cases, we have recognized that both proponents of the inclusion of CWIP in rate base and those who resist its inclusion have advanced arguments having merit in support of their respective positions, and those arguments have been repeated in this case. Where necessary to provide and maintain adequate financial integrity, we have included what we deem to be an appropriate amount of CWIP in rate base for the purpose of maintaining the financial integrity of the Company on the conviction that the resulting financial ratings of the Utility would lead to a lower cost of capital. It follows, however, that only that amount of CWIP needed to assure adequate financial integrity should be placed in rate base. This criterion, and not the Company's effort to arrive at an amount representative of future balances, will govern our decision.

In FPL's last rate case, we included $267,631,000 of CWIP in rate base because we found that amount would provide the cash flow necessary to assure the Company's financial integrity. In that case, FPL's projected 13-month average total company CWIP for 1982 was $1,234,196,000, most of which was related to its then uncompleted St. Lucie 2 nuclear **[*33]** unit. Utilizing the financial integrity model developed by Dr. Eugene Brigham, our Staff concluded that the inclusion of the $267,631,000 of CWIP in rate base would allow FPL to achieve times interest earned (TIE) coverage ratios of 3.1 and 1.6, with and without AFUDC, respectively. We found that those ratios, if achieved, would provide FPL with adequate financial integrity to maintain its A bond rating. In this case, FPL's total jurisdictional request for CWIP in rate base is $331,951,000 for 1984 and $339,911,000 for 1985.

Following FPL's last full rate case, the Company's investment in St. Lucie No. 2 was placed in rate base in a limited proceeding (See Order No. 12348), which had the effect of significantly decreasing the amount of CWIP earning AFUDC. This action, coupled with relatively stable bond yields, declining construction expenditures and rising internal cash generation should result in FPL achieving higher TIE ratios, lower AFUDC/net income ratios and higher returns on equity (ROE) in both 1984 and 1985. Based upon these trends, Staff witness Scott Wilson concluded that CWIP should be included in rate base in amounts necessary to obtain 1985 "market" indicators of: **[*34]**

TIE including AFUDC	3.3x
TIE excluding AFUDC	2.8x
AFUDC/NI	30%
Earned ROE	14.5%

Evidence in the record (Ex. 10-E) indicated that FPL would have investments in projects not earning AFUDC in the amount of $98,041,000 for 1984 and $106,590,000 for 1985. Utilizing the financial integrity test, our Staff determined that including the projects not earning AFUDC in rate base should result in achieved "market" ratios in both 1984 and 1985 that exceeded the financial indicators testified to by Mr. Wilson. Accordingly, our Staff recommended that we include in rate base $98,041,000 of CWIP not otherwise earning AFUDC in 1984 and $106,590,000 of that type CWIP in 1985.

As announced repeatedly in our more recent electric rate cases, our decision to include CWIP in rate base has been founded on our overriding concern of providing the particular utility with an opportunity to achieve and maintain adequate financial integrity. In this case, we have determined that even without the inclusion of any CWIP in rate base, FPL should be able to maintain its financial integrity in 1984 and 1985. Accordingly, we find that it is not necessary to include any CWIP or Nuclear Fuel in Process **[*35]** (NFIP) in rate base in either 1984 or 1985 in order to maintain FPL's financial integrity.

We understand from this record that FPL's inability to earn AFUDC on the amounts previously described is the result of several factors, including the manner in which the Company keeps its books and governmental rules or regulations prohibiting or limiting the utility's ability to earn AFUDC on projects of limited duration or cost. We are not unsympathetic to this situation and have increased FPL's working capital allowance by $854,000 in 1984 and by $195,000 in 1985 to account for certain non-AFUDC projects we found should be reclassified as working capital related. With regard to the remaining non-AFUDC projects, the record is not sufficiently adequate to determine with precision which projects are ineligible for AFUDC because of the Utility's accounting practices and which, if any, are ineligible because of governmental regulation. In any event, we shall, in the near future, initiate a workshop to investigate possible methods of reducing or eliminating projects ineligible for AFUDC due to governmental rule or regulation, if any, and in the meantime any rules we have are waived **[*36]** so that the Company can appropriately use AFUDC on projects under construction. Our final policy and decision on this subject will await further orders as a result of the workshop and further hearings, if necessary.

E. Property Held For Future Use

FPL originally proposed to include $37,393,000 and $38,717,000 for property held for future use for 1984 and 1985, respectively. As a result of our adjustments to the Company's jurisdictional separation factors, plant held for future use is reduced $393,000 in 1984 and $92,000 in 1985. Accordingly, we approve plant held for future use in the amount of $37,000,000 for 1984 and $38,625,000 for 1985.

F. Nuclear Fuel (Net)

FPL has proposed that the jurisdictional amount of net nuclear fuel to be included in rate base in 1984 is $166,066,000 and $219,923,000 in 1985. These amounts are comprised of the following accounts:

120.1 & 120.2	In process of refinement and stock
120.3	In reactor
120.4	Spent fuel
120.5	Accumulated Amortization

Based upon the record in this case, we find that Nuclear Fuel in Process (NFIP) is similar to and should be treated in the same manner as CWIP. That is to say that NFIP should not **[*37]** be included in rate base unless its inclusion is necessary to maintain the financial integrity of the Company. In accordance with our earlier discussed conclusions regarding the inclusion of CWIP in rate base, we find that it is not necessary to include any NFIP in rate base in order to maintain FPL's financial integrity. After we remove $61,079,000 of NFIP and $4,136,000 related to our adjustments to FPL's jurisdictional separation factors, approved net nuclear fuel included in rate base for 1984 is $100,851,000. For 1985, we have removed $62,877,000 of NFIP and $699,000 related to the jurisdictional separation factors leaving approved net nuclear fuel for 1985 in the amount of $156,347,000.

G. Net Utility Plant

Based upon the adjustments discussed above, total net utility plant for test year 1984 is $5,693,326,000, while the approved amount for 1985 is $6,071,689,000.

H. Working Capital

A traditional component of rate base is the value of the working capital committed to utility operations. In recent cases we have applied the balance sheet approach to determine the working capital allowance, as opposed to the "formula" approach previously utilized. **[*38]** The balance sheet approach generally defines working capital as current assets and deferred debits that are utility related and do not already earn a return, less current liabilities, deferred credits and operating reserves that are utility related and upon which the Company does not already pay a return.

FPL has proposed a working capital allowance of $201,861,000 for 1984 and $190,746,000 for 1985. We have determined that the appropriate working capital allowances are $120,240,000 for 1984 and $112,721,000 for 1985. Our adjustments are set forth as follows:

	1984	1985
Working Capital Allowance Per Company	$201,861,000	$190,746,000
Adjustments:		
1. Litigation Items-Turkey Point Spent Fuel Pits	430,000	673,000
2. Power Resources Accrued Liabilities	(17,000)	(28,000)
3. Unit Power Sales Capacity Charge	9,747,000	25,347,000
4. Short Term Debt Interest	358,000	436,000
5. Unbilled Revenue	2,835,000	2,897,000
6. Gain on Sale	(10,963,000)	(8,560,000)
7. Prepaid Interest on Commercial Paper	(179,000)	(168,000)
8. Conservation Clause Overrecovery	(240,000)	
9. Oil Backout Clause Overrecovery	(4,775,000)	(2,655,000)
10. Pole Attachment Rental Expense	(4,503,000)	(5,518,000)
11. Employee Loans	(1,402,000)	(2,401,000)
12. Oil Inventory	(24,418,000)	(37,557,000)
13. Unavailable Oil	(9,643,000)	(10,010,000)
14. Cash	(115,000)	(331,000)
15. Construction Working Funds	(551,000)	(526,000)
16. Accounts Payable	(16,000,000)	(20,400,000)
17. Bechtel Advance Payments	(10,338,000)	(9,827,000)
18. Jobbing Account	(6,912,000)	(7,319,000)
19. Accounts Receivable in CWIP	854,000	195,000
20. Separation Factor	(5,729,000)	(1,209,000)
21. Energy Store	(60,000)	(60,000)
22. Operating Reserves		(1,060,000)
Total Adjustments	(81,621,000)	(78,025,000)
Adjusted Working Capital	$120,240,000	$112,721,000

[*39]

1. Litigation Items

The previously discussed adjustments to the litigation items related to the spent nuclear fuel pits at Turkey Point result in an increase in working capital. On June 1, 1984, the Company received a settlement from Westinghouse of $12,231,387 which included $2,758,145 of court-awarded interest. As of June 1, 1984, the Company had recorded deferred carrying charges of $3,457,037 and deferred depreciation expense of $610,573, which is a total deferral of $4,067,610. After reductions for the interest recovered and for a portion of the deferred depreciation no longer appropriate for recovery, the net underrecovered deferral is $855,000 at June 1, 1984. Consistent with our decision to allow the inclusion of the net investment, after settlement, related to the spent nuclear fuel pits, we shall allow the Company to recover the net deferred costs over a five-year period. On a jurisdictional 13-month average basis, working capital should be increased by $430,000 in 1984 and by $673,000 in 1985, which represents a five-year amortization beginning in June 1984. This also results in an increase to the depreciation and amortization expense of $98,000 and **[*40]** $168,000 in 1984 and 1985, respectively.

2. Power Resources Accrued Liabilities

Per Exhibit 2-A, FPL has proposed an adjustment to working capital to correct "accrued liabilities - power resources" to correct an error in its original filing. The adjustment, which we approve, reduces working capital by $17,000 in 1984 and by $28,000 in 1985.

3. Unit Power Sales Capacity Charge

FPL's original filing incorrectly assumed that the payment of Unit Power capacity charges to the Southern Company was made with a one-month lag, when, in fact, the payment is made in the month the expense is incurred. The necessary correction is to increase working capital by $9,747,000 in 1984 and by $25,347,000 in 1985.

4. Short-Term Debt Interest

In its original filing, FPL incorrectly assumed that short-term debt interest was paid with a one-month lag. The necessary correction is to increase working capital by $358,000 in 1984 and by $436,000 in 1985.

5. Unbilled Revenue

In preparing its original filing, FPL failed to synchronize the starting date used in forecasting unbilled revenues with the starting date used in forecasting its other projections. The adjustment necessary **[*41]** to correct this error is to increase working capital by $2,835,000 in 1984 and by $2,897,000 in 1985.

6. Gain on Sale of Land

As evidenced by Exhibit No. 10-B, FPL has included in working capital the unamortized gains on the sale of future use property and on a portion of St. Lucie No. 2 in the amounts (system) of $7,292,322 for 1984 and $6,595,457 for 1985. FPL has not, however, included any of the actual or imputed gains on the sale or transfer of Account 101 property or future use property, which are $11,418,500 for 1984 and $8,813,633 for 1985. FPL states that unamortized imputed gains on transfers to subsidiaries should not be included in working capital because the transactions generate no cash. It also contends that the actual gains from the sale of utility plant in Account 101 should not be included in working capital based on the premise that the ratepayers only pay for the use of Utility assets which are owned by the stockholders. Therefore, FPL asserts that any gains on this type of property should be attributed to the stockholders. Public Counsel, on the other hand, states that all actual and imputed gains from the sale or transfer of both Utility property **[*42]** and future use property should be included above the line for ratemaking purposes unless the property was never included in rate base.

We have addressed the issue of the actual sale of Utility property in FPL's last full rate case and in a number of other rate cases. In those cases, we determined that gains or losses on the disposition of property devoted to, or formerly devoted to, public service should be recognized above the line and that those gains or losses, if prudent, should be amortized over a five-year period. We reaffirm our existing policy on this issue.

FPL has also transferred certain Utility and future use property to its subsidiary, West Flagler Investment Corporation (WFIC). Because the Company transferred the assets to WFIC at book value rather than through a sale, no cash was realized and no imputed gains were included in FPL's rate filing. FPL witness H. Williams acknowledged though that, had the property been sold to an unrelated third party, any unamortized gain would have been included in working capital.

We believe that any transfer of property to a subsidiary or affiliated company should be treated as though the property was actually sold to **[*43]** that party and that any imputed gains on the transfer should be recognized and be reflected in working capital. This treatment is consistent with our decision in Tampa Electric Company's 1982 rate case (Docket No. 820007-EU, Order No. 11307) and will serve to eliminate any incentive a utility might have of purchasing and holding in rate base property which could later be transferred to an affiliated company that would realize a gain on the property's subsequent sale. The net effect of this adjustment is to reduce working capital by $10,963,000 in 1984 and by $8,560,000 in 1985. The Company retains the option to sell the surplus property to a third party, but a transfer at the Company's option should not deprive the ratepayers of their fair share of gains.

7. Prepaid Interest on Commercial Paper

When FPL borrows through commercial paper, it prepays the interest. Thus, if the Company borrowed $1,000,000 at 10% interest, it would actually only receive $900,000, assuming the loan was for one year. FPL would then include the $100,000 interest as a prepayment in working capital (an increase) and would include $1,000,000 as short-term debt in its capital structure. When the **[*44]** loan was repaid, FPL would return $1,000,000 to the lender.

Consistent with our treatment of this issue in Tampa Electric Company's most recent rate case, we shall exclude prepaid interest from the Company's working capital allowance. The appropriate adjustment is to reduce working capital by $179,000 in 1984 and by $168,000 in 1985.

8. Conservation Clause Overrecovery

In this case, FPL has excluded from its calculation of working capital a $240,000 net overrecovery in its energy conservation cost recovery (ECCR) clause. FPL contends that both overrecoveries and underrecoveries should be excluded from working capital because it receives interest on underrecoveries and pays interest on overrecoveries. During his cross-examination, FPL witness H. Williams acknowledged that, if overrecoveries were excluded, working capital would be increased and the Company would earn a return on the amount of the underrecovery that was excluded. Stated simply, the ratepayers would provide the interest that the Company return to them in the consrvation clause proceedings for overrecoveries.

In Order No. 9273, Docket No., 74680-CI, we determined that interest should be applied to over/underrecoveries **[*45]** in order to counter any incentive to bias projections in either direction. If the ratepayer has to provide the interest on both over/underrecoveries, the Company will have no incentive to make its projections as accurate as possible.

In FPL's last rate case and in subsequent rate cases involving other electric utilities, we have consistently determined that adjustment clause overrecoveries should be included as a reduction to working capital. The appropriate adjustment is to reduce working capital by $240,000 in 1984. No adjustment is necessary for 1985 because the Company has properly excluded its projected 1985 underrecovery of $36,000.

9. Oil Backout Clause Overrecovery

FPL has projected net overrecoveries of $4,775,000 for 1984 and $2,655,000 for 1985 in its Oil Backout Recovery Clause that have been excluded from its calculation of working capital. Consistent with our decision in the previous issue, the appropriate adjustments are to reduce working capital by $4,775,000 for 1984 and by $2,655,000 for 1985.

10. Pole Attachment Rental Expense

FPL has included in its working capital allowance $4,503,000 in 1984 and $5,518,000 in 1985 of rent receivable **[*46]** from parties contracting with it to jointly utilize its poles for cablevision, telephone lines and the like. The receivable exists because of FPL's practice of billing the pole attachment rents in arrears on an annual basis. In FPL's last rate case, we stated that we thought it inequitable for FPL to expect its ratepayers, who are billed monthly, to bear the carrying costs associated with billing for pole attachment rents on an annual basis in arrears. We have not changed our policy. The necessary adjustments are to reduce working capital by $4,503,000 in 1984 and by $5,518,000 in 1985.

11. Employee Loans

FPL has included in working capital allowance $8,165,690 for 1984 and $9,889,544 for 1985 employee loans in Account 143, Other Accounts Receivable. These interest-free loans are for financing employee vehicles used on company business, assisting employees with the cost of relocating, and for financing employees' job-related educational efforts. FPL maintains that these loans are related to specific, legitimate business purposes and are necessary to retain qualified employees. Public Counsel contends that the loans are not related to the provision of electrical service **[*47]** and that they, therefore, should not earn a return as a component of working capital. In FPL's last rate case, we agreed with Public Counsel and eliminated all such employee loans from working capital.

In this case, FPL spent considerable time and effort attempting to demonstrate that the employee loans for vehicles used in company operations were a cost-effective alternative to the Company purchasing and maintaining the vehicles itself. We believe that the Company successfully demonstrated that the employee loans for vehicles are utility related and a cost-effective alternative to owning the necessary vehicles. Accordingly, we shall include in working capital the $6,763,000 related to contract vehicle loans for 1984. FPL and projected employee loans for contract vehicles to be $8,023,000 in 1985, which is approximately a 19% increase over the amount allowed for 1984. In the absence of competent, substantial evidence to specifically support an almost 19% increase in this program in one year, we decline to approve FPL's 1985 projected amount. Rather, we shall approve for 1985 the approved amount for 1984 increased by the approved CPI and customer growth percentage for 1984. **[*48]**

We shall continue to exclude employee loans related to relocations and educational assistance. The net effect is to reduce working capital by $1,402,000 in 1984 and by $2,401,000 in 1985.

12. Fuel Inventory

Fuel inventory is an element of working capital and, as such, the Company should earn a return on its investment in fuel stocks that are reasonably and prudently included in fuel inventory. Determining the amount of fuel inventory to be included in rate base involves a balancing process with many subjective factors. On the one hand, there is the overriding concern that fuel inventory be adequate to reasonably ensure the continuous generation of electricity and to avoid disruptions of service. On the other hand, is the desire to not require the ratepayers to support investment in fuel inventory beyond the amount necessary for the dependable operation of the generating system. In making this determination, it is necessary to examine the fuel mix of the Utility, historical consumption rates, potential consumption rates, the source-to-plant distance for each type of fuel, and potential bottlenecks that may impede the flow of fuel in the transportation system. **[*49]** Additionally, we must examine the potential for labor and weather-related disruptions at the source of the fuel as well as along the transportation chain, and we must be particularly careful to not allow excessive estimates to be included using forecasted data.

FPL's original filing in this case included a June, 1983 projection of fuel cost rates and volumes to be utilized in calculating the fuel inventory component of its working capital allowance. Subsequent to its actual rate case filing, FPL performed a re-evaluation of its fuel inventory needs, which utilized a "building-block" approach. Later still, approximately a week prior to the beginning of the hearing, FPL filed a computer-generated, quantitative analysis for heavy oil inventory. The Company attempted to introduce this quantitative analysis into the record through Mr. Cook, but Public Counsel's objection that the document should be rejected because there was inadequate time for the parties to study it was sustained.

Accordingly, we shall direct our efforts at analyzing FPL's so-called "building-block" inventory approach.

Prior to beginning our inventory analysis, though, a review of our decision on this issue in **[*50]** FPL's 1982 rate case may be instructive. In its 1982 filing FPL requested in inventory 5,861,000 barrels of heavy oil at an average price of $32.20/barrel for a total of $188,711,000. FPL's requested light oil inventory for its 1982 case was 854,000 barrels at a total value of $32,745,000. In that case, we found that:

FPL's fuel inventory policy, as stated, is vague and subjective to such a degree as to not provide a valid benchmark, with which to evaluate the Company's fuel inventory levels in the 1982 test year.

Accordingly, we used the mid-point, or 52.5 days, of the 40 to 65 burn days of inventory that the Company said it tried to maintain as necessary in establishing its approved inventory levels. Utilizing this benchmark, we approved 4,941,000 barrels of heavy oil, plus 466,000 barrels of non-recoverable, tank bottom oil for a total of 5,407,000 barrels of heavy oil in inventory. In calculating the Company's light oil inventory (used primarily for peakers), we multiplied 52.5 days times FPL's highest daily burn rate for either 1981 or 1982 of 4,184 barrels per day, which, when added to 71,000 barrels of non-recoverable light oil, resulted in an approved light oil inventory **[*51]** of 291,000 barrels.

In Order No. 12348, which addressed the inclusion of St. Lucie No. 2 in FPL's rate base, we determined that this fourth nuclear generating unit would displace heavy oil inventory equal to 1,210,178 barrels. Additionally, FPL witness Cook testified that unrecoverable heavy oil should have been established at 319,000 barrels rather than the 466,000 barrels allowed in the main case. These two adjustments led to an approved heavy oil inventory, including non-recoverable oil, of 4,049,822 barrels after the commercial operation of St. Lucie 2.

In the present case, utilizing its "building-block" approach, FPL requested 3,378,000 barrels of heavy oil in inventory in 1984 and 3,049,000 barrels in 1985. When the 319,000 barrels of unrecoverable heavy oil, now expensed through the fuel adjustment clause, were removed this left FPL's request at 3,059,000 barrels for 1984 and 2,730,000 barrels for 1985. FPL's light oil inventory request was 537,000 barrels for 1984 and 534,000 barrels in 1985.

Heavy Oil Inventory

FPL's building-block analysis is composed of three blocks. The first block contains unavailable oil and volumes of oil FPL has calculated **[*52]** are necessary in its storage tanks to keep them from either blowing or floating away due to the high winds, heavy rains or sea surges associated with hurricanes. The parties had stipulated that unavailable heavy oil consisted of 319,000 barrels and in its brief FPL reduced its request for hurricane protection from 808,000 barrels to 369,000 barrels, bringing the total for the first block to 688,000 barrels for both 1984 and 1985. Based upon the evidence in this record, we approve these amounts.

FPL's second building-block is directly related to planned burn and attempts to take into consideration cargo size constraints, physical constraints at ports, terminals and plants, lead times for transfers from terminals to plants, and typical delays in deliveries. FPL determined that the second block should contain a volume level equivalent to 30 days planned burn. Based upon PROMOD computer projections, FPL forecast 30 days planned burn to equate to 1,615,000 barrels in 1984 and 994,000 barrels in 1985. FPL's forecast 30-day burns were calculated using a 12-month average. We have recalculated the 30-day burns utilizing 13-month averages and approve block 2 amounts of 1,568,191 barrels **[*53]** for 1984 and 1,005,429 barrels for 1985.

The Company's third building-block of heavy oil which it maintains should be kept in inventory is to minimize the adverse consequences of major unplanned events. These "events" and the amounts requested each year are as follows:

		1984	1985
1.	Unplanned fossil outages	116,000 bbls	83,000 bbls
2.	Loss of 1 nuclear unit for 3 weeks	556,000	556,000
3.	Simultaneous loss of second nuclear unit for 2 weeks	371,000	371,000
4.	Loss of interruptible gas for 1 week during winter heating season	32,000	42,000
5.	Loss of coal-by-wire in 1985	0	315,000
Total		1,075,000	1,367,000

We have made certain adjustments to FPL's requested block 3. First, while we acknowledge that it is desirable for FPL to carry sufficient oil inventory to replace the loss of one nuclear unit for the period of time required to receive spot fuel, we have, based upon the record, reduced the period of time required to receive spot fuel from the 21 days requested by FPL to 18 days. Furthermore, we reject the 315,000 barrels associated with the loss of coal-by-wire in 1985 as being **[*54]** conjectural and, therefore, unnecessary in view of the amounts approved for the proceeding four contingencies. Our adjustments reduce block 3 by 79,429 barrels in 1984 and by 394,429 barrels in 1985. Our net adjustments result in approved heavy oil inventories of 2,932,762 barrels in 1984 and 2,347,000 barrels in 1985. In calculating the value of these inventories, we have utilized FPL's more recent December 1983 price forecast, which was included in its calculation of April-September, 1984 fuel adjustment projections. These amounts are $29.36/barrel in 1984 and $30.58/barrel in 1985. Thus, we approve for inclusion in working capital heavy fuel inventory of $86,105,892 in 1984 and $71,771,260 in 1985.

Light Fuel Oil

In its initial filing, FPL requested 537,000 barrels of light oil inventory at $37.18/barrel for a total of $19,965,000 in 1984, and 534,000 barrels at $37.23/barrel for a total of $19,879,000 in 1985. FPL justifies these requests by saying that an average of 83,000 barrels of light oil is required each year for hurricane protection and that over 450,000 barrels is required each year to meet contingencies.

Rather than merely allow FPL the 12-month average **[*55]** of light oil to meet the required protection during the months of the hurricane season, we shall allow in inventory the 144,041 barrels the Company deems necessary during the hurricane season. We do this because we consider it economically impracticable to shift inventory so substantially during the year.

Light oil is used primarily in "peaking" units, the vast majority of which are industrial jet engines connected to electrical generators. Their virtue is a relatively low capital cost per KW. Their liability is an extremely high cost per KWH generated due to their high cost fuel (light oil) and their relatively poor heat rate. Accordingly, they are normally used to provide generation: 1) while available lower-cost generation is being brought on line; 2) in geographic areas where lower-cost generation cannot be "imported"; and 3) when no lower-cost generation is available and peaking power must be utilized to meet system demand. Thus, peaking generation and, hence, light oil are normally used as a "last resort." This is borne out by the fact that only 71,855 and 84,410 barrels of light oil were burned in 1982 and 1983, respectively. Examining actual and projected data for **[*56]** the five-year period January 1980-December, 1985, we find that August, 1980 had the highest daily burn rate of 4,107 barrels for the period. Since August, 1980, FPL has added a new nuclear plant, has significantly larger coal-by-wire imports and a larger reserve margin, each of which argue for a lower probability of having to resort to the extensive use of peaking generation. In view of these factors, we consider FPL's claimed need for over 450,000 barrels of light oil per year to meet contingencies to be excessive and unsupported by competent, substantial evidence. Accordingly, we shall apply the generic light oil policy stated in Order No. 12645 to evaluate FPL's light fuel oil inventory request.

The generic light fuel oil policy provides for an inventory level equivalent to 30 days at a reasonably high average daily rate of burn. Utilizing FPL's highest average daily burn during the 1980-1985 period, results in a 30-day burn level of 123,210 barrels. When we add this amount to the previously discussed hurricane protection level, we approve a total light oil inventory level of 267,251 barrels each for the years 1984 and 1985. These amounts, when multiplied times **[*57]** the revised price levels of $37.46/barrel in 1984 and $37.43/barrel in 1985 result in approved light oil inventories of $10,011,222 and $10,003,205 for 1984 and 1985, respectively. Total oil inventory levels, then, are $96,117,114 for 1984 and $81,774,465 for 1985. Our adjustments necessitate a $24,418,000 reduction to working capital in 1984 and a $37,557,000 reduction in 1985.

13. Unavilable Oil

Unavailable or non-recoverable oil is the collective volume of oil at the bottom of each tank that is not recoverable due to the piping and valve arrangements of the tanks as well as to the sediment that has settled to the tank bottoms. Pursuant to Order No. 12645, entered in the generic fuel docket, FPL has expensed the value of unavailable heavy and light oil through the fuel adjustment clause (see Order No. 13092). However, because Order No. 13092 was entered subsequent to FPL's filing in this case, the Company's filing still includes the value of the unavailable oil in both 1984 and 1985. The parties have stipulated and we accept that the appropriate adjustments to remove nonrecoverable oil are 319,000 barrels of heavy oil and 32,000 barrels of light oil, the jurisdictional **[*58]** value of which is $9,643,000 in 1984 and $10,010,000 in 1985.

14. Cash

FPL has requested "cash balances" of $3,095,309 for 1984 and $3,469,422 for 1985.

The cash balance projections are essentially a consequence of FPL's other projections. FPL's 1983 actual average cash balance was $2,896,371. Absent record evidence that the yearly increases in this account are appropriate, we shall approve balances that more closely approximate the expected inflation in those years. Accordingly, we approve cash balances of $3,000,000 in 1984 and $3,150,000 in 1985, which require a reduction of working capital of $115,000 in 1984 and a reduction of $331,000 in 1985.

15. Construction Working Funds

FPL has included in working capital $551,000 in 1984 and $526,000 in 1985 related to working funds for construction, which represent monies advanced to Ebasco Services and United Engineering for the stated purpose of reducing the cost of construction projects those companies are doing for the Utility by eliminating their need to seek financing elsewhere at a higher cost. The Company contends that these advance payments are made only when they will serve to reduce the cost of construction **[*59]** projects.

We see no evidentiary basis supporting FPL's proposition that this methodology is cost-effective and in the interest of either the Company or its ratepayers. When one considers the approximate doubling of the revenue requirement caused by the tax effect, it appears that FPL's financing cost rate would have to approximate one-half of that of the construction companies before there could begin to be a savings to the utility or its customers. There being no such evidence in the record, we shall reduce working capital by $551,000 in 1984 and $526,000 in 1985.

16. Accounts Payable

FPL has included $84,335,273 of cost-free accounts payable in their working capital calculation for 1984 and $79,854,652 for 1985. These payables consist of fuel payables and other accounts payable. The Company states that the fuel payables are based on the monthly relationship between fuel payable and purchases based on actual data. The resulting relationship is then applied to the projected fuel purchases from the PROMOD model.

Public Counsel contends that the Company's accounts payable are under-projected and uses a specific comparison to demonstrate his point. He points **[*60]** out that 1982 actual accounts payable were $98,600,000 and increased to $100,300,000 in 1983. Public Counsel submits that it is unlikely that this account will decrease by some $16,000,000 from 1983 to 1984.

We agree with Public Counsel. With fuel costs increasing from year to year, one would expect that fuel payables would increase as well. There is no competent substantial evidence in this case to support the Utility's projections that payables will decrease in the face of rising costs. The appropriate adjustment is to reduce working capital $16,000,000 for 1984 and by $20,400,000 for 1985 on the assumption that payables will remain at their 1983 actual level.

17. Bechtel Advance Payments

The Company has included in working capital deferred debits of $10,403,225 in 1984 and $9,849,602 in 1985 related to advance payments it makes to Bechtel to cover construction costs in the following month.

This issue is similar to the earlier discussed Construction Working Funds issue and, as there, we see no competent substantial evidence proving that making advance payments to this construction firm is cost-effective and, therefore, beneficial to either the Utility or its ratepayers. **[*61]** Accordingly, we reduce working capital $10,338,000 in 1984 and $9,827,000 in 1985.

18. Jobbing Account

FPL has included in its calculation of working capital $8,565,245 in 1984 and $9,069,524 in 1985 related to Account No. 174.100 - the jobbing account. The Company contends that this account represents work done for and billed to customers, as well as the accumulation of amounts to be recovered from third parties, which are primarily insurance companies. Public Counsel, on the other hand, contends that this account does not represent an asset devoted to the provision of utility service and, further, that any return required should be recovered from those for whom the jobs were performed.

We agree with Public Counsel that this account is non-utility. In fact, it appears from the record that this account relates to work FPL does as an independent contractor when, for example, it installs a customer-owned transformer for an industrial customer or installs distribution lines within an industrial customer's property. The appropriate adjustment is to net Account 174 - Jobbing Account and Account 242 - Miscellaneous Liabilities, which results in a reduction to working capital **[*62]** of $6,912,000 in 1984 and a reduction of $7,319,000 in 1985.

19. Accounts Receivable in CWIP

This issue involves the working capital impact of our earlier discussed decision to not include any CWIP in rate base. The appropriate adjustment is to increase working capital by $854,000 in 1984 and by $195,000 in 1985.

20. Jurisdictional Separation Factors

As was previously discussed in the plant-in-service section of this order and as will be more thoroughly explained in a later section devoted to Jurisdictional Separation, we have modified the jurisdictional separation factors proposed by FPL. The working capital adjustments necessary to reflect our modification are a reduction of $5,729,000 in 1984 and a reduction of $1,209,000 in 1985.

21. The Energy Store

In its original filing, FPL included in its calculation of working capital $60,000 for each test year related to inventory at its Energy Stores. Subsequently, the Company, Staff and Public Counsel agreed that these amounts should be removed. We approve a reduction to working capital of $60,000 each for 1984 and 1985.

22. Operating Reserves

FPL has included in its calculation of working capital **[*63]** deferred debits relating to operating reserves in the amount of $8,839,000 for 1984 and $8,647,000 for 1985. These deferred debits are related to expected future payments to be made from a self-insured injuries and damages reserve.

We can find no competent substantial evidence to support these expected payments decreasing from 1984 to 1985 in the face of almost every other cost increasing. Accordingly, we shall approve the 1984 amount of $8,839,000 but shall increase the 1985 amount by multiplying the 1984 amount times the 9.82% CPI and customer growth factor projected from 1984 to 1985. This results in a 1985 amount of $9,706,000, which requires a $1,060,000 reduction to working capital for the year 1985.

Adjusted Working Capital

The net effect of our adjustments is to reduce working captial by $81,621,000 in 1984 and by $78,025,000 in 1985. These adjustments result in approved working capital allowances of $120,240,000 in 1984 and $112,721,000 in 1985.

I. Total Rate Base

Based upon total test year net utility plant of $5,693,326,000 and working capital of $120,240,000, the total 1984 test year rate base is $5,813,566,000. The 1985 total rate base is $6,184,410,000 **[*64]** based upon net utility plant of $6,071,689,000 and working capital of $112,721,000.

FAIR RATE OF RETURN

The Commission must establish the fair rate of return which the Company should be authorized to receive on its investment in rate base. The fair rate of return should be established so as to maintain the Company's financial integrity and to enable it to acquire needed capital at reasonable costs.

Capital Structure

The ultimate goal of providing a fair return is to allow an appropriate return on equity investment in rate base. Because, as a general rule, sources of capital cannot be clearly associated with specific utility property, the Commission has traditionally considered all sources of capital (with appropriate adjustments) in establishing a fair rate of return.

The establishment of a utility's capital structure serves to identify the sources of capital employed by a utility, together with the amounts and cost rates associated with each. After establishing the sources of capital, all capital costs, including the cost of equity capital, are allocated according to their relative proportion to total cost of capital. The weighted components are then **[*65]** added to provide a composite or overall cost of capital. The weighted cost of capital multiplied by the net utility rate base produces an appropriate return on rate base, including a return on equity capital in rate base. The return is also sufficient to recover the annual cost of other types of capital, including debt.

Since a return on all sources of capital is provided by this treatment, actual debt and similar capital costs are not included in test year operating expenses, but are treated "below the line." This assures that such capital costs are not double-counted for ratemaking purposes.

An appropriate capital structure is both economical and efficient. Such a capital structure should minimize the cost of capital by obtaining capital through an appropriate balance of equity and the other components. The capital structure used for ratemaking purposes for a particular company should bear an appropriate relationship to the actual sources of capital to the Company.

Consistent with our decision to employ projected test periods in this case, we have decided to utilize the capital structures projected by the Company to be in place in the years 1984 and 1985. We have adjusted **[*66]** the system capital structure to remove capital that is not being utilized to fund the jurisdictional rate base. Such adjustments are necessary to reconcile rate base with capital structure. The types and proportions of capital will be developed in a following schedule.

We have also determined to use 13-month average capital structures with average cost rates.

Approved Capital Structure and Fair Rate of Return

Based upon our review of the record, we approve the following capital structures for 1984 and 1985:

Florida Power and Light Company
Capital Structure
13-Month Average
1984

Class of Capital	Projected Average $ Amount	Percentage of Total Capital	Cost Rate	Weighted Cost Rate
	(000)	%	%	%
1. Long-Term Debt	2,234,039	38.4280	10.76	4.1349
2. Short-Term Debt	39,701	0.6829	10.08	0.0688
3. Preferred Stock	422,479	7.2671	9.10	0.6613
4. Customer Deposits	114,424	1.9682	7.30	0.1437
5. Common Equity	1,817,934	31.2705	15.60	4.8782
Tax Credits - Zero Cost	5,864	0.1009	0.00	0.000
Tax Credits - Weighted Cost	372,282	6.4037	10.56	0.6764
7. Deferred Income Taxes	806,645	13.8787	0.00	0.0000
Total	$5,813,568	100.00		10.5633

[*67]

RANGE ON RETURN ON EQUITY IS PLUS OR MINUS 1% RANGE ON OVERALL RATE OF RETURN IS 10.23% to 10.90%

Florida Power and Light Company
Capital Structure
13-Month Average
1985

Class of Capital	Projected Average $ Amount	Percentage of Total Capital	Cost Rate	Weighted Cost Rate
	(000)	%	%	%
1. Long-Term Debt	2,206,840	35.6839	10.64	3.7968
2. Short-Term Debt	45,296	0.7324	10.59	0.0776
3. Preferred Stock	451,061	7.2935	9.20	0.6710
4. Customer Deposits	126,717	2.0490	7.27	0.1490
5. Common Equity	1,983,498	32.0726	15.60	5.0033
6. Tax Credits - Zero Cost	5,454	0.0882	0.00	0.000
Tax Credits - Weighted Cost	416,707	6.7380	10.40	0.7006
7. Deferred Income Taxes	948,836	15.3424	0.00	0.0000
Total	$6,184,410	100.00		10.3983

RANGE ON RETURN ON EQUITY IS PLUS OR MINUS 1% RANGE ON OVERALL RATE OF

RETURN IS 10.05% to 10.74%

1. Cost of Long-Term Debt

The projected long-term debt interest rates filed by the Company were accepted. Based upon our reconciliation of the capital structure with the approved rate base, the appropriate long-term debt component of the capital structure is a 13-month **[*68]** average balance of $2,234,039,000 with a cost rate of 10.76% for 1984 and $2,206,840,000 with a cost rate of 10.64% for 1985.

2. Short-Term Debt

The Company's proposed interest rate for short-term debt has been adjusted to recognize the effective interest rate attributable to issuing commercial paper at a discount. FPL's short-term debt is approved at $39,701,000 with a cost rate of 10.08% for 1984 and $45,296,000 at 10.59% for 1985.

3. Cost of Preferred Stock

The Company's proposed cost rate for preferred stock has been accepted. The appropriate level and cost of preferred stock for 1984 is $422,479,000 at 9.10% and, for 1985, it is $451,061,000 at 9.20%.

4. Customer Deposits

We routinely consider, for ratemaking purposes, only the jurisdictional percentage of a given account, or that amount related to the utility's retail customers. In this case, FPL's wholesale customers are not required to make deposits and should not benefit by an allocation of the relatively lower cost customer deposits, which are supplied solely by the retail customers. Public Counsel proposed in this case to allocate all customer deposits to the final jurisdictional **[*69]** capital structure without regard to any rate base reconciliation adjustments. This proposal assumed that all customer deposits, being furnished solely by Florida's jurisdictional retail customers, should not be reduced for any rate base disallowance, particularly in a case such as this based upon projected data. Although implicitly attractive, this proposal would ignore the fact that sources of capital, once received by the Company, are intermingled and support all operations. We do, however, agree that all customer deposits remaining after reconciliation of capital structure and rate base belong in the jurisdictional capital structure. We therefore conclude that, in this case, the wiser course is to continue our present practice and approve customer deposits of $114,424,000 at 7.30% for 1984 and $126,717,000 at 7.27% for 1985. These interest rates recognize that, although the established rate is 8%, the existence of inactive accounts results in a lower effective rate.

5. Equity Capital

To arrive at an overall fair rate of return, it is necessary that we utilize our judgment to establish an allowable return on common equity capital.

Amount of Common Equity

Consistent **[*70]** with our adjustments to the Company's proposed rate base, we find that the appropriate amount of equity capital is $1,817,934,000 for 1984 and $1,983,498,000 for 1985.

Cost of Equity Capital

Dr. John K. Langum, testifying on behalf of the Company, utilized three principal methodologies in arriving at a fair rate of return on common equity capital: Comparable Earnings Analysis; Discounted Cash Flow Analysis (DCF); and a Risk Premium Analysis. Dr. Langum compared FPL to a group of 22 operating electric utilities. In selecting the group of comparison electric utilities, Dr. Langum reviewed their financial strength, the grade and ranking of their common and preferred stock, and the rating of their first mortgage bonds. He also reviewed various other measures of investment stature. Dr. Langum based his cost of common equity recommendation on the principles of commensurate return and attraction of capital on fair and reasonable terms and maintenance of credit and support of financial integrity. Dr. Langum utilized the allowed rate of return on common equity for his comparison electric utilities and the actual earnings experience of unregulated firms with a Moody's quality **[*71]** ranking of High Grade. Dr. Langum concluded that FPL should be allowed to earn no less than 17.0% on its common equity because the comparison group of high grade industrials earned 17.74% on common equity, on average, during the period 1972-1982.

Based on the allowed fair rate of return on common equity authorized for the comparison electric utilities during the period 1980-1983, Dr. Langum concluded FPL should be afforded the opportunity of earning in the range of 17.0% - 17.50%.

Dr. Langum conducted DCF analyses for FPL, his group of comparison electrics, and all electric utilities that issued common stock between January '82 - August '83. Dr. Langum used either current dividend yields (current dividend divided by current market price) or averages of historical current dividend yields to determine the dividend yields for the DCF analyses. His estimates of expected dividend growth included the most recent dividend growth as shown in actual common stock prospectuses, investment house forecasts of dividend growth, and actual average dividend growth. The results of Dr. Langum's DCF analyses used in determining his DCF cost of common equity ranged between 17.72% - 20.22% for FPL; **[*72]** 17.14% - 18.56% for the comparison electrics; and 16.55% - 21.0% for the utilities that issued common stock in 1982 or 1983. All of Dr. Langum's DCF results included an adjustment of 3.75% for issuance expense. Dr. Langum concluded the DCF cost of common equity to be in the range of 17.0% - 18.0%.

In performing the Equity Risk Premium Analysis, Dr. Langum added an equity risk premium of 5.1% (the arithmetic annual mean return of common stocks over corporate bonds for the period 1972-1981 obtained from the 1982 edition of Stocks, Bonds, Bills, and Inflation: The Past and Future by Ibbotson and Sinquefield) to the 12.9% interest rate offered on FPL's September, 1983 issue of First Mortgage Bonds. This resulted in an Equity Risk Premium cost of common equity of 18.0%.

As a check on the criteria to support present bond ratings and provide an opportunity for improvement, Dr. Langum compared FPL's projected times-interest-earned (TIE) ratio excluding AFUDC to the TIE ratio excluding AFUDC necessary to support double A and single A ratings. Dr. Langum determined that the TIE ratio excluding AFUDC should be at a level of 3.5x for double A ratings, and at least 3.0x for single A **[*73]** ratings. Based upon his 17.33% recommended allowed return on common equity, Dr. Langum projected FPL's TIE ratio excluding AFUDC to be 3.69x.

Dr. Langum concluded that given the capital structure ratios, the cost of debt and preferred stock, and the appropriate amount of CWIP included in rate base, a 17.33% allowed return on common equity would provide for the attraction of capital on fair and reasonable terms and for maintenance of credit and support of financial integrity.

Mr. J. L. Howard, testifying on behalf of the Company, also presented three methods of estimating FPL's cost of common equity capital: Discounted Cash Flow Model (DCF); Comparable Earnings Analysis; and a Risk Premium Analysis.

Mr. Howard used a quarterly DCF model that recognizes that investors receive their dividends quarterly. A dividend yield of 10.14% was derived using the average 12-month expected dividend from the period January-October, 1983 ($3.65), the average of the high and low market price from the same period ($37.65), and a 7.4% expected dividend growth rate. The expected dividend growth rate was calculated by averaging five investment house 5-year forecasts of FPL's dividend growth. **[*74]** Combining the dividend yield with the dividend growth factor and making a 5% adjustment for market pressure and issuance expense, Mr. Howard concluded FPL's DCF cost of common equity to be 18.05%.

To support his DCF findings, Mr. Howard presented a Comparable Earnings Analysis. Mr. Howard selected a reference group of fifty companies comparable to FPL. His selection criteria included Value Line's Safety Ranking and Beta Coefficient, and Standard and Poor's Stock Ranking and Bond Rating. In addition, every company whose market-to-book ratio was below 100% was eliminated. The analysis indicated that investors require an average return of at least 17.42% to invest in the common stock of non-utility companies of comparable risk.

As a check of his DCF and Comparable Earnings Analyses, Mr. Howard conducted a Risk Premium Analysis. Mr. Howard concluded FPL's Risk Premium Cost of common equity to be approximately 18.4%. This was determined by adding a 5.5% equity risk premium (the geometric mean return of common stocks over corporate bonds for the period 1926-1981 obtained from the 1982 edition of Stocks, Bonds, Bills, and Inflation: The Past and Future by Ibbotson and Sinquefield) **[*75]** to the 12.9% interest rate offered on FPL's September, 1983 issue of First Mortgage Bonds.

Based on the results of his various equity costing analyses, Mr. Howard concluded FPL's cost of common equity to be not less than 17.42% nor more than 18.05%.

Mr. James D. Rothschild, testifying for the Citizens of the State of Florida presented a Discounted Cash Flow Analysis and a Comparable Earnings Analysis.

Mr. Rothschild relied upon the theory that the appropriate cost of equity for purposes of rate regulation is the earned rate of return which would make the marketplace valuation of a Company's used and useful net assets equal to the total book value of the common stock (i.e., the market-to-book ratio equals 1.0). Mr. Rothschild performed DCF analyses for the Moody's 24 electric utilities and for FPL using an "internally consistent" DCF methodology. Mr. Rothschild used current dividend yields adjusted for a possible increase in interest rates. For the Moody's 24, the dividend yield was 11.20%-11.45% and for FPL the dividend yield was 8.94%-9.19%.

The expected growth rate for the Moody's 24 and FPL was derived using the "internally consistent" methodology also known as the earnings **[*76]** retention method. Under Mr. Rothschild's assumptions, the dividend yield, expected return on equity, and market-to-book ratio combine to produce retention rates of 22.8%-25.63% for the Moody's 24 and 30.51%-35.30% for FPL. These retention rates in conjunction with the estimated returns on equity of 13.5%-14.0% for the Moody's 24 and 13.5%-14.5% for FPL resulted in expected growth rates of 2.82%-3.32% for the Moody's 24 and 4.29%-5.59% for FPL. After adjustments for issuance expense and capital structure differentials, Mr. Rothschild determined the DCF Cost of common equity capital to be between 14.18%-14.96% for the Moody's 24 and 13.42%-14.72% for FPL.

Mr. Rothschild presented a Comparable Earnings Analysis to support his DCF findings. The analysis was developed by examining the earnings of industrial companies with achieved market-to-book ratios of approximately 1.0. Based on the results of his analyses, Mr. Rothschild concluded the cost of common equity capital for FPL to be in the range of 14.25%-14.75%.

Mr. Philip R. Winter, testifying on behalf of the Federal Executive Agencies presented a Discounted Cash Flow Analysis; a Risk Premium Analysis; and a Market-to-Book **[*77]** Ratio Analysis. Mr. Winter relied on a "two-stage" DCF model. He computed his dividend yield (8.93%) using end-of-week stock prices and effective dividend rates from the period 11/4/83 through 2/17/84. His short-term (6.0%-6.5%) and long-term (4.5%-5.5%) expected dividend growth rates were derived using historical rates as well as investment house forecasts. Mr. Winter's DCF results, adjusted for market pressure and issuance expense, indicated investor requirements of 14.35%-15.28% on common equity capital for FPL.

As a check of his DCF findings, Mr. Winter presented a risk premium analysis. He calculated an equity-debt risk premium of 290 to 387 basis points based on the available returns of Moody's 24 utilities over the available returns on government bonds for all whole year holding periods of one year to ten years between 1929-1982.

As a further check of his DCF results, Mr. Winter conducted a market-to-book ratio analysis by fitting a regression equation to twenty-six data points using the market-to-book ratio as the dependent variable and expected ROE and financial strength as independent variables. The data was compiled from Value Line using electric utilities that **[*78]** had financial strength ratings of B++ or above.

Based on his regression equation, Mr. Winter concluded that his DCF range of 14.31% to 15.24% corresponded to a market-to-book ratio range of 1.03 - 1.07. Based on these results, Mr. Winter concluded that his DCF results were reasonable and should offer the company the opportunity to sell new equity with net proceeds near book value. Mr. Winter concluded the cost of common equity capital to FPL to be in the range of 14.35%-15.28%.

Mr. Steven F. Clinger, appearing on behalf of the Florida Public Service Commission staff presented four cost of equity analyses: a Discounted Cash Flow Analysis; a Capital Asset Pricing Model; an Earnings/Price Analysis; and a Risk Premium Regression Analysis. Using the DCF, CAPM, and E/P analyses, Mr. Clinger developed a quarterly interval weighted average cost of common equity for an index of high quality electric utilities (including FPL) for June '83, September '83 and December '83.

Mr. Clinger used two broad measures of overall investment risk to select his index of high quality electric utilities: S&P's Stock Ranking and Value Line's Stock Safety Ranking. In his DCF analysis, Mr. Clinger used a **[*79]** finite, variable growth rate DCF model. The dividend yields were determined by dividing the next twelve months expected dividend payment by the then current stock price. The dividend growth rates for the initial non-constant growth period (years 1-4) were taken from Value Line. The expected long-term constant dividend growth rates for the years 5-30 were calculated by the b times r method using dividend, earnings, and book value information obtained from Value Line. By calculating the annual expected cash flows over the investment horizon and solving for the investor required rate of return, Mr. Clinger concluded the Electric Utility Index's DCF cost of common equity to be 15.0%.

To support his DCF analysis, Mr. Clinger presented a Capital Asset Pricing Model. The risk free rates used were the then current yields of long term treasury bonds. The market return was estimated by adding an equity-debt risk premium of 6.1% to the risk free rate. The 6.1% risk premium, representing the earned returns on long-term U.S. Treasury Bonds over the earned returns on common stock for the period 1926-1981, was obtained from the 1982 edition of Stocks, Bonds, Bills, and Inflation: **[*80]** The Past and Future by Ibbotson and Sinquefield. The beta values were obtained from Value Line. The CAPM indicated a cost of equity to the Electric Utility Index of 15.6%.

As a further check of his DCF analysis, Mr. Clinger presented an Earnings/Price Analysis. Using an expected earnings-per-share amount (current earnings adjusted for one period's growth) and the then current market price, the model yielded a cost of common equity to the index of 14.6%.

In addition to the DCF, CAPM, and E/P Analyses, Mr. Clinger presented an independently developed Risk Premium Regression Analysis. This approach assumes the cost of common equity is a function of the Company's cost of debt. Applying Eggert Economic Enterprises' consensus forecast of 1984 A+/A1 bond yields to his regression equation, Mr. Clinger determined FPL's 1984 cost of common equity to be 15.7%.

Based on his analyses, Mr. Clinger concluded the cost of common equity capital for FPL to be in the range of 15.1% - 15.7% with a midpoint of 15.4%. Mr. Clinger updated his testimony at the hearing, resulting in a recommended cost of common equity range of 15.1% - 15.8% with a midpoint of 15.45%.

We discount the use of the **[*81]** results of Dr. Langum's DCF analyses due to his use of expected dividend growth rates that do not reflect investors' long-term dividend growth expectations. We discount the use of Mr. Howard's DCF results because his quarterly DCF model is misspecified and misapplied. It fails to consider reinvestment (the time value of money), and does not produce a yield equivalent to the annual model. We discount Dr. Langum's, Mr. Howard's and Mr. Rothschild's use of the Comparable Earnings technique due to the inherent practical and conceptual problems associated with this technique which none of these witnesses were able to overcome. Based on the evidence in the record and a review of the equity costing methodologies presented, we adopt an allowed rate of return on common equity capital for Florida Power and Light Company of 15.60% for 1984 and 1985.

6. & 7. Tax Credits and Deferred Taxes

Certain tax credits are recognized as a source of capital having no cost to the utility, thereby reducing the overall cost of capital. Other tax credits are apparently required by the Internal

Revenue Code to be allowed to earn the overall cost of capital calculated without regard to the existence **[*82]** of the tax credits. Deferred taxes arise from depreciation book-tax timing differences and are also treated as zero-cost capital. Public Counsel proposed that tax credits and deferred taxes be treated similarly to his suggestion for customer deposits: these balances should be unaffected by any disallowance of items in rate base that did not give rise to the credits or deferred taxes when rate base is reconciled with the capital structure. We believe tax credits and deferred taxes should be construed as supporting all assets on a pro rata basis. We therefore include $5,864,000 of zero-cost tax credits for 1984 and $5,454,000 for 1985 in FPL's capital structures. Tax credits allowed in the overall return are $372,282,000 for 1984 and $416,707,000 for 1985. Deferred taxes are $806,645,000 for 1984 and $948,836,000 for 1985.

NET OPERATING INCOME

Having established the Company's rate base, and fair rate of return, the next step in the revenue requirements determination is to ascertain the net operating income applicable to the test period. The formula for determining NOI is Operating Revenues less Operating Expenses equals NOI.

The Company has proposed a test year **[*83]** net operating income of $543,600,000 in 1984 and $506,760,000 in 1985. Evidence developed during these proceedings has led us to increase these amounts to $573,103,000 for 1984 and $542,405,000 for 1985.

Our adjustments are set forth as follows:

	1984		
	Per Company	Adjustments	As Adjusted
I. Operating Revenues	$3,200,982,000	$ 7,756,000	$3,208,738,000
Less Fuel and Conservation	(1,310,601,000)	0	(1,310,601,000)
Base Operating Revenues	1,890,381,000	7,756,000	1,898,137,000
II. Operating Expenses			
A. Operation and Maintenance	2,032,110,000	(119,269,000)	1,912,841,000
Less Fuel and Conservation	(1,249,025,000)	0	(1,249,025,000)
Base Operating and Maintenance	783,085,000	(119,269,000)	663,816,000
B. Depreciation and Amortization	245,486,000	6,985,000	252,417,000
C. Decommissioning	18,384,000	(251,000)	18,133,000
D. Amortization of Property Loss	2,127,000	(22,000)	2,105,000
E. Taxes Other Than Income Taxes	127,446,000	(20,031,000)	107,415,000
F. Income Taxes - Current	97,890,000	40,899,000	138,789,000
G. Deferred Income Taxes (Net)	109,374,000	11,591,000	120,965,000
H. Investment Tax Credit (Net)	28,617,000	(875,000)	27,742,000
I. Gain on Sale of Plant	(4,052,000)	(2,350,000)	(6,402,000)
Total Operating Expenses	2,657,382,000	(1,332,348,000	1,325,034,000
III. Net Operating Income	$ 543,600,000	$29,503,000	$ 573,103,000

[*84]

	Per Company	1985 Adjustments	As Adjusted
I. Operating Revenues	$3,409,584,000	$14,686,000	$3,424,270,000
Less Fuel and Conservation	(1,449,273,000)	0	(1,449,273,000)
Base Operating and Maintenance	1,960,311,000	14,686,000	1,974,997,000
II. Operating Expenses			
A. Operation and Maintenance	2,281,924,000	(80,702,000)	2,201,222,000
Less Fuel and Conservation	(1,428,454,000)	0	(1,428,454,000)
Base Operating Revenues	853,470,000	(80,702,000)	772,768,000
B. Depreciation and Amortization	264,172,000	9,174,000	273,346,000
C. Decommissioning	18,878,000	(56,000)	18,822,000
D. Amortization of Property Loss	2,184,000	(7,000)	2,177,000
E. Taxes Other Than Income Taxes	135,313,000	(21,313,000)	114,000,000
F. Income Taxes - Current	47,561,000	63,244,000	110,805,000
G. Deferred Income Taxes (Net)	126,079,000	(8,919,000)	117,160,000
H. Investment Tax Credit (Net)	31,166,000	(725,000)	30,441,000
I. Gain on Sale of Plant	(4,453,000)	(2,474,000)	(6,927,000)
Total Operating Expenses	2,902,824,000	(1,470,232,000	1,432,592,000
III. Net Operating Income	$ 506,760,000	$35,645,000	$ 542,405,000

[*85]

I. Operating Revenues

The Company proposed test year operating revenues for 1984 of $3,200,982,000 and $3,409,584,000 for 1985. We have made adjustments decreasing operating revenues for 1984 by a total of $1,302,845,000 and decreasing 1985 operating revenues by a total of $1,434,587,000. These adjustments result in approved operating revenue amounts of $1,893,137,000 for 1984 and $1,974,997,000 for 1985. The adjustments are as follows:

	1984	1985
Company Test Year Revenues	$3,200,982,000	$3,409,584,000
Adjustments:		
A. Unbilled Revenues	102,000	17,000
B. Parrish Lake Revenue	130,000	142,000
C. Jurisdictional Separation Factors	(158,000)	(33,000)
D. Revenue Forecast	7,682,000	14,560,000
E. Fuel	(1,269,049,000)	(1,404,442,000)
F. Conservation	(41,552,000)	(44,831,000)
Total Adjustments	(1,302,845,000)	(1,434,587,000)
Adjusted Operating Revenue	$1,898,137,000	$1,974,997,000

A. Unbilled Revenues

As previously discussed in this order, we increased working capital by $2,835,000 for 1984 and by $2,897,000 for 1985 based on a recalculation of retail unbilled revenues. The corresponding NOI adjustments are **[*86]** to increase revenues $102,000 in 1984 and $17,000 in 1985.

B. Parrish Lake Revenue

The Company inadvertently entered the revenues associated with Parrish Lake Park as a negative amount. The necessary adjustment to correct this error is to increase revenues by $130,000 in 1984 and $142,000 in 1985.

C. Jurisdictional Separation Factors

As a result of our having modified FPL's proposed jurisdictional separation factors, it is necessary to decrease revenues by $158,000 in 1984 and by $33,000 in 1985.

D. Revenue Forecast

As is more fully discussed in the rate design section of this order, FPL's original customer and sales forecasts were prepared in the fall of 1982. We found these forecasts to be unreasonable and, instead, utilized an updated forecast prepared by FPL in December 1983. The resulting increases in both forecasted sales and customers results in higher revenues than contained in the original filing. The necessary adjustment is to increase revenues by $7,682,000 in 1984 and by $14,560,000 in 1985.

E. Fuel Revenues

Fuel revenues, although recovered through the Company's fuel and purchased power cost recovery clause, were included in FPL's original **[*87]** filing. We determine that fuel revenues and expenses, as "breakeven" items, should be "equalized" or removed from the case because they are not recovered through the Utility's base rates. The Company, Staff and Public Counsel stipulated that the following adjustments were necessary to remove fuel revenues and expenses:

$ (000)

	1984	**1985**
Fuel Operating Revenues	$1,269,049	$1,404,442
O&M - Fuel	1,211,339	1,383,989
Deferred Expense	37,686	1,469
Taxes Other Than Income	20,024	21,921
Income Taxes - Current	(19,066)	(1,428)
Deferred Income Taxes	19,066	1,429
Total Fuel Expenses	$1,269,049	$1,404,442
Net Operating Income		

We approve these adjustments and decrease revenues by $1,269,049,000 in 1984 and $1,404,442,000 in 1985.

F. Conservation Revenues

In a similar manner to fuel, FPL's approved conservation costs are recovered through its energy conservation cost recovery clause and not through its base rates. Notwithstanding this fact, conservation revenues and expenses were included in FPL's original filing. As with fuel, the Company, the Staff and Public Counsel stipulated that conservation revenues and expenses have been equalized. **[*88]** The necessary adjustments to remove conservation revenues and expenses are:

$ (000)	1984	1985
Conservation Operating		
Revenues	$41,552	$44,831
O&M - Other	39,813	42,996
Depreciation	1,101	1,156
Taxes Other Than Income	639	680
Income Taxes - Current	(133)	(435)
Deferred Income Taxes	132	434
Total Conservation Expenses	$41,552	$44,831
Net Operating Income		

We approve these adjustments and decrease revenues by $41,552,000 for 1984 and by $44,831,000 for 1985.

II. Operating Expenses

A. Operating and Maintenance

The Company has proposed test year operating and maintenance expenses of $2,032,110,000 for 1984 and $2,281,924,000 for 1985. We have determined that these amounts should be reduced to $663,816,000 for 1984 and $772,768,000 for 1985 as follows:

	1984	1985
Operations and Maintenance Expenses		
Per Company	$2,032,110,000	$2,281,924,000
Adjustments:		
1. Pole Attachment Rental Expense	5,579,000	6,136,000
2. Conservation Expense Error	(1,152,000)	(1,944,000)
3. Charitable Contributions	(556,000)	(434,000)
4. Interest on IRS Tax Deficiencies	(798,000)	(807,000)
5. Industry Association Dues	(406,000)	(423,000)
6. Rate Case Expenses	(402,000)	
7. Advertising Expenses	(237,000)	(254,000)
8. O&M Reasonableness	(82,022,000)	(85,767,000)
9. Juno Relocation Costs	(724,000)	(1,466,000)
10. Recoverable Fuel Expenses	(1,249,025,000)	(1,382,520,000)
11. Recoverable Conservation Expenses	(39,813,000)	(42,996,000)
12. Economy Energy Sales Profits	1,262,000	1,320,000
13. Separation Factors		(1,000)
Total Adjustments	(1,368,294,000)	(1,509,156,000)
Adjusted O&M Expenses	$ 663,816,000	$ 772,768,000

[*89]

1. Pole Attachment Rental Expense

In its original filing, FPL failed to include the expenses related to its attachments on Southern Bell's poles. The adjustments to correct this error are to increase expenses by $5,579,000 in 1984 and by $6,136,000 in 1985.

2. Conservation Expense Error

FPL witness Gower proposed a reduction in O&M expense in order to equate the amounts entered in the Company's rate of return model with its projected conservation program expenditures. Specifically, he stated that the amount included in FPL's forecast was higher than it should have been and his adjustment was necessary to correct the overstatement. We agree and reduce O&M by $1,152,000 in 1984 and $1,944,000 in 1985.

3. Charitable Contributions

Consistent with our decisions in FPL's last two rate cases, we remove from operating expenses $556,000 of charitable contributions in 1984 and $434,000 in 1985. FPL may, of course, continue to make contributions to charities; our decision merely provides that the stockholders, and Federal and State governments make the contributions, not the ratepayers.

4. Interest on IRS Tax Deficiencies

FPL has proposed to include **[*90]** in O&M certain amounts of interest on Internal Revenue Service income tax deficiencies and refunds. The Company argues that these deficiencies result from it occasionally being overruled by the IRS on aggressive position it takes in computing its taxes. Furthermore, FPL states that the IRS frequently adopts a compromise position after negotiations so that even a deficiency determination may result in lower current taxes than would be the case had the Company initially adopted a more conservative tax position.

We find that FPL has failed to demonstrate that its actions leading to the imposition of interest charges by the IRS are in the best interest of itself or its ratepayers. Accordingly, the interest charges are disallowed as being neither prudent nor reasonable. The necessary adjustments are to reduce O&M expense by $798,000 in 1984 and $807,000 in 1985.

5. Industry Association Dues

FPL has included in its filing a request for industry association dues of $1,805,343 in 1984 and $1,944,764 for 1985. Of these dues, FPL has requested $425,269 and $449,510 for 1984 and 1985, respectively, for administrative dues to the Edison Electric Institute (EEI). With regard to these **[*91]** dues, FPL witness Bauer acknowledged during cross-examination by Commissioner Cresse that 18% to 20% are for direct lobbying or in support of direct lobbying. However, the NARUC Staff Subcommittee on Accounts in its Preliminary Report stated that, in the absence of an adequate segregation of EEI expenditures, it favored an allocation of from 1/4 to 1/3 of EEI administrative dues payments to be borne by the shareholders. We find that FPL has not presented an adequate segregation of EEI expenditures and in the absence of such a segregation shall conservatively disallow 1/3 of the administrative dues FPL pays to EEI in each year as being for lobbying or lobbying-related. While in many instances EEI lobbying efforts are beneficial to the ratepayers, we believe it is the best policy not to study the purpose of lobbying expenses, but instead to disallow all lobbying expenses rather than attempt to make a subjective judgment on the reasonableness of the lobbying effort.

FPL has also requested $178,059 in 1984 and $188,208 in 1985 for the EEI's Media Communications Program. As evidenced by the record, this program is administered separately from other EEI operations and is **[*92]** supported by voluntary contributions from its member utilities. We consider that this program is not necessary to the provision of adequate and efficient electrical service and, therefore, disallow the associated contributions.

FPL has also requested total dues to the Atomic Industrial Forum in the amount of $100,000 for 1984 and $103,000 for 1985. We consider these dues to be for lobbying efforts and disallow them. We also disallow as being non-utility the requested dues for the Broward County Hotel and Motel Association, the Melbourne Restaurant Association, and the Miami Beach Resort Hotel. Our total adjustments are to reduce O&M by $406,000 in 1984 and $423,000 in 1985.

6. Rate Case Expense

FPL has included total amounts of rate case expense in its projections of $875,000 for 1984 and $438,000 for 1985. These amounts include an amortization for the Company's 1982 rate case expense as well as for this case. Public Counsel has proposed, as he did in FPL's last rate case, that rate case expense should be shared equally between the Utility's investors and ratepayers. Once again, we must reject Public Counsel's proposition for the reason that rate case expense is a cost **[*93]** of doing business, which should be fully recognized.

FPL's requested amounts are based upon an amortization period that begins when the new rates become effective. However, we believe that the amortization should begin with the beginning of the test year since a full year of the amortization of rate case expense is included in the income statement. Additionally, FPL has included a full year's amortization of its last rate increase in its present request. However, because the Company's present rates will have been in effect for approximately a year and seven months prior to the new rates in this case becoming effective, FPL will have already recovered the majority of its expenses from previous cases. To compensate for this factor, we shall remove $615,000 of rate case amortization associated with the Company's last case in Docket No. 820097-EU.

The net effect of our adjustments is to decrease O&M by $402,000 for 1984.

7. Advertising Expenses

FPL originally requested advertising expenses of $4,486,721 for 1984 and $4,759,296 for 1985. Subsequent to its filing, FPL identified an error and recommended that Account No. 909.5, Other Advertising, be reduced to zero. Public **[*94]** Counsel agrees with these reductions and has also recommended that institutional advertising be disallowed as well.

We agree with Public Counsel that the institutional advertising is of a promotional or image-building nature, which should be disallowed. The necessary adjustments are to reduce O&M expense by $237,000 in 1984 and by $254,000 in 1985.

8. O&M Reasonableness

By far, the most significant disallowances we have made in this case are those in which we have reduced FPL's operating and maintenance expenses (O&M) as a result of the Company's failure to adequately control their O&M expenditures or to prove by competent substantial evidence that all of those projected expenses for the years 1984 and 1985 are reasonable and prudent. The net effect of our adjustments on this major issue is to reduce the requested 1984 O&M by $82,022,000 and that requested for 1985 by $85,767,000. Because these adjustments are so significant and also represent a recurring problem, we think it especially important that the reader fully understand the nature of the problem, the facts bearing on this issue and the logic supporting our decision.

The simple basic problem is that FPL's **[*95]** base electric rates, and the costs that comprise them, have for many years consistently grown at a rate in excess of that accounted for by a compound factor including the Utility's increases in new customers and general inflation as measured by the Consumer Price Index (CPI). Beginning in 1973 and throughout most of the 1970's, overall electric rates were impacted most dramatically by rising fuel costs. For a few years now fuel prices have generally stabilized, even though low sulfur fuel has recently increased and have contributed less to the continued rise in electric rates. In any event, the Commission has for a number of years provided for the full recovery of reasonably and prudently-incurred fuel costs through the Fuel Cost and Purchased Power Recovery Clause (presently Docket No. 840001-EI). As discussed previously, the revenues and expenses associated with fuel and purchased power, as well as the Company's conservation programs, have been equalized or removed from this case. However, even with these potentially volatile costs removed from consideration, FPL's O&M expenses continued to outstrip a level of growth explained by customer growth and increases in the CPI.

In **[*96]** the Company's 1982 rate case, we inquired of Mr. Hudiburg what the Utility was doing to keep the rate of growth of O&M expenses in check. He responded that it was management's long-term goal to keep the overall rate of increase in these expenses at or below the level accounted for by customer growth and increases in the CPI. As a result, we noted the following, at page 34 of Order No. 11437, which is the final order entered in FPL's 1982 rate case:

With regard to the overall increase in operating and maintenance expenses, we note that the Company has expressed a goal of limiting increases in these expenses to a percentage equal to the combined growth in customers and the rate of inflation. In this Company's next rate case we intend to closely examine the Company's percentage growth in operating and maintenance expense and may, if we deem it appropriate, hold the Company to its stated goal. (Exphasis supplied.)

As noted at page 6 of this order, a primary reason for our denial of FPL's request for interim rates was its failure to justify an increase in its 1982 to 1983 O&M costs of $47,566,000 over and above that accounted for by increases in the CPI and customer growth. Seeking **[*97]** additional information on O&M increases beyond the CPI and customer growth level, we requested that FPL prepare a table depicting a comparison of the Company's actual 1979-1983 and budgeted 1984 and 1985 (total company) O&M expenses, excluding fuel, interchange, net purchased power, conservation and COM/CWM costs with amounts which assumed a 1979 base year adjusted for CPI and customer growth. The Company supplied the following table, which appeared at page 32 of the Prehearing Order:

The following table depicts a comparison of FPL's actual 1979-1983 and budgeted 1984 and 1985 (total company) O&M expenses, excluding fuel interchange, net purchase power, conservation, and COM/CWN costs with amounts which assume a 1979 base year adjusted for CPI and customer growth:

($000)

Year		Amount	Compound Multiplier	Benchmark	Difference from Benchmark
1979	Actual	361,176	1.0000	361,176	0
1980	Actual	446,726	1.1958	431,894	14,832
1981	Actual	541,559	1.3804	498,567	42,992
1982	Actual	610,410	1.5118	546,026	64,384
1983	Est/Act	702,383	1.6062	580,121	122,262
1983	Actual	699,096	1.6077	580,663	118,433
1984	Forecast	759,030	1.7483	631,444	127,586
1985	Forecast	817,520	1.9149	691,616	125,904

[*98]

The following data were used to construct the CPI and customer growth multiplier:

Reference Data for Compound Multiplier:

Year		Customers	Ave CPI
1979	Actual	2,074,340	217.4
1980	Actual	2,184,985	246.8
1981	Actual	2,285,187	272.4
1982	Actual	2,358,168	289.1
1983	Est/Act	2,420,924	299.2
1983	Actual	2,429,690	298.4
1984	Forecast	2,509,266	314.2
1985	Forecast	2,600,195	332.1

So, for example, the CPI increased 44.53% from 1979 to 1984 (314.2/217.4 = 1.4453 = 44.53% increase) while customers increased 20.97% (2,509,266/2,074,340 = 1.2097%) during the same period. The sum of the two equals a 65.49% increase from 1979 to 1984. To get the compound multiplier we multiply 44.53 X 20.97 = 9.34, which we add to the sum of those two numbers to get 1.7483 CPI and customer growth factor.

Multiplying FPL's 1979 base year O&M expenditures of $361,176,000 times the CPI and customer growth compound multiplier of 1.7483 results in a 1984 O&M benchmark of $631,444,000. Stated another way, had FPL's management been successful at keeping the rate of growth of O&M expenses equal to the combined rate of CPI and customer growth, their forecasted non-fuel/conservation O&M **[*99]** costs for 1984 would have been $631,444,000. The long-term goal was not met over this five year period and requested O&M costs in the 1984 test year were $759,030,000 or $127,586,000 over and above the increase explained by CPI and customer growth. Similarly, for the 1985 test year, FPL's requested non-fuel/conservation of $817,520,000 is $125,904,000 in excess of the $691,616,000 that would have been required had O&M costs held the line with CPI and customer growth since 1979.

FPL and other regulated utilities are entitled to recover through their rates prudently and reasonably-incurred expenses, necessary to the provision of adequate, sufficient and efficient service. The law provides that entitlement, but no more. Thus, the burden of establishing its O&M expenses as prudent and reasonable rests with the Utility and the responsibility of holding the Utility to its proof rests with this Commission. We want to make abundantly clear that our use of the CPI and customer growth comparison factor is not a statement that all expense increases above CPI and customer growth are prima facie unreasonable or imprudent. On the other hand, we do not imply that all expenses **[*100]** increasing at a rate below CPI and customer growth are automatically reasonable and prudent. Rather, we use this standard to "flag" certain expenses that because of their dramatic rates of growth demand a greater level of scrutiny and we expect our Staff to develop further refinements in our analysis of "necessary costs."

Once the general area of O&M expenses had been identified as significantly exceeding the CPI and customer growth factor, we examined FPL's filing to ascertain whether the Company had carried its burden of demonstrating that its expenses were reasonably and prudently-incurred. For the most part, the pre-filed testimony did not specifically address increased costs, but, rather, described what amount was being spent and on what.

The Commission was not convinced, after hearing the testimony, that the Company had "justified" the increased cost levels being requested. Rather, the Commission considered that the Utility had merely "explained" the increases, which is akin to reporting that something has or will take place without offering competent evidence that that thing is necessary, or, if necessary, at a cost that is reasonable.

During the first week of hearings, **[*101]** the Commission offered the Company an additional opportunity to justify the significant number of increased items that had been left wanting. The Company accepted this offer and as a result prepared late-filed exhibit No. 4M/5H, which detailed some 27 specific activities and attempted to justify why those activities increased at a rate faster than CPI and customer growth.

The table below was submitted by FPL witness Dady as late-filed Exhibit 4P at the request of the Commission. Its purpose was to place the 27 activities discussed in Exhibit No. 4M/5H in the nine major functional accounts shown.

TABLE 1

O&M INCREASES BY FUNCTIONAL ACCOUNT

1979 ACTUAL TO 1984 FORECAST *

($000)

1984 Forecast	$759,030	
1984 Benchmark	631,444	
Difference:	$127,586	Benchmark Factor 1.7483

* Excludes Fuel, Interchange and Purchased Power, Conservation & COM/OWM

Function	1979 Actual	1984 Benchmark	1984 Forecast
Production - Steam	$ 44,670	$ 78,097	$ 98,255
Production - Nuclear	44,702	78,153	96,962
Production - Other	11,289	19,737	18,554
Other Power Supply	757	1,323	1,427
Transmission	13,066	22,843	28,215
Distribution	77,609	135,684	157,093
Customer Accounts	42,417	74,158	85,260
Cust. Service and Info.	7,243	12,663	4,752
Administrative and General	119,423	208,786	268,512
Total	$361,176	$631,444	$759,030

[*102]

Function	Difference	Amount Justified in Late Filed Exhibit 4M/5H	Remaining Difference
Production - Steam	$ 20,158	$ 20,826	$ (668)
Production - Nuclear	18,809	29,816	(11,007)
Production - Other	(1,183)	3,750	(4,933)
Other Power Supply	104	56	48
Transmission	5,372	3,126	2,246
Distribution	21,409	17,092	4,317
Customer Accounts	11,102	12,486	(1,384)
Cust. Service and Info.	(7,911)	282	(8,193)
Administrative and General	59,726	52,385	7,341
Total	$127,586	$139,819	$ (12,233)

At our request, FPL provided the following table, which "functionalized" each of the 27 activities in Exhibit No. 4M/5H into the appropriate functional account. This table resulted in a more detailed explanation of how the amounts in excess of the 1984 CPI and customer growth benchmark are distributed among the Company's major functions. For example, the table reveals that a portion of the $21,680,000 above the 1984 benchmark for "Pay Rate Increase for Existing Employees" is spread among each of the nine major functional accounts, with the largest portion ($5,919,000) residing in distribution.

TABLE 2

FUNCTIONALIZATION OF LATE FILED EXHIBIT 4M/5H BY ITEM

	Differ-ential	Prod Steam	Prod Nuclear	Prod Other	Other Power Supply
St. Lucie Unit #2	$10,710	$1,285	$9,425		
Martin Plant Op.	7,819	6,451		1,368	
Cutler Plant Op.	3,615	2,982		633	
Riveria Plant Op. (1&2)	1,351	1,115		236	
St. Lucie Unit #1 Rotor Refurb.	10,500	1,260	9,240		
NRC Mandated Work	2,690		2,208		
NRC Req. Personnel Adds.	5,511	661	4,850		
Nuclear Emer. Planning	2,000	240	1,760		
Putnam Pipeline Amort.	1,114	919		195	
Boiler Mod. Study	2,000	1,650		350	
R&D Expenditures	1,076	28	51	2	
Pay Rate Increase for Existing Employees	21,680	3,621	2,016	499	65
Prop. & Liab. Insurance	18,801	602	263	56	
Pension & Welfare	11,503				
Computer Service	7,408				
Telephone Expenses	1,252				
Rate Reg. Expense	629				
Juno Bch. Fac. Op.	1,073				
Juno Bch. Relocation Expenses	750				

Biweekly Payroll Adj.	5,895			407	
Rented Office Space	581				
Contract Line Clearing	1,891				
Vehicles-Company	4,694				
Uncollectible Accounts Receivable	2,319				
Transmission Ops.	943				
Arbitration Case-CM/DM	913				
Division Programs	11,101				
Rounding Between Functions	0	12	3	4	(9)
Total Per LF Exh. 4P	$139,819	$20,826	$29,816	$3,750	$56

[*103]

TABLE 2

FUNCTIONALIZATION OF LATE FILED EXHIBIT 4M/5H BY ITEM

	Trans	Dist	Cust Accts	Cust Serv & Info	A&G	Total
St. Lucie Unit #2						$10,710
Martin Plant Op.						7,819
Cutler Plant Op.						3,615
Riveria Plant Op. (1&2)						1,351
St. Lucie Unit #1 Rotor Refurb.						10,500
NRC Mandated Work					482	2,690
NRC Req. Personnel Adds.						5,511
Nuclear Emer. Planning						2,000
Putnam Pipeline Amort.						1,114
Boiler Mod. Study						2,000
R&D Expenditures	15	5			975	1,076
Pay Rate Increase for Existing Employees	1,192	5,919	3,837	87	4,444	21,680
Prop. & Liab. Insurance		(19)			11,148	18,801
Pension & Welfare					11,503	11,503
Computer Services			1,222		6,186	7,408
Telephone Expenses			207		1,045	1,252
Rate Reg. Expense					629	629
Juno Bch. Fac. Op.			177		896	1,073
Juno Bch. Relocation Expenses					750	750
Biweekly Payroll Adj.			(124)		5,612	5,895
Rented Office Space					581	581
Contract Line Clearing		1,891				1,891
Vehicles-Company	276	2,614	1,360	54	390	4,694
Uncollectible Accounts Receivable			2,319			2,319
Transmission Ops.	943					943
Arbitration Case-CM/DM	54	508	264	11	76	913
Division Programs	653	6,181	3,216	129	922	11,101
Rounding Between Functions	(7)	(7)	8	1	(5)	0
Total Per LF Exh. 4P	$3,126	$17,092	$12,486	$282	$52,385	$139,819

[*104]

As may be seen from the first table, FPL's forecast 1984 O&M expenditures of $759,030,000 were $127,586,000 in excess of the 1984 benchmark of $631,440,000. As a result of our review of the record in this case, we have disallowed as either unreasonable or unproved $81,919,000 of projected 1984 O&M costs in excess of the CPI and customer growth benchmark. Our net adjustments per functional account are set out in the table below and the rationale for the adjustments follows:

Function	1979 Actual	1984 Benchmark	1984 Forecast	Difference	Amount Justified
Production - Steam *	$ 44,670	$ 64,771	$ 98,255	$ 33,484	$12,869
Production - Nuclear *	44,702	64,817	96,962	32,145	31,192
Production - Other *	11,289	16,369	18,554	2,185	56
Other Power Supply	757	1,097	1,427	330	330
Transmission	13,066	22,843	28,215	5,372	922
Distribution	77,609	135,684	157,093	21,409	10,679
Customer Accounts	42,417	74,158	85,260	11,102	5,543
Cust. Service and Info.	7,243	12,663	4,752	(7,911)	0
Administration and General	119,423	208,786	268,512	59,726	14,332
Total	$361,176	$601,188	$759,030	$157,842	$75,923

Function	Remaining Difference	Amount Allowed	Juris. n3 Factor	Juris. Amt. Allow
Production - Steam *	$ 20,615	$ 77,640	.93836	$ 72,854
Production - Nuclear *	953	96,009	.9383	90,085
Production - Other *	2,129	16,425	.93748	15,398
Other Power Supply	n2 0	1,427	.93748	1,338
Transmission	4,450	23,765	.94101	22,363
Distribution	10,730	146,363	.99826	146,108
Customer Accounts	5,559	79,701	.99893	79,616
Cust. Service and Info.	n1 (7,911)	12,663	.99893	12,649
Administration and General	45,394	223,118	.97062	216,563
Total	$81,919	$677,111		$656,975

[*105]

n1 Productivity increase resulting in O&M of $7,911 being less than index is used to offset total remaining difference.

n2 Zero remaining difference assumed for other power supply.

n3 Jurisdictional factors taken from TAMMY LFX No. 14C, page 3/6

* 1979 Actual inflated by CPI only to calculate 1984 Benchmark

Appropriateness of CPI and Customer Growth Benchmark

As was discussed earlier, our use of the CPI and customer growth benchmark comparison resulted, in part, from Mr. Hudiburg's statement that keeping O&M costs within CPI and customer growth was a long-term goal of the Company. However, the record in this case reveals that allowing both CPI and customer growth is not appropriate for all categories of expenses. Specifically, we find that production plant O&M should only be inflated for the CPI increases and not for customer growth. This is so, because, unlike customer or line crew personnel whose numbers have a logical and fairly direct correlation to the number of customers served, generating plant is built to serve a certain maximum load and its non-fuel O&M expenses do not rise as a result of new customers being added to the system, but, rather, rise when new **[*106]** plant is built. Accordingly, we have inflated the three production functions by only the increases in the CPI. This adjustment results in a decrease to the 1984 benchmark for these functions in the amount of $30,030,000 as shown below.

	CPI & Customer Growth	CPI Only
Production - Steam	$ 78,097,000	$ 64,771,000
Production - Nuclear	78,153,000	64,817,000
Production - Other	19,737,000	16,369,000
	$175,987,000	$145,957,000
	-145,957,000	
	$ 30,030,000	

Instead of granting a customer growth factor to Production Plant, we have analyzed the specific additions to plant in these categories and allowed certain increased O&M expenses associated with those additions.

St. Lucie Unit No. 2

As reflected in Exhibit No. 4M/5H, 1984 O&M expenses projected for St. Lucie 2 nuclear unit were $10,710,000. Because this unit was not in service in 1979 and, therefore, has no base year for expansion by the CPI, we have included the entire $10,710,000 projected by the Company in allowable 1984 O&M.

Martin Plant Operation

FPL's Martin Plant units were only beginning operations in 1979 and they also have no representative 1979 O&M base. Accordingly, we **[*107]** have included the entire $8,476,000 FPL has forecast for these units in allowable 1984 O&M.

Cutler and Riveria Plant Operation

The Cutler and Riveria generating plants were in extended cold standby in 1979 and, therefore, had only relatively minimal O&M costs during that year. Because these units have now been reactivated, we have included the full amounts projected by FPL of $4,300,000 for Culter and $2,750,000 for Riveria in allowable 1984 O&M.

The above production plant adjustments increase allowable 1984 O&M by a total of $26,636,000. However, since FPL's 1979 actual O&M costs include $1,568,000 related to the Martin, Cutler and Riveria plants, which has already been increased for CPI only and included in allowable O&M, we must subtract that amount so as to not double-count on inflation. ($1,568,000 X 1.45 = $2,273,000). The resulting net increase in allowable 1984 O&M costs due to the addition or reactivation of these four generating plants since 1979 is $23,963,000.

St. Lucie Unit No. 1 Rotor Refurbishment

FPL has included in 1984 O&M $10,500,000 related to the repair or replacement of cracked rotor disks in the St. Lucie Unit 1 turbine rotor. Because there **[*108]** was no comparable repair item in the Company's 1979 base year, we will include this amount in the allowable 1984 O&M.

NRC Mandated Work

The Company has included in 1984 O&M $8,900,000 related to certain work at its four nuclear generating units, which has been mandated by the U.S. Nuclear Regulatory Commission (NRC). FPL states that completing this work is a condition of the plants' operating licenses and, further, that the level of work bears no correlation to either customer growth or inflation. We agree that these increased costs are not logically related to either inflation or customer growth and, further, that they are mandated by an appropriate governmental agency. Accordingly, we shall approve this amount, minus the $3,552,000 in the 1979 base expanded for the CPI increases that we had already included in allowable 1984 O&M.

NRC Required Personnel Additions

FPL states that the impact of NRC requirements since 1979 has resulted in the addition of 230 personnel to the Company. As with the previously-discussed NRC mandated work, FPL states that these personnel are required as a condition of its operating licenses and, further, that the costs associated with **[*109]** these additional personnel are correlated with neither the CPI nor customer growth. We agree, and because there is no base amount for this category in 1979, we shall include the entire $5,511,000 projected.

Nuclear Emergency Planning

Radiological emergency response plans and preparedness requirements of the NRC are established by federal rule. Additionally, Section 252.60, Florida Statutes, has established that the state and its political subdivisions are not responsible for funding programs for radiological emergencies. Consequently, FPL has forecast $2,000,000 for nuclear emergency planning funding for 1984. We agree that this is an appropriate expenditure and, because there was no comparable expenditure in 1979, we shall include the entire $2,000,000 in allowable 1984 O&M.

Putnam Pipeline Amortization

FPL contracted with Florida Gas to build a pipeline to the Utility's Putnam Plant in order to allow that plant to burn natural gas. In 1982, this Commission ordered FPL to amortize the costs related to the pipeline through base rates over five years beginning in October 1982. There was no comparable cost in 1979, therefore, we shall include the full **[*110]** amount of the amortization of $1,114,000. The Company projected reduced plant O&M expenses related to the use of gas in the amount of $2,100,000, which we have recognized.

Boiler Modification Study

FPL included $2,000,000 in 1984 O&M related to studies to determine what modifications are necessary to accommodate cyclical operations on its Foster Wheeler boilers. The purpose of the studies is to find modifications that will maintain unit availability and reliability while limiting maintenance costs. We shall approve this item and allow the full $2,000,000 projected inasmuch as there was no comparable amount or category in 1979.

R&D Expenditures

FPL's actual 1979 O&M expenses for research and development were $6,278,000. When inflated for both CPI and customer growth the 1984 benchmark is $10,976,000. FPL defends the $1,076,000 forecast above the benchmark by indicating that its R&D expenditures are primarily based on an Electrical Power Research Institute (EPRI) formula which is not directly related to customer growth and inflation.

We find that there is no competent substantial evidence of record to justify the $1,076,000 increment above the benchmark and, therefore, **[*111]** disallow it.

Pay Rate (Salary) Increase Differential for Existing Employees

In 1979, FPL's actual O&M expenses in this category were $151,881,000. When multiplied times the rate for CPI, the 1984 benchmark for this category is $219,508,000, or some $21,680,000 short of the 1984 forecast of $241,188,000 that the Utility seeks to recover through this case. The 1984 benchmark of $219,508,000 and the 1984 forecast of $241,188,000 are in reference only to the salaries of the number of employees FPL had in 1979 and do not include the salaries of employees added since then. Because we find that FPL has offered no competent substantial evidence to support the reasonableness of the level of its projected 1984 salaries in this category, we disallow the $21,680,000 above the level that is explained by the rate of increase of general inflation as measured by the CPI.

This is the largest single O&M adjustment in this case and, while we believe that there is insufficient evidence to prove the reasonableness of the projected salaries, we believe that there is sufficient evidence of record to demand a high degree of scrutiny.

FPL, at year-end 1983 employed 12,796 individuals **[*112]** with diverse skills. At year-end

1982 there were 12,514 employees. As evidenced by Exhibit 4-C, below, (Public Counsel Interrogatory No. 194), the average annualized salary for the Exempt employee group, as of December 31, 1982, was $37,944. Bargaining Unit employees averaged $24,108 for the same period, and Non-Bargaining Unit Biweekly employees averaged $19,488.

Exhibit 4-C

Question. Provide the annualized salary for each employee group as of December 31, 1982. For each employee or employee group, provide the amount in dollars or percentage of wage increases granted over the past three years. For each employee or employee group, provide the amount of wage increase projected for the year ended December 31, 1983.

Answer. The requested data is summarized below:

	Exempt	Non-Bargaining Unit Biweekly	Bargaining Unit
Annualized Salary	$37,944	$19,488	$24,108
% Increase - 1980	8.8	8.1	8.9
% Increase - 1981	10.2	7.4	9.3
% Increase - 1982	12.7	9.6	10.5
% Increase - 1983	9.7	8.8	8.9

Note: The bi-annual effect of contract negotiations with its associated retroactive/delayed increase distorts comparisons using **[*113]** year-end data. For that reason, September data has been used to respond to this interrogatory for all years.

This exhibit also demonstrates that the average exempt employee received as high as a 12.7% salary increase in 1982 and a four-year average increase of 10.35%. Bargaining Unit employees were next with a 9.4% four-year average increase and Non-Bargaining Unit Biweekly employees were third with 8.48%. Average inflation, as measured by the Consumer Price Index, for those years was:

	% Increase Over Previous Year
% Increase - 1980	10.37%
% Increase - 1981	6.13%
% Increase - 1982	3.49%
% Increase - 1983	3.22%

FPL witness Bentley in his Exhibit No. 3-G, below, provided the assumptions used by the Company's 1983 Rate of Return Forecasting Process, including forecasts for the CPI during the two test years and the expected increases in Real Per Capita Income in Florida.

Exhibit No. 3-G

	Percent Change from Prior Year			
	Actual 1983	Forecast 1983	Forecast 1984	Forecast 1985
Current Assumptions *				
Consumer Price Index	3.2	3.5	5.0	5.7
Producer Price Index - All Commodities	1.3	1.0	5.5	5.8
Producer Price Index - Capital Equipment	2.8	4.5	5.7	5.9
Gross National Product Implicit Price Deflator	4.2	4.3	5.3	5.5
Average Hourly Earnings Construction Workers	4.4	6.7	6.8	6.9
Real Gross National Product	3.3	3.0	4.9	3.2
Florida (Non-Farm) Employment	3.0	2.5	4.5	4.5

Florida Real Per Capita Income	N/A	0.2	1.5	2.0

[*114]

* These assumptions were also used for the 1983 Rate of Return Forecasting Process and the December 16, 1983 Load Forecast.

Dady's Revised Late-Filed Exhibit No. 4-D, below, demonstrates that when all of the employees' salaries are weighted, the gross payroll per employee was projected to be $35,111 in the 1984 test year and $37,751 in 1985.

Exhibit No. 4-D

Salaries and Fringe Benefits

	1980	**1981**	**1982**	**1983**	**1984**	**1985**
Per Employee Basis						
Gross Payroll	$24,994	$27,198	$29,538	$32,625	$35,111	$37,751
Fringe Benefit						
Retirement-Funded Plan	$ 2,723	$ 2,736	$ 3,368	$ 3,607	$ 3,918	$ 4,196
FICA Tax	1,343	1,620	1,814	1,988	2,243	2,429
Group Insurance	975	840	1,147	1,321	1,714	2,013
Unemployment Comp. Tax	77	52	50	66	71	77
Workman's Compensation	183	197	238	231	235	242
Other (Thrift Plan, Power Caps, Adm. Exp. etc.)	619	753	729	818	866	928
Subtotal - Fringes	$ 5,920	$ 6,198	$ 7,346	$ 8,031	$ 9,046	$ 9,884
Percentage of Payroll	23.7%	22.8%	24.9%	24.6%	25.8%	26.2%
Total Payroll & Fringes	$30,913	$33,396	$36,883	$40,656	$44,158	$47,634
Total Package Increase Per Year Per Employee						
Dollar Increase		$ 2,483	$ 3,487	$ 3,773	$ 3,501	$ 3,477
Percentage Increase		8.0%	10.4%	10.2%	8.6%	7.9%

[*115]

As also indicated by this table, total fringe benefits of $9,046 increased the projected 1984 total payroll and fringes to $44,158 per employee. 1985 is projected to increase fringes to $9,884 per employee and raise the total of payroll and fringes to $47,634. If you compare the "Percent Increase" rates on the bottom line of Revised Exhibit No. 4D to the actual and projected rates of increase in the CPI for the same period, you will notice wide disparities, and especially so, in 1982 and 1983 when the rate of total employee benefits increased 10.4% and 10.2%, respectively, and represented 170% (10.4/6.13 = 169.66%) of the increase the CPI in 1982 and 319% (10.2/3.2 = 318.75%) in 1983. Thus, it can be seen that since FPL's last full rate case in 1982, the Company's salary and fringe benefit expense has, in two years, increased over 20%.

We believe that increases of this magnitude demand that the Company fulfill its burden of demonstrating by competent substantial evidence that these rates of increase and the resulting salary levels are both necessary and reasonable. However, based upon our having heard the testimony in this case and examined the other evidence, we **[*116]** find that FPL has failed to meet its burden.

The gist of FPL's evidence in support of its request on this subject is that its proposed salary levels are reasonable and necessary from the standpoint, of attracting and retaining a skilled workforce. Additionally, the Company states in Exhibit No. 4M/5H:

The pressure of the market place continues to be a force in determining the magnitude of increases we have included in our forecast for 1984 and 1985. For example, starting engineering salaries drive up existing salaries, nuclear power operations continue to be in great demand in this high technology area.

While FPL's defense of these salary levels may be entirely correct, its support consists entirely of conclusory statements by the Company's witnesses that the projected salaries are necessary if FPL is to remain a competitive employer. FPL has not offered comparative salary exhibits that would demonstrate the salary levels of other comparable utilities or high technology industries that it must compete for employees with. In the absence of such concrete evidence that its requested salary levels are both necessary and reasonable, we shall disallow the $21,680,000 increment requested **[*117]** in 1984 O&M that exceeds the 1984 benchmark, which is the CPI only for existing 1979 employees on Exhibit No. 4M/5H. While we shall allow the benchmark amount in 1984 O&M, which should be adequate to cover raises and additional employees due to customer growth, we emphasize that a rate of O&M expense increase equal to the combined rate of increase in the CPI and customer growth will not automatically be considered as necessary and reasonable. Rather, in future cases for this Utility and others, we shall expect concrete evidence in the form of comparative salary studies, and the like, justifying the salary levels requested to be included in the customer's rates.

Property and Liability Insurance

In 1979, FPL's actual O&M for this account was $12,275,000. When expanded for CPI and customer growth, the 1984 benchmark is $21,460,000, or $18,801,000 short of the 1984 forecast of $40,261,000. In defending the increases, FPL states that the major contributing factors were:

1. St. Lucie #2 was placed on line in 1983 which increased 1984 insurance costs by $6,106,000;

2. the addition of NEIL 1 in 1980 to cover replacement energy costs in the event of a nuclear incident **[*118]** increased insurance costs by $5,327,000 over 1979;

3. the addition of NEIL 2 in 1981 to provide increased nuclear property insurance increased insurance costs by $2,043,000 over 1979;

4. in 1981 the FPSC approved annual additions to the Storm and Property Insurance Reserve, which increased funding expense by $3,000,000 over 1979;

5. NML premiums increased above escalation rates, due to increases in property values and increased coverage limits, which increased insurance costs by $629,000 over 1979;

6. excess liability insurance premiums increased by $532,000 over 1979 due to the availability and selection of lower optimal deductibles; and

7. increases in public claims against FPL for either damage or bodily injuries and for increased property damage and loss increased the needed reserve accrual by $1,164,000 over 1979.

After studying the record evidence on this issue, we disallow $9,185,000 and approve for inclusion in allowed 1984 O&M $31,076,000. The basis for our decision is as follows: We accept each of the justifications offered by the Company on the above seven items and will include in allowable O&M the $18,801,000 represented by these items. However, because FPL **[*119]** has not specified what portion of these increased items had a comparable expense in the 1979 base, we will not allow the CPI and customer growth expansion represented by the 1984 benchmark, but will, instead, include only the $12,275,000 in the 1979 base. Accordingly, we approve property and liability insurance for 1984 of $31,076,000.

Pension and Welfare

FPL's 1979 actual O&M expenses for this account were $33,661,000. For 1984, the Company has forecast $70,353,000, which is $11,503,000 in excess of the 1984 benchmark of $58,850,000. FPL states that the major contributions to these resulted from:

1. Bargaining Unit employees became eligible to contribute to the Employee Thrift Plan, and employees in general increased the level of their participation, which resulted in an increase of $2,820,000;

2. The initiation of the Dental Assistance Program in 1982 added $1,625,000;

3. Employee Pension costs increased $3,317,000 due to increased contribution requirements, IRS changes to funding requirements and the accrual needed because of additional employees; and

4. Medical costs have increased faster than inflation by $5,889,000.

We accept the additional $3,317,000 **[*120]** related to IRS changes and increased contribution requirements and add that amount to the benchmark of $58,850,000 for an approved amount of 1984 O&M in this account of $62,167,000. We reject the $1,625,000 associated with the Dental Program because FPL has not provided competent substantial evidence that assisting its employees with their dental expenses is either necessary or, if it is, that the costs are reasonable. Likewise, the Company has failed to demonstrate by competent substantial evidence that its Employee Thrift Plan (essentially a Company-subsidized savings plan), let alone the increases in that plan, are necessary to its provision of electric service to its customers. Accordingly, we disallow the $2,820,000 associated with the increases in this program. We also disallow the $5,889,000, for inclusion in rates, in medical costs that have increased faster than inflation, we have expanded the 1979 costs by customer growth in addition to inflation.

Computer Services

FPL's 1979 actual computer services expenses were $5,124,000 and are projected to be $46,366,000 for 1984, which is $7,408,000 in excess of the 1984 benchmark. We consider that expansion by CPI **[*121]** and customer growth should have been adequate for these services. Stated another way, FPL has not demonstrated by competent substantial evidence that these additional projected computer costs are necessary for the provision of the efficient electric service. Additionally, the Company has not indicated what productivity savings have been realized in manpower reductions, or others, through the use of greater computer services. We allow the 1984 benchmark of $8,958,000 in 1984 O&M.

Telephone Expenses

FPL's actual 1979 expense in this category was $5,831,000 and is forecast to be $11,446,000 in 1984, which is $1,252,000 in excess of the 1984 benchmark. Based upon our understanding of this record, we find that the $1,252,000 in excess of the benchmark was based upon projected telephone rate increases that have not occurred. Accordingly, we disallow $1,252,000 and approve for inclusion the $10,194,000 benchmark figure.

Rate Regulation Expense

FPL has forecast $2,047,000 for this category in 1984, which is $629,000 in excess of the 1984 benchmark. While the Company states that the difference is due to increased regulatory activity at the State and Federal levels, we **[*122]** note that one such activity, fuel adjustment hearings, have been reduced from 12 per year to 2 per year since 1979, which should have resulted in reduced costs. We find that FPL has not presented competent substantial evidence to quantify the increase above the benchmark, and, therefore, disallow $629,000.

Juno Beach Facility Operations

FPL has projected $1,073,000 for the operation of this facility, which was completed in 1982 and for which there was no cost in 1979. While this is a new facility, we find that the costs of operating it should have been covered by the increases we have allowed in most areas for both inflation and customer growth. Accordingly, we disallow the $1,073,000 related to this item.

Juno Beach Relocation Expenses

FPL has forecast $750,000 for relocating employees to the Juno Beach facility. This issue is more throughly discussed below, where the expense is disallowed.

Biweekly Payroll Adjustment

FPL has forecast $1,000,000 in order to properly match payroll expenses paid with expenses incurred each month. FPL has failed to adequately explain this adjustment. We do not understand how this adjustment occurs and, therefore, **[*123]** disallow the $1,000,000 requested.

Rental Office Space

FPL has requested $5,459,000 for rental office space in 1984, which is $581,000 greater than the 1984 benchmark. We find that FPL has not proven that the increases above and beyond those provided by inflation and customer growth are either necessary or reasonable. Accordingly, we disallow $581,000 in this category.

Contract Line Clearing

FPL has forecast $14,844,000 or $1,891,000 in excess of the 1984 benchmark for line clearing operations. We accept the Company's justification that its earlier attempts to reduce costs in this area were not successful and that customer dissatisfaction with lower service and increased storm damage demand that the historical real funding to this activity be restored. Accordingly, we allow $14,844,000 for line clearing in 1984.

Vehicles - Company

FPL's 1979 actual expense for this activity was $10,321,000. When expanded for CPI and customer growth the 1984 benchmark is $18,044,000. FPL's 1984 forecast and request in this case is for $23,594,000. In defense of the increase above the benchmark, FPL states, in part, that vehicle utilization has risen as a result of going **[*124]** to two-men work crews, so that the vehicles used per T&D filed employee is up from 1979 levels. We accept this justification and allow the incremental increase of $276,000 associated with transmission and the $2,614,000 associated with distribution. We find that the Company has not justified the remainder of the increase by competent substantial evidence. We, therefore, approve the inclusion of the 1984 benchmark plus the increment proven of $2,890,000, for a 1984 total of $20,934,000.

Uncollectible Accounts Receivable

FPL has forecast 1984 expenses for this account as $10,629,000, which is $2,319,000 in excess of the banchmark. FPL has also provided convincing evidence that uncollectibles are more closely correlated to unemployment levels than to inflation and customer growth. We find this evidence persuasive and include the requested amount of $10,629,000 in allowable O&M.

Transmission Operations

FPL has requested $12,700,000 for this activity, which is $943,000 more than accounted for by the benchmark. We have considered FPL's explanation for this additional increase but do not accept it as constituting adequate proof that the increment is either **[*125]** necessary or that its cost is reasonable. Accordingly, we disallow the $943,000 amount above the 1984 benchmark of $11,757,000.

Impact of 1980 Arbitration Case

FPL says that a labor dispute involving the connecting and disconnecting of meters resulted in its arbitration in 1980. The arbitrator ruled that the bargaining unit should be given the work of reconnecting meters, which has resulted in two field trips where only one was previously necessary. FPL states that this ruling resulted in the hiring of an additional 29 personnel and additional annual expense of $913,000.

We note that FPL has renegotiated its union contract since 1980 and question why this obviously wasteful and inefficient practice of using two field trips where one was sufficient was not bargained away. We consider that such additional expense is clearly not necessary to the provision of efficient electric service and shall disallow the same.

Divisions Programs

FPL has requested $12,376,000 for divisions programs in 1984. Although this amount is significantly above the 1984 benchmark, FPL has provided detailed justification showing that these programs are mandated by governmental agencies, will **[*126]** result in more efficient service to its customers or are otherwise necessary and prudent. Accordingly, we approve the inclusion of $12,376,000 for this activity for 1984.

Total Adjustments to 1984 and 1985 for Reasonableness

As was mentioned at the beginning of this section of the order, we were initially dissatisfied with most of the Company's explanations for why its 1984 projected costs exceeded the 1984 benchmark for CPI and customer growth. As a result of an additional opportunity to justify these increases, the Company has persuaded us that a significant portion of the incremental increases are necessary and reasonable. On the other hand, despite this additional opportunity, FPL has failed to justify why its customers should be required to shoulder the burden of some $82,022,000 of increased O&M costs over and above the level of increases explained by expanding the Utility's 1979 O&M costs for both increases in inflation and customer growth. Accordingly, we disallow $82,022,000 of the O&M requested for 1984. When the approved amounts have been jurisdictionalized, the approved O&M for 1984 is $656,975,000. In order to arrive at the O&M for 1985, we have expanded **[*127]** the approved O&M for 1984 of $656,975,000 for CPI and customer growth which results in an approved O&M for 1985 of $721,490,000 (656,975,000 X 1.0982). It is also appropriate to note here, that all electric utilities are on notice that their initial filings should contain all justification of expenditures above the guidelines used in this case, as we are under no obligation to give each utility more than one opportunity to justify that their actual or estimated costs are necessary and prudent.

9. Juno Relocation

In its 1982 rate case, FPL requested in operating expense $5,100,000 associated with its relocation of certain administrative personnel from the Miami general office to a new headquarters building in Juno. In that case, we disallowed the entire amount on the basis that it was non-recurring. During his cross-examination in this case, witness Dady acknowledged that the Company's estimate in the last rate case was overstated and that the actual amount of the relocations was approximately $1,700,000.

In the present case, FPL has included Juno office relocation costs of $724,000 for 1984 and $1,466,000 for 1985. While these projections for continued moving **[*128]** expenditures may address our "non-recurring" concern, the Company still has not adequately proven that these projected expenses are necessary to the provision of electric service and, if so, that the level of expenses are reasonable. Absent such proof, we shall disallow $724,000 for 1984 and $1,466,000 for 1985 as being unreasonable.

10. Fuel

As previously discussed, fuel has been removed from the calculation of base rates. This results in a reduction in O&M of $1,249,025,000 for 1984 and $1,382,520,000 for 1985.

11. Conservation

As with fuel, conservation revenues and expenses have been removed from the calculation of the Utility's base rates. Accordingly, O&M is reduced $39,813,000 in 1984 and $42,996,000 in 1985.

12. Economy Sales

The parties have stipulated and we approve the exclusion of economy energy sales profits from O&M expenses.

The necessary adjustments are to increase O&M expense by $1,262,000 in 1984 and by $1,320,000 in 1985.

B. Depreciation and Amortization

The Company has proposed test year depreciation expense of $265,997,000 for 1984 and $285,234,000 for 1985. As a result of our adjustments, 1984 depreciation and amortization are **[*129]** increased by $6,712,000 to an approved amount of $272,709,000, while 1985 is increased by $9,111,000 to $294,345,000.

C. Decommissioning of Nuclear Generating Units

In its original filing, FPL proposed a decommissioning expense accrual of $18,384,000 for 1984 and $18,878,000 for 1985. These amounts were initially correct, however, our revision to the jurisdictional separation factors requires a reduction of $251,000 in 1984 and $56,000 in 1985. The resulting decommissioning expense for 1984 is $18,133,000 and $18,822,000 for 1985.

D. Amortization of Property Loss

As a result of our revisions to the jurisdictional separation factors, amortization of property loss must be reduced by $22,000 in 1984 for an approved amount of $2,105,000. The 1985 amount must be reduced by $7,000 to an approved amount of $2,177,000.

E. Taxes Other Than Income Taxes

1. Revision of the Regulatory Assessment Fee

Subsequent to the filing of the Company's petition, the regulatory assessment fee was increased from one-sixteenth (1/16) of one percent (1%) to one-eighth (1/8) of one percent (1%), effective January 1, 1984. We believe an adjustment to the Company's filing is appropriate **[*130]** to recognize this known change. This adjustment increases taxes other than income taxes by $1,178,000 in 1984 and $1,223,000 in 1985.

2. Effect of Other Adjustments

The total of taxes other than income taxes included in operating expense is $107,415,000 for 1984 and $114,000,000 for 1985, determined as follows:

	1984	1985
Company per books adjusted jurisdictional	$127,446,000	$135,313,000
Unbilled Revenue	2,000	
Parrish Lake	2,000	2,000
Regulatory Assessment Fee	1,178,000	1,223,000
Separation Factors	(668,000)	(167,000)
Revenue Forecast	118,000	230,000
Fuel	(20,024,000)	(21,921,000)
Conservation	(639,000)	(680,000)
TOTAL	$107,415,000	$114,000,000

F. Income Taxes Currently Payable

1. Interest Synchronization

All parties agreed that the interest expense used to compute income tax expense should be the interest inherent in the allowed capital structure. The Company made the proper adjustment in its filing. However, due to adjustments we made to the Company's requested rate base, both the amount of debt and the cost of debt in the allowed capital structure are different than those contained in the Company's **[*131]** filing. These adjustments result in less interest expense being reflected in the Company's capital structure. Therefore, income tax expense must be increased by $11,602,000 in 1984 and $10,811,000 in 1985.

2. Effect of Other Adjustments

This adjustment is mechanical in nature and serves to reflect the effect on income tax expense of the various other adjustments we have made to the Company's proposed operating income, including the adjustment made to the Company's proposed separations factors. This results in an increase to income tax expense of $29,297,000 in 1984 and $52,433,000 in 1985.

G. Deferred Federal Income Taxes (Net)

1. Adjustment to properly state the deferred income tax reserve.

This adjustment to the Company's filing was proposed by the Company's witness, Mr. Hugh Gower. The adjustment is meant to correct the Company's filing which omitted the effect of various book-tax timing differences from the deferred income tax provision. The effect of the adjustment is to increase deferred income taxes by $585,000 for 1984 and $525,000 for 1985.

2. Effect of Other Adjustments

This adjustment is mechanical in nature and reflects the effect on deferred **[*132]** income tax expense of the various other adjustments that we have made to the Company's proposed net operating income. The adjustment increases deferred income taxes by $11,006,000 in 1984 and reduces deferred taxes by $9,444,000 in 1985.

H. Investment Tax Credits (Net)

The Public Counsel once again urges us to treat the Investment Tax Credit (ITC) differently than we have done in the past. Once again, we decline to do so for fear that Public Counsel's proposed treatment may jeopardize the Company's ability to utilize the credit. We recognize that the treatment proposed by Public Counsel is more beneficial to the ratepayers, and we have directed two Florida utilities to submit revenue ruling requests to the Internal Revenue Service (IRS) on this issue. As we have done in the past, we will treat the ITC as common equity for purposes of determining the Company's income tax expense allowed for ratemaking purposes. The revenues related to the increased taxes allowed on the debt portion of ITC are to be collected under bond or corporate undertaking, subject to refund with interest. Final resolution of this issue will wait until a response is received from the IRS. **[*133]** The revenues subject to refund are $16,731,709 in 1984 and $17,394,106 in 1985.

1. ITC Amortization Rate

In its filing the Company used a 3.45% rate, its proposed composite depreciation rate, to amortize the ITC to cost of service. Subsequent to the rate filing, we denied the proposed depreciation rates and, pending a new study, required that the Company use its existing depreciation rates. This results in a 3.58% composite rate being utilized. Therefore, we believe this rate should be used to amortize the ITC. This adjustment decreases income tax expense by $597,000 in 1984 and $660,000 in 1985.

I. Gain on Sale of Plant

FPL has included $4,051,064 in 1984 and $4,452,902 in 1985 as gain from the sale of land. However, because we have previously determined we would include the unamortized gain on the sale of Account 101 property in the calculation of working capital, we shall also include the amortization of these gains in the income statement. The net adjustment for 1984, including the revision to the separation factors, is a decrease to operating expense of $2,350,000, for a total decrease related to gain on sale of land for 1984 of $6,402,000. For 1985, the **[*134]** additional decrease is $2,474,000 for a total decrease of $6,927,000.

Total Operating Expenses

Total operating expenses, as adjusted herein, are $1,325,034,000 for 1984 and $1,432,592,000 for 1985.

III. Net Operating Income

The net operating income is derived by subtracting total operating expenses from operating revenues. For the 1984 test year, net operating income is $573,103,000 ($1,898,137,000 - $1,325,034,000). In 1985, net operating income is $542,405,000 ($1,974,997,000 - $1,432,592).

Special Comment Regarding O&M Costs

Florida's electric utilities are now facing a "breather time" in their construction requirements. Our review of the state ten-year site plan indicates that it will be in the mid 1990's before any new generating plant not already certified is needed, therefore it affords management the opportunity to spend more effort in increasing productivity and controlling their O&M costs. We commend to them that they do so. Furthermore, we believe a good first step is to justify to their own Board of Directors their operating budgets and establish procedures for more Board involvement in this critical area. It is not only important **[*135]** that the electric utilities provide reliable service, but that they do so as economically and efficiently as possible. Our interest is to provide them with the incentives to do so.

REVENUE EXPANSION FACTOR

The purpose of the revenue expansion factor (NOI multiplier) is to gross up or expand the Company's net operating income deficiency to compensate for income taxes and revenue taxes that the Company will incur as the result of any revenue increase. Subsequent to the filing of the Company's petition, the regulatory assessment fee was increased from one-sixteenth of one percent to one-eighth of one percent, effective January 1, 1984. The parties have stipulated and we approve the use of the one-eighth of one percent regulatory assessment fee in calculating the revenue expansion factor. Consistent with our decision in Tampa Electric Company's most recent rate case in Docket No. 830012-EU, FPL has requested the inclusion of an uncollectible account component, which is necessary to recognize that a portion of the revenue increase will not be realized because of uncollectible accounts. Because of projected variances in both projected uncollectibles and sales between 1984 and **[*136]** 1985, FPL proposed a .2760% component in 1984 and .2656% in 1985.

We approve the inclusion of an uncollectible accounts component in the revenue expansion factor, however, because we consider that the .2656% proposed for 1985 is more representative of the Company's historical experience, we shall utilize that number in the calculation of the factor for both 1984 and 1985. The resulting approved revenue expansion factor is 1.986883 for both years, developed as follows:

	1984 & 1985
Revenue Requirement	100.0000
Gross Receipts Tax	(1.5000)
Regulatory Assessment Fee	(.1250)
Uncollectible Accounts	(.2656)
Net Before Income Taxes	98.1094
Income Taxes	(47.7793)
Revenue Expansion Factor	50.3301
NOI Multiplier	1.986883

REVENUE REQUIREMENTS

Having determined the Company's rate bases, the net operating income applicable to the test period, and the overall fair rate of return, it is possible to calculate any excess/deficiency of revenues. Multiplying the rate base value for 1984 of $5,813,566,000 by the fair overall rate of return of 10.56% yields an NOI requirement for 1984 of $614,104,000. The adjusted net operating income for the test year amounted **[*137]** to $573,103,000 resulting in an NOI deficiency of $41,001,000. Applying the appropriate NOI multiplier of 1.986883 to this figure yields a deficiency of $81,464,000 in gross annual revenues. The comparable figure for 1985 is $114,984,000, the calculation of which is detailed below:

(000's)	1984	1985
Rate Base	$5,813,566	$6,184,410
Rate of Return	X 10.5633%	X 10.3983%
Required NOI	$ 614,104	$ 643,074
Adjusted NOI	- 573,103	- 542,405
NOI Deficiency	$ 41,001	$ 100,669
NOI Multiplier	X 1.986883	X 1.986883
Gross Revenue Increases	$ 81,464	$ 200,018
Prior Year Increase	0	- 85,034
Net Revenue Increase	$ 81,464	$ 114,984

In view of the above, we find and conclude that FPL should be authorized to increase its rates and charges so as to generate $81,464,000 in additional revenues annually for the year 1984.

1985 Subsequent Year Adjustment

As a result of these proceedings, we have determined that the Company should be allowed to increase its rates and charges effective January 1, 1985, so as to allow it to collect additional gross annual revenues in the amount of $114,984,000. While effective on the first day of the year, these **[*138]** new rates and charges will not be applicable to customer billings until 30 days later.

While we have tentatively approved the additional revenue requirement for 1985, we recognize that our decision was based in large part on data in this rate filing that was compiled in mid to late 1983. Inherent in this fact is the possibility that the assumptions we relied on in reaching our decision may materially change before the resulting rates become effective. Of course, this possibility, if it occurs, could result in conditions under which the Company would either under or over earn. Likewise, is the possibility that the underlying assumptions will not materially change and the Company will earn within the authorized range.

In order to address the possibility of material changes in the underlying assumptions, we shall, in August, hold a workshop for the purpose of identifying specific criteria and procedures to be used in determining whether the subsequent year adjustment will become effective as initially approved or require modification. This workshop will be held in a separate docket and will be open to all interested parties. A primary purpose of the workshop will be to acquire **[*139]** the input necessary to our establishing a rulemaking docket on subsequent year adjustments.

It is our present intention to allow the tentatively approved 1985 revenue increase to go into effect as scheduled. Following the workshop in August, the burden will be on the affected parties to petition for a modification of the 1985 increase if they believe one is required. Additionally, we emphasize that the burden will be on the moving party to demonstrate that the alleged changed assumptions are sufficiently material to place the Company's earnings outside the range of reasonableness. Quite simply, we do not propose to hold a hearing on the 1985 increase unless it is requested by Staff, the Company, or other intervenors in this case.

JURISDICTIONAL SEPARATION

Jurisdictional separation is the result of allocating the Company's total system costs for the test period between its retail and wholesale operations. Jurisdictional separation provides the basis for determining the Company's retail revenue deficiency. At issue is whether the jurisdictional separation performed by the Company properly reflects the jurisdictional NOI and rate base responsibility. The most important **[*140]** jurisdictional separation factors are those for energy and production plant. For 1984, the Company proposed 96.404 and 3.596, respectively, for the retail and wholesale energy separation factors and 95.045 and 4.955, respectively, for the retail and wholesale production plant separation factors. For

1985, the Company proposed 97.270 and 2.730 respectively, for the retail and wholesale energy separation factors and 97.598 and 2.402, respectively, for the retail and wholesale production plant factors. We decline to approve these separation factors.

The initial problem that we find with the Company's proposal is that it is based upon the forecast prepared in July 1983. As was earlier discussed in this Order, the Company's December 1983 forecast more accurately reflects the conditions expected to exist in the test year. Thus, separation factors should be based on this forecast. Additionally, the Company's recommended factors need to be adjusted for the load research errors discovered after the filing, also discussed earlier in this Order.

The major issue relating to jurisdictional separation in this case is the treatment of the loss of wholesale load resulting from the plant constructed **[*141]** by Seminole Electric Cooperative, Inc. (Seminole). As a matter of principle, we must decide whether it is appropriate for the retail jurisdiction to pick up the costs associated with serving the lost wholesale load. We do not find the problem limited to which jurisdiction is responsible for the excess plant. We must consider the fact that the Commission approved Seminole's new plant and the Oil Backout project entered into by FPL.

Because we cannot collect from bygone customers, we must look to the situation as it will exist in the test year and the period the rates will be in effect. The most recent forecast does take these factors into consideration. We, therefore, approve separation factors for 1984 of 93.894 and 6.106, respectively, for energy and 93.748 and 6.252, respectively, for production plant. For 1985, we approve the factors of 96.963 and 3.037, respectively, for energy and 97.308 and 2.692, respectively, for production plant. These factors provide the most equitable results when the rates will be in effect. We recognize that the retail ratepayers will be paying for a greater percentage of FPL's rate base, but we expect FPL to aggressively market the capacity **[*142]** not currently needed for retail loads. The revenue from this marketing should be credited to the retail ratepayers to help offset the additional plant costs abandoned by wholesale customers.

RATE STRUCTURE AND RATE DESIGN

Having ascertained the Company's revenue requirement and the amount of revenue increase necessary, we now turn our attention to rate design. We must determine the rate of return currently earned by each rate class, the increase in revenue requirement allocated to each class, and how each class's revenue responsibility will be spread between the customer, energy and demand charges. In this rate proceeding, we have also reviewed the continued appropriateness of several aspects of the Company's present rate structure. We begin first with the cost of service studies presented in this case.

Cost of Service Methodology

In this rate case, several cost of service studies based on four different demand allocation methodologies were presented to us for consideration. The Company sponsored the Classification of Facilities Method (CFM), which recognizes the different characteristics of FPL's production facilities in classifying production investment. **[*143]** FIPUG proposed the average of the four summer and two winter coincident peak methodology. FRF supported the use of the 12 coincident peak and one-thirteenth average demand method (12CP and 1/13), as did the FEA. Staff advocated the 12CP and 1/13 method adjusted so that the portion of the cost of the St. Lucie 2 plant over and above the cost of a peaking unit is allocated to energy.

Mr. Tammy, testifying for FPL, advocated the use of the CFM method that he developed. He testified that the CFM method appreciably improves upon previous attempts to measure how facilities are used to serve customers and that it ensures the most fair and equitable allocation of costs among the Company's ratepayers. Mr. Tammy's methodology employs a classification process that recognizes that different types of production facilities have different demand and energy serving characteristics. A capacity factor approach was used in classifying steam facilities as 77% demand and 23% energy. Nuclear facilities were classified as 15% demand and 85% energy based on the lowest cost option to the nuclear facility that would enable FPL to meet its peak demand. Other production facilities were classified as **[*144]** 100% demand because they are operated to meet peak loads of short duration. We find inconsistencies with Mr. Tammy's method in that it classifies production plant under one method and transmission plant under another method. Additionally, different types of production plant are classified differently; the classification being based upon steam units being dependent upon the availability of nuclear units. If the assumptions about nuclear units lower, steam will be projected greater use and, therefore, more demand. The CFM method would require some refinement before we would approve its implementation.

This Commission has approved the use of the 12CP and 1/13 methodology for cost of service studies in the last five major electric rate cases. In the Company's last rate case, we employed the 12 CP and 1/13 methodology, but adjusted it so that a portion of the cost of the St. Lucie 2 plant equal to the fuel savings associated with this nuclear plant was allocated on energy, as opposed to demand. In this case, Staff recommended that a portion of St. Lucie 2, equal to the residual cost above that of a peaking unit capable of satisfying the Company's "peaking" needs, be allocated on **[*145]** energy. This adjustment is based on the fact that plants are needed to serve loads at more than just the system peak hours. We agree with Staff's analysis and find that the 12 CP and 1/13 methodology adjusted for St. Lucie 2 is the appropriate cost of service methodology to be used in this case. However, in approving this methodology, we recognize the inconsistency in failing to treat all of the Company's nuclear generating plants in the same fashion as St. Lucie 2. Additionally, we note that in the future we shall consider the relationship of off-peak to peak rates and shall attempt to treat the inconsistency between the 12 CP methods and peak/off peak allocation.

FIPUG proposed that fuel costs should be allocated among customer classes with all costs and that fuel revenues received through the fuel adjustment clause should be subtracted to determine the revenues to be received through base rates. Fuel costs and revenues were excluded from the cost of service studies by the Company. Staff agreed with the Company's treatment of these dollars. We find that fuel costs and revenues are properly handled in the fuel adjustment docket, which provides for a true-up every **[*146]** six months, and that they should continue to be excluded from base rates (with the exception of fuel in working capital). FIPUG's argument that it should receive lower than average fuel costs has already been partially considered by imputing different line losses by rate class and by making available rates with different energy charges for on-peak and off-peak use.

The question of the treatment of purchased power capacity costs was also raised by FIPUG. Specifically at issue is the treatment of FPL's capacity costs under its Unit Power Sales Agreement (UPS) with the Southern Company. FIPUG contends that purchased power costs should be allocated among customer classes with all other costs and that revenues received should be subtracted with fuel revenues to determine the revenues to be received through base rates. Where the price paid for purchased power includes a capacity charge and is higher than what it would cost the utility to generate the power, FIPUG argues that the costs should be allocated partially to demand. However, where purchased power costs are being rolled into base rates, FIPUG contends that any capacity charges should be allocated on the basis of demand. FIPUG **[*147]** did not present any evidence delineating the impact or amount of UPS costs that are capacity related. Our decision on this issue is based on Order No. 11217, holding that the primary purpose of the project was fuel savings and approving FPL's transmission line as an Oil-Backout Project pursuant to Rule 25-17.16, Florida Administrative Code. In that Order, we determined that all of the costs of the project are to be recovered in the Oil-Backout Clause. We find that these costs have not been included and should not be included in the cost of service study because they will be treated in the separate clause.

A separate issue raised in this case is whether the cost of the 500kv transmission line Oil-Backout project and the related capacity charges should be rolled into base rates for all customer classes. The Company proposed to include .302¢ per KWH in base rates. Public Counsel objected to this treatment. Staff recommended that the cost of the project, less related capacity charges, should be included in base rates. The Commission has removed from base rates items such as fuel and conservation. Rule 25-17.16(4)(d), Florida Administrative Code, provides for oil-backout project **[*148]** costs to be included in base rates at the Company's next rate case filing, but does not mandate such treatment in all cases. Consequently, we favor keeping base rates as "pure" as possible, within the constraints of the Commission's rules and decline to accept FPL's proposal to roll the oil-backout project costs into base rates at this time.

FIPUG raised the issue as to whether regulatory assessment fees and bad debt expenses were allocated properly by the Company in the cost of service study. Regulatory assessment fees were properly allocated on revenues. Bad debt expenses were allocated to the various rate classes on the historical write-off of revenues and then assigned to the energy component. We find that the Company's cost of service treatment of these items is proper.

Allocation of Revenue Increase

We have granted the Company an overall increase of $81,464,000 for 1984. Staff recommended, and we approve, that the increase be allocated among customer classes so that each class moves toward parity in rate of return for 1984 to the greatest extent practical with no class receiving an increase greater than 1 1/2 times the system average including base revenue, **[*149]** fuel, conservation, and oil-backout. In accordance with this policy, the classes furthest from parity, GSLD-1, CS-1, GSLD-2, CS-2, SL-1, OL-1, and MET, shall receive the maximum allowed increase of 1 1/2 times the system average. The GSD-1, GSLD-3, CS-3, and SL-2 rate classes shall be given no increase because these classes are already over parity at present rates. The OS-2 class shall be given an increase equal to the system average. The remainder of the revenue increase shall be distributed between the RS and GS rate classes to move RS closer to parity and to set the breakeven point between RS and GS rates at approximately 3,000 KWH.

The rates of return for 1984, by customer class, with the revenue increase we have approved are:

RATE CODE	ROR /	INDEX
RS	10.16/	.96
GS-1	11.93/	1.13
GSD-1	11.94/	1.13
OS-2	11.96/	1.13
GSLD-1	9.74/	.92
CS-1	10.39/	.98
SUM GSLD/CS-1	9.83/	.93
GSLD-2	9.53/	.90
CS-2	10.24/	.97
SUM GSLD/CS-2	9.79/	.93
GSLD-3	10.10/	.96
CS-3	11.42/	1.08
SUM GSLD/CS-3	10.51/	.99
OL-1	10.24/	.97
SL-1	8.92/	.84
SL-2	11.04/	1.04
METRORAIL	9.94/	.94
TOTAL RETAIL	10.56/	1.00

The 1984 rates will only be in effect for six months **[*150]** when the second-step revenue increase will go into effect for 1985. Because of this fact and the problems with the load research data described below, and because the rate classes will be reasonably close to parity after the 1984 increase, we have determined that the 1985 increase shall be distributed to all classes by a uniform percentage increase collected through the base KWH charge (except for the SL-1 and OL-1 classes).

Load Research

Load research is used to estimate class contributions to monthly system coincident peak demands and class noncoincident demands for those classes of customers not equipped with magnetic tape meters. These estimates are used to develop allocation factors for demand-related items in the cost of service study. The results of a cost of service study are dependent upon the quality of the load research upon which the study is based. The issue presented in this case is whether the load research performed by FPL is adequate.

For this rate proceeding, the Company conducted load research for the RS-1, GS-1, GSD-1, and GSLD-1 rate classes. Subsequent to the filing of the rate case, FPL discovered errors in the entering and processing **[*151]** of stratum data for the GS-1, GSD-1 and GSLD-1 rate classes. In response to this problem, the Company filed Exhibit 3b, which corrects the errors and replaces the load research previously filed. The Company and Staff support the use of the revised data. We agree.

Statistical accuracy or precision refers to the measurement of the difference between a sample result and the result from a complete measurement under the same conditions. The Commission has adopted Rule 25-6.437, Florida Administrative Code, regarding cost of service load research. This Rule requires the four large investor-owned utilities to design samples to provide estimates of the summer and winter peak demands and the average of the 12 monthly coincident peaks for each class (that accounts for more than 1% of a utility's annual retail sales) within plus or minus 10% at the 90% confidence level. Neither the GS, GSD or GSLD load data meet this criterion because all or part of the load data is based on judgmental sampling. The precision or accuracy of a judgmental sample cannot be calculated. Only judgment statements can be made about the accuracy of the data. However, Exhibits 3A and 3J provide comparisons of **[*152]** the load and noncoincidence and coincidence factors from the judgmental samples and the portions of the 1983 probability samples which are available. For most of the months, the factors for the two GS samples are fairly close. However, Exhibit 3J shows that the load and coincidence factors for the judgmental samples for GSD-1 and GSLD-1 are considerably higher than those from the probability samples. Since the Company did not compare the factors for the same months, it is not clear whether the demand related costs for those classes are understated in the cost of service study.

Staff raised the question of whether there was a large non-response bias for the RS sample because the response rate for that sample was only 30%. The Company's sampling procedure probably does minimize the nonresponse bias. However, we do not know whether there is a bias from nonresponse, and, if so, how large it is. Company witness Bentley testified that he was not satisfied with the 30% response rate and that the Company has worked to obtain a 75% response rate in its new RS sample.

The final question regarding the Company's load research relates to the fact that the load research for the various **[*153]** classes does not cover the same time period. The Company used load data from 1977, 1981 and 1982 and part of 1983. The Company feels the difference in time periods is of little importance, particularly when using a 12 CP demand allocator, although Dr. Bentley conceded that it could have an effect on any given month. We feel that load research for cost of service purposes should be conducted on all classes in the same year so that possible fluctuations due to weather, price and economic conditions are eliminated. The four major electric utilities are now conducting load research on all classes at the same time.

The Company contends that the load research is adequate for the purpose of this case. Dr. Bentley testified that the Company was upgrading the load research program. FPL now has statistically valid samples in place for the RS-1, GS-1, GSD-1 and GSLD-1 classes, which are the ones requiring sampled data, and thus is now at the threshold of having complete and more accurate load research for all the classes requiring it. We agree with Staff and find that the load research submitted by the Company is inadequate, for the reasons previously stated, but it is the best **[*154]** data that we have for this case and will be used for rate design in this case.

Forecast by Revenue Class

The customer, KW and KWH forecast for 1984 and 1985, by revenue class, that the Company filed in this case were prepared in the fall of 1982. This forecast was based on unreasonably high and inconsistently applied CPI assumptions. In FPL's original load forecast, the CPI was assumed to increase 8.4% in 1983 and 7.5% in 1984 and 1985. The Company filed an updated forecast for 1984 and 1985 that it prepared in December 1983. The CPI assumptions used in FPL's December 1983 forecast were 3.5% in 1983, 5.0% in 1984 and 5.7% in 1985. Other assumptions used in the load forecasting models were updated in the December 1983 forecast, but the changes were not as large as the CPI change. The latest sales forecast is .77% greater than originally forecast for 1984 and .67% greater for 1985. The latest customer forecast is .98% greater than originally forecast for 1984 and 1.26% greater for 1985.

Dr. Bentley, testifying on behalf of the Company, stated that the most recent forecast is the more accurate forecast. We find that the most accurate forecast should be used in this rate **[*155]** case. Therefore, the December 1983 forecast shall be used in lieu of the forecast originally filed by the Company.

Billing Determinants

Billing determinants are the estimates, by rate class, of the number of bills, KWH consumption, and billed KW. The Company's proposed billing determinants were based on an overall forecast prepared in July 1983. As discussed previously, we determined that the Company's most recent forecast, prepared in December 1983, should be used in this case. Consequently, we reject the Company's proposed billing determinants and shall use the billing determinants from the December 1983 forecast in this case.

The projected billing determinants are based on historical relationships between rate classes and revenue classes. The ratios are then applied to the updated revenue class forecast. We find that the methodology and assumptions used to develop the test year billing determinants are reasonable.

To design time of use rates, the Company must estimate how much of the total KW and KWH for each class is consumed in the peak periods. For the GSD class, the Company assumed 100% of the billed demand would occur in the peak periods. Lloyd Williams, **[*156]** testifying on behalf of FPL, stated that this was done for rate design purposes so that the on-peak demand charge, when added to the maximum demand charge, would equal the standard demand charge. He further testified that the percentage of billing demand for this class that could actually be expected to occur in the peak period is 85%. We find that it is more appropriate to use what is expected to occur, 85%, than to use 100%, simply to make the rates come out to a desired level. Therefore, we shall consider that 85% of the total demand is registered during the on-peak period for the purpose of designing time of use rates.

Customer Charges

We find that customer charges should reflect customer-related costs, as determined in the cost of service study. The proposed customer charges are based on the Company proposed CFM cost of service methodology, at an equalized rate of return. We decline to approve the Company's proposed customer charges, but instead accept the Staff's recommendation, which employs the customer charges resulting from the unit cost at the class proposed rate of return developed from the Commission approved cost of service study. The only exceptions **[*157]** are, for the GS, GSLDT-3, and CST-3 classes, the customer charge shall be raised to the limit of 50% and for the unmetered GS customers, a $3.00 differential shall be employed to recognize the lack of meter-related costs to serve these customers. The approved customer charges are as follows:

Rate Cost	Present Customer Charges	Unit Cost W/O Minimum Distribution System	Approved Customer Charges	
RS	$5.15	$5.66	$5.65	
GS	6.00	16.29	9.00	Metered
GS Unmetered	6.00	11.97	6.00	Unmetered
GSD	41.00	36.29	35.00	
GSLD-1	70.00	41.55	41.00	
GSLD-2	265.00	168.12	170.00	
GSLD-3	265.00	2287.07	400.00	
CS-1	210.00	111.33	110.00	
CS-2	265.00	177.35	170.00	
CS-3	265.00	2573.68	400.00	
OS-2	6.00		9.00	
MET	285.00	210.64	215.00	

Standard Demand Charges

We find that the standard demand charges should remain at present levels, with the exception of the MET class, which should be set at unit cost at the approved class rate of return. The decision to maintain demand charges at their present level is based on the fact that presently on-peak KWH's are more highly correlated with coincident demand than billing demand. Plant costs are for the most part allocated **[*158]** on coincident demand. Furthermore, the demand charges for GSLD-3 and CS-3 are above unit cost at the class rates of return at present rates. We view setting demand charges above unit cost as more inequitable to low load factor customers than the inequity to high load factor customers, from having demand charges at below unit cost, because of the present higher correlation between on-peak KWH's and coincident demand than between billing demand and coincident demand. The MET rate should be set at unit cost at the approved class rate of return because MET is billed on its maximum demand, which is concident with the system monthly peaks.

FIPUG contended that the failure to set the demand charge at full unit cost results n an improperly calculated energy charge. We find that we must be fair to both high and low load factor customers and, therefore, approve the following standard demand charges:

Rate Code	Approved Standard Demand Charges
GSD	$6.25
GSLD-1	6.25
GSLD-2 *	6.25
GSLD-3 *	6.25
CS-1	6.25
CS-2 *	6.25
CS-3 *	6.25
MET	10.45

In the Company's last rate case, the policy of not billing the first 20 KW of demand on rate schedules GSD-1 and GSDT-1 **[*159]** was reduced to not billing the first 15 KW. In that case, the Company proposed to discontinue this policy. We agreed that it should be eliminated gradually so as to temper the impact on small GSD customers. In this case it has been stipulated that the level of demand not billed be reduced to 10 KW, as the second step in the gradual elimination of this policy. We accept this stipulation.

Curtailable Service

At the present time, the Company offers customers three curtailment rates, CS-1, CS-2 and CS-3, corresponding to rate schedules GSLD-1, GSLD-2 and GSLD-3. To receive curtailable service a customer must, by contract, agree to curtail his load to a level specified by the customer when called upon to do so by the Company. In return, the customer receives a credit of $1.70 per KW for the difference between his maximum demand in any month and either the demand the customer agreed to curtail to or the actual level the customer curtailed to if curtailment was requested during the month in question. If the customer failed to curtail when requested to do so, he is assessed a one time penalty charge for the month in question and is also billed for the amount of credits he received **[*160]** for the previous 12 months or the number of months since the prior curtailment period, whichever is less.

A properly administered curtailable rate should benefit all ratepayers because it would allow a utility both to avoid purchasing expensive emergency power from other utilities when it would otherwise be necessary for the Company to do so and to treat some portion of the curtailable load as nonfirm load in the generation expansion planning process. A curtailable rate should be a valuable step between firm and interruptible service. The Company has proposed to maintain the level of the curtailment credit at $1.70. FIPUG has proposed that the credit be raised by 25%. In order to evaluate this question, we must consider that benefit is received by the body of ratepayers for the cost of the curtailment credit.

The record evidence establishes that the benefit to all ratepayers of the curtailable rate is non-quantifiable, if it exists at all. The Company has only requested curtailment eight times in the past five years. The Company has not requested curtailment before it has purchased expensive off system emergency power. It also treats all of the curtailable load as firm in **[*161]** the generation planning process. In the forecast year, the ratepayers of FPL will pay approximately 5.6 million dollars for the theoretical benefit of having curtailable service. Since neither the Company or FIPUG were able to quantify the benefits of curtailable service, we find that it would be inappropriate to increase the curtailment credit.

In the last FPL rate case, the Commission voted to require the Company to request curtailment before purchasing emergency Schedule A power from other utilities. However, in response to a Petition for Reconsideration, the Commission reversed tht decision, stating that: "We think that this specific issue was not sufficiently identified as an issue at hearing and, therefore, in the interest of fairness to all concerned, shall reverse our decision requiring the utility to ask its curtailable customers to reduce load prior to buying emergency power." The issue was raised in this proceeding so that it could be discussed adequately by all interested parties. Having considered the testimony of all the witnesses on this issue, we find that the Company should, where practical, request curtailment in lieu of purchasing emergency Schedule **[*162]** A power from other utilities.

The Company posited that there is insufficient time within which to request a curtailment prior to an emergency power purchase being made. However, the evidence established that notification of a curtailment usually requires two hours, while many emergency power purchases last much longer than two hours. Even where there is insufficient time to call a curtailment prior to the actual purchase, curtailments can be called during the purchase. Additionally, the Company should explore the use of solid state data receivers to notify curtailable customers in the future. Finally, we find that the recovery of emergency purchased power may be disallowed in subsequent fuel adjustment proceedings if the Company fails to demonstrate that it requested curtailment before buying emergency power.

FIPUG has raised the issue that FPL would have difficulty inducing any customers to accept the curtailable service if significant additional curtailments were anticipated. The record shows that from 1981-1983 there were only 12 days on which Schedule A purchases were made and curtailments were called on four of them. If these customers could not handle eight more curtailments **[*163]** over a two year period, then perhaps there is not sufficient benefit to the Company, the curtailable customers or the body of ratepayers to continue offering a curtailable rate. With this point in minds we shall request that the Company establish why the curtailable service should not be discontinued in the Company's next rate case. Furthermore, we recognize that at least some of these customers, as well as all ratepayers, could benefit from interruptible rates and we believe that the Company would be prudent to explore this type of offering, as Tampa Electric Company and Florida Power Corporation have.

Street and Outdoor Lighting Rates

Under the Company's proposed street and outdoor lighting rates, the non-fuel energy charge, which recovers non-fuel energy-related, demand-related and customer-related costs other than those related to the fixture and maintenance of the fixture, is subsidizing the cost of the Company-owned fixtures and the maintenance of those fixtures.

The Company proposed non-fuel energy charge for the street and outdoor lighting rates is 2.837¢, while unit cost for those classes, respectively, from the Commission approved cost of service study, are 2.0040¢ **[*164]** and 2.5372¢. It is inequitable that customers who own their fixtures should share in the cost of Company-owned fixtures. Lloyd Williams, testifying on behalf of the Company, agreed that if one wanted all street lighting customers to provide the same rate of return, the energy charge would have to be set at the class approved rate of return. Furthermore, having the energy charge above the unit cost at the class rate of return gives the Company a competitive edge in providing fixtures and poles.

Therefore, the non-fuel energy charge should be set at unit cost at the class approved rate of return. However, because there should be no difference in the actual non-fuel energy-related costs between street and outdoor lights, but because a difference does result from the disparity in class rates of return and customer accounting costs, we shall set the outdoor light non-fuel energy charge at the street light energy charge unit cost.

Turning next to the maintenance charge for these two rate classes, the Company used a 2.5% maintenance factor to develop maintenance charges for 1984. However, maintenance charges developed with this factor generated considerably less revenue **[*165]** than the projected 1984 maintenance expense. Mr. Williams agreed that maintenance charges based on a 3.8% maintenance factor produce revenues closest to the projected maintenance expense and, therefore, are the most cost-based maintenance charges.

Based on the previous adjustments to the proposed street and outdoor lighting rates, the fixture charges need to be adjusted to produce the classes' revenue requirements. Staff agreed with the Company's preference to adjust the fixture charges on a percentage basis. Therefore, fixture charges would be developed on whatever carrying charge is necessary to meet the revenue requirement for each of the classes, except that no fixture charge should be increased by more than 40%. We agree with this treatment. However, Staff proposed to reduce the fixture charge for incandescent lights. We agree with the Company's proposal to price the fixture charge higher than the installed cost of the light in order to encourage the use of more energy efficient lights. Therefore, no total charge for Company-owned fixtures should be lower than the present charge. This decision is in accord with the Commission's conservation policies as stated in the various **[*166]** conservation dockets. Street and outdoor lighting pole charges have been increased approximately 20% and 40%, respectively.

The Company's prefiled 1984 relamping charges should also be approved since they produce revenues close to the projected expense.

For 1985, Staff recommended that all charges should be increased on an equal percentage basis. We agree because if only the energy charge is increased, the customer-owned fixtures would get a much larger percentage increase than the Company-owned fixtures. The result would be the subsidization of Company-owned fixtures by customer-owned fixtures.

The City of Coral Gables raised the issue of whether FPL should be required to provide more pole and fixture choices for its street lighting customers. Sarah Anderson, testifying on behalf of the City, stated that the City presently has 21 different types of street lights in the residential areas. She stated that, in her opinion, this is visual pollution and that FPL owes to the citizens of Florida, generally, and to the City of Coral Gables an obligation to enhance the environment in which it operates.

FPL's position was that it presently offers a wide range of hardware and services **[*167]** for regulated street lighting that it believes is adequate. Mr. Brunetti, on behalf of the Company, stated that he understood the City of Coral Gables' desire for more historically accurate and architecturally appropriate lighting alternatives, but that providing special fixtures for the City of Coral Gables would result in undue costs to the rest of FPL's customers. We agree with the Company, but note that the Company is not prohibited from entering into a contract with the City of Coral Gables to provide additional choices, provided the City pays the full cost of these additional choices. Moreover, we would urge the City of Coral Gables to reconsider the evidence presented that establishes that it would be more cost-effective for the City to own and store whatever fixtures and poles it desires. If the City does purchase additional fixtures and poles, FPL could provide relamping services.

Inverted Residential Rates

The Company's current residential rate is based on an inverted schedule with a 750 KWH breakpoint and a 1¢ per KWH differential. The Company proposes to convert the residential rate to a flat rate pricing schedule. Staff and the Company have taken **[*168]** the position that inverted rates are not cost-based. We decline to accept this conclusion. The data submitted by FPL is inadequate and fails to justify any conclusion as to whether inverted rates are cost based. We find that inverted rates are intuitively conservation oriented and should be continued. Furthermore, we have been unable to understand the basis of the Staff's or the Company's conclusion. Both are invited to present understandable date to back-up their conclusion.

Time of Use Rates

In FPL's last rate case, time of use (TOU) rates were made mandatory for customers with monthly demands in excess of 2000 KW, i.e., customers on the GSLD-2, CS-2, GSLD-3 and CS-3 rate schedules. At issue in this case is whether TOU rates should become mandatory for all customers with monthly demands in excess of 500 KW and should continue to be mandatory for customers with demands over 2000 KW. Several parties presented witnesses on this question.

Dr. Bentley, on behalf of the Company, testified that TOU rates for customers with demands over 500 KW are cost-effective, quantifying the benefit/cost ratio at 24:1. Company witness Williams stated that those customers currently **[*169]** on mandatory TOU rates have adjusted their loads and billing units to conform to a TOU billing format and that none of these customers have received an increase in excess of 110% of billing under the "standard" non-time differentiated rates. The Company contends that TOU rates will more closely reflect the cost causation on the system, by ensuring that those customers who consume energy at the more costly system peak hours will be charged a higher rate than customers consuming on the off-peak hours. Consequently, customers on TOU rates will strive to shift their usage to the off-peak hours, thus benefiting the entire FPL system.

FIPUG, FRF, and FEA took the position that all TOU rates should be optional, either contending that customers should have the freedom of choice or that some customers cannot shift their usage to the off-peak. Staff recommended that FPL's TOU rates be made mandatory for all customers with monthly demands in excess of 500 KW. Staff posited that mandatory TOU rates have provided superior price signals to these large customers and have thereby reduced the inequity and discrimination which would be involved in mandating, via optional TOU rates, that low-cost **[*170]** customers subsidize high cost customers. Agreeing with the Company, Staff pointed out that many of the current mandatory TOU customers have had lower bills since being on TOU rates. Responding to the argument that electrical usage is inelastic, Staff argued that we would still want to charge high-cost customers more than low-cost customers. Staff contended that the advantages of mandatory TOU rates outweigh any disadvantages.

Having considered the testimony of all the witnesses, we have determined that mandatory TOU rates eliminate the customers' freedom of choice, and this we cannot tolerate. The goal of TOU rates is to discourage consumption at the time when energy is most expensive, thus shifting some on-peak usage to the off-peak. This result can be reached without mandatory TOU rates, if optional TOU rates, for the cost-savings, if the rate contains the proper incentive. Therefore, FPL's TOU rates shall be optional for all customers at all demand levels.

The next question is how should the optional TOU rates be designed. The Company's present TOU rates were designed under the load factor method, which incorporates on-peak and maximum demand charges and separate **[*171]** charges for on-peak and off-peak KWH usage. The Company proposed to continue designing its TOU rates under the load factor method. Staff took the position that TOU rates should be designed under the system lambda method, which prices the off-peak fuel charge at the incremental system cost of providing that energy. Staff's proposal contains no demand charges. FIPUG proposed a method whereby all demand charge revenues are recovered through an on-peak demand charge. FEA agreed with FIPUG's proposal.

In determining the proper TOU rate design, we must keep in mind the objective behind TOU rates, to encourage off-peak usage. However, we do not want to create too great a penalty if a customer cannot consume off-peak in all twelve months. A proper TOU rate design should provide an incentive to all customers to shift their usage to the off-peak through a rate reduction.

We believe that demand charges are a necessary element of TOU rates. Dr. Stanley, testifying on behalf of the Staff, designed the TOU rates without a demand charge, stating that demand charges are unnecessary because on-peak KWH is more highly correlated with coincident demand than is on-peak billing demand and that **[*172]** eliminating demand charges allows a higher on-peak KWH charge that will discourage on-peak usage. However, we find that demand charges are a good device for sending price signals to customers to induce shifting demand to the off-peak periods. Mr. Williams, on behalf of the Company, proposed the use of an on-peak and maximum demand charge. However, FPL's design does not recover all of the demand-related costs through the demand charge. FIPUG witness Brubaker testified that the on-peak and off-peak demand charges should be strictly based on the unit costs. We find that there should be an on-peak demand charge and that it should be set at the KW charge for the standard rate. Under this approach, the TOU incentive is gained through the on-peak and off-peak KWH charges. Additionally, we believe that under this design, high load factor customers will be more fairly charged.

Having determined that the methods proposed by the parties do not meet the criteria we have set out and that the demand charge for TOU rates should be set equal to the demand charge for the applicable standard rate, we must determine the appropriate on-peak and off-peak energy charges for TOU rates. All energy-related **[*173]** costs, including the average-demand cost that we have determined is related to energy, must be recovered through the KWH charges. We find that the appropriate rate design will recover energy unit costs in the off-peak KWH charge. The on-peak KWH charge will then recover the energy unit costs as well as the remaining revenue requirement assigned to the class that is not being recovered in any of the other charges. This TOU rate design is consistent with our goal that TOU rates should match the standard rates and that high load factor customers should be compensated for the benefit that they provide to the system.

The TOU rate structure that we have approved presents a problem in the non-demand metered rate classes that do not have a demand charge, specifically the RS and GS classes. The problem is that without a demand charge, the RS and GS customers' on-peak KWH charge is too high, relative to the off-peak KWH charge. Therefore, we shall set the off-peak KWH charge at 2.5¢ for the RS and GS classes and the resultant on-peak KWH charge will be closer to the off-peak charge, but high enough to provide an incentive to RS and GS customers to opt for TOU rates and to shift **[*174]** some of their usage to the off-peak.

Having determined that all TOU's rates shall be optional, we are faced with the potential of a revenue shortfall from those customers presently on mandatory TOU rates, who are paying more than under standard rates, returning to the applicable standard rate. Additionally, there will be a savings attributable to those customers who find it cheaper to remain on TOU rates. We have calculated that savings to be $825,711 from the GSLD-2/CS-2 classes and $257,607 from the GSLD-3/CS-3 classes. We shall, therefore, incorporate these savings into the standard rates so as to be sure that the Company recovers its entire revenue requirement. Realizing that the shortfall may not be as the Company has projected, we order that true-ups shall be held, in conjunction with the Conservation Cost Recovery hearings, to determine the actual revenue shortfall.

Service Charges

The Company proposed changes in its present service charges that result in a net decrease in service charge revenues of $456,000 in 1984. The Company proposed to increase the initial reconnection charge from $14.00 to $20.00; to decrease the normal reconnection after disconnection for **[*175]** cause charge from $18.00 to $19.00; to decrease the underground temporary service charge from $103.00 to $100.00; and to increase the overhead temporary service charge from $136.00 to $147.00.

We decline to accept all of the Company proposed service charges. The initial connection and normal reconnection charges should be equal. Looking to unit costs, we find that the charges shall be $16.00. We accept the charge of $19.00 for reconnection after disconnection for cause. The charges for temporary service, underground and overhead, respectively, shall be $110.00 and $145.00.

Sports Fields

In Docket No. 810002-EU, we eliminated the Sports Field Rider wherein all sports fields were billed under the General Service Demand rate with a discount based on the waiver of the demand charge. A transition rate was established to avoid placing excessive rate increases on these customers. In FPL's last rate case, we voted to continue the transition rate. In this case, the Company originally proposed to discontinue the transition rate and to reassign those customers to the appropriate general service rate. During the hearing, Company witness Williams proposed that customers **[*176]** with demands from 21 to 499 KW be allowed to continue on the transition rate, instead of being transferred to the GSD-1 rate, but that all other customers be moved. Staff recommended that those customers who qualify for the GS-1 and GSLDT-2 rates should be moved to those rates and all other customers should remain on the transition rate. Dade County posited that the transition rate should be continued for all customers.

Evidence as to the impact of discontinuing the transition rate established that the eight customers who would be transferred to the GS-1 rate and the one customer who would be transferred to the GSLDT-2 rate would receive a slight decrease in rates. The approximately 372 customers who would be transferred to the GSD-1 rate would receive an increase of approximately 69%. The three customers who would go to the GSLDT-1 rate (500 KW to 1999 KW) would receive an increase of about 46% under standard rates. Therefore, we decline to discontinue the transition rate and shall leave the decision as to whether to transfer to the appropriate general service class up to the individual customer. For purposes of the 1984 increase, the sports field class shall receive an increase **[*177]** equal to the system average increase including fuel.

The evidence also revealed that the sports field transition rate is available to loads which do not have the same characteristics as a "classic" sports field. Also being served on this rate are auditoriums and sports fields with offices that have air conditioning and lighting loads used during the daytime. Since this type of customer is considerably more expensive to serve than sports fields with evening lighting load only, we shall, in the future, consider billing sports fields with evening lighting load on the OL energy rate and the customer charge from the otherwise applicable rate schedule. We find that sports fields and auditoriums with daytime load could be moved to the applicable rate schedules or remain on the transition rate until such time as they could be moved to the applicable rate schedules. In order to accomplish this proposed rate design, we order the Company to survey all OS-2 customers to determine which ones have evening lighting loads only and which have lighting or air conditioning loads which are used during the day. The Company shall complete this survey before they file their next rate case.

The issue **[*178]** was raised whether sports fields are currently paying their fully allocated cost as a separate rate class. Although the cost of service study filed by the Company overstates this class's rate of return, the use of proper load research data and the Commission approved cost of service study shows that sports fields' rate of return is close to the jurisdictional rate of return. The specific problem with the Company's calculation is that the Company assumed that none of the sports field customers would contribute to all 12 monthly peaks. The evidence establishes that it was erroneous to assume that none of the sports fields would contribute to nine of the twelve monthly peaks in view of the fact that the three large magnetic tape metered sports fields contributed to each of the 12 monthly peaks in 1983. Estimating the rate of return, based on the forecast approved by the Commission, with the proper adjustments referred to previously, the sports field rate of return is 8.73%. This is below the jurisdictional rate of return.

Transformer Metering Adjustment

The Company currently has a transformer metering adjustment if the customer is metered at the secondary voltage **[*179]** level but takes service on a rate stated at the primary voltage level. This adjustment is 2% for demand and 3% for energy. The issue was raised whether the 2% and 3% transformer metering adjustments are appropriate. The parties stipulated that a 1% adjustment, for both demand and energy, is the appropriate level, based on data the Company filed as to losses due to transformation. We decline to accept this stipulation because of the insufficiency of the data to implement the stipulation at this time, but shall consider this issue in the Company's next rate case.

Facilities Rental Charge

The Company assesses a Facilities Rental Charge when it provides and maintains transformers and other facilities required by the customer beyond the point of delivery or when it provides unusual facilities required due to the nature of the customer's equipment. The present charge is 22% per year of the agreed upon installed cost of such facilities. The Company provided an exhibit of the calculation of the present charge and a recalculation based on the Company's proposed capital structure and updated depreciation and maintenance components. The present charge has been in effect for a **[*180]** number of years and has not been updated in recent rate cases. The Company's proposed charge is based on the marginal cost of capital, as opposed to Staff's recommendation to base the charge on the current overall cost of capital. We find that the charge should be based on current embedded costs and that 30.62% is the appropriate amount. This amount was calculated using the capital structure approved by the Commission and adding in a composite depreciation rate and a maintenance component based upon 1982 figures for distribution plant and associated O&M.

A concern was raised at the hearing that if the facilities rental charge is revised, the customer would have the option of purchasing the equipment in lieu of paying the rental fee. In response to this, the Company filed a proposed revision to its tariff allowing the customer the following options: (1) continue to rent the facilities at the revised charge; (2) purchase such facilities from the Company; (3) purchase or lease the facilities from another source; or (4) redesign its operation to receive standard electric service from the Company. We accept the proposed tariff revision.

Transformer Ownership Credit

Transformer **[*181]** ownership discounts are credits applied to the demand charge for those customers who take service at primary voltage and provide their own transformation. This discount is appropriate because demand charges include costs associated with the transformation necessary to provide service from the production plant down to the secondary distribution level. If a customer takes service at primary and provides his own transformation, a credit is warranted to cover those transformation costs avoided in serving him. Presently, the transpormer discount is 40¢ per KW. There have been no significant changes relative to the credit approved in the Company's last rate case. Therefore, no change has been proposed in this case. We find that this treatment is appropriate.

Effective Date of the New Rates

In previous electric utility rate cases, we have allowed all rate changes to become effective upon the date of the Commission vote, pursuant to Section 366.072, Florida Statutes. To prevent the imposition of new rates to consumption prior to the vote, we have ordered that new rates be charged to meter readings taken on or after 30 days from the vote. This simply recognizes the **[*182]** realities of cycle billing. Our interpretation and method of implementation was sanctioned by the court in Gulf Power v. Cresse, 410 So.2d 492 (Fla. 1982). An issue raised in this case, not previously addressed, is whether there should be a 30 day delay in the imposition of both consumption-related charges and one-time service charges.

Our staff recommended that FPL be allowed to charge the newly approved service charges on the day after the vote, since such dharges could not thereby apply retroactively to services rendered before the voting date. Demand and energy charges would continue to apply to meter readings 30 days or more after the vote because, to do otherwise, would amount to approval of retroactive rate application. We conclude that the better practice and one which is more easily administered and understandable would be to require all charges, consumption related as well as service charges, be applied only to meter readings or services rendered 30 days after our vote.

As regards the second step 1985 rate increase, the Company shall follow the same procedure of waiting 30 days, until January 31, 1985, to begin applying all new rates.

CONCLUSIONS OF LAW

1. **[*183]** Florida Power and Light Company is a public utility within the meaning of Section 366.02, Florida Statutes, and is subject to the jurisdiction of the Commission.

2. This Commission has the legal authority to approve and use a projected test period for ratemaking purposes. Additionally, the Commission has statutory authority to approve and consider for ratemaking purposes a "subsequent year" test period. Calendar year 1984 is an appropriate base test period and calendar year 1985 is an appropriate "subsequent year" test period for this proceeding.

3. The adjustments to rate base made herein are reasonable and proper. The value of the Company's 1984 rate base for ratemaking purposes is $5,813,566,000 and for 1985 $6,184,410,000.

4. The adjustments made to the calculation of net operating income are proper and appropriate. For ratemaking purposes, FPL's net operating income for 1984 is $573,103,000 and $542,405,000 for 1985.

5. The fair rate of return on the equity capital of FPL lies in a range of 14.6% to 16.6% for both 1984 and 1985. A return of 15.6% should be used to determine revenue requirements.

6. The range of reasonableness for the overall fair rate of return **[*184]** for the Company is 10.23% to 10.90%, with a focus upon 10.56% for ratemaking purposes in 1984. For 1985, the range is 10.05% to 10.74% with the focus upon 10.40% for ratemaking purposes.

7. Florida Power and Light Company should be authorized to increase its rates and charges by $81,464,000 in annual gross revenues in 1984 to provide it with an opportunity to earn a fair rate of return of 10.56%.

8. About a modification to the 1985 revenue requirement determination, FPL should be authorized to increase its rates and charges by $114,984,000, in annual gross revenues, effective January 1, 1985, to provide it an opportunity to earn a fair rate of return of 10.40% in 1985.

9. The rate schedules prescribed and approved herein are fair, first and reasonable within the meaning of Chapter 366, Florida Statutes.

10. The new rate schedules shall be reflected upon billings rendered for meter readings taken on or after July 20, 1984. The new rate schedules for the 1985 increase shall be reflected upon billings rendered for meter readings taken on or after January 31, 1985, unless modified by this Commission prior to December 31, 1984.

Accordingly, it is

ORDERED by the Florida **[*185]** Public Service Commission that the findings of fact and conclusions of law set forth herein are approved. It is further

ORDERED that the petition of Florida Power and Light Company for authority to increase its rates and charges is granted to the extent delineated herein. It is further

ORDERED that Florida Power and Light Company's Motion for Reconsideration of Order No. 12919 is denied. It is further

ORDERED that Florida Power and Light Company is hereby authorized to submit revised rate schedules consistent hereiwth designed to generate $81,464,000 in additional gross revenues annually in 1984 and $114,984,000 in additional gross revenues annually in 1985. The Company shall include with the revised rate schedules all calculations and workpapers used in deriving the revised rates and charges. It is further

ORDERED that the revised rate schedules authorized herein for the 1984 increase shall be reflected upon billings rendered for meter readings taken on or after July 20, 1984. It is further

ORDERED that the Florida Power and Light Company provide to each customer a bill stuffer describing the nature of the increase and conforming to the requirements specified herein. **[*186]** It is further

ORDERED that the revised rate schedules authorized herein for the 1985 increase shall, if implemented, be reflected upon billings rendered for meter readings taken on or after January 31, 1985. It is further

ORDERED that $16,731,709 of 1984 and $17,394,106 of the 1985 rate increase awarded by this Order is to be collected under bond or corporate undertaking, subject to refund with interest, pending resolution of the treatment to be awarded the Company's Investment Tax Credit by the Internal Revenue Service and this Commission.

By ORDER of the Florida Public Service Commission this 24th day of July, 1984.

APPENDIX A

INDEX OF ORDER

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APPENDIX B

FLORIDA POWER & LIGHT COMPANY
COMPARITIVE AVERAGE RATE BASES
TEST YEAR ENDED 12/31/84
(THOUSANDS) ($)

	COMPANY		
	JURIS.PER BKS. AS FILED	JURIS.ADJS. AS FILED	ADJ.JURIS. AS FILED
PLANT IN SERVICE	7,577,709		
C-Riviera Units		-13,174	
C-Atrium		-310	
C-Future Use Corr.		-1,783	
1A-Masonry Wall Rpr.		0	
2-Distribution Plt.		0	
3-Transmission Plt.		0	
4-General Plt.		0	
5-Oil Backout		-71,587	
6-St. Lucie No. 1		0	
7-Litigation Items		-178,444	
87-Separ. Factors		0	
TOTAL	7,577,709	-265,298	7,312,411
ACCIM. DEPR. & AMORT.	-1,766,505		
C-Riviera Units		13,174	
C-Atrium		61	
1A-Masonry Wall Rpr.		0	
2-Distribution Plt.		0	
3-Transmission Plt.		0	
4-General Plt.		0	
5-Oil Backout		16,137	
6-St. Lucie No. 1		0	
7-Litigation Items		14,127	
8-Deprec. Rates		0	
9-Removal Costs		0	
25-Decommissioning		45,712	
87-Separ. Factors		0	
TOTAL	-1,766,505	89,211	-1,677,294
NET PLANT IN SERVICE	5,811,204	-176,087	5,635,117
CWIP-NO AFUDC	447,490		
C-Future Use Corr.		-525	
C-CWIP Not Requested		-106,535	
C-Add'l CWIP		692	
38-Martin Coal Costs		-9,171	

48-Amount of CWIP		0	
87-Separ. Factors		0	
TOTAL	447,490	-115,539	331,951
PLANT HELD FOR FUTURE USE	35,067		
C-Future Use Corr.		2,326	
87-Separ. Factors		0	
TOTAL	35,067	2,326	37,393
NET NUCLEAR FUEL	242,397		
C-Amt. Not Requested		-84,956	
C-Add'l Nuclear Fuel		8,625	
48A-Amt. of Nuclear Fuel		0	
87-Separ. Factors		0	
TOTAL	242,397	-76,331	166,066
NET UTILITY PLANT	6,536,158	-365,631	6,170,527
WORKING CAPITAL ALLOWANCE	208,777		
C-Non-Utility		-378	
C-Special Deposits		-5	
C-St. Lucie Shortfall		-5,520	
C-Temporary Cash Invest.		-4,834	
C-Unamort. Debt Exp.		-9,203	
C-Loss on Reocq. Debt		-613	
PC-Company Error		0	
7-Litigation Items		-47,370	
10A-Power Res. Accrued Liab.		0	
10B-UPS Capacity Charge		0	
10C-Short-term Investments	0		
11-DeSoto Plant Costs		0	
12-Amt. to Balance		0	
13-Pole Attachments		0	
14-Unbilled Revenue		0	
15-Oil Inventory		0	
16-Gain on Sale		-4,348	
17-Prepaid Interest		0	
18-Fuel Adj. Clause		-9,528	
19-ECOR		240	
20-Oil Backout Clause		4,775	
21-Pole Attachments		0	
22-Employee Loans		0	
23-Oil Inventory		0	
24-Unavailable Oil		0	
25-Decommissioning		793	
26-Spent Nuclear Fuel		15,589	
27-Cash		0	
28-Working Funds		0	
29-Matured Debt		0	
30-Accounts Receivable		0	
31-Unbilled Revenue		0	
32-Accounts Payable		0	
33-Misc. Deferred Debits		0	
34-Right of Way		0	
35-St. Lucie Legal Exp.		0	
36-Bechtel		0	
37-Martin Dam		0	
38-Martin Coal Costs		11,871	
39-Operating Reserves		25,249	

40-Common Dividends		16,366	
41-Unclaimed Dividends		0	
42-Accrued Taxes		0	
43-Jobbing Account		0	
44-Utility/Non-Utility		0	
45-Orange Groves		0	
46-Preferred Dividends		0	
47-Amt. to Balance		0	
48-CWIP		0	
87-Separ. Factors		0	
123-Energy Store		0	
TOTAL	208,777	-6,916	201,861
TOTAL RATE BASE	6,744,935	-372,547	6,372,388

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FLORIDA POWER & LIGHT COMPANY

COMPARITIVE AVERAGE RATE BASES

TEST YEAR ENDED 12/31/84

(THOUSANDS) ($)

	COMMISSION VOTE	
	JURISD ADJUSTS	ADJSTD JURISD
PLANT IN SERVICE		
C-Riviera Units	0	
C-Atrium	0	
C-Future Use Corr.	0	
1A-Masonry Wall Rpr.	-3,463	
2-Distribution Plt.	0	
3-Transmission Plt.	0	
4-General Plt.	0	
5-Oil Backout	0	
6-St. Lucie No. 1	0	
7-Litigation Items	1,639	
87-Separ. Factors	-67,866	
TOTAL	-69,690	7,242,721
ACCIM. DEPR. & AMORT.		
C-Riviera Units	0	
C-Atrium	0	
1A-Masonry Wall Rpr.	50	
2-Distribution Plt.	0	
3-Transmission Plt.	0	
4-General Plt.	0	
5-Oil Backout	0	
6-St. Lucie No. 1	0	
7-Litigation Items	-15,874	
8-Deprec. Rates	$-7,491	
9-Removal Costs	0	
25-Decommissioning	0	
87-Separ. Factors	13,363	

TOTAL	-9,952	-1,687,246
NET PLANT IN SERVICE	-79,642	5,555,475
CWIP-NO AFUDC		
C-Future Use Corr.	0	
C-CWIP Not Requested	0	
C-Add'l CWIP	0	
38-Martin Coal Costs	0	
48-Amount of CWIP	-328,113	
87-Separ. Factors	-3,838	
TOTAL	-331,951	0
PLANT HELD FOR FUTURE USE		
C-Future Use Corr.	0	
87-Separ. Factors	-393	
TOTAL	-393	37,000
NET NUCLEAR FUEL		
C-Amt. Not Requested	0	
C-Add'l Nuclear Fuel	0	
48A-Amt. of Nuclear Fuel	-61,079	
87-Separ. Factors	-4,136	
TOTAL	-65,215	100,851
NET UTILITY PLANT	-477,201	5,693,326
WORKING CAPITAL ALLOWANCE		
C-Non-Utility	0	
C-Sepecial Deposits	0	
C-St. Lucie Shortfall	0	
C-Temporary Cash Invest.	0	
C-Unamort. Debt Exp.	0	
C-Loss on Reocq Debt	0	
PC-Company Error	0	
7-Litigation Items	430	
10A-Power Res. Accrued Liab.	-17	
10B-UPS Capacity Charge	9,747	
10C-Short-term Investments	358	
11-DeSoto Plant Costs	0	
12-Amt. to Balance	0	
13-Pole Attachments	0	
14-Unbilled Revenue	2,835	
15-Oil Inventory	0	
16-Gain on Sale	-10,963	
17-Prepaid Interest	-179	
18-Fuel Adj. Clause	0	
19-ECOR	-240	
20-Oil Backout Clause	-4,775	
21-Pole Attachments	-4,503	
22-Employee Loans	-1,402	
23-Oil Inventory	-24,418	
24-Unavailable Oil	-9,643	
25-Decommissioning	0	
26-Spent Nuclear Fuel	0	
27-Cash	-115	
28-Working Funds	-551	
29-Matured Debt	0	

30-Accounts Receivable	0	
31-Unbilled Revenue	0	
32-Accounts Payable	-16,000	
33-Misc. Deferred Debits	0	
34-Right of Way	0	
35-St. Lucie Legal Exp.	0	
36-Bechtel	-10,338	
37-Martin Dam	0	
38-Martin Coal Costs	0	
39-Operating Reserves	0	
40-Common Dividends	0	
41-Unclaimed Dividends	0	
42-Accrued Taxes	0	
43-Jobbing Account	-6,912	
44-Utility/Non-Utility	0	
45-Orange Groves	0	
46-Preferred Dividends	0	
47-Amt. to Balance	0	
48-CWIP	854	
87-Separ. Factors	-5,729	
123-Energy Store	-60	
TOTAL	-81,621	120,240
TOTAL RATE BASE	-558,822	5,813,566

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FLORIDA POWER & LIGHT COMPANY

COMPARITIVE AVERAGE RATE BASES

TEST YEAR ENDED 12/31/85

(THOUSANDS) ($)

	COMPANY		
	JURIS.PER BKS. AS FILED	JURIS.ADJS. AS FILED	ADJ.JURIS. AS FILED
PLANT IN SERVICE	8,375,197		
C-Riviera Units		-13,528	
C-Atrium		-312	
C-Future Use Corr.		-1,469	
1A-Masonry Wall Rpr.		0	
2-Distribution Plt.		0	
3-Transmission Plt.		0	
4-General Plt.		0	
5-Oil Backout		-301,021	
6-St. Lucie No. 1		0	
7-Litigation Items		-183,822	
87-Separ. Factors		0	
TOTAL	8,375,197	-500,152	7,875,045
ACCIM. DEPR. & AMORT.	-2,063,817		
C-Riviera Units		13,528	
C-Atrium		67	
1A-Masonry Wall Rpr.		0	

2-Distribution Plt.		0	
3-Transmission Plt.		0	
4-General Plt.		0	
5-Oil Backout		21,915	
6-St. Lucie No. 1		0	
7-Litigation Items		21,660	
8-Deprec. Rates		0	
9-Removal Costs		0	
25-Decommissioning		67,454	
87-Separ. Factors		0	
TOTAL	-2,063,817	124,624	-1,939,193
NET PLANT IN SERVICE	6,311,380	-375,528	5,935,852
CWIP-NO AFUDC	402,983		
C-Future Use Corr.		-540	
C-CWIP Not Requested		-47,450	
C-Add'l CWIP		-5,640	
38-Martin Coal Costs		-9,442	
48-Amount of CWIP		0	
87-Separ. Factors		0	
TOTAL	402,983	-63,072	339,911
PLANT HELD FOR FUTURE USE	36,701		
C-Future Use Corr.		2,016	
87-Separ. Factors		0	
TOTAL	36,701	2,016	38,717
NET NUCLEAR FUEL	263,836		
C-Amt. Not Requested		-52,616	
C-Add'l Nuclear Fuel		8,703	
48A-Amt. of Nuclear Fuel		0	
87-Separ. Factors		0	
TOTAL	263,836	-43,913	219,923
NET UTILITY PLANT	7,014,900	-480,497	6,534,403
WORKING CAPITAL ALLOWANCE	210,906		
C-Non-Utility		-341	
C-Special Deposits		-5	
C-Temporary Cash Invest.		-3,328	
C-Loss on Reocq. Debt		-594	
C-St. Lucie Shortfall		0	
C-Unamort. Debt Exp.		-8,993	
PC-Company Error		0	
7-Litigation Items		-74,835	
10A-Power Res. Accrued Liab.		0	
10B-UPS Capacity Charge		0	
10C-Short-term Investments		0	
11-DeSoto Plant Costs		0	
12-Amt. to Balance		0	
13-Pole Attactments		0	
14-Unbilled Revenue		0	
15-Oil Inventory		0	
16-Gain on Sale		-4,040	
17-Prepaid Interest		0	
18-Fuel Adj. Clause		-1,580	
19-ECOR		-36	

20-Oil Backout Clause		2,655	
21-Pole Attachments		0	
22-Employee Loans		0	
23-Oil Inventory		0	
24-Unavailable Oil		0	
25-Decommissioning		807	
26-Spent Nuclear Fuel		9,888	
27-Cash		0	
28-Working Funds		0	
29-Matured Debt		0	
30-Accounts Receivable		0	
31-Unbilled Revenue		0	
32-Accounts Payable		0	
33-Misc. Deferred Debits		0	
34-Right of Way		0	
35-St. Lucie Legal Exp.		0	
36-Bechtel		0	
37-Martin Dam		0	
38-Martin Coal Costs		10,668	
39-Operating Reserves		30,438	
40-Common Dividends		19,136	
41-Unclaimed Dividends		0	
42-Accrued Taxes		0	
43-Jobbing Account		0	
44-Utility/Non-Utility		0	
45-Orange Groves		0	
46-Preferred Dividends		0	
77-Amt. to Balance		0	
48-CWIP		0	
87-Separ. Factors		0	
123-Energy Store		0	
TOTAL	210,906	-20,160	190,746
TOTAL RATE BASE	7,225,806	-500,657	6,725,149

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FLORIDA POWER & LIGHT COMPANY
COMPARITIVE AVERAGE RATE BASES
TEST YEAR ENDED 12/31/85
(THOUSANDS) ($)

	COMMISSION VOTE	
	JURISD ADJUSTS	ADJSID JURISD
PLANT IN SERVICE		
C-Riviera Units	0	
C-Atrium	0	
C-Future Use Corr.	0	
1A-Masonry Wall Rpr.	-4,922	
2-Distribution Plt.	0	
3-Transmission Plt.	0	
4-General Plt.	0	
5-Oil Backout	0	

6-St. Lucie No. 1	0	
7-Litigation Items	-1,109	
87-Separ. Factors	-15,637	
TOTAL	-21,668	7,853,377
ACCIM. DEPR. & AMORT.		
C-Riviera Units	0	
C-Atrium	0	
1A-Masonry Wall Rpr.	220	
2-Distribution Plt.	0	
3-Transmission Plt.	0	
4-General Plt.	0	
5-Oil Backout	0	
6-St. Lucie No. 1	0	
7-Litigation Items	-17,734	
8-Deprec. Rates	-23,424	
9-Removal Costs	0	
25-Decommissioning		0
87-Separ. Factors	3,471	
TOTAL	-37,467	-1,976,660
NET PLANT IN SERVICE	-59,135	5,876,717
CWIP-NO AFUDC		
C-Future Use Corr.	0	
C-CWIP Not Requested	0	
C-Add'l CWIP	0	
38-Martin Coal Costs	0	
48-Amount of CWIP	-339,005	
87-Separ. Factors	-906	
TOTAL	-339,911	0
PLANT HELD FOR FUTURE USE		
C-Future Use Corr.	0	
87-Separ. Factors	-92	
TOTAL	-92	38,625
NET NUCLEAR FUEL		
C-Amt. Not Requested	0	
C-Add'l Nuclear Fuel	0	
48A-Amt. of Nuclear Fuel	-62,877	
87-Separ, Factors	-699	
TOTAL	-63,576	156,347
NET UTILITY PLANT	-462,714	6,071,689
WORKING CAPITAL ALLOWANCE		
C-Non-Utility	0	
C-Special Deposits	0	
C-Temporary Cash Invest.	0	
C-Loss on Reocq. Debt	0	
C-St. Lucie Shortfall	0	
C-Unamort. Debt Exp.	0	
PC-Company Error	0	
7-Litigation Items	673	
10A-Power Res. Accrued Liab.	28	
10B-UPS Capacity Charge	25,347	
10C-Short-term Investments	436	

11-DeSoto Plant Costs	0	
12-Amt. to Balance	0	
13-Pole Attachments	0	
14-Unbilled Revenue	2,897	
15-Oil Inventory	0	
16-Gain on Sale	-8,560	
17-Prepaid Interest	-168	
18-Fuel Adj. Clause	0	
19-ECOR	0	
20-Oil Backout Clause	-2,655	
21-Pole Attachments	-5,518	
22-Employee Loans	-2,401	
20-Oil Inventory	-37,557	
24-Unavailable Oil	-10,010	
25-Decommissioning	0	
26-Spent Nuclear Fuel	0	
27-Cash	-331	
28-Working Funds	-526	
29-Matured Debt	0	
30-Accounts Receivable	0	
31-Unbilled Revenue	0	
32-Accounts Payable	-20,400	
33-Misc. Deferred Debits	0	
34-Right of Way	0	
35-St. Lucie Legal Exp.	0	
36-Bechtel	-9,827	
37-Martin Dam	0	
38-Martin Coal Costs	0	
39-Operating Reserves	-1,060	
40-Common Dividends	0	
41-Unclaimed Dividends	0	
42-Accrued Taxes	0	
43-Jobbing Account	-7,319	
44-Utility/Non-Utility	0	
45-Orange Groves	0	
46-Preferred Dividends	0	
47-Amt. to Balance	0	
48-CWIP	195	
87-Separ. Factors	-1,209	
123-Energy Store	-60	
TOTAL	-78,025	112,721
TOTAL RATE BASE	-540,739	6,184,410

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APPENDIX C

FLORIDA POWER & LIGHT COMPANY

COMPARITIVE NOI'S

TEST YEAR ENDED 12-31-84

(THOUSANDS) ($)

	COMPANY			COMMISSION VOTE	
	JUR.PER BKS. AS FILED	JUR.ADJS. AS FILED	ADJ.JUR. AS FILED	JURISD ADJUSTS	ADJUSTED JURISD

OPERATING REVENUES	3,481,164				
C-Oil Backout		-140,926		0	
C-Franchise Fee		-139,316		0	
C-Conservation		15		0	
13-Pole Attachments		0		0	
14-Unbilled Revenue		0		102	
50A-Parrish Lake Rev.		0		130	
87-Separ. Factors		0		-158	
89-Revenue Forecast		0		7,682	
93-Orange Groves		45		0	
124-Fuel		0		-1,269,049	
125-Conservation		0		-41,552	
31-Unbilled Revenue		0		0	
TOTAL	3,481,164	-280,182	3,200,982	-1,302,845	1,898,137
OPERATING EXPENSES					
OPERATION & MAINTENANCE	2,164,726				
C-Public Communications		-49		0	
C-Fin. Planning Services		-22		0	
C-Atrium		-7		0	
C-Payroll Correction		2,364		0	
C-Putnam Pipeline		-1,093		0	
C-Riviera Units		-2		0	
C-Oil Backout		-125,855		0	
13-Pole Attachments		0		5,579	
51-Conservation		0		-1,152	
52-O&M (Gower)		0		0	
54-Contributions		605		-556	
55-IRS Interest		798		-798	
56-Industry Dues		-156		-406	
57-Rate Case Expense		144		-402	
58-Advertising		0		-237	
59-O&M Reasonableness		0		-82,022	
60-Executive Salaries		0		0	
61-Toxic Chemical Expense		0		0	
62-Fines & Penalties		0		0	
63-Air Fare (1st classes)		0		0	
64-WINZ Radio		0		0	
65-Martin Coal		0		0	
66-Juno costs		0		-724	
87-Separ. Factors		0		0	
93-Orange Groves		-232		0	
121-Oil Backout		0		0	
124-Fuel		0		-1,249,025	

125-Conservation		0		-39,813	
127-Economy Sales		0		1,262	
C-Fuel		-9,111		0	
TOTAL	2,164,726	-132,616	2,032,110	-1,368,294	663,816
DEPR. & AMORTIZATION	266,750				
C-Atrium		-6		0	
C-Riviera Units		-90		0	
C-Oil Backout		-2,172		0	
C-Conservation		32		0	
1A-Masonry Wall Rpr.		0	0	-130	
7-T.P. Fuel Pits		0		105	
8-Depreciation Rates		0		10,366	
65-Martin Coal		1,483		0	
87-Separ. Factors		0		-2,528	
121-Oil Backout		0		0	
125-Conservation		0	0	-1,101	
TOTAL	266,750	-753	265,997	6,712	272,709
TAX OTHER THAN INC.					
TAX	269,146				
C-Riviera Units		0	0	0	
C-Franchise Fee		-139,329		0	
C-Fuel		30		0	
C-Conservation		-4		0	
C-Oil Backout		-2,398		0	
13-Pole Attachments		0		0	
14-Unbilled Revenue		0		2	
50A-Parrish Lake Rev.		0		2	
59-O&M Reasonableness		0		0	
67-Reg. Assess. Fee		0		1,178	
87-Separ. Factors		0		-668	
89-Revenue Forecast		0		118	
93-Orange Groves		1		0	
121-Oil Backout		0		0	
124-Fuel		0		-20,024	
125-Conservation		0		-639	
TOTAL	269,146	-141,700	127,446	-20,031	107,415
INC. TAXES-CURRENT					
PAY.	95,163				
74-Interest Sync.		7,221		11,602	
87-Separ. Factors		0		4,189	
Effect of Adjs.		-4,494		25,108	
TOTAL	95,163	2,727	97,890	40,899	138,789
DEFERRED TAXES (NET)	108,087				
53-Gower Correction		0		585	
74-Interest Sync.		-7,436		0	
87-Separ. Factors		0		-1,136	
Effect of Adjs.		8,723	0	12,142	
TOTAL	108,087	1,287	109,374	11,591	120,965
INVEST.TAX CREDIT					
(NET)	35,131				
C-Oil Backout		-7,050	0	0	

7-Litigation Items		536		0	
71-ITC Amort. Rate		0		-597	
87-Separ. Factors		0		-278	
121-Oil Backout		0	0	0	
TOTAL	35,131	-6,514	28,617	-875	27,742
GAIN ON SALE OF PLANT	-3,304				
C-Gain		-748		0	
76-Gain		0		-2,391	
87-Separ. Factors		0		41	
TOTAL	-3,304	-748	-4,052	-2,350	-6,402
TOTAL OPERATING EXPENSES	2,935,699	-278,317	2,657,382	-1,332,348	1,325,034
NET OPERATING INCOME	545,465	-1,865	543,600	29,503	573,103

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FLORIDA POWER & LIGHT COMPANY

COMPARITIVE NOI'S

TEST YEAR ENDED 12-31-85

(THOUSANDS) ($)

	COMPANY			COMMISSION VOTE	
	JUR.PER BKS. AS FILED	JUR.ADJS. AS FILED	ADJ.JUR. AS FILED	JURISD ADJUSTS	ADJUSTED JURISD
OPERATING REVENUES	3,963,723				
C-Oil Backout		-396,233		0	
C-Franchise Fee		-157,948		0	
C-Conservation		-6		0	
13-Pole Attachments		0		0	
14-Unbilled Revenue		0		17	
50A-Parrish Lake Rev.		0		142	
87-Separ. Factors		0		-33	
89-Revenue Forecast		0		14,560	
93-Orange Groves		48		0	
124-Fuel		0		-1,404,442	
125-Conservation		0		-44,831	
31-Unbilled Revenue		0		0	
TOTAL	3,963,723	-554,139	3,409,584	-1,434,587	1,974,997
OPERATING EXPENSES					
OPERATION & MAINTENANCE	2,597,622				
C-Public Communications		-52		0	
C-Fin. Planning Services		-24		0	
C-Atrium		-7		0	
C-Payroll Correction		5,358		0	
C-Putnam Pipeline		-1,102		0	
C-Riviera Units		-15		0	
C-Oil Backout		-320,552		0	
13-Pole Attachments		0		6,136	

51-Conservation		0		-1,944	
52-O&M (Gower)		0		0	
54-Contributions		476		-434	
55-IRS Interest		807		-807	
56-Industry Dues		-166		-423	
57-Rate Case Expense		-319		0	
58-Advertising		0		-254	
59-O&M Reasonableness		0		-85,767	
60-Executive Salaries		0		0	
61-Toxic Chemical Expense		0		0	
62-Fines & Penalties		0		0	
63-Air Fare (1st class)		0		0	
64-WINZ Radio		0		0	
65-Martin Coal		0		0	
66-Juno costs		0		-1,466	
87-Separ. Factors		0		-1	
93-Orange Groves		-246		0	
121-Oil Backout		0		0	
124-Fuel		0		-1,382,520	
125-Conservation		0		-42,996	
127-Economy Sales		0		1,320	
C-Fuel		144		0	
TOTAL	2,597,622	-315,698	2,281,924	-1,509,156	772,768
DEPR. & AMORTIZATION	292,863				
C-Atrium		-6		0	
C-Riviera Units		-442		0	
C-Oil Backout		-8,755		0	
C-Conservation		52		0	
1A-Masonry Wall Rpr.		0		-176	
7-T.P. Fuel Pits		0		14	
8-Depreciation Rates		0		11,013	
65-Martin Coal		1,522		0	
87-Separ. Factors		0		-584	
121-Oil Backout		0		0	
125-Conservation		0		-1,156	
TOTAL	292,863	-7,629	285,234	9,111	294,345
TAX OTHER THAN INC. TAX	301,618				
C-Riviera Units		-436	0	0	
C-Franchise Fee		-157,964	0	0	
C-Fuel		-23		0	
C-Conservation		-14		0	
C-Oil Backout		-7,869		0	
13-Pole Attachments		0		0	
14-Unbilled Revenue		0		0	
50A-Parrish Lake Rev.		0		2	
59-O&M Rrasonableness		0		0	
67-Reg. Assess. Fee		0		1,223	
87-Separ. Factors		0		-167	
89-Revenue Forecast		0		230	
93-Orange Groves		1		0	
121-Oil Backout		0		0	
124-Fuel		0		-21,921	

125-Conservation		0		-680	
TOTAL	301,618	-166,305	135,313	-21,313	114,000
INC. TAXES-CURRENT PAY.	43,156				
74-Interest Sync.		3,944		10,811	
87-Separ. Factors		0		945	
Effect of Adjs.		461		51,488	
TOTAL	43,156	4,405	47,561	63,244	110,805
DEFERRED TAXES (NET)	152,285				
53-Gower Correction		0		525	
74-Interest Sync.		-7,701		0	
87-Separ. Factors		0		-246	
Effect of Adjs.		-18,505	0	-9,198	
TOTAL	152,285	-26,206	126,079	-8,919	117,160
INVEST.TAX CREDIT (NET)	33,097				
C-Oil Backout		-2,470	0	0	
7-Litigation Items		539	0	0	
71-ITC Amort. Rate		0		-660	
87-Separ. Factors		0		-65	
121-Oil Backout		0	0	0	
TOTAL	33,097	-1,931	31,166	-725	30,441
GAIN ON SALE OF PLANT	-3,352				
C-Gain	-3,304	-1,101			
76-Gain		0		-2,487	
87-Separ. Factors		0		13	
TOTAL	-3,352	-1,101	-4,453	-2,474	-6,927
TOTAL OPERATING EXPENSES	3,417,289	-514,465	2,902,824	-1,470,232	1,432,592
NET OPERATING INCOME	546,434	-39,674	506,760	35,645	542,405

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In Re: Determination of cost-effective level of demand-side management credit for Interruptible and Curtailable rate classes of Florida Power Corporation

DOCKET NO. 950645-EI; ORDER NO. PSC-96-0842-FOF-EI

Florida Public Service Commission

1996 Fla. PUC LEXIS 1010

96 FPSC 7:31

July 1, 1996

CORE TERMS: customers, non-firm, billing, load, interruptible, coincidence, interruption, curtailable, reduction, monthly, maximum, ratio, load factor, benefit-cost, revised, generation, protest, smaller, notice, tariff, notice requirement, rate case, non-traditional, cost-effective, conservation, effective, metering, embedded, shelter, insure

[*1]

The following Commissioners participated in the disposition of this matter: SUSAN F. CLARK, Chairman; J. TERRY DEASON; JOE GARCIA; JULIA L. JOHNSON; DIANE K. KIESLING

ORDER APPROVING TARIFFS

BY THE COMMISSION:

By Order No. PSC-95-0691-FOF-EG adopting Florida Power Corporation's (FPC) Demand-Side Management (DSM) Plan, we ordered that this docket be opened to consider the treatment of FPC's curtailable and interruptible programs because the Company's analysis indicated that its existing curtailable and interruptible rates were no longer cost-effective. Following discussions and correspondence between our staff and the parties, on February 19, 1996, FPC and the Florida Industrial Power Users Group (FIPUG) filed a Joint Motion for Approval of Stipulation.

At the agenda conference held on April 16, 1996, we approved the proposed stipulation, and the existing rates were closed to new customers. In addition, the new interruptible (IS-2, IST-2) and curtailable (CS-2 and CST-2) rate schedules were suspended to allow time for further study.

DECISION

In FPC's last rate case, the Company designed its IS and CS rates using a fully allocated embedded cost study paired with [*2] a credit developed on avoided cost. This approach treats non-firm customers as though they were firm for embedded costing purposes, and then determines credits to account for the conservation benefits they provide by being interruptible at times of capacity shortage. Using the avoided cost at that time, the credits developed reflected a benefit-cost ratio of 1.2.

The new rates originally proposed by FPC reflected a benefit-cost ratio of 1.0, or the minimum acceptable for cost recovery of a conservation program. However, the closed non-firm rates were based on a benefit-cost ratio of 1.2. In addition, we recently approved a reduction in the credits paid under FPC's Residential Load Management program to make that program meet a 1.2 cost effectiveness ratio. Following discussions with our staff, FPC revised its proposed rates to reflect the higher benefit-cost ratio. These changes significantly reduced the demand credits compared to the closed rates.

The revised petition also modifies the manner in which the credit is applied to the customer's load. In the initial filing, the credit was applied to the customer's monthly maximum demand subject to interruption or curtailment. [*3] Under the revised petition, the credit is applied to the customer's maximum monthly demand multiplied by their billing load factor. Under this revised method, customers with higher than average load factors receive a larger total credit than customers with lower load factors. Customers with average load factors of approximately 63% will receive the average IS and CS credits of $ 1.79 and $ 0.94 per KW. This method of billing customers results in the same total amount of credits paid to non-firm customers as if all customers received the same flat credit.

This adjustment of the amount of the credit is justified because load research data indicates that there is a positive relationship between the customer's billing load factor and his coincidence factor. Coincidence factor is a measure of the relationship between a customer's maximum billing demand and his demand at the time of the system peak. Customers with high coincidence factors are more likely to be on the system at the time of peak demand and thus are more likely to provide significant load reductions to the system when interruptions are required.

While the coincidence factor cannot be measured directly, billing load factor, [*4] which measures the relationship between the customer's maximum monthly billing demand and his kilowatt hour consumption, has been shown to track coincidence factor. Billing load factor is readily available from billing records and is a suitable proxy for coincidence in adjusting the credits.

In addition to the lowered demand credit, the new rates differ from the closed rates with regard to their eligibility requirements. Under the new rates, customers must have a minimum monthly demand of 500 kw in order to qualify for service. This minimum monthly demand requirement was removed from the closed rates at the time of FPC's last rate case. At that time, FPC wanted to extend the availability non-firm rates to smaller customers. Traditionally, non-firm rates have been available only to large, predominantly industrial customers who have the ability to incur extended outages via process scheduling and back-up generation.

Smaller, non-traditional customers often require customized installation of interruption and metering equipment due to differing delivery and metering voltages, shared transformers, and space constraints. FPC indicates that those customers with less than 500 kw maximum [*5] demand who are currently taking service under the closed IS and CS rates represent less than 5 % of the total expected demand reductions for the programs. Because of the additional administrative and technical demands and the small amount of demand reduction that smaller, non-traditional customers provide, FPC now indicates it is not cost-effective to offer non-firm rates to these customers.

The proposed tariffs contain a provision which prohibits customers whose premises are designated for use as a public shelter during periods of emergency or natural disaster from taking service under the rates. This restriction is needed to insure that shelter facilities are not interrupted during times of capacity shortfall, and to insure that FPC will be able to achieve the required load reduction from its non-firm customers.

The proposed tariffs require that customers give FPC three years' notice to discontinue service and return to a firm rate schedule. The closed rates required a five-year notice. Rule 25-6.0438(8), Florida Administrative Code requires that non-firm rates require a five year notice, unless it can be demonstrated that a shorter notice period is appropriate. FPC does [*6] not include the demands of non-firm customers when it plans for its generation needs, therefore the notice requirement allows FPC time include the customer's firm load in its generation plans. Given the estimated construction lead times required for FPC's planned unit additions, we find that the reduced notice requirement is appropriate.

The proposed IS-2 and IST-2 rates also contain a provision which allows FPC to exercise at least one interruption per year in order to test the operation of interruption devices and related equipment. In addition, the CS-2 and CST-2 rates allow FPC to curtail customers for test purposes at least once a year.

Upon consideration, we find that the proposed new interruptible and curtailable rates are in the public interest and should be approved. The rates will become effective on June 11, 1996, as requested by the Company.

Based on the foregoing, it is

ORDERED by the Florida Public Service Commission that Florida Power Corporation's Interruptible (IS-2 and IST-2) and Curtailable (CS-2 and CST-2) rate schedules are approved effective June 11, 1996. It is further

ORDERED that if a protest is filed in accordance with the requirement set forth below, [*7] the tariff shall remain in effect with any increase in revenues held subject to refund pending resolution of the protest. It is further

ORDERED that if no protest is filed in accordance with the requirements set forth below, this docket shall be closed.

By ORDER of the Florida Public Service Commission, this 1st day of July, 1996.

In Re: Approval of Demand-Side Management Plan of Florida Power & Light Company. In Re: Approval of Demand-Side Management Plan of Florida Power Corporation. In Re: Approval of Demand-Side Management Plan of Gulf Power Company. In Re: Approval of Demand-Side Management Plan of Tampa Electric Company

DOCKET NO. 941170-EG; DOCKET NO. 941171-EG; DOCKET NO. 941172-EG; DOCKET NO. 941173-EG; ORDER NO. PSC-95-0691-FOF-EG

Florida Public Service Commission

1995 Fla. PUC LEXIS 815

95 FPSC 6:47

June 9, 1995

CORE TERMS: customer, energy, saving, conservation, residential, electric, methodology, audit, heating, staff, low income, installation, technology, water, maximum, pump, heat, load, pricing, green, peak, duct, monthly, air, repair, cogeneration, low-income, participating, measurement, industrial

[*1]

The following Commissioners participated in the disposition of this matter: SUSAN F. CLARK, Chairman, J. TERRY DEASON, JOE GARCIA, JULIA L. JOHNSON, DIANE K. KIESLING

NOTICE OF PROPOSED AGENCY ACTION ORDER APPROVING DEMAND-SIDE MANAGEMENT PLANS

BY THE COMMISSION:

NOTICE IS HEREBY GIVEN by the Florida Public Service Commission that the action discussed herein is preliminary in nature and will become final unless a person whose interests are substantially affected files a petition for a formal proceeding, pursuant to Rule 25-22.029, Florida Administrative Code.

CASE BACKGROUND

The Florida Energy Efficiency and Conservation Act (FEECA), Chapter 366.82, Florida Statutes, requires the Commission to adopt goals to reduce and control the growth rates of electric consumption, and to reduce and control the growth rates of weather sensitive peak demand. In Order No. PSC-94-1313-FOF-EG issued October 25, 1994, we set numeric demand-side management (DSM) goals for the four largest investor-owned electric utilities (IOU). Rule 25-17.0021(4), Florida Administrative Code, states that within 90 days of a final order establishing goals, each utility shall submit a DSM plan designed to [*2] meet the utility's goals. Each IOU filed its DSM plan following extensions granted by the prehearing officer.

DECISION

PLAN APPROVAL ISSUES:

In Order No. 22176, issued November 14, 1989, we stated that conservation programs will be judged by the following criteria:

1. Does each component program advance the policy objectives set forth in Rule 25-17.001 and the FEECA statute?

2. Is each component program directly monitorable and yield measurable results?

3. Is each component program cost-effective?

A. Florida Power and Light Company's Demand-Side Management plan:

FPL's proposed DSM plan contains 26 programs, including six residential programs; nine commercial/industrial programs; and nine research and development programs. FPL has also described its continuing cogeneration activities and a green pricing concept program.

We have reviewed FPL's plan and believe its conservation programs meet our three-pronged test.

We will decide at a later time whether FPL's C/I Load Control program meets our three-pronged test. At the time staff's recommendation was written in these dockets, interrogatory responses from FPL were still being received. This C/I program [*3] is still being analyzed and requires further consideration. Staff is instructed to bring a separate recommendation before us on the issue of whether this C/I program should be approved for cost recovery.

FPL's plan also contains research and development programs, a green pricing program, and a cogeneration program which, while not directly measurable, are specifically identified in FEECA. A summary of each of these programs is contained in Attachment 1. The research and development programs are approved and the expenditures are capped at the level shown in Attachment 1.

FPL's proposed methodology for measuring actual kW and kWh savings achieved for each program is too general. The Company shall file a more detailed methodology for each approved program within six months of this Order. The methodology will contain a general time-frame for conducting the measurement of savings, and the estimated frequency of measurement (such as quarterly, yearly, every five years, etc.). Also, a detailed methodology of savings evaluation (such as pre- and post-billing analysis, enhanced metering, engineering studies, etc.) and an estimate of the costs shall be indicated for each program to insure [*4] that measurement costs do not reverse the program's cost-effectiveness.

Staff will review FPL's methodology and bring any deficiencies to our attention. Parties or interested persons, who believe deficiencies exist, can petition us to correct them.

GREEN PRICING

Based on the preliminary information submitted in response to Order No. PSC-1313-FOF-EG, issued 10/25/94, FPL's green pricing program appears to adequately address the development of alternate funding sources to promote the installation of renewable technologies. FPL will purchase photovoltaic modules to be located at powerplants or substations.

We approve the green pricing administrative program costs that are subject to ongoing review in the ECCR clause. These costs should be separately identified as a line item in FPL's ECCR filings. This program contributes toward the commercialization of renewable technologies; also, this program may stimulate economic and technological growth in the field of renewable technologies.

Solar water heating is not part of the green pricing program at this time. FPL's petition proposed to discontinue the residential solar water heating rebate program, and move the program over to [*5] the research and development area. This was done to identify technology improvements and market segments that could potentially help the program pass a RIM test. We agree with these proposed program modifications.

LOW INCOME

Based on the preliminary information submitted in response to Order No. PSC-1313-FOF-EG, FPL's analysis of DSM program availability, saturation, and benefits to residential low income customers appears to be adequate. Additionally, because all of the proposed programs in FPL's DSM plan pass the RIM test, they reduce rate impacts for all customers, including those with low income.

FPL originally petitioned to discontinue the HELP program in Docket No. 900091-EG on the basis that it was not projected to be cost effective. In Order No. 23560, issued 10/2/90, the Commission denied FPL's petition to discontinue the HELP program, and ordered the Company to "consider changes to the program to enhance its implementation and cost-effectiveness." FPL responded by filing a petition to combine the HELP program with the Duct Testing program which was subsequently approved by the Commission in Order No. 25258, issued 10/28/91.

FPL petitioned again to discontinue the [*6] HELP program, which is currently combined with the Duct Testing program. The HELP program includes the following low cost measures: water heater insulation wraps, hot water pipe insulation, faucet restrictors, low flow showerheads, door sweeps, caulking and weatherstripping. Approximately 22% of the customers participating in the HELP program are low income.

We approve FPL's request to discontinue the HELP program. Discontinuance may remove one program from consideration by those in the low income bracket, however, FPL structured its DSM programs in order to achieve its goals in a cost-effective manner.

To facilitate continuing low income participation, FPL will target public agencies and governmental housing authorities for program education and implementation of its residential DSM programs. FPL is investigating the potential for qualifying public agencies or housing authorities to install certain measures as participating contractors.

FPL also performed an analysis assessing the availability and saturation of its residential conservation programs to low income customers whose annual incomes are less than $ 20,000. The Company found that significant numbers of low income customers [*7] are participating in most of its residential DSM programs. The low income sector comprises about 14% of FPL's customer base, while low income customers comprise about 20% of the participants in all of FPL's conservation programs.

Not all low income customers are low users of electricity. Many use a great deal more electricity due to lifestyle and behavioral choices, as well as old inefficient appliances and dwellings.

B. Florida Power Corporation's Demand-Side Management plan:

FPC's proposed DSM plan contains four residential programs, nine commercial and industrial (C/I) programs, and one research and development program. These DSM programs are designed to minimize free riders, minimize rate impacts, and meet our prescribed DSM goals. In addition, FPC has described its continuing cogeneration activities, the expenses of which are recovered through the Energy Conservation Cost Recovery Clause.

We have reviewed FPC's plan and believe its conservation programs meet our three-pronged test. FPC's plan contains a research and development program with an $ 800,000 annual cap, and a cogeneration program which, while not directly measurable, is specifically identified in FEECA. [*8] A summary of these programs is contained in Attachment 2. While FPC is the only utility with a residential decoupling mechanism, it still relies heavily on traditional load management to achieve its residential goal.

FPC's proposed methodology for measuring actual kW and Kwh savings achieved for each program is too general. FPC shall file a more detailed methodology for each approved program within six months of this Order. The methodology shall contain a general time-frame for conducting the measurement of savings, and the estimated frequency of measurement (such as quarterly, yearly, every five years, etc.). Also, a detailed methodology of savings evaluation (such as pre- and post-billing analysis, enhanced metering, engineering studies, etc.) and an estimate of the costs shall be indicated for each program to insure that measurement costs do not reverse the program's cost-effectiveness.

Staff will review FPC's methodology and bring any deficiencies to our attention. Parties or interested persons, who believe any deficiencies exist, can petition us to correct them.

INTERRUPTIBLE AND CURTAILABLE LOAD

In its petition, FPC states that the current IS and CS tariffs are no longer [*9] cost-effective DSM programs. FPC will not count any incremental additions to these programs towards achieving its C/I goal. However, FPC may continue to offer these rate schedules and collect the credits paid to customers on the IS and CS rates through the ECCR clause. Staff recommended that the tariffs be closed to new customers and that FPC file cost-effective rate schedules if they choose to continue to offer these types of rates. Because of the complex interrelation between cost-effectiveness and cost of service, we instead directed staff to open a docket limited to the future treatment of these DSM programs. In the interim, FPC will be allowed to continue to offer these programs and collect any credits paid through the ECCR clause.

GREEN PRICING

FPC's plan includes an analysis of green pricing and also addresses other sources for renewable funding. FPC plans to perform a green fund survey of its customers during the third quarter of 1995 to determine the market's interest in the concept.

Additionally, FPC is currently investigating other funding sources for renewable measures. FPC proposes that the initial costs associated with green fund surveys and evaluation of the [*10] green pricing concept be recovered through the Energy Conservation Cost Recovery Clause. FPC is taking reasonable action on green pricing in response to the Commission's DSM Goals order; therefore, we approve FPC's proposal.

Green pricing administrative program costs will be subject to ongoing review in the ECCR clause. These costs will be separately identified as a line item in FPC's ECCR filings.

LOW INCOME

FPC's plan adequately addresses the needs of low-income ratepayers. FPC continues to investigate methods to assist low-income customers. Several of FPC's programs address the special needs of low-income customers. There is no income barrier for participation in the Home Energy Check program and Residential Energy management programs, as they are offered at no customer cost.

An additional benefit of the Home Energy Check is that it allows FPC to work with other relief agencies. The Home Energy Improvement program assists low-income customers with substantial up-front capital costs by offering zero-interest loans with installment billing. FPC continues to work with the Department of Community Affairs, the Florida Client Council, and the Legal Environmental Assistance [*11] Foundation (LEAF) to discuss ways to facilitate low-income participation in DSM programs. FPC worked with LEAF in the design of its DSM plan.

FPC is involved with low-income assistance outside of its DSM programs. Examples include an average billing plan, donations from other FPC ratepayers to assist low-income customers in paying energy bills, and assisting with dissemination of information through involvement with social service agencies. FPC is aware of the special needs of its low-income customers. The correlation between energy use and household income for FPC's customers is similar to that of FPL.

C. Tampa Electric Company's Demand-Side Management plan:

TECO's proposed DSM plan was filed on February 6, 1995, and contains 16 programs, including seven residential programs; seven commercial/industrial programs; one research and development program; and a homebuilder awareness program. In addition, TECO has described its continuing cogeneration activities.

We have reviewed TECO's plan and believe its conservation programs meet our three-pronged test. In addition, TECO's plan contains a research and development program and a cogeneration program which, while not directly [*12] measurable, are specifically identified in FEECA. A summary of these programs is contained in Attachment 3.

TECO has provided a brief description of its monitoring and evaluation plans for each of the programs in its DSM plan. TECO's proposed methodology for measuring actual kW and kWh savings achieved for each program is much too general. TECO shall file a more detailed methodology within six months of this Order. TECO should provide a specific methodology for each approved program. A general time frame for conducting the measurement of savings should be identified, along with the estimated frequency of measurement (such as quarterly, yearly, every five years, etc.). Also, a detailed methodology of savings evaluation (such as pre- and post-billing analysis, enhanced metering, engineering studies, etc.), and an estimate of costs, shall be indicated for each program to insure that measurement costs do not reverse the program's cost-effectiveness.

Staff will review the methodology to be filed by TECO and bring any deficiencies to our attention. Parties and interested persons who believe deficiencies exist can petition us to correct them.

COMMERCIAL MEASURES RESEARCH AND DEVELOPMENT [*13] **PROGRAM**

TECO proposes to conduct research on the potential of different DSM measures under this program. TECO estimates program costs at $ 150,000 per year, and has requested a five year period with continuation based on annual review of results by the Commission. Traditionally, we have limited the time frame and placed spending limits on research programs. Utilities should conduct timely, focused research efforts in order to determine the feasibility of including a DSM measure in a utility program.

TECO's research program shall likewise be limited, in this case to three years with a total spending cap of $ 450,000. TECO shall also provide a detailed report on the results of its research efforts at the end of the period.

GREEN PRICING

Based on the preliminary information submitted in response to Order No. PSC-94-1313-FOF-EG, TECO's green pricing program appears to adequately address the development of alternate funding sources to promote the installation of renewable technologies. TECO proposes to survey its ratepayers to help determine interest in Green Pricing and to identify specific areas of solar and renewable technologies that TECO's customers would most support. [*14] TECO plans to utilize data from a University of Florida Energy Extension Service survey on green pricing, in connection with its own planned survey.

We approve TECO's green pricing administrative program costs that shall be subject to ongoing review in the ECCR clause. These costs shall be separately identified as a line item in TECO's ECCR filings.

LOW INCOME

Based on the preliminary information submitted in response to Order No. PSC-94-1313-FOF-EG, TECO's analysis of DSM program availability, saturation, and benefits to the residential low-income customers appears to be adequate.

TECO is making appropriate efforts to address the special needs of its low-income ratepayers. A Social Service Advisor was established in the company to directly assist low-income ratepayers and to interface with social service agencies in order to better coordinate efforts in assisting low-income customers.

In addition, TECO has estimated DSM program participation by low-income customers using data from a recent appliance saturation survey. The correlation between energy use and household income for TECO's customers is similar to that of FPL.

D. Gulf Power Company's Demand-Side Management [*15] plan:

Gulf's proposed DSM Plan was filed on February 22, 1995, and contained: five Residential programs, three Commercial/Industrial programs, two Conservation Demonstration and Development Programs, in addition to Gulf's existing six conservation programs. The energy conservation achieved by the six existing programs will not be counted toward achievement of the conservation goals that were established by Order No. PSC-94-1313-FOF-EG.

We have reviewed Gulf's plan and find the conservation programs, including the six existing programs, meet our three-pronged test. In addition, Gulf's plan contains a research and development program which, while not directly measurable, is specifically identified in FEECA. A summary of each of these programs is contained in Attachment 4.

Gulf provided a brief description of its monitoring and evaluation plans for each of the programs in its DSM plan. Gulf's proposed methodology for measuring actual kW and kWh savings achieved for each program, however, is much too general. Gulf shall file a more detailed methodology within six months of this Order approving the programs. Gulf shall provide a specific methodology for each program, new and existing, [*16] that we approved. At least a general time frame for conducting the measurement of savings shall be stated along with the estimated frequency of measurement (such as quarterly, yearly, every five years, etc.). Also, a detailed methodology of savings evaluation (such as pre- and post-billing analysis, enhanced metering, engineering studies, etc.) and an estimate of the costs shall be indicated for each program to insure that measurement costs do not reverse the program's cost-effectiveness.

Staff will review the methodology to be filed by Gulf and bring any deficiencies to our attention as needed. Parties and interested persons who believe any deficiencies exist can petition the Commission to correct them.

ADVANCED ENERGY MANAGEMENT PROGRAM

Among the many assumptions needed to calculate a conservation program's costs and benefits are the kW savings per customer and the cost and timing of the utility's next avoidable electric generating unit. When costs equal benefits, the accuracy of the many assumptions become critical because cost overruns are borne by non-participating as well as participating customers.

The equipment now being used for the Advanced Energy Management program [*17] is manufactured by a company that is one-third owned by the Southern Company. Each Advanced Energy Management installation is expected to cost $ 750. The participating Advanced Energy Management customer pays $ 450, which is amortized over 20 years. Gulf proposes that the remaining $ 300 be collected from all customers through the energy conservation cost recovery (ECCR) clause.

Gulf conducted a two year experiment with the Advanced Energy Management system in Gulf Breeze, Florida. This is a somewhat upscale community on Highway 98 across the bay from Pensacola. The community is surrounded by water. Customers were selected on a volunteer basis, which introduces some unknown bias in the experiment. The experiment consisted of three set cost periods, plus a fourth very high cost period based on system capacity shortfalls. Rates were below the average rate in the P1 and P2 off-peak periods and above the system average in the P3 shoulder load period and the P4 capacity shortfall period. With Advanced Energy Management, the customer can set major appliances, such as the water heater, air-conditioning, heating, or pool pump to be automatically curtailed as prices increase. The curtailment [*18] signal is sent through the house wiring relays controlling each appliance. Peak period P4 prices were in effect for 53 hours in 1992 and 64 hours in 1993, or about one percent of the year. Based on this experiment, Gulf assumed a 2.0 kW savings per participating customer that results in a benefit/cost ration of 1.03 to 1.0.

Gulf also filed an analysis of direct load control (DLC) in its program filing as required by Order No. PSC-94-1486-FOF-EG. Since Gulf had no experience in DLC, it modelled a DLC program after Tampa Electric Company's (TECO's) filing using the data and assumptions utilized by TECO in the conservation goals docket. The pertinent assumptions were the installation costs, $ 396/customer, and peak load reduction, 1.22 kW. Gulf concluded that a DLC program was not cost effective for controlling summer loads. Since Advanced Energy Management and DLC control virtually the same appliances, staff questions why the per customer demand reductions would not be similar for both Advanced Energy Management and a less costly DLC program. Staff believes Gulf may be able to achieve the same results in a less costly manner.

Despite staff's reservations, we believe that utilities [*19] should be given flexibility to determine what programs they wish to implement. Since the program is cost effective based on Gulf's assumptions and since Gulf is projecting Advanced Energy Management to account for approximately 75% of its summer and 103% of its winter residential demand goal, we approve Gulf's program. We instruct staff, however, to scrutinize this program in evaluating its cost effectiveness and the kW and kWh savings it achieves.

GREEN PRICING

Gulf's Project Share program generates approximately $ 100,000 annually through a bill check-off system to pay the electric bill of needy families. Gulf stated that it can implement a similar check-off system for the Solar for Schools Pilot Program. For each installation Gulf will provide $ 35,000 towards the program, which will supplement the dollars needed for the installation of the solar equipment at each participating school.

Gulf will also continue to work with the Florida Solar Energy Industries Association to promote solar energy in Gulf's service territory. In addition, Gulf has a memorandum of understanding with the Florida Department of Community Affairs (DCA) that establishes a collaborative effort with [*20] DCA to identify and pursue actions necessary to ensure sustainability of cost effective solar programs which meet Gulf's and DCA's common objectives.

We approve Gulf's green pricing administrative program costs that will be subject to ongoing review in the ECCR clause. These costs will be separately identified as a line item in Gulf's ECCR filings.

LOW INCOME

Gulf presently has in effect a check-off procedure on the customer's utility bill wherein the customer can donate money for needy families to pay their electric bills. Gulf acts as a conduit for the money and distributes all monies received directly to the Salvation Army. Approximately, $ 100,000 per year is received through this program.

In addition Gulf plans to (1) offer targeted energy education programs and literature to assist low income customers in energy conservation, (2) strengthen the relationship between Gulf and low income service providers, (3) promote Gulf's free services (such as energy audits) through the low income service providers, (4) continue to be responsive to the individual needs of customers and (5) match participant lists with geodemographic database information. The correlation between energy [*21] use and household income for Gulf's customers is similar to that discussed in issue 1 for FPL.

GOAL ACHIEVEMENT ISSUES

A. Tampa Electric Company

FEECA mandates the Commission to adopt conservation goals, and requires each utility to develop plans and programs to meet the overall goals within its service area. Only savings from programs identified in a utility's DSM plan should count toward that utility's goals. In the description of its Commercial/Industrial Load Management program TECO states:

Incrementally, customers who qualify and select service under the IS interruptible rates over participation in the C/I Load Management program, will be counted toward the summer and winter commercial MW goals under this program.

Pursuant to the stipulation in TECO's last rate case, recovery of TECO's IS rate credit was not allowed through the ECCR clause, and the IS rate is therefore not a program. In TECO's goal setting docket, (930551-EG) no potential savings from its interruptible rate customers was identified and included in its goals. Nonetheless, TECO has requested that savings from a non-DSM program be counted toward its C/I goal.

We deny TECO's request because [*22] only savings from programs identified in a utility's commission approved DSM plan will count toward that utility's goals.

B. Florida Power Corporation

FPC has requested approval to allow up to 15% of any excess savings in the residential market segment to be applied to the commercial/industrial market segment, or vice versa, to insure goal achievement in both market segments. A decision on this issue is premature because FPC projects that it will achieve both its residential and commercial/industrial goals. Therefore, we decline to make a determination on this issue at this time.

OTHER ISSUES

A. Detailed program participation standards:

Florida Power and Light Company, Florida Power Corporation, Gulf Power Company, and Tampa Electric Company shall file program participation standards within 60 days of the issuance of this Order.

Each utility's program standards shall clearly state the Company's requirements for participation in the programs, customer eligibility requirements, details on how rebates or incentives will be processed, technical specifications on equipment eligibility, and necessary reporting requirements. Staff shall administratively approve these [*23] program participation standards if they conform to the description of the programs contained in each utility's DSM plan.

B. Effective date:

The tariff revisions corresponding to the DSM programs approved by this Order shall become effective the date the order becomes final.

C. Workshop:

Our staff has indicated its concerns over the competitive relationship between the electric and gas industry and the effect of commercial/industrial conservation programs on competition between the industries. Staff will conduct a workshop on September 5, 1995, with both the gas and electric industries participating, to gather information regarding staff's concerns.

Based on the foregoing, it is, therefore,

ORDERED by the Florida Public Service Commission that Florida Power and Light Company's Demand-Side Management plan is approved as discussed in the Order above with the exception of Florida Power and Light Company's C/I Load Control program which will be considered for approval at a later date. It is further

ORDERED that Florida Power Corporation's Demand-Side Management plan is approved as discussed in the Order above. It is further

ORDERED that Tampa Electric Company's Demand-Side [*24] Management plan is approved as discussed in the Order above. It is further

ORDERED that Gulf Power Company's Demand-Side Management plan is approved as discussed in the Order above. It is further

ORDERED that Tampa Electric Company will not be permitted to count savings from incremental IS customers toward its C/I goals. It is further

ORDERED that no decision will be made at this time on whether Florida Power Corporation will be permitted to count demand and energy savings from one market segment towards the goals of another market segment. It is further

ORDERED that Florida Power and Light Company, Florida Power Corporation, Tampa Electric Company and Gulf Power Company shall file program participation standards within 60 days of the issuance of this Order and that these standards will be administratively approved. It is further

ORDERED that Florida Power and Light Company, Florida Power Corporation, Tampa Electric Company and Gulf Power Company shall each file an updated monitoring plan identifying the specific approaches implemented for each program within 180 days of the issuance of this Order. It is further

ORDERED that the tariff revisions associated with the DSM program [*25] discussed in this Order will become effective the date this Order becomes final. It is further

ORDERED that Docket Nos. 941171-EG, 941172-EG and 941173-EG shall be closed unless an appropriate petition for formal proceedings is received by the Division of Records and Reporting, 101 East Gaines Street, Tallahassee, Florida 32399-0870, by the close of business on the date indicated in the Notice of Further Proceedings or Judicial Review. It is further

ORDERED that Docket No. 941170-EG shall remain open pending Commission vote on staff's recommendation on the issue of whether Florida Power and Light Company's Commercial/Industrial load control programs are approved for cost-recovery. It is further

ORDERED that this Order shall become final and effective unless an appropriate petition for formal proceedings is received by the Division of Records and Reporting, 101 East Gaines Street, Tallahassee, Florida 32399-0870, by the close of business on the date indicated in the Notice of Further Proceedings or Judicial Review.

By ORDER of the Florida Public Service Commission, this 9th day of June, 1995.

DISSENTBY: DEASON; GARCIA

DISSENT: Commissioner Deason and Commissioner Garcia dissent from the Commission's [*26] decision to refrain from deciding whether Florida Power Corporation should be permitted to count demand and energy savings from one market segment towards the goals of another market segment.

ATTACHMENT I - FPL

NOTE: All programs in Attachment 1 contribute toward FPL's goals, and the costs are to be recovered through the ECCR clause. The Cogeneration & Small Power Production program, however, will not contribute toward FPL's goals

RESIDENTIAL PROGRAMS - FPL

Conservation Service Audit: This program provides a free walk through energy audit, a computer generated Class A audit, and a customer assisted energy audit. Program serves as a vehicle to introduce customers to FPL's conservation incentive DSM programs.

Building Envelope Program: The objective of this program is to encourage the installation of: ceiling insulation up to R-30, window treatments such as solar film, and high efficiency replacement windows. Incentives range from $ 346 to $ 348 per kw.

Duct System Testing and Repair: The objective of this program is identification and repair of air leaks in air conditioning duct systems. FPL is petitioning to discontinue the HELP program which [*27] was previously combined with the duct program because it is not cost-effective. This program consists of low cost conservation measures such as weatherstripping and water heater tank wraps.

Air Conditioning Program: The objective of this program is to induce customers to purchase higher Seasonal Energy Efficiency Ratio (SEER) central heat pumps, central air conditioning equipment, and window/wall units. Incentives range from $ 336 to $ 384 per kw. **Load Management Program:** The objective of this program is to install direct load control equipment on central air conditioners, central electric space heaters, electric water heaters, and swimming pool pumps. Monthly incentives are $ 6.00 to $ 9.00 for air conditioners, $ 2.00 to $ 4.00 for electric space heaters, $ 3.50 for water heaters, and $ 3.50 for swimming pool pumps.

Heat Recovery Water heating: The objective of this program is to encourage customers to purchase heat recovery units. Solar water heaters are proposed to be phased out of this program and treated as a research and development project. Incentives will average $ 509.00 per summer kW.

COMMECIAL/INDUSTRIAL PROGRAMS - FPL

Business Energy Evaluation: [*28] The objective of this program is to identify opportunities for demand and energy reduction in commercial and industrial facilities. Program offers free walk-through evaluations, with cost sharing for more complex evaluations.

Building Envelope: The objective of this program is to encourage customers to increase the efficiency of buildings through the installation of cost-effective high-efficiency building envelope measures such as window treatments and roof/ceiling insulation. Incentives will be capped an average incentive of $ 483.00 kw.

Efficient Lighting: The objective of this program is to encourage customers to install cost-effective replacement lighting measures. Incentives range from $ 20.00 to $ 250.00 per kw.

Efficient Motors: The objective of this program is to encourage customers to install high efficiency three phase motors rather than standard efficiency motors. Incentives average $ 250.00 per kw.

Off Peak Battery Charging Program: The objective of this program is to encourage the installation of control systems that will restrict a customer's battery charging of golf carts, electric vehicles, or material handling equipment to off-peak periods. [*29] Incentives will not exceed $ 57 per kw.

Heating, Ventilating, and Air Conditioning: Program combines the following four previously approved programs; Water Cooler Chiller Retrofit, C/I Thermal Energy Storage, Air Cooled Chiller Enhancement and High Efficiency DX HVAC. Program provides various levels of incentives to encourage the installation of high efficiency HVAC equipment.

Business Custom Incentive: Program encourages the implementation of unique energy conservation measures or projects not covered by other FPL programs to reduce or shift demand to off-peak periods. FPL proposes to eliminate the current incentive cap of $ 250.00 per kw and determine rebates based on a case-by-case analysis using the RIM cost-effectiveness test.

C/I Load Control: Program is designed to reduce peak demand by allowing FPL to directly control or switch load to the customer's standby generator for loads 200 kw or greater. Incentive is a discounted rate from the firm rate. This program has not been approved as staff is still analyzing the tariff sheets and evaluating program cost-effectiveness. A separate recommendation will be filed.

General Service Load Management: The [*30] objective of this program is to install load control equipment on Direct Expansion (DX) central air conditioners. Monthly incentives are $ 2.00 per ton of air conditioning equipment controlled.

RESEARCH & DEVELOPMENT PROJECTS - FPL

The following are active research projects, including their original expenditure caps as previously approved by the Commission:

Hot Water Storage--evaluate kw and kwh impacts of heating water in off peak periods. ($ 225,000)

Residential Thermal Energy Storage--determine technical feasibility of producing ice during off-peak which is used for air conditioning. ($ 413,400)

Residential New Home Construction--identify and investigate cost- effective activities which exceed Florida's building code. ($ 5,900,000)

C/I Dehumidification--evaluate the demand and energy impacts of recent federal standards increasing the outside air requirement for ventilation. ($ 750,000)

The following are proposed research projects, including proposed expenditure caps:

Residential Heat Pump Water Heatin--establish actual kw and kwh savings, and evaluate current reliability of the improved heat pump technology. ($ 456,660)

Demand [*31] **Load Control Trial Project**--trial project applying to 120 middle to large commercial/industrial customers. Monthly incentives are $ 1.00 kw for process control, and $ 2.00 per ton of air conditioning load. ($ 566,000)

Cool Communities--Dade county has been selected by American Forests and the DOE to evaluate the impact of strategic tree planting and surface color lightening on energy consumption. ($ 550,000)

Residential Solar Water Heating--FPL will provide up to 100 installations to identify technology improvements and market segments which could potentially help the program pass a RIM test. If the results fail to meet any of FPL's criteria, the research project will be discontinued with no further ECCR funding. ($ 789,200)

Conservation Research and Development Program: This program is intended to serve as an umbrella program to research developing technologies for possible inclusion in future DSM programs. If and when research on a particular technology progresses to the point that a trial project is warranted, the company will petition the Commission separately for approval of that trial project. FPL is requesting approval for a three year period with [*32] a cumulative spending cap of $ 3,600,000.

Florida Coordinating Group (FCG) Research: DSM measures categorized by the Commission as R&D in the goals hearing are being evaluated by the FCG Energy Conservation Committee with participation and funding from other electric utilities. ($ 50,000)

OTHER PROGRAMS - FPL

Green Pricing: Customers voluntary contribute to a fund used to purchase renewable generating technologies. FPL will purchase photovoltaic modules to be located at powerplants or substations.

Cogeneration & Small Power Production: The objective of this program is to identify and encourage cost-effective qualifying facility projects, and assist customers in the evaluation of potential cogeneration and self generation applications. ($ 1,084,000 per year).

ATTACHMENT 2 - FPC

NOTE: All programs in Attachment 3 contribute toward FPC's goals, and the costs are to be recovered through the ECCR clause, except as follows. The C/I interruptible, curtailable service, and cogeneration programs do not count toward goals, however, costs for existing participants are recovered through ECCR.

RESIDENTIAL PROGRAMS - FPC

Home Energy Check: Energy [*33] audit program that serves as foundation for all other DSM programs for residential customers. Company auditor examines home and makes recommendations on low-cost or no-cost energy-saving practices and measures. Level 1 audit is a "do-it-yourself" mail-in audit performed by the customer. Level 2 audit is a free walk-through inspection performed by an auditor; Level 3 audit is a paid ($ 15) walk-through energy analysis performed by an auditor. This program is a consolidation of the previous Home Energy Check and Home Energy Analysis programs.

Home Energy Improvement: Umbrella efficiency program for existing homes. Combines thermal envelope efficiency improvements with upgraded equipment and appliances. Promotes energy-efficiency measures described below:

Ceiling Insulation Upgrade: Encourages customers who have electric space heat to add ceiling insulation. FPC pays portion of the installed cost. Specific incentive amount based on increase in insulation amount above a maximum of R-12, with maximum incentive amount of $ 100 per customer.

Duct leakage Test and Repair: Promotes energy efficiency through improved duct system sealing. Program helps identify and reduce [*34] energy loss by measuring air leakage rate through the central duct system under controlled pressurization. Customer must have electric heating and centrally-ducted cooling system to participate; building must be capable of being pressurized. FPC pays incentive of up to $ 25 per unit for duct leakage test; maximum of $ 100 per unit is paid for duct repair.

High Efficiency Electric Heat Pumps: Pays financial incentive, not exceeding $ 300 per unit, for purchase of high-efficiency electric heat pumps. Specific incentive based on minimum heating and/or cooling efficiency levels. Indoor air handler and outdoor condenser must both be replaced to qualify for this rebate.

High-Efficiency Alternate Electric Water heating: Promotes installation of high-efficiency alternative electric water heating equipment. Provides incentive of up to $ 100 for each heat recovery unit and up to $ 200 per unit for each dedicated heat pump water heater unit.

FPC encourages the adoption of several energy-efficiency measures through a supplemental incentive bonus up to $ 50. Incentive is paid to a participant in FPC's high efficiency electric heat pump program who also implements the ceiling [*35] insulation upgrade, duct leakage repair, or both, within 90 days.

Home Energy Improvement program offers two financing options in lieu of rebates mentioned above: interest-free installment billing over a 12 month period (amount not to exceed $ 500), and financing assistance through participating financial institutions and/or Federal programs.

Residential New COnstruction: Promotes energy-efficient new home construction. Provides more efficient cooling and heating consumption with improved comfort. Provides information, education, and advice to home builders and contractors on energy-related issues and efficiency measures. Promotes energy-efficient electric heat pumps and alternate electric water heating units with incentives that are identical to those offered in the Home Energy Improvement program for existing homes.

Residential Energy Management: Direct load control program that allows FPC to reduce peak demand. At its option, during peak periods, FPC can interrupt electric service to water heaters, central electric heating and/or cooling systems, or swimming pool pumps. Participation and incentives limited to customers who use at least 600 kWh per month. Customers [*36] receive monthly bill credit which is dependent on the interruption schedule and the devices subject to interruption. Maximum incentive is $ 3 under Schedule A, $ 13 under Schedule B, and $ 6 under Schedule C.

COMMERCIAL/INDUSTRIAL PROGRAMS - FPC

Business Energy Check: Energy audit program that serves as foundation for all other DSM programs for existing C/I customers. Company auditor examines lighting, building envelope, HVAC system, and water heating system. Level 1 audit is a free walk-through inspection; Level 2 audit is a paid walk-through energy analysis whose cost is based on facility's average monthly energy use.

Better Business: Umbrella efficiency program for existing C/I buildings. Provides information, education, and advice on energy-related issues and efficiency measures. Promotes energy-efficiency measures described below:

Interior Lighting: Promotes installation of energy-efficient lighting fixtures. Utility conducts a lighting audit, provides information to the customer, and pays an incentive not exceeding $ 50 per kW reduced. Baseline for calculating incentives premised on the minimum efficiency level allowable by federal EPAct laws and [*37] the Florida Building Code.

HVAC Equipment: Pays financial incentive, not to exceed $ 100 per kW reduced, for the purchase of high-efficiency HVAC equipment such as packaged terminal heat pumps, water-cooled and air-cooled chillers, and unitary heat pumps and air conditioners. Baseline for calculating incentives premised on ARI Standard Test Rating Conditions.

Motors: Promotes installation of high-efficiency poly-phase motors. Incentives paid according to motor size on a per-horsepower basis, with larger motors receiving up to $ 2 per horsepower.

Heat Recovery units: Promotes installation of heat recovery units for domestic water heating applications. Provides incentives based on peak kW demand, up to a maximum of $ 100 per kW reduced.

Roof Insulation upgrad: Encourages customers who have electric space heat to add roof insulation. FPC pays portion of the installed cost. Eligibility based on demonstration that additional insulation results in heating and/or cooling use reductions. Specific incentive amount based on increase in insulation amount above a maximum of R-12, with maximum incentive amount of $ 100 per customer.

Duct Leakage Test and Repair: [*38] Promotes energy efficiency through improved duct system sealing. Program helps identify and reduce energy loss by measuring air leakage rate through the central duct system under controlled pressurization. Customer must have electric heating and centrally-ducted cooling system to participate; building must be capable of being pressurized. FPC pays incentive of up to $ 25 per unit for duct leakage test; maximum of $ 100 per unit is paid for duct repair.

Window Film: Provides incentive for a customer to install window film having a shading coefficient of 0.45 or less on an existing window with a shading coefficient of 0.84 or greater. Incentive paid on a per-square foot of installed film basis; maximum incentive is $ 125 per customer. Facilities with multiple guest rooms (hotels, hospitals, etc.) are eligible for maximum incentive of $ 50 per room.

The Better Business program also offers two financing options in lieu of incentives mentioned above: interest-free installment billing over a 12 month period (amount not to exceed $ 500), and financing assistance through participating financial institutions and/or Federal programs.

C/I New Construction: Umbrella efficiency [*39] program for new C/I buildings. Provides information, education, and advice on energy-related issues and efficiency measures. Promotes energy-efficient HVAC equipment, motors, heat recovery units, and duct leakage test and repair. Incentive levels are nearly identical to those offered in the Better Business program (for existing buildings).

Energy monitor: Provides consulting services to improve the O&M of building and process systems. FPC tailors its services to the needs of its C/I customer. No incentives are paid under this program. Rather, FPC charges a fee for four types of services: energy accounting, load monitoring, commissioning assistance, and energy project assistance. Program impacts will be site-specific.

Innovation Incentive: Catch-all program that subsidizes energy efficiency measures and equipment, resulting in substantial demand and energy savings. Encompasses measures not otherwise addressed by other DSM programs. To be eligible, projects must reduce or shift a minimum of 10 kW. Rebates based on the application's cost-effectiveness and will be limited to $ 150 per kW reduced or shifted. Cost-effectiveness is evaluated on a case-by-case basis, and only [*40] those projects that are cost-effective (1.0 RIM) will be approved by FPC.

Commercial Energy Management: Direct load control program that reduces FPC's demand during peak or emergency conditions. Offered under the GSLM-2 tariff, energy management is available to all C/I customers with the GS-1, GST-1, GSD-1, and GSDT-1 tariffs. Program allows FPC to interrupt electric service to water heaters, central electric heating and/or cooling systems, or swimming pool pumps. Customers receive a monthly bill credit which is dependent on the interruption schedule and the devices subject to interruption. Maximum incentive is $ 0.26/kW under Schedule A and $ 0.56/kW under Schedule B.

Standby Generation: Demand control program that reduces FPC's demand based on indirect control of customer equipment. Different from the Energy Management program in that FPC will have no direct control of customer equipment. Offered under the GSLM-2 tariff, the program is available to all C/I and agricultural customers who have on-site generation and are willing to use this generation to reduce their demand on FPC's system at times when FPC deems it necessary. Monthly bill credit based on the customer's [*41] demonstrated ability to reduce its demand at FPC's request.

Interruptible Service: Direct load control program that reduces FPC's demand during peak or emergency conditions. Offered under the IS-1 and IST-1 tariffs, interruptible service is available to any non-residential customer willing to have their power interrupted. Monthly demand credit paid to customer based on level of billing demand.

Curtailable Service: Direct load control program that reduces FPC's demand during peak or emergency conditions. Offered under the CS-1 and CST-1 tariffs, curtailable service is available to any non-residential customer willing to have their power curtailed. The maximum demand curtailed will not exceed either 25 kW or 25% of the customer's average annual billing demand. Monthly demand credit paid to customer based on level of curtailable demand.

OTHER PROGRAMS - FPC

Technology Development Program: Program under which FPC will undertake certain development and demonstration projects which have promise to become cost effective conservation programs. Examples of potential projects include amorphous core transmission and distribution transformers, indoor air quality measures, [*42] thermal energy storage technologies, innovative metering techniques, and measures identified as research and development in the Conservation Goals Docket. FPC will provide a final report on each demonstration project or file and offer a permanent conservation program for each program investigated. Program expenses will not exceed $ 800,000 annually.

Cogeneration: The objective of this program is to identify and encourage cost-effective qualifying facility projects and administer the power sales agreements between the utility and qualifying facilities.

ATTACHMENT 3 - TECO

NOTE: All programs in Attachment 5 contribute toward TECO's goals, and the costs are to be recovered through the ECCR clause. The Home Builder Awareness, Commercial Measures Research & Development, and Cogeneration programs, however, will not contribute towards TECO's goals.

RESIDENTIAL PROGRAMS - TECO

Alternate Audit (Free): Free walk-through audit offered to all residential customers. This program is designed to save demand and energy by increasing customer awareness of available conservation measures which can reduce their energy use.

Mail-In Energy Audit: Customers are supplied [*43] with an energy data collection form which the customer completes and returns for analysis. Energy conservation recommendations are made based on form responses. There is no charge to the customer.

Residential Conservation Service (RCS) Audit: Comprehensive energy audit where specific data on the structure of the residence and the customer's lifestyle is collected. The data is then entered into a computer program which calculates installation cost, investment payback period and estimated energy savings of available conservation programs. The charge for the audit is $ 15.00.

Ceiling Insulation: Program to reduce demand and energy by decreasing the load on residential air conditioning and heating equipment. Customers must add a minimum of R-11 insulation in order to qualify for the incentive of $ 100.00 in the form of a certificate which the customers may apply to the total cost of installing ceiling insulation.

Duct Repair: This program identifies demand and energy savings opportunities in HVAC equipment by inspecting air distribution system losses with a blower door test. The customer receives an assessment of any problems discovered during the inspection and, will receive [*44] a certificate equal to 75 percent of the total repair up to a maximum of $ 200 to be used towards repairs performed by an approved HVAC contractor. The cost to the customer for the blower door test will be $ 25.

Heating and Cooling: This targets reducing the rate of growth in peak demand (particularly winter) and energy in the company's service area by increasing the saturation of high efficiency heat pumps and/or central air conditioning (without oil or resistance heat) in single family dwellings. An incentive of $ 75 per qualifying unit is paid to participating dealers. The customer receives $ 350 for a unit with an SEER of 11.0, and $ 750 for a unit with an SEER of 13.0.

Prime Time Load Management: Prime Time is a residential load management program designed to control summer and winter peak demand loads. Certain selected appliances such as air conditioners, water heaters and pool pumps are controlled by a radio signal from TECO's system dispatchers. Except during emergencies, appliances are only interrupted during peak hours. Participants receive a monthly credit on their electric bill based on the appliances selected for load control and the type of interruption. [*45] The credit for central heating and cooling appliances is $ 12.00 per month for a continuous 3-hour interruption and $ 6.00 per month for summer cycle interruption. Hot water heaters and swimming pool pumps are $ 4.00 and $ 3.00 per month, respectively.

COMMERCIAL/INDUSTRIAL PROGRAMS (TECO)

C/I Audit-Free: A conservation program designed to reduce demand and energy consumption by increasing customer awareness of energy use in their facilities. Recommendations are based on the replacement of less efficient equipment and systems or modifications to operations to enhance the customer's overall efficiency. Recommendations are primarily standardized and encourage the customer to implement measures that, if cost-effective, move the customer beyond the efficiency level typically installed in the marketplace. C/I customers on firm rates are eligible.

Mail-In C/I Audit: The customer is supplied with a data collection form which the customer completes and returns to TECO or its agent for analysis. Results are then submitted to the customer for review and implementation. There is no charge to the customer.

Comprehensive C/I Audit-Paid: A more detailed audit [*46] which may involve monitoring of specific equipment within a customer's facility to determine its electric usage with respect to time of operation. Based on the results, recommended changes to save energy on equipment and/or operation are made. Charges to the customer range from $ 15.00 to $ 75.00 depending on rate class.

Commercial Indoor Lighting: This incentive program for existing facilities is designed to encourage investment in more efficient fluorescent lighting technology within conditioned space. The customer receives a $ .16 per watt incentive by achieving a minimum of 1 KW in lighting reduction from any lighting source retrofitted with more efficient fluorescent lighting system (ballast and lamps).

C/I Load Management: Monthly credits are paid based on duration of interruption, for control of specified end-use equipment. Large loads, such as walk-in freezers, are interrupted for up to three hours, and Commercial air conditioning equipment is cycled during summer control periods. The credit for large loads interrupted up to three continuous hours is $ 3.00/kW/month. Cycled air conditioning equipment is given a $ 1.00/kW/month credit.

Commercial [*47] **Standby Generator:** Program designed to utilize the on-site generation of C/I facilities in order to reduce weather sensitive peak demand. Participating customers are given an hour notice to start their generators and arrange for orderly transfer of load. The standby generators are metered to determine the average portion of customer load served by the generators when called on by TECO. Participants receive a monthly credit of $ 3.00 per kW.

Conservation Value: An incentive program designed to encourage investment in C/I measures which will substantially reduce or shift demand but which have limited application within the C/I sector and are consequently not covered under other conservation programs. To be approved, the measure must have a minimum summer and winter demand savings of 5 kw. The maximum incentive is $ 225 per kw for measures which reduce summer peak only, $ 150 per kw for measures which reduce winter peak only and $ 275/kw for measures which reduce both.

OTHER PROGRAMS (TECO)

Home Builder Awareness: The objective of this program is to improve construction techniques used on air distribution systems (ADS) in new residential structures. [*48] The program will involve field demonstrations at construction sites, classroom instruction, and the evaluation of new construction techniques applied to residences and their ADS. A $ 100 incentive will be offered to contractors to perform a blower door test and repair any ADS leakage found in the builder's model homes. TECO is requesting approval for three years with costs estimated at $ 22,000 per year, however total costs will not exceed $ 66,000.

Commercial Measures Research & Development: This program will 1) Continue the field efficiency testing portion of the DSM R&D program which is scheduled to end May 1995. This program allowed TECO to collect and analyze data of commercial DSM measures; 2) Fund TECO participation in the Energy Technology Assessment Committee (ETAC) of the FCG; and 3) Fund the planned evaluation of the measures designated as R&D by the Commission in Docket No. 930551-EG. Program costs are estimated at $ 150,000 per year. TECO has requested a Five year period with continuation based on annual review of results by the Commission.

Cogeneration: Program to encourage cogeneration by providing assistance to commercial/industrial customers [*49] in the development of cost effective cogeneration alternatives to help meet and offset base load energy and peak load demands.

ATTACHMENT 6 -- Gulf

NOTE: All programs in Attachment 7 contribute toward Gulf's goals, and the costs are to be recovered through the ECCR clause, except as follows. The C/I Real Time Pricing Pilot program will count toward goals, however, costs will not be recovered through ECCR pursuant to Commission order.

RESIDENTIAL PROGRAMS -- Gulf

Advanced Energy Management Program: The AEM system allows the customer to control more precisely the amount of electricity purchased for various selected loads within the house whether it be heating, cooling water heating or other. The various components of the AEM system installed in the customer's home, as well as the components installed at Gulf, provide constant communication between customer and utility. The AEM is based upon three set cost periods, plus a fourth very high cost period based on system capacity shortfalls (P1, P2, P3 & P4). Rates are below the average rate in the P1 and P2 off-peak periods and above the system average in the P3 shoulder load period and the P4 [*50] capacity shortfall period. In times of extreme peak load conditions the AEM system allows a critical price signal communications from Gulf to the customer's premise at least a half hour before the highest rate goes into effect. The customer's thermostat and relay system can be programmed to react to these price signals.

In Concert With The Environment: The objective of this program is to make 8th and 9th grade science students, in Gulf's service area, aware of how everyday energy use impacts the environment and how using energy wisely increases environmental quality. Program materials include a video, an introductory presentation to launch student participation, complete lesson plans, an energy survey, and student handbooks. Participants in the program become energy experts in three easy steps. First, students become energy investigators, seeking real life data on their homes and family transportation and recycling habits. Next, they analyze the information through a sophisticated, "hands-on" software program that generates a personal plan using graphs to illustrate energy savings and environmental benefits on each students research. Finally, students become energy experts [*51] by discussing the material in class and presenting their plans for saving energy and preserving natural resources to their families.

Duct Leakage Repair: The objective of the Duct Leakage Program is to provide Gulf's customers a means to identify house air duct leakage and recommend repairs that can reduce customer kWh energy usage and kW demand.

Good Cents Environmental Home Program: The objective of the Good Cents Environmental Home Program is to provide Gulf's customers with guidance concerning energy and environmental efficiency in new construction. The program promotes energy-efficient and environmentally sensitive home construction techniques by evaluating over 500 components in six categories of design and construction practices. The categories are: 1) Energy Efficiency, 2) Building Design, 3) Construction Practices, 4) Building Materials, 5) Water Efficiency, and 6) Ecological Planning. The Good Cents Environmental Home will need to meet standards that exceed the present building codes.

Residential Geothermal Heat Pump Program" The objective of the Geothermal Heat Pump Program is to reduce the demand and energy requirements of new and existing [*52] residential customers through the promotion and installation of advanced and emerging geothermal systems. Standard air source heat pumps utilize the outside air to provide the heat needed to make the system work while geothermal heat pumps utilize constant temperature water to provide the heat. The water is contained in a closed loop system of pipes that are buried beneath the earth in the yards of the customers homes.

COMMERCIAL/INDUSTRIAL PROGRAMS -- Gulf

Real Time Pricing Pilot Program: This program was approved by the Commission in Order No. PSC-95-0256-FOF-EI, Docket No. 941102-EI dated February 23, 1995. Gulf's Real Time Pricing (RTP) Pilot Program provides large industrial/commercial customers with hourly kilowatt-hour energy prices. To be eligible for the RTP rate schedule, customers must have a maximum monthly demand of at least 2,000 kilowatts. Participation in the program is voluntary and is limited to a maximum of 12 customers.

RTP is a refinement of time-of-use (TOU) pricing, which has been in existence for many years. The purpose of TOU pricing is to encourage customers to shift usage from high cost on-peak hours to lower cost off-peak hours by [*53] setting prices that better reflect system cost during those periods. Under the RTP proposal, Gulf will transmit to customers by 4:00 P.M. a set of hourly prices that will be in effect for the following 24-hour period beginning at midnight. Customers then have an opportunity to take advantage of lower priced hours.

Good Cents Building: This program has been in effect for several years. What Gulf has done in this program filing is to modify the program to provide for increased standards for both HVAC efficiency and Thermal Envelope requirements above the Florida Energy Code. As in the past, the Good Cents standards for Gulf's average commercial building has been compared to the Florida Energy Code. One of the modifications to the present program is the addition of a Prescriptive Envelope Option. In addition there are HVAC SEER specific efficiency requirements (A/C or Heat Pump) that exceed the Florida Building Code. Only incremental savings of the modified version of the Good Cents Building Program over the existing Good Cents Building Program are being included towards Gulf's goal achievements.

Energy Efficiency Services Program: This program is designed to offer [*54] advanced energy services to customers which would include comprehensive audits, design, construction and financing of energy conservation projects. The types of projects covered under this program would be demand reduction or efficiency improvement retrofits having a payback of no longer than ten years, such as lighting, HVAC retrofit and new technologies. The audit portion would be recovered through ECCR under Gulf's existing audit program. After that point the customer would be charged with the cost associated with the design and financing of the project. This program is limited to customers with a minimum of 500 kW demand. All costs associated with the energy efficiency project will be financed by Gulf and repayment of the loans will be based on the energy savings attained through the project. Gulf will bill the customer for the repayment monthly on the customer's electric bill.

OTHER PROGRAMS -- Gulf

The Efficiency Store -- Residential Energy Education: & Commercial Technology Demonstration: The objective of the Efficiency Store is to display and demonstrate those technologies that are designed to promote energy efficiency.

The store will combine an Energy [*55] Education area with a Commercial Technology Demonstration area, customer bill-payment area, district marketing employee offices, an auditorium and a retail sales area. The design of the Energy Education area of the store allows display of full scale examples of actual wall sections, roof trusses, and efficient HVAC equipment so that customers will be encouraged to repair their existing homes and to replace existing less energy efficient equipment. Gulf energy consultants will be on site to demonstrate energy saving technologies and equipment such as a leaking duct system along side a tight duct system will be available for a "hands-on" demonstration. Customers that are building new homes will be able to bring their plans in to have the energy consultants review and enter into a computer program which will let the customer know whether their new home meets the State of Florida's requirements for energy conservation.

The Commercial Technology Demonstration portion of the Efficiency Store will be available to show both new technologies as well as technologies already available for energy conservation. Technologies for demonstrations will include, but are not limited to, lighting, space [*56] conditioning, ventilation, cooking, heat recovery, water heating and renewable energy sources.

In Re: Approval of Demand-Side Management Plan of Florida Power & Light Company. In Re: Approval of Demand-Side Management Plan of Florida Power Corporation. In Re: Approval of Demand-Side Management Plan of Gulf Power Company. In Re: Approval of Demand-Side Management Plan of Tampa Electric Company

DOCKET NO. 941170-EG, DOCKET NO. 941171-EG, DOCKET NO. 941172-EG, DOCKET NO. 941173-EG; ORDER NO. PSC-95-0691A-FOF-EG

Florida Public Service Commission

1995 Fla. PUC LEXIS 917

95 FPSC 7:2

July 5, 1995

[*1]

The following Commissioners participated in the disposition of this matter: SUSAN F. CLARK, Chairman, J. TERRY DEASON, JOE GARCIA, JULIA L. JOHNSON, DIANE K. KIESLING

NOTICE OF PROPOSED AGENCY ACTION AMENDATORY ORDER CORRECTING INCENTIVE RANGE FOR FLORIDA POWER & LIGHT COMPANY'S COMMERCIAL/INDUSTRIAL EFFICIENT LIGHTING PROGRAM

BY THE COMMISSION:

NOTICE IS HEREBY GIVEN by the Florida Public Service Commission that the action discussed herein is preliminary in nature and will become final unless a person whose interests are substantially affected files a petition for a formal proceeding, pursuant to Rule 25-22.029, Florida Administrative Code.

On page 18 of Order No. PSC-95-0691-FOF-EG, issued in these dockets on June 9, 1995, we incorrectly identified the incentive range for Florida Power & Light Company's (FPL) Commercial/Industrial Efficient Lighting Program as $ 20.00 to $ 250.00 per kW. The range of incentive requested by FPL in its Demand-Side Management Plan was $ 10.00 to $ 250.00. Through this amendatory order, we correct Order No. PSC-95-0691-FOF-EG to accurately reflect our approval of the $ 10.00 to $ 250.00 incentive range requested by FPL in its Demand-Side [*2] Management Plan.

Order No. PSC-95-0691-FOF-EG, issued in these dockets on June 9, 1995, shall remain unchanged in all other respects.

By ORDER of the Florida Public Service Commission, this 5th day of July, 1995.

In Re: Approval of Demand-Side Management Plan of Florida Power Corporation

DOCKET NO. 941171-EG; ORDER NO. PSC-95-1344-S-EG

Florida Public Service Commission

1995 Fla. PUC LEXIS 1374

95 FPSC 11:73

November 1, 1995

CORE TERMS: solar, customer, conservation, protest, demand-side, weatherization, energy, staff, heating, low income, providers, pilot, water, cost-effective, recommendation, consultant, industrial, facsimile, electric, training, modification, workshop, approve, audit, substantial interest, modified, cost-effectiveness, confidentiality, encouragement, adversarial

[*1]

The following Commissioners participated in the disposition of this matter: SUSAN F. CLARK, Chairman, J. TERRY DEASON, JOE GARCIA, JULIA L. JOHNSON, DIANE K. KIESLING

ORDER APPROVING STIPULATIONS, DISMISSING PETITIONS FOR FORMAL PROCEEDING, AND REINSTATING ORDER NO. PSC-95-0691-FOF-EI AS A FINAL ORDER AS MODIFIED

BY THE COMMISSION:

CASE BACKGROUND

On June 9, 1995, the Commission issued a Notice of Proposed Agency Action, Order No. PSC-95-0691-FOF-EI. That order memorialized our decision in four dockets that had been consolidated for hearing: Docket No. 941170-EI, In Re: Approval of Demand-Side Management Plan of Florida Power & Light Company; Docket No. 941171-EI, In Re: Approval of Demand-Side Management Plan of Florida Power Corporation; Docket No 941172-EI, In Re: Approval of Demand-Side Management Plan of Gulf Power Company; and, Docket No. 941173-EI, In Re: Approval of Demand-Side Management Plan of Tampa Electric Company. In Order No. PSC-95-0691-FOF-EI the Commission approved Florida Power Corporation's (FPC) Demand-Side Management Plan, as well as the Demand-Side Management Plans of the other three electric utilities. We held that the plans complied with Order [*2] No. PSC-94-1313-FOF-EG, which set numeric conservation goals for the electric utilities. We stated that our approval of the plans would not become effective or final if any person whose substantial interest was affected by the proposed action filed a petition for a formal proceeding, as provided by Rule 25-22.029(4), Florida Administrative Code, by the close of business on June 30, 1995.

The Independent Savings Plan Company (ISPC) and Solar City, Inc. (SOLAR) timely filed a joint petition protesting Order No. PSC-95-0691-FOF-EI. Legal

Environmental Assistance Foundation, Inc., (LEAF), Peoples Gas System, Inc. (Peoples) and Florida Industrial Power User's Group (FIPUG) also filed timely petitions for formal proceedings in the case. Several protests were also filed in the other dockets, and, as here, several stipulations were reached in those dockets. We will issue separate orders in each docket to address the protests and the stipulations unique to each case.

On July 7, 1995, FPC and LEAF filed a Joint Motion to Approve Stipulation, which settled all issues relating to LEAF's protest. The stipulation is attached to and incorporated in this Order. See Attachment A. On July [*3] 20, 1995, FPC filed Motions to Dismiss the protests of ISPC/SOLAR and Peoples. FPC did not move to dismiss FIPUG's petition; but on July 26, 1995 FIPUG sent a letter to our staff in which it suggested that, in view of the new docket opened to review the cost-effectiveness of FPC's management credit for FPC's interruptible and curtailable rate classes, Docket No. 950645-EI, the Commission could either consolidate that docket with this one or enter an administrative order determining that FPC's cost effective methodology could be addressed in Docket No. 950645-EI.

On October 3, 1995 ISPC/SOLAR and FPC filed a stipulation resolving all issues relating to ISPC/SOLAR's protest. The stipulation is attached to and incorporated in this Order. See Attachment B.

Upon review, we approve the stipulations, and we deny the protests filed by Peoples and FIPUG. We reinstate Order No. PSC-95-0691-FOF-EI approving FPC's demand-side management plan as a final order, as modified by the stipulations. Also, as we explain below, the Commission's Bureau of Regulatory Review will conduct a management review to provide information regarding the competitive relationship between the electric and gas industries, [*4] and to study the effect of commercial/industrial conservation programs on competition in the industries.

DECISION

Stipulation between LEAF and FPC

In their July 7, 1995, stipulation, LEAF and FPC state that the stipulation is designed to attain "an informal disposition of LEAF's request for hearing in Docket No. 941170-EG . . . to avoid the time, expense and uncertainty associated with adversarial litigation in this docket in keeping with the Commission's encouragement to settle issues wherever possible". In return for LEAF's agreement to withdraw its protest of the PAA order, FPC has agreed to take several actions in the implementation of its demand-side management plan. FPC has agreed to: 1) incorporate certain language in its standards and procedures implementing the plans that LEAF requested; 2) further evaluate a variety of detailed procedures designed to measure and maximize participation in FPC's conservation programs, and; 3) pilot and evaluate a customized low income program. The agreement is described in detail in the stipulation attached to and incorporated in this recommendation.

We have reviewed the terms of the stipulation and we find that they are consistent with [*5] our decisions in the Conservation Goals Docket and in Order No. PSC-95-0691-FOF-EI approving FPC's demand-side management plans. With the understanding that we are not preapproving any proposed new programs, we approve the stipulation. The stipulation will avoid additional time-consuming, expensive litigation and will allow FPC to proceed with the implementation of its new conservation programs. We find the stipulation to be in the public interest.

Stipulation between ISPC/SOLAR and FPC

In their September 29, 1995, stipulation, ISPC/SOLAR and FPC state that the stipulation is designed to attain "an informal disposition of the joint request for hearing submitted by ISPC and SOLAR in Docket No. 941171-EG . . . to avoid the time, expense and uncertainty associated with adversarial litigation in this docket, in keeping with the Commission's encouragement to settle disputes". In return for ISPC/SOLAR's agreement to withdraw its protest of the PAA order and refrain from further participation in the review and approval of FPC's program participation standards, FPC has agreed to consult with ISPC/Solar over the contents of objective solar water heating educational information [*6] to be provided to customers during residential energy audits. FPC has also agreed to provide adequate training for appropriate FPC employees to ensure accurate dissemination of objective solar water heating information. If agreement cannot be reached, the parties will bring the disagreement to the Commission for resolution.

We have reviewed the terms of the stipulation and find that they are consistent with our decisions in the Conservation Goals Docket and in Order No. PSC-95-0691-FOF-EI approving FPC's demand-side management plans. We approve the stipulation. The stipulation will avoid additional time-consuming, expensive litigation, and will allow FPC to proceed with the implementation of its new conservation programs. We find the stipulation to be the public interest.

FIPUG's Petition on Proposed Agency Action

FIPUG filed a protest to Order No. PSC-95-0691-FOF-EI to protect its interest in preserving the terms of the rate design stipulation it had entered into with FPC in FPC's last full-requirements rate case. (Docket No. 910890-EI). The stipulation provided that FPC's interruptible/curtailable rate would be considered a conservation program, and non-firm customers who took [*7] service at that rate would receive a conservation credit of a certain amount on their bills. In its recommendation to approve FPC's demand-side management programs, our staff suggested that we should eliminate or freeze that program because it was not a cost-effective conservation program. FIPUG objected to that recommendation. We agreed with FIPUG and denied our staff's recommendation on that issue. We approved the program and the existing credit to interruptible curtailable customers, but directed staff to review the program to determine its cost-effectiveness. Staff will conduct that review in Docket No. 950645-EI, and FIPUG has intervened in that case.

We believe, and FIPUG agrees, that the proper forum to consider FIPUG's interests in this matter is Docket No. 950645-EI. A formal evidentiary proceeding in this case is not appropriate, because FIPUG has not been harmed by our decision to approve FPC's existing interruptible/curtailable rate as part of its demand-side management program with the existing credit contemplated by the rate case stipulation. Before one can be considered to have a substantial interest in the outcome of a decision, he must show that he will suffer injury [*8] in fact which is of sufficient immediacy to entitle him to a section 120.57 hearing. FIPUG has not shown that it has or will be harmed. Therefore, we deny FIPUG's petition. At our October 10, 1995, Agenda Conference, where we considered FIPUG's protest to the PAA order approving FPC's demand-side management plans, we assured FIPUG that it will have the opportunity to challenge the methodology FPC has used to determine the credit for its non-firm customers in Docket No. 950645-EI.

Peoples' petition

Rule 25-22.029(4), Florida Administrative Code, "Point of Entry into Proposed agency Action Proceedings", provides that a person may file a petition for a formal hearing pursuant to Section 120.57, Florida Statutes, if that person's substantial interests will be affected by the Commission's proposed action. As the Court stated in Agrico Chemical Company v. Department of Environmental Regulation, 406 So.2d 478, 482 Fla. 2d DCA 1981):

Before one can be considered to have a substantial interest in the outcome of the proceeding he must show 1) that he will suffer injury in fact which is of sufficient immediacy to entitle him to a section 120.57 hearing, and 2) that his substantial [*9] injury is of a type or nature which the proceeding is designed to protect.

Both requirements must be met to demonstrate a substantial interest. Peoples' petition has not met the Agrico standard because Peoples' allegations of harm are very speculative at this point in the process.

Peoples requests a hearing ". . . on issues relating to potentially discriminatory provisions of the electric utilities' DSM plans and programs." Peoples states that it believes FPC's program participation standards will discriminate against customers who use natural gas. Peoples states that "until the standards are filed, Peoples cannot know whether they are discriminatory or objectionable." Peoples argues that because the Commission has directed staff to administratively approve the program participation standards when they are filed, Peoples will have no point of entry to protest the standards it finds objectionable unless it protests Order No. PSC-95-0691-FOF-EG.

Peoples' speculative concerns about the content of the utilities' program participation standards do not demonstrate injury in fact of sufficient immediacy to establish a substantial interest that will be affected by the our approval [*10] of FPC's conservation programs themselves. See International Jai-Alai Players, 561 So.2d at 1226. (Abstract injury is not enough. The injury or threat of injury must be both real and immediate, not conjectural or hypothetical). We therefore deny Peoples' petition, because it is based on a speculative concern that the implementation of the plan through FPC's program participation standards may be discriminatory. We are, nevertheless, sensitive to Peoples' concern that FPC's program participation standards may be objectionable in some way. Therefore we will permit Peoples to file a petition requesting our review of FPC's participation standards and procedures after FPC has filed them if Peoples finds the standards objectionable.

Management Review

At our May 16, 1995 Agenda Conference, we directed our staff to conduct a Commission workshop addressing issues involving the competitive relationship between the electric and gas industries and the effect of commercial/industrial conservation programs on competition between the industries. During the course of preparing for the workshop, concerns arose over confidentiality and access to data. Some of the data necessary to adequately [*11] address the issues involves detailed customer KW and KWH usage information. In response to these concerns, staff cancelled its data request, and the workshop was cancelled as well. In its place our staff proposes to initiate an investigation of the issues with a management review conducted by the Bureau of Regulatory Review. The review will address the following questions, among others that may arise as the study progresses:

1. Whether the implementation of conservation programs by the electric and gas utilities, particularly for commercial/industrial customers, has complied with the Commission's policy of fuel neutrality.

2. Whether the conservation programs of the electric and gas utilities, particularly for commercial/industrial customers, have resulted in the increased usage of electricity and natural gas.

We agree with our staff's proposal. The process necessary to protect the confidentiality of information is built into the Bureau's audit process. According to Rule 25-22.006, Florida Administrative Code, all information gathered by the Audit Document/Record Request Notice of Intent form during the investigative process will be treated confidentially through the audit [*12] exit conference. At the audit exit conference the utility will have the opportunity to review the draft audit report and workpapers. Then the utility will have twenty one days thereafter to file a formal request for confidential treatment of all confidential information to be used in the final report. Technical assistance will be provided from the Division of Electric and Gas, as needed. Staff will bring the results of the study to the Commission for review.

Based on the foregoing, it is, therefore,

ORDERED by the Florida Public Service Commission that the stipulation between Florida Power Corporation and the Legal Environmental Assistance Foundation resolving LEAF's protest of Order No. PSC-95-0691-FOF-EI is approved. It is further

ORDERED that the stipulation between Florida Power Corporation and The Independent Savings Plan Company and Solar City, Inc. resolving ISPC/SOLAR's joint protest of Order No. PSC-95-0691-FOF-EI is approved. It is further

ORDERED that Florida Industrial Power Users Group's Petition on Proposed Agency Action is denied. It is further

ORDERED that Peoples Gas System, Inc.'s Petition on Proposed Agency Action is denied. It is further

ORDERED [*13] that the Notice of Proposed Agency Action, Order No. PSC-95-0691-FOF-EI, as modified by the stipulations approved in this Order, will be reinstated as a Final Order. It is further

ORDERED that this docket shall remain open until the Commission has reviewed Florida Power Corporation's demand-side management program participation standards and procedures, if Peoples files a petition for such a review.

By ORDER of the Florida Public Service Commission, this 1st day of November, 1995.

Attachment A

STIPULATION

THIS STIPULATION is entered into between Florida Power Corporation (FPC) and the Legal Environmental Assistance Foundation (LEAF), pursuant to Section 120.57(3), Florida Statutes, for the purposes of an informal disposition of certain aspects of the above-styled causes. FPC and LEAF wish to avoid the time, expense and uncertainty associated with adversarial litigation in these dockets in keeping with the Commission's encouragement to the parties to settle issues whenever possible. Accordingly, without prejudice as to either FPC's or LEAF's position in any other proceeding before this Commission, present or future, or any other venue, FPC and LEAF agree and stipulate [*14] as follows:

1. In consideration of the actions to be undertaken by FPC pursuant to this stipulation, LEAF agrees not to participate further in either Docket Nos. 941171-EG or 941232-EG. In this regard, LEAF will withdraw its request for hearing in Docket No. 941232-EG. However, nothing herein shall prevent LEAF from participating in the monitoring and evaluations spin-off proceedings, or in the workshops, or other proceedings created by the Commission's May 16, 1995 vote in Docket No. 941171-EG.

2. FPC agrees to the following:

a. FPC will incorporate, at minimum, the language contained in Attachment 1 into its initial filing of the Standards and Procedures established pursuant to its DSM Plan.

b. FPC will further evaluate its DSM Plan in areas identified in Attachment 2 and will implement LEAF's recommendations to the extent possible under the constraints stated in Attachment 2 and paragraphs 3 and 4 of this Stipulation.

c. FPC will pilot and evaluate a low income program and develop a custom low income program, if cost-effective under the Rate Impact Measure (RIM) test, in the manner described in Attachment 3; provided, however, the FPC's obligation under this paragraph [*15] 2c is expressly conditioned on the Commission's final approval of FPC's petition in Docket No. 941232-EI substantially as proposed by FPC.

3. Nothing in this stipulation shall be construed to require FPC to implement, or to prevent FPC from implementing, any DSM options that do not pass the RIM cost-effectiveness test, nor to require a modification of FPC's conservation goals approved in Docket No. 930549-EG, nor, but the low income market segment initiatives described in Attachment 3, to require any increase in FPC's total DSM Plan costs above the level identified in FPC's DSM Plan.

4. This stipulation shall become null and void, and FPC shall be relieved of any ongoing obligations pursuant to paragraph 2 above, in the event of any regulatory or legislative change that impairs FPC's ability to recover its conservation costs for the initiatives stated in paragraph 2 above, or reduces the savings levels of FPC's conservation goals.

5. This stipulation may not be modified except by the mutual written consent of the parties.

6. This stipulation shall be subject to the jurisdiction of the Florida Public Service Commission.

Dated: July   , 1995

FLORIDA [*16] POWER CORPORATION

By James A. McGee, Office of the General Counsel, Post Office Box 14042, St. Petersburg, FL 33733

LEGAL ENVIRONMENTAL ASSISTANCE FOUNDATION

By Debra Swim, 1115 North Gadsden Street, Tallahassee, Florida 32303-6327

ATTACHMENT 1

FPC agrees to include, at minimum, the following language into its Procedures and Standards filing that is due 60 days after the Commission's order in Docket No. 941171-EG:

Program: Residential New Construction Program

Topic Covered: Type of Residence

The home must be either single family detached or single family attached (e.g. townhouses).

Program: Home Energy Improvement Program

Topic Covered: Correct Air Flow and System Charge

Contractors shall certify that the air flow meets the manufacturer's recommendations and specifications for the system installed.

Refrigerant charge and type shall be according to manufacturer's specifications and recommendations for the unit installed. The contractor will certify that the proper charge is installed, that the unit is tested and is leak free.

Program: Energy Monitor Program

Design Assistance

Florida Power will provide customers with design assistance [*17] as part of the identification of package of measures that can be cost-effectively implemented or as part of the commissioning process. This service supports other FPC energy efficiency programs by assisting customers in identifying cost effective energy efficiency measures which may then be eligible for financial incentives.

Measures and recommendations may include, but are not limited to, lighting system enhancements, cooling load reductions (including the Early HVAC Retirement feature), industrial process improvements, high efficiency motors, and comprehensive analysis of interactions between these measures.

FPC's commissioning and technical design assistance services include technical assistance in both the new construction and retrofit markets.

Program: Innovation Incentive Program

Early HVAC Retirement

The early retirement of HVAC equipment (exclusive of the replacement of worn-out equipment treated under other components of FPC's Better Business Program) is encouraged under the Innovation Incentive Program (IIP). Lighting, window film, and other load reduction measures are combined with the replacement and down-sizing of HVAC equipment. Each project is [*18] evaluated for cost effectiveness based on the total demand and energy savings of the combined measures to determine the applicable RIM-based rebate.

The customer must submit cooling and/or heating load calculations, as applicable, for the existing and revised HVAC systems. This determines how much HVAC down-sizing has actually occurred as a result of the measures. Impacts for the HVAC equipment down-sizing are calculated as the difference between the demand and energy requirements of the properly sized baseline efficiency unit sized to meet the existing load and the properly sized high efficiency unit sized to meet the new load.

High efficiency HVAC equipment must meet or exceed the minimum efficiency standards detailed in the HVAC section of the Better Business Program.

Program: Innovation Incentive Program

New Construction Lighting

High efficiency lighting for commercial new construction projects is evaluated under the IIP program. The high efficiency system must be at least 10% more efficient than the Florida State Energy Code to be eligible for rebate consideration. Each project is evaluated for cost effectiveness based on the total demand and energy savings of [*19] the measures to determine the applicable RIM-based rebate.

ATTACHMENT 2

FPC agrees to contract with a consultant that is acceptable to LEAF to assist FPC's efforts in integrating LEAF's program proposals within budget and rate constraints. Except for contingencies specified herein, payments under the contract shall not exceed $ 50,000. Regarding said contingencies, the parties acknowledge that performance of this contract may involve unforeseeable contingencies which would require the consultant to conduct additional work on topics specified in the scope of work. To address these contingencies, FPC will establish and maintain a $ 10,000 contingency fund out of which such additional work will be funded when the parties agree such additional work is necessary. The contract shall contain FPC's standard terms and conditions for the employment of consultants, including confidentiality restrictions. Provided, however that, so long as LEAF agrees in writing to be bound by the confidentiality restrictions contractually imposed on the consultant, the consultant may freely confer with LEAF and confidentiality or work-product restrictions in the FPC-Consultant contract shall not [*20] apply to communications between the consultant and LEAF. Specifically, within 12 months from the execution date of this stipulation, the consultant will help FPC to:

1. further refine the systematic treatment of costs and benefits in the screening of program improvements proposed by LEAF.

2. determine the maximum amount of Residential Energy Management (REM) Program spending that can be reallocated to fund additional efficiency efforts without affecting overall goals compliance or the viability of the REM program.

3. develop detailed program budgets and savings targets for maximizing the benefits of additional RIM-passing efficiency efforts under overall budget constraints.

4. develop detailed delivery strategies and rebate structures for maximizing program participation and net benefits of customer participation, while minimizing rate effects.

5. develop standards and procedures for implementing program-delivery strategies and integrating design-assistance and early-HVAC-retirement services with existing program efforts.

6. develop field protocols for effective and efficient implementation of standards and procedures, particularly with regard to delivery of design-assistance [*21] and early-HVAC-retirement services.

7. develop a pilot program for delivering comprehensive RIM-cost effective energy efficiency services to low-income customers.

FPC will retain final decision-making authority for all program modifications. The scope of the consultant's assistance will be limited to the following potential program design modifications:

. Home Energy Improvement Program - incentives for high efficiency central air conditioners; proper refrigerant charge and air flow for central air systems.

. Residential New Construction Program - incentive levels and qualifying efficiency levels.

. Innovation Incentive/Better Business Program - industrial process efficiency improvements; duct leakage measures.

. Design assistance in commercial/industrial programs.

. Early-HVAC-Retirement services.

. Commercial/Industrial New Construction Program - incentive levels; lighting measures.

. The low income program initiative described in paragraph 7.

ATTACHMENT 3

FPC Agrees to:

1) Implement, as a pilot under its technology development program, a customized DSM program targeted to deliver DSM to the low income n1 market segment in [*22] its service territory that has the following features:

a) While delivering weatherization assistance services through federal or state government-approved weatherization assistance initiatives including, at minimum, the federal Weatherization Assistance Program ("WAP"), weatherization providers will also deliver FPC RIM cost-effective DSM options and FPC-approved targeted energy education to the same household.

b) FPC will provide training (not to include salaries and expenses of trainees to attend the training) for these weatherization providers to deliver DSM options available under its DSM plan filed in Docket No. 941171-EG and pay the full amount of the measure (on a measure-by-measure basis; unless FPC chooses to combine measures) that is RIM cost-effective, not to exceed the cost of purchasing and installing the measure or measures. Included in the FPC RIM cost-effectiveness will be a reasonable share (to be negotiated) of the weatherization provider's incremental administrative costs of delivering the integrated weatherization/DSM program and FPC's tracking and oversight costs. Further, the cost-effectiveness of all costs will be assessed fairly so that, at minimum, [*23] all program costs are not allocated to less than all measure or bundled measure (if chosen) participants and FPC-approved first-year ramp-up costs are distributed over a reasonable duration.

c) the pilot will be initiated with local weatherization providers within 60 days of the FPSC final approval of FPC's DSM Plan procedures and standards.

d) The pilot will be limited to the first-occuring of either:

i) 12 months duration (measured from when local weatherization providers commence measure installation under the pilot); or

ii) $ 100,000 spent (for installed DSM measures exclusive of FPC standard auditor training costs; provided that up to $ 15,000 may be spent for monitoring and evaluation; and further that the parties agree to use all good faith efforts to achieve their mutual goal of allocating at least $ 75,000 for installed DSM measures); or

iii) 500 participants; or

iv) FPC implementation of an FPSC-approved Low Income Program as contemplated by paragraph 4.

2) Prior to the training in 1.b, FPC will work with the Department of Community Affairs (DCA) and the local weatherization providers within FPC's service territory to develop detailed procedures, [*24] protocols, reporting requirements, quality control mechanisms and training for the pilot of integrated delivery of weatherization and RIM cost-effective DSM services by weatherization providers. FPC will retain the right of approval of all final details.

3) As the pilot is implemented, FPC will monitor and conduct impact and process evaluations of the costs and benefits of delivering DSM to the low income households in FPC's service area to determine whether additional DSM is RIM cost-effective for these households. This evaluation will include, at a minimum, assessment of the benefits to FPC which are specific to DSM which serves low income customers such as demand and energy savings specific to this segment, compliance with the standards and procedures developed in paragraph 2, and consideration of reduced credit and collection costs.

4) After completing the monitoring and evaluation described in paragraph 3, FPC will seek FPSC approval of the custom DSM program targeted to deliver, at minimum, all FPC RIM cost-effective options identified during implementation and evaluation of the pilot, along with FPC-approved targeted energy education through integrated delivery with FPC-approved [*25] weatherization providers. If FPC receives FPSC approval for a Low Income Program, the additional Low Income Program cost shall be no more than 20% of the annual Home Energy Improvement Program costs budgeted in FPC's DSM Plan unless FPC agrees to exceed that limit. These costs are limited to the sum of Utility Program Costs and Incentive Payments identified in the RIM test as filed in FPC's DSM Plan, February 22, 1995.

5) From a non-DSM or customer assistance standpoint, FPC will continue to work closely with the low income service providers to identify individuals who may be eligible for assistance from the non-ECCR related Energy Neighbor Fund which provides funding for one time energy bill assistance.

n1 For the purpose of this stipulation, low Income is defined as 125% of the federal OMB poverty guidelines published annually in the Federal Register as well as any applicable qualification requirements adopted by the federal or state weatherization program.

Submitted for filing: July 7, 1995

JOINT MOTION TO APPROVE STIPULATION

To avoid the time, expense, and uncertainty associated with adversarial litigation, and consistent with the Commission's encouragement [*26] to the parties to settle issues whenever possible, the Legal Environmental Assistance Foundation, Inc, and Florida Power Corporation have, as reflected in the attached stipulation, reached agreement regarding the above referenced dockets. WHEREFORE, Legal Environmental Assistance Foundation, Inc., and Florida Power

Corporation move that the Commission enter an Order approving the attached stipulation.

Respectfully submitted,

JAMES A. McGEE, Esquire, Florida Power Corporation, Office of the General Counsel, Post Office Box 14042, St. Petersburg, FL 33733, (813) 866-5184

DEBRA SWIM, Esquire, Legal Environmental Assistance Foundation, Inc., 1115 North Gadsden Street, Tallahassee, Florida 32303, (904) 681-2591

ATTACHMENT B

In Re: Approval of Demand Side Management Plan of Florida Power Corporation

Docket No. 941171-EG Filed: October , 1995

STIPULATION OF FLORIDA POWER CORPORATION AND THE INDEPENDENT SAVINGS PLAN COMPANY AND SOLAR CITY, INC.

This stipulation is entered into by Florida Power Corporation ("FPC"), The Independent Savings Plan Company ("ISPC") and Solar City, Inc. ("SOLAR") (hereinafter sometimes collectively referred to as ISPC/SOLAR) pursuant to Section [*27] 120.57(3), Florida Statutes, for the purpose of an informal disposition of the joint request for hearing submitted by ISPC and SOLAR in Docket No. 941171-EG and reflects a negotiated settlement of all issues between FPC and ISPC/SOLAR in this docket. FPC and ISPC/SOLAR wish to avoid the time, expense and uncertainty associated with adversarial litigation in this docket, in keeping with the Florida Public Service Commission's ("Commission") encouragement to settle disputes. Accordingly, without prejudice as to either FPC's or ISPC/SOLAR's position in any other proceeding before this Commission, FPC and ISPC/SOLAR agree and stipulate as follows:

1. In consideration of the actions undertaken by FPC pursuant to this stipulation, ISPC/SOLAR:

a. agree to withdraw their request for hearing in Docket No. 941171-EG;

b. agree not to participate further in Docket No. 941171-EG, including the review and approval of FPC's program participation standards arising from Docket 941171-EG, and the review and approval of any FPC monitoring and evaluation plan required by the Commission in Docket No. 941171-EG, and any workshops created as a result of orders in Docket No. 941171-EG, [*28] so long as the review, approval and/or workshops do not affect the agreements reached in this stipulation; and

c. agree to meet and agree with FPC regarding the content of objective solar water heating educational information to be provided by FPC to its customers.

2. In consideration of the actions undertaken by ISPC/SOLAR pursuant to this stipulation, FPC:

a. agrees to meet with ISPC/SOLAR regarding the contents of the objective solar water heating information to be provided by FPC to its customers during residential energy audits and in response to residential customer inquiries related to solar water heating. Except under the circumstances set forth below, ISPC/SOLAR and FPC will endeavor in good faith to agree upon the content of the objective solar water heating educational materials to be provided by FPC as outlined above. In the event FPC cannot reach an agreement with ISPC/SOLAR, the initial dispute as to what constitutes objective solar water heating information to be provided during residential energy audits may be brought before the Florida Public Service Commission for resolution via a proceeding limited to that purpose, and FPC agrees not to contest the standing [*29] of ISPC/SOLAR to participate in such limited scope proceeding. After the initial determination (by agreement or Commission resolution) of what constitutes objective solar water heating information to be provided by FPC as described above, if FPC desires to modify the substantive content of such information or to discontinue providing such information, FPC will notify the Commission of this intent and will, upon the Commission's request, submit a petition requesting approval of the desired change. A copy of such notifications to the Commission and any such petition shall be provided to ISPC/SOLAR. If FPC does not file a petition, ISPC/SOLAR may file a petition or other appropriate documents seeking a Commission determination of the propriety of such modification or discontinuance. However, nothing in this stipulation or its implementation shall be construed as granting ISPC and/or SOLAR standing to participate in such a proceeding or waiving FPC's right to challenge ISPC's and/or SOLAR's potential participation in such a proceeding.

b. agrees to provide adequate training for appropriate FPC employees to ensure the accurate dissemination of objective solar water heating [*30] information.

3. Nothing in this stipulation shall be construed as requiring FPC to implement or to continue to offer any DSM option or program that is not cost-effective under the Rate Impact Measure and Participants tests; to modify or to refrain from seeking modification of the conservation goals established for FPC in Order No. PSC-94-1313-FOF-EG; to modify or to refrain from seeking modification of its DSM Plan.

4. This stipulation shall become null and void in the event that it is not approved in its entirety by the Florida Public Service Commission.

5. This stipulation may not be modified except by the written consent of ISPC/SOLAR and FPC. However, the parties to this stipulation recognize that the Commission has continuing jurisdiction regarding FPC's DSM programs and may, on its own initiative, suggest changes within the realm of its jurisdiction. The Commission's suggestions are subject to the rights of appropriate parties to participate in the resulting proceedings. Nothing herein shall be binding upon the Commission with regard to whether ISPC and/or SOLAR may be designated an appropriate party to such a proceeding.

6. This stipulation shall be subject to [*31] the jurisdiction of the Florida Public Service Commission, and the Commission shall be the sole body for the resolution of any disputes arising out of the discharge of this agreement.

WHEREFORE, The Independent Savings Plan Company and Solar City, Inc., jointly, together with Florida Power Corporation request that the Florida Public Service Commission accept and approve this stipulation as a negotiated settlement of contested matters.

Dated this 29th day of September, 1995.

The Independent Savings Plan Company and Solar City, Inc.

Robert B. Hicks, Florida Bar Number 369535, 6302 Benjamin Road, Suite 414, Tampa, Florida 33634, (813) 881-1988, Attorney for ISPC/SOLAR

Florida Power Corporation

James A. McGee, Florida Bar Number 0150483, Senior Counsel, Florida Power Corporation, Post Office Box 14042, St. Petersburg, FL 33733, Attorney for Florida Power, Corporation

Attachment C

McWHIRTER, REEVES, McGLOTHLIN, DAVIDSON, RIEF & BAKAS, P.A. 100 North Tampa Street, Suite 2800, Post Office Box 3350 (33601-3350), Tampa, Florida 22602-5126, Tampa (813) 224-0866, Telefax (813) 221-1854

TELEFAX COVER PAGE

TO: J. Terry Deason

TELEFAX NUMBER: 904-413-6250

DATE: [*32] July 26, 1995

Following is a facsimile consisting of 3 pages, including this telefax cover sheet. If you should have any problems in receiving this facsimile, please contact Andrea at (813) 224-0866.

This facsimile contains PRIVILEGED AND CONFIDENTIAL information intended only for the use of the addressee(s) named above. If you are not the intended recipient of this facsimile, or the employee or agent responsible for delivering it to the intended recipient, you are hereby notified that any dissemination or copying of this facsimile is strictly prohibited. If you have received this facsimile in error, please immediately notify us by telephone and return the original facsimile to us at the above address via U.S. Mail. We will reimburse you for postage. Thank you.

Original Documents will not follow by mail.

McWHIRTER REEVES

John W. McWhirter, Jr.

SPECIAL INSTRUCTIONS:

File Number: F16-11352

July 26, 1995

Via Fax

Martha Carter Brown

Florida Public Service Commission
Capital Circle Office Center
2540 Shumard Oak Boulevard
Tallahassee, Florida 32399-0850

Re: Florida Power Corporation Demand Side Management Plan Docket 941171-EG

Dear Ms. [*33] Brown:

I spoke to Vicki Johnson this morning concerning Docket 95065-EI, which is the new docket spun-off from the Florida Power Demand Side Management docket dealing with the Florida Power Corporation non-firm service credits. Ms. Johnson advised us that FIPUG is the only protestant in Docket 941171-EG.

FIPUG protested in that docket because it questions the cost effectiveness methodology used by Florida Power Corporation. It seems to me that the administrative burden could be reduced substantially if the Commission would either consolidate Docket 95065-EI with 941171-EG or in the alternative enter an administrative order determining that Florida Power Corporation's cost effective methodology may be addressed in Docket 95065-EI.

If the Commission elects the latter approach, FIPUG would be pleased to withdraw its protest to 941171-EG to enable that docket to be closed.

Sincerely yours,

John W. McWhirter, Jr.

In re: Petition of Gulf Power Company for an increase in its rates and charges

DOCKET NO. 891345-EI; ORDER NO. 23573

Florida Public Service Commission

1990 Fla. PUC LEXIS 1320; 120 P.U.R.4th 1

90-10 FPSC 195

October 3, 1990

CORE TERMS: customer, rate base, energy, standby, plant, outage, rate case, load, allocated, kwh, projected, working capital, rate of return, load factor, methodology, reduction, billing, net operating income, classified, fuel, appliance, budgeted, peak, demand-related, mismanagement, ratepayers, billed, rider, customer-related, maximum

G. EDISON HOLLAND, JR. and JEFFREY A. STONE, Esquires, Beggs and Lane, P.O. Box 12950, Pensacola, Florida 32576, on behalf of Gulf Power Company

JACK SHREVE and STEPHEN C. BURGESS, Esquires, Office of the Public Counsel, c/o The Florida Legislature, 111 West Madison Street, Room 812, Tallahassee, Florida 32399-1400, On behalf of the Citizens of the State of Florida

GARY A. ENDERS, Major, USAF, HQ USAF/ULT, Stop 21, Tyndall AFB, Florida 32403-6001, On behalf of the Federal Executive Agencies

JOSEPH A. McGLOTHLIN and JOHN W. McWHIRTER, JR., Esquires, Lawson, McWhirter, Grandoff & Reeves, 522 East Park Avenue, Suite 200, Tallahassee, Florida 32301, on behalf of the Industrial Intervenors

RONALD C. LaFACE and WILLIAM L. HYDE, Esquires, Roberts, Baggett, LaFace and Richard, P.O. Drawer 1838, Tallahassee, Florida 32302, On behalf of the Florida Retail Federation

ROBERT VANDIVER, MARSHA RULE and MICHAEL PALECKI, Esquires, Legal Division, Florida Public Service Commission, 101 East Gaines Street, Tallahassee, Florida 32399-0850, On [*2] behalf of the Staff of the Florida Public Service Commission

PRENTICE P. PRUITT, Esquire, Office of the General Counsel, Florida Public Service Commission, 101 East Gaines Street, Tallahassee, Florida 32399-0850, On behalf of the Commissioners

[*1]

The following Commissioners participated in the disposition of this matter: MICHAEL McK. WILSON, Chairman; THOMAS M. BEARD; BETTY EASLEY; GERALD L. GUNTER

Pursuant to duly given notice, the Florida Public Service Commission held public hearings in this docket on April 5, 1990, in Panama City, Florida; April 4, 1990, in Pensacola, Florida; and June 11 through June 21, 1990, in Tallahassee, Florida. Having considered the record herein, the Commission now enters its final order.

ORDER GRANTING CERTAIN INCREASES

BY THE COMMISSION:

On December 15, 1989, Gulf Power Company (Gulf or Company) filed its petition for permanent and interim increases to its rates and charges. In its petition, Gulf requested a permanent increase in its rates and charges designed to generate an additional in its rates and charges designed to generate an additional $ 26,295,000 of gross annual revenues. This request was based upon a projected 1990 test year and a 13-month average jurisdictional rate base of $ 923,562,000. Gulf requested an overall rate of return of 8.34%, which assumed an allowed rate of return on common [*3] equity of 13.00%. The most significant basis for the requested increase, according to Gulf, was the commitment of over 500 MW of additional capacity from its Plants Daniel and Scherer to territorial service and the O&M expenses associated with this capacity. Additionally, the utility claimed an increase in net operating income resulting from substantial capital additions in the transmission, distribution, and general plant areas as well as increased O&M expenses.

Pursuant to Section 366.06(3), Florida Statutes, Order No. 22681, issued on March 13, 1990, suspended Gulf's permanent rate schedules and granted Gulf an interim rate increase of $ 5,751,000 in annual revenues.

The Federal Executive Agencies (FEA), and Industrial Intervenors (II) were granted intervention status in this docket by Orders Nos. 22363 and 22878, respectively. Order No. 22953, issued on May 18, 1990, granted intervention status to the Florida Retail Federation (FRF). The Office of the Public Counsel (OPC) is a party to this docket pursuant to Section 350.0611, Florida Statutes.

I. SUMMARY OF DECISION

We authorize Gulf an increase in gross annual revenues of $ 11,838,000 for two years beginning September [*4] 13, 1990. Thereafter, we authorize Gulf an increase in gross annual revenues of $ 14,131,000.

We have set the rate of return on common equity capital at 12.55%. The reduced increase in gross annual revenues for the two years beginning September 13, 1990, reflects a 50 basis point penalty on return on equity imposed for mismanagement.

II. REVENUE REQUIREMENTS DETERMINATION

The revenue requirements of a utility are derived by establishing its rate base, net operating income (NOI) and fair rate of return. A test year of operations, traditionally based upon one year of operations, is used to derive these factors. Multiplying the rate base by the fair rate of return provides the net operating income the utility is permitted to earn. Comparing the permitted net operating income with the test year net operating income determines the net operating income deficiency or excess. The total test year revenue deficiency or excess is determined by adjusting the deficiency or excess by the revenue expansion factor.

III. THE TEST YEAR

The test year in a rate case provides a set period of utility operations that may be analyzed so the Commission can set reasonable rates for the period [*5] the rates will be in effect. A test period may be based upon an historic test year, adjusted to reflect typical conditions in the immediate future, which should make it reasonably representative of expected future operations. Alternatively, a test period may be based upon a projected test period which, if appropriately developed and adjusted, may reasonably represent expected future operations. We approved Gulf's choice of calendar year 1990 as a projected test year.

IV. TEST YEAR RATE BASE

To establish the Company's overall revenue requirements, we must determine its rate base. The rate base represents that investment on which the Company is entitled to earn a reasonable return. A utility's rate base is comprised of various components. These include: 1) net utility plant-in-service, which is comprised of plant-in-service less accumulated depreciation and amortization; 2) total net utility plant, which is comprised of net utility plant-in-service, Construction Work in Progress (CWIP) (where appropriate) and plant held for future use; and 3) working capital.

Gulf has submitted a proposed jurisdictional rate base of $ 923,562,000. Evidence developed during the course of the [*6] proceedings has led us to reduce that amount to $ 861,159,000. Our adjustments are set forth as follows:

1990 Rate Base
Jurisdictional (000's)

		GULF	ADJUSTMENTS	ADJUSTED RATE BASE
A.	Utility Plant-in-Service	$ 1,275,624	($ 57,337)	$ 1,218,287
B.	Accumulated Depreciation	(454,964)	(6,913)	(448,051)
C.	Net Plant-in-Service	820,660	(50,424)	770,236
D.	Construction Work in Progress	14,949	- 0 -	14,949
E.	Property Held for Future Use	3,925	(135)	3,790
F.	Acquisition Adjustment	2,317	(2,317)	- 0 -
G.	Net Utility Plant	841,851	(52,876)	788,975
H.	Working Capital	81,711	(9,527)	72,184
I.	Total Rate Base	$ 923,562	($ 62,403)	$ 861,159

A. Plant-In-Service

The amount of plant-in-service proposed by Gulf was $ 1,275,624,000. We have made certain adjustments, described below, which reduce plant-in-service to $ 1,218,287,000.

	(000s)
Plant-In-Service per Gulf	$ 1,275,624
Adjustments:	
1. New Corporate Headquarters	(3,892)
2. Navy House	(23)
3. Appliance Division	(214)
4. Tallahassee Office	(24)
5. Leisure Lakes	(142)
6. Plant Scherer	(52,987)
7. Misc. Plant-In-Service	(55)
Total Adjustments	(57,337)
Adjusted Plant-In-Service	$ 1,218,287

[*7]

1. New Corporate Headquarters

Gulf's new corporate office building occupies 17.42 acres on Bayfront Parkway overlooking Pensacola Bay. The building is five stories tall and each floor has approximately 50,000 square feet of space. A level below the building is for parking company vehicles. The building was occupied March 31, 1987.

The total building area is 308,634 square feet and consists of 149,945 square feet of office space, 57,057 square feet of parking garage, 41,237 square feet for specialty areas, and 8,832 square feet for the equipment room. The specialty areas are the mailroom and duplicating, cafeteria, system control and ready room, auditorium, MIS computer center, communications, and the like. In addition to the square footage described above, 51,563 square feet on the third floor is presently unfinished and used as a temporary storage and maintenance area.

We believe that the cost of the third floor of $ 3,840,807 should be removed from plant-in-service. Evidence developed during the course of the proceedings indicates that Gulf has adequate space for storage and maintenance functions at other locations. We find that the ratepayers of Gulf receive no benefit [*8] from Gulf's use of the third floor for storage and maintenance and therefore disallow $ 3,840,807. Gulf is allowed, however, to earn a deferred return on this plant investment and related expenses equal to the allowance for funds used in construction (AFUDC).

The Business Development Center occupies 495 square feet on the first floor of the Corporate Headquarters Building. The room was designed and furnished for presentations to representatives of businesses that are interested in moving to Northwest Florida, and for press conferences relating to weather-related emergencies. The Center is equipped with laser disk players, color monitors, and VCR's that allow prospective business customers to view various areas, industrial parks, and cities in Northwest Florida with an eye toward relocation to this area. The purpose of the laser disk players and VCR's is their use in economic development efforts. The investment capitalized for the Business Development Center in 1987 was $ 51,548. There has been no capital investment since 1987 and none is projected for 1990. We believe that $ 51,548 should be removed from rate base for the Business Development Center since the recruitment of [*9] business and industry to Florida is not a responsibility of a regulated public utility. The Chamber of Commerce and the Florida Department of Commerce perform that function. The total disallowance for the new corporate headquarters is $ 3,892,355.

2. Navy House

The Navy House is a former residence which became the property of the company when it purchased land needed to install a transmission line from the company's Bayou Chico Substation to serve the Pensacola Naval Air Station. The initial purchase price of the land and the home on the land was $ 110,000. We have no reason to believe the price paid was not proper; this amount is not at issue. In addition to the purchase price, however, the company completely renovated the residence to serve as additional training space for its employees. There appears to be ample training space at Gulf's Chase Street facility and at the new corporate headquarters. We therefore find that rate base should be reduced by $ 23,257 and that 1990 operating expenses for the Navy House be reduced by $ 7,516.

3. Appliance Division

Gulf has an appliance sales and service operation which is operated out of Gulf buildings which are included in rate [*10] base. A portion of this investment has been removed from rate base based on usage studies performed by Gulf. In several instances, the appliance operation has its own buildings which are recorded in non-utility plant.

Gulf made an error in allocating the plant investment to the appliance operation. Therefore, it would be proper to correct the error by reducing plant, accumulated depreciation and depreciation expense $ 214,000, $ 7,000 and $ 12,000, respectively.

4. Tallahassee Office

Gulf maintains an office in Tallahassee for use by its lobbyist, PSC liaison and other Pensacola-based employees while conducting business in Tallahassee. The office space is leased while the office furniture has been capitalized by the company and included in rate base. In addition, Gulf's lobbyist has a company car which is also included in rate base.

Gulf has agreed that 25% of the office investment which is used for lobbying activity should be removed from rate base. In addition Gulf agrees that 100% of the lobbyist's car should be removed. We believe these percentages are reasonable and make the following adjustments:

Reduce Plant-In-Service	$ 23,860
Accumulated Depreciation	11,193
Depreciation Expense	1,217

[*11]

5. Leisure Lakes Subdivision (Greenhead Substation)

On October 18, 1984, in Docket No. 830484-EU, Gulf Coast Electric Cooperative, Inc. (Gulf Coast) petitioned the Commission for resolution of a territorial dispute between itself and Gulf Power Company. The dispute involved the Leisure Lakes Subdivision, which consists of approximately 2,300 acres divided into approximately 750 lots. The dispute arose when Gulf Power constructed 2.2 miles of distribution line from its transmission line to the subdivision along a graded county road. After Gulf Coast's petition was filed, and with knowledge of the Commission's jurisdiction over the matter, Gulf Power also constructed the Greenhead substation near the site. In Order No. 13668 we determined that Gulf Coast was entitled to provide electric service to the disputed area. It was also ordered that Gulf Power is prohibited from serving, either temporarily or permanently, the disputed area. In our order we encouraged Gulf Power to sell the facilities they built to serve Leisure Lakes to Gulf Coast, should Gulf Coast desire to purchase them.

Gulf subsequently sold all of its facilities built to serve Leisure Lakes and has no facilities [*12] in that area except the Greenhead substation. The book value of the facilities Gulf built to serve Leisure Lakes Subdivision was approximately $ 131,000 and the sale price to Gulf Coast was $ 130,353. The Greenhead Substation was not needed to serve load since neither the Sunny Hills or Vernon Substations have reached peak capacity. Therefore, the investment made by Gulf to serve Leisure Lakes subdivision should not be included in rate base. We reduce plant-in-service by $ 142,000 and depreciation expense by $ 5,000.

6. Plant Scherer

Gulf acquired 25 percent of Plant Scherer 3 in 1984 and it came in line in January 1987. Since Plant Scherer came on line after Gulf's last rate case, this is the first time Gulf has requested that a portion of Plant Scherer be included in rate base. Of Gulf's 212 MW share of Scherer 3, 63 MW is available to serve Gulf's territorial customers in 1990 and 149 MW is dedicated to unit power sales. The 63 MW of Scherer 3 that Gulf is requesting to be included in rate base includes 44 MW that would have been sold to Gulf States Utilities if they had not defaulted on a unit power sales contract. Gulf is requesting that 63 megawatts of its 212 megawatt [*13] share of Plant Scherer 3 be included in its rate base.

Gulf's reserves are reasonable with or without Scherer. Without Scherer, Gulf's reserves are 21.9 percent and with 63 megawatts of Scherer, Gulf's reserves are 25.5 percent. Gulf's parent corporation, Southern Company, maintains reserves which are 19.9 percent without Scherer and 20.1 percent with Scherer. It appears that with or without Plant Scherer, Gulf is well able to achieve its target reserves of 20 to 25 percent.

Gulf will be selling increasing amounts of Scherer's capacity as unit power sales starting in 1992. The following table shows the amount of Scherer dedicated to Gulf's territorial customers from the year 1990 to the year 2010.

Time	Capacity Available to Retail Customers
January 1990 - May 1992	63 megawatts
June 1992 - December 1992	11 megawatts
January 1993 - May 1993	37 megawatts
June 1993 - December 1993	16 megawatts
January 1994 - May 1994	17 megawatts
June 1994 - May 1995	35 megawatts
June 1995 - May 2010	0 megawatts

As shown above, Gulf is scheduled to sell increasing amounts of Scherer 3 under unit power sales agreements starting in 1992. By 1995, none of Scherer 3 will be available [*14] to serve Gulf's territorial customers. This capacity will not be available to serve Gulf's territorial customers until the year 2010. Since Gulf is dedicating this unit to unit power sales in years that Gulf's territorial load is expected to be greater than it is in 1990, it would appear that Gulf does not need the unit in 1990 for its territorial customers.

Under Southern's contract with Gulf States Utilities, Gulf had committed to sell 44 MW of Scherer 3 to Gulf States Utilities during the test year 1990 through May, 1992. Gulf States Utilities failed to perform its contractual obligations and on July 1, 1988, FERC ruled that Southern no longer had to perform under the contract. It is clear that Gulf would not have requested 63 MW of Scherer to be in rate base had Gulf States Utilities not defaulted on their contracts. When Gulf made the decision to purchase 25 percent of Scherer 3 it was aware of the potential that their contract with Gulf States Utilities might not be honored. Since the profits from the unit power sales go to Gulf's stockholder, they should bear the risk of default, and not Gulf's ratepayers. Therefore, we remove all of Plant Scherer from rate base. All [*15] profits and losses derived from unit power sales of Scherer, and any costs or benefits accruing from any settlement with Gulf States Utilities are to go to the stockholders of Gulf Power Company. Gulf's ratepayers, who will not see the profits from Gulf's unit power sales contracts, should not be required to pay when such a contract falls through.

As a result of our exclusion of Scherer 3 from rate base, we make the following rate base and Net Operating Income adjustments:

Plant-in-Service	$ 52,987,000
Accumulated Depreciation	6,557,000
Acquisition Adjustment	2,317,000
Working Capital	2,187,000
O&M - Expenses	722,000
Depreciation Expense	1,701,000
Amortization of Plant Acquisition Adjustment	73,000
Amortization of ITC	(96,000)
Other Taxes	245,000
IIC Offset	(4,792,000)

7. Miscellaneous Plant-In-Service

We have made miscellaneous plant-in-service adjustments in the amount of $ 55,000. This resulted from discovery of two work orders that were completed and ready for service but were not immediately transferred to Account 106 (completed construction not classified). As a result, Gulf over-accrued allowance for funds used in construction (AFUDC) [*16] by $ 55,000. We therefore reduce plant-in-service by this amount.

B. Accumulated Depreciation and Amortization

The amount of accumulated depreciation and amortization proposed by Gulf was $ 454,964,000. Our previously discussed adjustments to plant-in-service require a net reduction to accumulated depreciation and amortization of $ 6,913,000. Approved accumulated depreciation and amortization is $ 448,051,000, as follows:

(000s)	
Accumulated Depreciation per Gulf	$ 454,964
Adjustments:	
Appliance Division	(7)

Tallahassee Office	(11)
Plant Scherer	(6,557)
New Corporate Headquarters	(338)
Total Adjustments	(6,913)
Adjusted Depreciation	$ 448,051

C. Net Utility Plant-In-Service

Net utility plant-in-service is comprised of utility plant-in-service, less accumulated depreciation and amortization. We find that the appropriate amount of net utility plant-in-service for test year 1990 is $ 770,236,000.

D. Construction Work in Progress (CWIP)

The company has included $ 14,949,000 of construction work in progress in rate base. We believe this amount is appropriate.

E. Property Held for Future Use

Gulf has included in its rate base the [*17] sum of $ 3,925,000 in plant held for future use. We believe this is appropriate except for the 10% of Gulf's Caryville site which is allocated to the sod farm. The sod farm, known as "Southern Sod Company", occupies approximately 200 acres of property at Gulf's Caryville site, or 10% of the Caryville acreage. Southern Sod leases this acreage from Gulf. This is a non-utility operation and we therefore find that 10% of the value of the Caryville Site included in rate base ($ 135,000) should be removed. We therefore reduce plant held for future use by $ 135,000 to $ 3,790,000. We also remove from "other revenues" the $ 3,450 in lease payments received from Southern Sod.

F. Acquisition Adjustment

As a result of its purchase of a portion of the common facilities at Plant Scherer, Gulf requested an acquisition adjustment of $ 2,317,000. Since we have not allowed Plant Scherer in rate base, no adjustment for its acquisition will be allowed in rate base. We therefore reduce rate base by $ 2,317,000.

G. Net Utility Plant

Based upon the adjustments discussed above, total net utility plant for test year 1990 is $ 788,975,000.

H. Working Capital

The company has included $ 81,711,000 [*18] of working capital in rate base. We have made certain adjustments described below, which reduce working capital to $ 72,184,000.

	(000's)	
Working Capital per Gulf		$ 81,711
Adjustments:		
1. Rate Case Expenses	(765)	
2. Temporary Cash Investments	0	
3. Heavy Oil Inventory	(576)	
4. Light Oil Inventory	(123)	
5. Coal Inventory	(6,017)	

6. Plant Scherer	(2,187)
7. Caryville Subsurface Study	(28)
8. PIP	169
Total Adjustments	(9,527)
Total Working Capital	$ 72,184

1. Unamortized Rate Case Expense

The company has included $ 765,385 in working capital for unamortized rate case expense. Commission policy is to exclude unamortized rate case expense from working capital. We therefore reduce working capital by the entire $ 765,385.

2. Temporary Cash Investments

Gulf, in its rebuttal testimony, has requested $ 6,045,000 in working capital for temporary cash investments. The appropriate regulatory treatment of either continuing cash balances or temporary cash investments should depend upon their prudency. If the utility can demonstrate, through competent evidence, that their cash balances or temporary cash investments are necessary for the [*19] provision of regulated utility service, they should remain in rate base and earn at the utility's overall rate of return. Any earnings generated by these funds should then be used to offset revenue requirements. The burden of proof however is on the Company to demonstrate through competent evidence that their temporary cash investments are necessary for the provision of utility service.

Gulf gave the following reason that temporary cash investments are necessary for its provision of utility service:

The test year amount for Temporary Cash Investments (13-month average amount) of $ 6,399,000 is approximately 10 percent of the average monthly disbursements. In addition we are projecting to borrow funds during five months of the test year. The Company again maintains that these funds are required and necessary in providing utility services for our customers. (Ex. 439)

During cross-examination Gulf's witness stated:

". . . we don't know of any other way to pay our bills than to have cash available. Either you are going to have temporary cash, cash, or short-term debt, one of the three, because if you -- once you stop paying your bills, you're going into bankruptcy at that stage, [*20] and you'll be shut down. You've got to have liquid assets . . ." (TR 793)

While we agree that a company needs to maintain a certain degree of liquidity to operate, we note that Gulf maintains substantial liquidity through short-term debt.

The Company has budgeted to pay $ 60,000 in 1990, for access to lines of credit totalling $ 42 million. In addition, the Company continues to keep compensating balances of $ 436,900 for additional lines of credit totalling approximately $ 6.2 million. Thus, the Company has access to approximately $ 48.2 million through lines of credit.

We do not dispute that the Company needs to maintain a certain degree of liquidity to operate. We believe, however, that the burden is on the Company to demonstrate that the additional liquidity provided by holding $ 6,045,000 in temporary cash investments is necessary. In our opinion the Company has not provided this proof. Statements such as, "its all our available cash" or "temporary cash investments represent less than 10 percent total monthly expenditures" do not constitute competent evidence. We therefore deny Gulf's request that $ 6,045,000 be included in working capital for temporary cash investment. [*21] It is not necessary for us to make an adjustment to working capital since Gulf has already removed temporary cash investments from its filing, consistent with our treatment of this matter in Gulf's last rate case.

3. Heavy Oil Inventory

Gulf has overcalculated the amount of heavy oil inventory necessary for standby fuel at Plant Crist Units 1, 2 and 3. Heavy oil inventory should be reduced to a level equal to seven days burn at 100% capacity factor.

A seven-day supply of heavy oil for Crist Units 1, 2 and 3 operating at 100% of their demonstrated capability would equal 32,774 barrels. Gulf Power has requested a heavy oil inventory of 78,533 barrels with an average price of $ 13.603 per barrel and valued at $ 1,042,000 (system). We will allow a heavy oil inventory level of 32,774 barrels at an average price of $ 13.603 per barrel. We reduce working capital by $ 596,178 (system), or by $ 576,462 (jurisdictional).

4. Light Oil Inventory

Gulf has requested that 650,895 gallons of light fuel oil (system) be included in working capital. We are of the opinion that Gulf has failed to justify its request for light oil inventory. We will allow a level equal to 30 days burn at [*22] the highest average monthly rate which calculates to 383,210 gallons. This would require a reduction in working capital of $ 125,339.

5. Coal Inventory

Gulf has requested a coal inventory level equal to 105 days projected burn. We are of the opinion that Gulf has failed to justify this request and will allow a level equal to 90 days projected burn or the amount actually maintained in the test year at each plant site, whichever is less. In Gulf's system this would amount to a total of 784,887 tons valued at $ 37,000,502 (system). This reduces working capital by $ 6,222,498 (system) or $ 6,016,717 (jurisdictional).

6. Plant Scherer

As previously discussed, our exclusion of Plant Scherer from rate base will result in an adjustment of $ 2,187,000 to working capital.

7. Caryville Subsurface Study

The subsurface study was a geological study of the Caryville site to determine if the land could support the weight of a power plant and supporting facilities. As pointed out in the company's brief, the results of the study are obviously still valid. Such a study would be necessary before any major construction of this type could be done on any site. Therefore, costs associated [*23] with the study should be considered together with the Caryville site itself. Since Caryville remains in Rate Base, the cost of the study or $ 568,000 should be allowed, however we will require that this amount be amortized to expense over a 10 year period. This necessitates a $ 28,000 reduction in working capital.

8. Productivity Improvement Plan (PIP)

The Productivity Improvement Plan (PIP) is a part of the total compensation plan for the top 11 employees of the company. Due to a change in the design of the PIP program after the budgeting process was completed, the company feels a reduction in the program is in order. The original amount for this program was $ 438,473. The company's new amount is $ 99,066. Since it appears that Gulf's overall salary and benefits program is not excessive, and this plan was allowed in the last rate case, the expenses in the amount of $ 99,066 for this program will be allowed. Therefore, expenses should be reduced $ 339,000.

Since this adjustment reduces Accounts Payable, a current liability in working capital, the 13-month average of working capital will be increased by $ 169,187.

I. Total Rate Base

Gulf has submitted a proposed jurisdictional [*24] rate base of $ 923,562,000. Based upon the above described adjustments we have reduced rate base by $ 62,403,000 to $ 861,159,000. See Attachment 1 for a complete breakdown of rate base.

V. FAIR RATE OF RETURN

The Commission must establish the rate of return which the Company should be given an opportunity to earn on its investment in rate base. The fair rate of return should be established so as to maintain the Company's financial integrity and to enable it to acquire needed capital at a reasonable cost.

A. Capital Structure

The ultimate goal of providing a fair rate of return is to allow the utility an appropriate return on its investment in rate base. Because all sources of capital cannot be clearly associated with specific utility property, the Commission has traditionally considered all sources of capital (with appropriate adjustments) in establishing a fair rate of return.

The establishment of a utility's capital structure serves to identify the sources of the capital employed by a utility, as well as the amounts and cost rates associated with each. After establishing the sources of capital, all capital costs, including the cost of equity capital, are weighted according [*25] to their relative proportion to total capital. The weighted components are then added to provide a composite or overall cost of capital. The weighted cost of capital multiplied by the net utility rate base produces an appropriate return on rate base, including a return on equity capital invested in rate base.

B. Cost of Common Equity Capital

To arrive at a fair overall rate of return, it is necessary that we utilize our judgement to establish an allowable rate of return on common equity capital.

This issue was the subject of prefiled testimony by several witnesses. By stipulation of all the parties, their testimony was inserted into the record as though read and the witnesses presence and cross-examination were waived.

The following three witnesses presented testimony on the appropriate cost of equity capital:

Dr. Roger A. Morin, Professor of Finance at the College of Business Administration, Georgia State University and Professor of Finance for Regulated

Industry at the Center for the Study of Regulated Industry at Georgia State University. (On behalf of Gulf Power) Dr. Morin recommends the adoption of a return on common equity of 13.5%.

Mr. James A. Rothschild, President, [*26] Rothschild Financial Consulting. (On behalf of the Citizens of the State of Florida) Mr. Rothschild recommends that the proper calculated return on equity for Gulf Power is 11.75%.

Mr. Scott A. Seery, Regulatory Analyst, Bureau of Finance, Division of Auditing and Financial Analysis, Florida Public Service Commission (On behalf of the Florida Public Service Commission Staff) Mr. Seery recommends the adoption of a return on common equity of 12.25%.

The witnesses used three different equity costing methodologies to arrive at their estimates of Gulf's cost of equity. Witness Morin used the risk premium, discounted cash flow (DCF) and capital asset pricing model (CAPM) methodologies. Witness Rothschild relied primarily on the DCF method. Witness Seery used the DCF and risk premium methods.

When analyzing the cost of equity one should realize that it is a subjective process. Based on the evidence in the record and a review of the equity costing methodologies presented, we find that a reasonable allowed rate of return on common equity capital for Gulf is 12.55%. This rate of return on common equity will allow Gulf the opportunity to raise capital on fair and reasonable terms and [*27] to maintain its financial integrity.

We believe a 12.55% cost of common equity is well supported by the evidence presented and represents the best estimate of the Company's cost of equity. To put this finding in perspective, at the time revised testimony was filed by these witnesses, the average yield on long-term treasuries was 8.74% and the yield on A-rated utility bonds was 9.92% for April 1990. The average yield for June 1990 was 8.60% for long-term treasuries and 9.80% for A-rated utility bonds as reported by Moody's Bond Survey, July 16, 1990.

C. Capital Structure Reconciliation

We require that there be a reconciliation of the rate base and the capital components which support the rate base. In order to determine the appropriate overall cost of capital for which the utility will be allowed to earn a return, several adjustments must be made to the capital structure as presented by the utility in its minimum filing requirements. First, as all parties agree, the preferred stock balance is to be presented net of discounts, premiums, and issuance expenses. The effect on capital structure is to reduce the preferred stock balance by $ 948,000 and to increase the common equity [*28] balance by $ 948,000.

Next, we believe all non-utility investment should be removed directly from equity when reconciling the capital structure to rate base unless the utility can show, through competent evidence, that to do otherwise would result in a more equitable determination of the cost of capital for regulatory purposes. In the case of Gulf, we believe that the non-utility investments should be removed from equity. This will recognize that non-utility investments will almost certainly increase a utility's cost of capital since there are very few investments that a utility can make that are of equal or lower risk. Removing non-utility investments directly from equity recognizes their higher risks, prevents cost of capital cross-subsidies, and sends a clear signal to utilities that ratepayers will not subsidize non-utility related costs.

We believe that specific adjustments should be made to the tax components of the capital structure. We have specifically identified the effects of the rate base adjustments for the navy house, the Tallahassee office, Leisure Lakes, unamortized rate case expense, and Plant Scherer, including the plant acquisition adjustment, and have decreased [*29] the average balance of accumulated deferred income taxes by $ 5,877,000 and of investment tax credits by $ 2,402,000. The remaining amount of these rate base adjustments are then reconciled over all investor sources and customer deposits.

All other adjustments to rate base are on a pro rata basis over all sources of capital. We believe the remaining adjustments should be removed at the company's overall cost of capital.

Based upon the rate base/capital structure reconciliation that we discussed above and our review of the record of the cost rates and capital components, the appropriate capital structure for Gulf Power is as follows:

COMPONENT	AMOUNT	PERCENT OF TOTAL CAPITAL	COST RATE	WEIGHTED COST
Long Term Debt	311,950	36.22%	8.72%	3.16%
Short Term Debt	3,971	0.46%	8.00%	0.04%
Preferred Stock	51,358	5.96%	7.75%	0.46%
Customer deposits	14,134	1.64%	7.65%	0.13%
Common Equity	264,857	30.76%	12.55%	3.86%
Accumulated Deferred Income Taxes Deferred	175,796	20.41%	0.00%	0.00%
ITC-Zero Cost	823	0.10%	0.00%	0.00%
Deferred ITC-Weighted Cost	38,270	4.44%	10.26%	0.46%
	861,159	100.00%		8.10%

For a complete breakdown of Gulf's [*30] 13-month average capital structure see Attachment 2.

VI. MISMANAGEMENT

The record is clear: Gulf Power Company admitted that corrupt practices took place at Gulf Power Company from the early 1980s through 1988, including but not limited to theft of company property, use of company employees on company time to perform services for management personnel, utility executives accepting appliances without payment, and political contributions made by third parties and charged back to Gulf Power Company. The majority of the unethical/illegal activities involved Jacob Horton, the Senior Vice President of Gulf Power Company. Mr. Horton was killed in a plane crash on April 10, 1989.

The question then becomes whether the management of the power company knew or should have known of the illegal and/or unethical conduct that was taking place. At this point it is incumbent upon the Commission to note that there is no record evidence to indicate that Mr. Douglas McCrary, President of Gulf Power Company from May of 1983 through the present, knew that illegal or unethical conduct was taking place as it happened. Mr. McCrary testified under oath as to his lack of contemporaneous knowledge of the [*31] activities.

We do believe that Gulf Power's senior management should have known of some of these activities and should have acted sooner and with sterner measures with regard to Mr. Horton's activities. This inaction constitutes mismanagement. As a totally independent ground, the activities of Mr. Horton and his subordinates as Senior Vice President alone constitute mismanagement. This recommendation is premised upon the structure of Gulf Power management with four vice presidents reporting to the president. As one of those vice presidents, Mr. Horton's actions are those of Gulf Power management.

We believe that there were many early warning signals which indicated that illegal or unethical conduct was present. In December of 1983 Mr. McCrary received anonymous letters concerning employee misappropriation of goods. Mr. McCrary commissioned an independent investigation by security personnel from a sister company to avoid one peer investigating another. The result of this investigation was the "Baker-Childers report", which was Exhibit 391 at the hearing. This report focused on warehouse thefts directed by Kyle Croft. Also contained in this report were allegations of company [*32] personnel performing personal services for Gulf Power executives, including Mr. Horton, on company time with company materials. When Mr. Horton was asked about these allegations, Mr. Horton denied them, and no further action was taken. (R169) This incident did, however, raise suspicions about Mr. Horton. (R168)

With regard to the principal allegations contained within the Baker-Childers report, Mr. Croft was fired on a Sunday morning in late January 1984. However, Mr. Horton intervened and persuaded the president to rescind the firing decision and allow Mr. Croft to resign. Unknown to others in senior management at the time, Mr. Horton arranged for Mr. Croft's attorneys fees and health insurance to be paid and billed back to Gulf Power. Gulf's senior management learned of this payment in 1988. (R197) As part of Mr. Croft resigning from Gulf Power, Mr. Croft executed a promissory note for $ 15,986.62 to Gulf Power Company. This represented an estimate of the property Mr. Croft had stolen from Gulf Power. Concurrent with the execution of this note, Mr. Horton stated that Gulf Power would not enforce the note, and Mr. Horton executed a note payable to Mr. Croft for the same [*33] amount. (Ex. 396 at p. 55) This was done to protect Mr. Croft if Gulf Power decided to enforce the note. When the senior management learned of Mr. Horton's note in 1986 it also heightened suspicion of Mr. Horton. (R199)

In June of 1984 it was learned that Gulf Power had delivered approximately $ 10,000 worth of appliances to Mr. Ed Addison, former president of Gulf Power Company and now head of the Southern Company, the parent company of Gulf Power. Mr. Addison was not billed for these goods, and it was the intent of Gulf Power employees to give the appliances to Mr. Addison. (R183) The president learned of this arrangement and discussed the matter with Mr. Addison. Mr. Addison was billed and then promptly paid for the appliances. (R184) The employees involved reported to Mr. Horton which again raised suspicion concerning Mr. Horton. (R186) No further investigation of the appliance division was made. (R187)

In July of 1984 Mr. Horton instructed a Gulf Power employee to solicit a $ 1,000 political contribution from a local architect that worked with Gulf Power Company. The president learned of this several days later. (R223) He spoke to Mr. Horton and "reemphasized" that [*34] pressure would not be placed on vendors to make political contributions. (R223) Mr. McCrary conceded that he was very much suspicious about Mr. Horton by July of 1984. (R225) Unknown to the president at the time was the fact that Gulf Power in fact reimbursed the architect for the political contribution. (Ex. 396 at p. 21) In the fall of 1986, the president learned that Gulf Power had reimbursed Mr. Graves (the architect), and had Mr. Graves reimburse Gulf Power Company, and then had Mr.

Horton reimburse Mr. Graves. Any suspicion created in 1984 by this situation should have been greatly increased by the 1986 transactions.

On October 31, 1989 Gulf Power Company entered guilty pleas to two felony counts in the United States District Court for the Northern District of Georgia, Atlanta Division. Gulf Power paid a $ 500,000 fine for these crimes. (Ex. 413) This negotiated plea agreement grew out of Gulf Power activities from 1981-1988. Over 120 counts were detailed in Exhibit 413. Basically Gulf Power management, through Mr. Horton and his subordinates, "systematically, repeatedly and willfully instructed its outside vendors, such as its advertising agencies, to submit false [*35] or inflated invoices to Gulf Power Company for payment by Gulf Power Company in order to reimburse those vendors for payments they had made to political candidates and others at the direction of Gulf Power Company." (Ex. 413 at p. 13) These illegal acts were not isolated cases and are factually indistinguishable from the Graves contribution which the senior management knew of 1984 and learned more about in 1986.

We believe that the explicit warnings the senior management received concerning Mr. Horton, coupled with the Baker Childers Report in early 1984, the Addison appliances in June of 1984, the Graves contribution in July of 1984, the 1986 Kyle Croft lawsuit revealing more information concerning Mr. Croft's resignation and the subsequent information in 1986 regarding the 1984 Graves contribution all indicate that Gulf's senior management should have been aware of Mr. Horton's activities. This is especially true in light of the close business relationship between the two senior executives (CR 219; 231; 236; 245, 246). An investigation of Mr. Horton's activities was clearly indicated by 1986.

In the fall of 1988 senior management became aware of the Appleyard ledgers. It was [*36] known at that time that violations of the law were involved. (R244) These accounts were handled by the organization reporting to Mr. Horton. Mr. Horton was informed that he was to be separated from the company on April 10, 1989. (R4192) As of May 1, 1989, the company had not undertaken an investigation of Mr. Horton, despite the events described above. See Exhibit 382 at p. 16A. We believe that the lack of action regarding Mr. Horton constitutes mismanagement because management should have been aware of Mr. Horton's activities or started an investigation into Mr. Horton's activities based on the events discussed above.

Not only did management fail to initiate an investigation of Mr. Horton, but Mr. Horton has never received a written reprimand. (R4186-87) This lack of written reprimands is troubling considering management's subsequent knowledge of Mr. Horton's promissory note, the Graves Contribution, and paying Mr. Croft's legal and insurance costs. In one case (the Graves situation) Mr. Horton lied to the president in 1984 and the president knew he lied in 1986. In another case (paying the legal and insurance costs for Mr. Croft) Mr. Horton directly disobeyed the president's [*37] explicit instructions. (R197) Mr. Horton also received Productivity Improvement Program payments for his job performance in 1983, 1984, 1985, 1986, and 1988 and his base salary rise each year from 1983-1988. (Ex. 547)

Although we believe Gulf's lack of action regarding Mr. Horton constitutes mismanagement, we believe that given Mr. Horton's position, his actions alone constitute mismanagement regardless of senior management's inaction. Gulf Power has over 1600 employees. Mr. McCrary is the leader of these employees, and four executives reported directly to him, as well as the director of Public Relations. (See R192; Ex. 414) Thus all policy decisions and supervision of all Gulf Power personnel are vested in this management team. We do not use the term "management team" loosely. The president expressed it this way:

I did that [consulted the vice-presidents on the decision to fire Mr. Croft] because we operate that company on a -- in a manner such that all very important decisions that we make, we try to do as a group, so that all vice presidents are satisfied that they have had their input and they agree with the decision.

(R193; See R217; 3050)

Given this management philosophy [*38] and practice, we believe it totally appropriate to find Mr. Horton's actions as those of Gulf Power management. Mr. Horton was one of the five people who management Gulf Power. In carrying out his duties as Senior Vice President, he committed illegal and unethical acts on behalf of the utility. Therefore, Gulf Power Company was guilty of mismanagement.

In terms of the scope of the corruption taking place at Gulf Power Company, several company programs were initiated to deal with the problem. Among these programs were adoption of a company Code of Ethics in August of 1984 and the implementation of an amnesty program around the same time. The Code of Ethics was adopted in response to the "myriad of things that had been going on in the early 1980s." (R204) The president agreed that every large well run utility should have a Code of Ethics and he couldn't say why Gulf Power lacked a Code of Ethics prior to that time. (Id.) All existing and new employees were required to sign a compliance statement. To implement the Code, Gulf Power had a series of meetings to explain the Code and the reason for it. The president was unable to point to anything Gulf Power did to further implement [*39] the Code from August of 1984 through January 5, 1989. On January 5, 1989, the Audit Committee of the Gulf Power Board of Directors adopted a resolution to reiterate the Code of Ethics and ordered management to take certain actions to implement the Code. (R206) The president explained the action as follows:

We thought it was in -- that what we should do is to reemphasize the Code of Ethics; to have an educational program; to have a program of ethics awareness, and to generally have employees focus on the Code of Ethics being a real and living document. (R206)

The Code of Ethics was adopted in 1984 to combat the embezzlement of Gulf Power property and by 1989 different sorts of ethical violations were apparent, indicating that some employees ignored the Code or failed to take it seriously. (R214-15) We believe the 1989 measures should have been in effect in 1984 and there was haphazard enforcement of the Code from 1984 to 1988.

Gulf Power's amnesty program was initiated in the summer of 1984. This program was implemented in response to numerous allegations against Gulf Power personnel in the Baker-Childers Report. (R128) An outside law firm administered the program in order [*40] to shield the identity of the participants from the company. (Ex. 396 at p. 40-41) The program was designed to allow company employees that had improperly obtained goods or services from the company to make restitution to the company and then be subject to no further action. (R128) Gulf Power had no way of knowing whether the amounts collected under the amnesty program were correct. (R136; 140) A total of $ 13,124.23 was collected pursuant to this program. Of this amount, $ 10,500 (80%) came from two individuals in leadership positions at Gulf Power Company. (R138; 201; See Ex. 414)

On January 1, 1988, one of the persons who reported directly to the president was involved in three automobile accidents while driving a company vehicle. He was charged with D.U.I. and a number of traffic violations at the scene of the third accident. The president believed it would be very damaging to Gulf Power if the incident were reported in the media and he made a conscious decision not to have the accident reported as required by company procedures. (Ex. 396 at p. 66) Although this activity constituted a violation of the Code of Ethics, the individual involved received no written reprimand. [*41] (R180) He was orally reprimanded, although it is not clear by whom. (R181) Two points concerning this incident appear relevant to our analysis. First, it would appear that this incident supports the lack of commitment to enforcement of the Code of Ethics from 1984 to 1988. Second, it also raises the issue of Gulf Power treating executives differently concerning ethical violations than other employees. This is buttressed by the lack of investigation of allegations concerning personal use of company materials involving an ex-president of the Southern Company. (R134) Discriminatory enforcement is further indicated by considering that a lower-level employee was fired for stealing a gallon of gas and certain other unspecified violations. (R107; 128; 182)

Gulf Power also did business in 1983 with Scott Addison, the son of Ed Addison, the Chief Executive Officer of the Southern Company. Although this specific transaction does appear prudent in and of itself, we do question the propriety of doing business with relatives of the parent company personnel. This is especially true when the transaction was not handled in the normal manner and Gulf Power conceded that absent the family [*42] connection, the person would probably not have received the same treatment. (See R3841-3844)

To summarize, we believe the events described above support a finding of mismanagement on the part of Gulf Power Company. The finding of mismanagement is premised on the activities of Mr. Horton, the president's lack of knowledge of those activities despite the incidents discussed above, the lack of investigation of Mr. Horton, the lack of written reprimands to Mr. Horton, the circumstances relating to the readoption of the Code of Ethics, the uneven enforcement of same, the various executives accepting goods or services without payment and the other factors discussed above. These factual circumstances as well as the fact that the illegal activity continued for at least eight years, lead us to agree with Ms. Bass, "that the corporate culture was such that employees believed these types of illegal activities were, at the least, condoned by top management." (R2994; See Ex. 391 at p. 10; 28; 33) This is particularly true when one considers that illegal activity continued for at least eight years.

Given the foregoing discussion, the issue becomes what action the Commission should take. Gulf [*43] Power argues that the commission lacks authority to lower the return on equity in absence of a demonstrable impact on rates or service from the mismanagement. (Gulf Power Brief at 110; See Id. at 107-138) In United Telephone Co. of Florida v. Mann, 403 So.2d 962, 966 (Fla. 1981), the court stated that after the rate of return is calculated, "the commission can make further adjustments to account for such things as accretion, attrition, inflation and management efficiency." (Emphasis supplied) We believe this case, in conjunction with the fact that public utility regulation is an exercise of the police power (See Section 366.01, Florida Statutes) and other statutory provisions (See Sections 350.117, 366.041, 366.07, and 366.075, Florida Statutes) grant this Commission ample authority to take management efficiency into account in setting rates.

The statutory provisions cited above give the Commission authority to consider management efficiency in setting rates. In consideration of relative efficiency, the Commission should reward the more efficient and give less relief to those operating in a less efficient manner. As the court stated in Deltona Corp. v. Florida Public Service Commission, [*44] 220 So.2d 905, 907 (Fla. 1969):

A statutory grant of power or right carries with it by implication everything necessary to carry out the power or right and make it effectual and complete.

We believe the proper method of dealing with mismanagement is through the return on equity. The New Hampshire Public Utilities Commission has acted in conformity with this principle:

The method of addressing managerial inefficiency which is most soundly rooted in proper regulatory principles and is most appropriate to the instant situation is a reduction in the allowed return on common equity. Re: Public Service Commission of New Hampshire, 57 P.U.R.4th 563, 594

In the instant case there were various ongoing criminal conspiracies reaching to the highest levels of management. These events, widely reported in the media, have hurt the company's relationship with its customers, as was made clear from the testimony customers gave at the service hearings. It is axiomatic that the involvement of managerial personnel in criminal activities lessened the efficiency of management in providing electric service.

As previously discussed, expert testimony of record established that a fair rate of return [*45] on equity (ROE) for this utility lies between 11.75% and 13.50%. Analysis of the cost of equity is a subjective process and an exact figure is impossible to measure precisely. The Commission must evaluate the testimony presented and then utilize its expertise to arrive at a fair rate of return for the particular utility at issue. As previously discussed, we believe the appropriate ROE for Gulf Power Company to be 12.55%. Were the previous pages recounting Gulf Power mismanagement not in the record of this proceeding, we could stop there. This record reflects a disregard for the ratepayers and public service, however. Accordingly, we will reduce Gulf Power Company's ROE by fifty (50) basis points for a two year period. This results in a final ROE of 12.05%.

This final ROE is well within the parameters established as fair and reasonable by expert testimony of record. This reduction in the authorized ROE for a two year period is meant as a message to management that the kind of conduct discussed above, which was endemic for at least eight years at this company, will not be tolerated for public utilities which operate in Florida. We have limited the reduction to a two year period [*46] to reflect our belief that Gulf Power has turned the corner on dealing with the extensive and long-standing illegal/unethical behavior within the company.

VII. NET OPERATING INCOME (NOI)

Having established the Company's rate base, and fair rate of return, the next step in the revenue requirements determination is to ascertain the net operating income (NOI) applicable to the test period. The formula for determining NOI is Operating Revenues less Operating Expenses equals NOI.

The Company has proposed a net operating income of $ 60,910,000. Evidence developed during these proceedings has led us to increase this amount to $ 61,085,000. Our adjustments are set forth as follows:

JURISDICTIONAL NET OPERATING INCOME

(000's)

	Gulf	Adjustments	As Adjusted
VIII. Operating Revenues *	$ 255,580	108	$ 255,688
IX. Operating Expenses *			
A. O&M	113,382	762	114,144
B. Deprec. & Amort.	47,701	(1,893)	45,808
C. Taxes - Other	20,822	(274)	20,548
D. Current Income Taxes	13,185	529	13,714
E. Def.Income Taxes (net)	1,621	712	2,333
F. ITC (net)	(2,041)	96	(1,945)
G. Total Oper. Exp.	194,670	(67)	194,603
H. Net Operating Income	$ 60,910	175	61,085

[*47]

* Operating Revenues and Expenses are net of fuel and conservation.

VIII. OPERATING REVENUES

The Company proposed an operating revenue for test year 1990 of $ 255,580,000. We have made adjustments increasing operating revenues for 1990 by a total of $ 108,000 to $ 255,688,000. Our adjustments to revenues are as follows:

(000's)

Company Test Year Revenues	$ 255,580
Adjustments:	
A. PXT misbilling:	16
B. Non-utility electric billing:	35
C. Sod Farm revenues	(3)
D. Appliance division-use of logo	-0-
E. Revision of OS-I and OS-II Revenue	66
F. Revision of OS-III and OS-IV Revenue	(6)
Total Adjustments	$ 108
Adjusted Operating Revenue	$ 255,688

A. PXT Misbilling

A PXT customer experienced a forced outage during September 2 and 3 of 1989, and took standby power of 7959 KW during that outage. The PXT customer had taken a generator off line for maintenance to repair the boiler during the period in question. Nonetheless, the customer was not billed for standby power as it should have been (see Commission Order No. 17159).

Additional revenues of $ 16,325 should therefore be imputed for 1990 as the customer should properly have been billed for standby [*48] power of 7959 KW.

B. Non Utility Electric Billing

The company has several non-utility operations including the sod farm, vision design, and the appliance sales and service. In the past and currently, Gulf has allocated the cost of the metered electric consumption to these operations at the actual cost of generation.

We believe that these non-utility operations are being subsidized in part by paying less for electricity than they would have if their consumption had been billed-out at the appropriate tariff rate. It is therefore appropriate to increase revenues by $ 34,913.

C. Sod Farm Revenues

We have previously ruled that the percentage of the Caryville site devoted to the sod farm (10%) be excluded from rate base. Therefore, it is appropriate to remove from other operating revenues $ 3,450 in rental revenues received from the sod farm operations.

D. Appliance Division - Use of Logo

After considering the briefs of the parties on this issue we have decided that the value of the Gulf logo to the non-utility appliance sales division should be recognized. It follows that an appropriate allowance for the use of the logo should be credited to the company as revenue above the [*49] line.

In the record before us however, we find no evidence concerning the dollar value of Gulf's corporate logo to the appliance division. In the absence of a record basis, we therefore make zero ($ 0) adjustment.

E. Adjustment to OS-I and OS-II

The company failed to use the revenues shown on their most recently revised MFR Schedule E-16 for these classes. It is, therefore, appropriate to increase revenues by $ 66,000.

F. Adjustment to OS-III and OS-IV

The company failed to correctly transfer revenues from MFR Schedule E-16d to E-16a. This resulted in the utility overstating its current revenues. We therefore decrease revenues by $ 6,000.

IX. OPERATING EXPENSES

Gulf has requested total operating expenses of $ 194,670,000. We have made additional adjustments reducing total operating expenses by $ 67,000 to $ 194,603,000.

A. Operating and Maintenance Expense (O&M)

Gulf has proposed total O&M expense of $ 113,382,000. We have determined that this amount should be increased by $ 762,000 to $ 114,144,000 as follows:

(000's)	
Operating and Maintenance Expenses	
Per Company	$ 113,382
Adjustments:	
1. Navy House	(8)
2. Plant Scherer-Net of IIC Offset	4,070
3. Out-of-Period, Non-Recurring, etc.	(190)
4. Industry Association Dues	(20)
5. Current Rate Case Expenses	(250)
6. Cogeneration & Industrial Programs	(426)
7. Good Cents Incentive Program	(50)
8. Presentation/Seminars Program	(55)

9. Shine Against Crime	(	92)
10. Economic Development	(	687)
11. Lobbying Expenses	(	264)
12. IRS, Grand Jury, etc.	(	5)
13. Research & Development Projects	(	32)
14. Transmission Rents	(	423)
15. Labor Complement Vacancies	(	403)
16. Productivity Improvement Plan	(	339)
17. Employee Relocation & Development Programs	(	56)
18. Management Perks	(	65)
19. Caryville Subsurface Study		57
20. Pension Expense		0
21. Retirement Medical and Life Insurance		0
Total Adjustments	$	762
Adjusted O&M Expenses	$	114,144

[*50]

1. Navy House

As discussed earlier, we find that 1990 operating expenses for the Navy House should be reduced by $ 7,516.

2. Plant Scherer - Net of IIC Offset

The Intercompany Interexchange Contract (IIC) is a methodology for equalizing the capacity reserves among the various operating companies of the Southern Company. Since Plant Scherer is being excluded from the rate base, it is also appropriate to exclude the $ 4,792,000 capacity payment that Gulf would receive for the Plant Scherer capacity. This would have the effect of increasing operating and maintenance expenses by $ 4,792,000.

On the other hand, the exclusion of Plant Scherer from rate base would also have the opposite effect of reducing operating and maintenance expenses by $ 722,000 (the cost of operating and maintaining the plant). The net of these two adjustments results in an increase in operating and maintenance expenses of $ 4,070,000.

3. Out of Period, Non Recurring or Non Utility

For 1990, Gulf budgeted $ 1,663,247 for other non-recurring expenses compared to a 5-year average of actual expenses of $ 1,473,407 or a difference of $ 189,840. Gulf did not offer any explanation as to what activities were [*51] projected for 1990 in support of the $ 1,663,247 non-recurring expenses. Since these expenses affect all functional categories of expenses, the adjustment has been included in the O&M benchmark schedule as a single adjustment to total O&M expenses. We have therefore reduced O&M expenses by $ 189,840.

4. Industry Association Dues

We have adjusted the company's budgeted industry association dues from $ 167,193 to $ 147,172. This includes a disallowance of $ 19,378 for that portion of the Edison Electric Institute Dues which is used for lobbying (1/3 of $ 58,133 total dues), and $ 643 associated with miscellaneous organizations that were not identified by the company except as "Organization to be joined in 1990."

5. Current Rate Case Expenses

The company projected rate case expense at $ 1,000,000. This amount is not contested and consists of:

Outside Consultants	$ 248,000
Legal Services	164,000
Meals and Travel	37,000
Paid Overtime	7,000
Other Expenses*	544,000
Total	$ 1,000,000

*Includes SCS expenses, postal charges, printing costs and transcripts.

At issue is the amortization period over which the expense will be spread. Commission policy is to amortize [*52] rate case expense over a period of time because a rate case benefits not only the current period, but future periods as well. In Gulf's last rate case, in Order No. 14030, we allowed a two year amortization period. In Gulf's 1982 rate case, in Order No. 10557, we allowed a three year period. In the FPUC-Fernandina Beach Division rate case, we approved a 5 year amortization period since it had been approximately 15 years since the company's last rate case. (Order No. 22224, Docket No. 881056-EI).

Gulf's witness testified that a two year amortization period was appropriate because over the past ten years Gulf has had five rate cases for an average of one rate case every two years.

It has been six years since Gulf's last rate case. Pursuant to Chapter 366, Florida Statutes, Gulf must file Modified Minimum Filing Requirements (MMFRs) in 1994. We believe that the amortization period should be greater than the two years ordered in Gulf's last rate case but less than the six years between cases, since the company must file MMFRs in four years. Therefore, rate case expense will be amortized over four years. Expenses should be reduced by $ 250,000.

6. Cogeneration and Industrial [*53] Programs

We do not believe that expenses related to Gulf's Industrial Customer Activities Cogeneration Program should be allowed. From the record in this docket, this program appears to be little more than a load retention program for large industrial customers.

As justification for this expense, Gulf states that this program provides benefits to the general body of ratepayers by preserving revenues. This presents us with the age old question of the benefits of high load factor customers to the general body of ratepayers.

Gulf contends that the retention of high load factor customers benefits all customers. On the other hand, in this rate proceeding the company has requested that additional plant be placed in base rates. From this record it cannot be concluded that high load factor customers have necessarily benefitted Gulf's general body of ratepayers.

In addition, Gulf has proposed an Energy Audit and Technical Assistance Program as part of its overall conservation plan. This program not only addresses conservation measures, but cogeneration applications, and appears to duplicate the Industrial Customer Activities Cogeneration Program in several respects. We therefore [*54] find that the amount budgeted for the Industrial Customer Activities Cogeneration Program ($ 426,464) should be disallowed.

7. Good Cents Incentive Program

The Good Cents Incentive program offers merchandise and travel packages to contractors for the installation of energy efficient appliances. It also offers these incentives for the retrofit of gas furnaces to electric heat pumps. The provision of these appliances does not require the use of an incentive. The general public, as well as the real estate community, is well aware of the benefits of having an energy efficient home. In fact, energy efficiency has become a major selling point as customers have come to demand energy efficient homes.

Since the provision of incentives to contractors is not necessary, we believe that the $ 50,000 budgeted by Gulf for the Good Cents Incentive Program should be disallowed.

8. Presentation/Seminar Program

Gulf had budgeted $ 55,429 for its Presentation/Seminar Program. Gulf contends that this program provides presentations to local contractors about the energy efficiency of electric appliances. This appears to be a duplication of the company's Education and Good Cents programs. Today's [*55] contractors are well aware of the importance of an energy efficient home. While these presentations and seminars do foster a better relationship between Gulf and the local contractors, we do not see any additional benefits accruing to the general body of ratepayers. We therefore disallow the $ 55,429 budgeted for this program.

9. Shine Against Crime

The Shine Against Crime program is simply an outdoor lighting program. These types of programs have been in existence for some time mainly to replace inefficient lighting with more efficient high pressure sodium lighting. This practice reduces kwh consumption and conserves resources. In addition to this purpose however, Gulf's program promotes the installation of new outdoor fixtures.

Section 366.80-.85 of the Florida Statutes, also known as the Florida Energy Efficiency and Conservation Act (FEECA), mandates that utilities control energy growth. While the replacement of inefficient outdoor fixtures helps to reduce energy requirements, the promotion of "new" outdoor installations increases energy requirements. It is this facet of the Shine Against Crime program that we take exception with. The promotion of off-peak load does [*56] not contribute to reducing energy requirements and may be contrary to FEECA. The company's witness stated that approximately 35 to 37% of the expenses for this program are attributable to changeouts of existing fixtures. This means that 63% of the expenses, or $ 91,761, is attributable to new installations and the promotion of off-peak sales. We therefore disallow $ 91,761 of the $ 145,652 Gulf has budgeted for this program.

10. Economic Development

Gulf contends that its well-being is directly related to that of the community, and that it has a direct stake in the community's overall development. As a result, Gulf has developed a marketing and promotional campaign designed to attract new businesses to the area.

It appears that Gulf has assumed some of the responsibilities of local chambers of commerce or development boards. Traditionally, those organizations have been in the forefront of attracting businesses to expand and relocate in their area. Gulf is duplicating these efforts. The company admits that it has "assumed a leadership role in furthering the capability of communities in its service territory to attract and/or expand the industrial base." In seeking to expand [*57] industry or business activity in general, Gulf is actively attempting to increase sales of electricity.

This type of marketing expense might be expected of a company operating in a non-regulated environment. A desire to increase sales or market share against the competition is normal and healthy when there is competition. Gulf however, has no competitors supplying electrical power in the same geographic area it serves.

We do not believe that this expense should be passed on to Gulf's ratepayers. We therefore disallow the entire $ 687,000 Gulf has budgeted for economic development.

11. Lobbying Expenses

We have removed $ 263,534 used for lobbying and lobbying-related activities from operating expenses. This adjustment removes $ 96,643 for SCS expenses for Outside Consultants and $ 119,923 for expenses incurred by Gulf's registered lobbyist and 25% of the office rent on the Tallahassee office. In addition, 10% of the expenses of Gulf's Regulatory Matters Coordinator or $ 5,375 should also be removed. This is consistent with Gulf's book treatment of these expenses in 1989.

Further adjustments are necessary to remove 25% of the expenses allocated to Gulf for the Governmental [*58] Affairs office in Atlanta and Washington or $ 41,593. Because of the similarities between these Governmental Affairs offices and the Tallahassee office it is appropriate to make this adjustment (TR 3855-3856).

12. IRS, Grand Jury Expenses

At the time of its filing, Gulf identified $ 615,000 in expenses related to grand jury and IRS investigations which it agreed to remove from its 1990 test year budget. Since its filing Gulf discovered an additional $ 5,000 used for a presentation made by Gulf's outside auditors to its Board of Directors. Gulf has stipulated to the removal of this amount and we therefore disallow $ 5,000.

13. Research and Development Projects

Gulf has budgeted $ 210,000 in O&M expenses for research and development. Of this amount, the $ 31,813 Gulf has budgeted for the Acid Rain Monitoring Program is an extension of a previous acid rain program and not a new research and development program. In removing this amount from Gulf's proposed 1990 budget, we are not disallowing funds for acid rain research. Rather, we find that Gulf has failed to sustain its burden of proof in justifying this variance from the 1990 benchmark.

14. Transmission Rents

Transmission [*59] rents, or facilities charges, are a cost effective alternative to Gulf building its own transmission lines to receive power from Plants Daniel and Scherer, which are physically located outside the State of Florida.

Since we have removed Plant Scherer from Gulf's rate base it is also appropriate that we remove the associated transmission expenses. We therefore remove $ 423,000 in transmission rents from Gulf's O&M budget.

15. Labor Complement Vacancies

An adjustment in O&M expenses is necessary to remove the effect of vacancies on the labor complement. On the average there were fifty (50) vacant positions in Gulf's labor complement over the twelve month period ending May, 1990. Four positions were eliminated however in Gulf's 1990 budget, leaving a net average vacancy rate of 46 positions. We therefore reduce O&M expenses by $ 403,222 and payroll taxes of $ 29,982 to remove the effect of vacancies on the labor complement. This adjustment is in addition to adjustments made by Gulf recognizing vacant positions.

16. Productivity Improvement Plan

As previously discussed, the Productivity Improvement Plan (PIP) is part of the total compensation plan for Gulf's top 11 employees. [*60] Due to a change in the design of the PIP program after the budgeting process was completed, a reduction in O&M expenses is in order.

The original amount budgeted for this program was $ 438,473, whereas the amount now budgeted is $ 99,066. We therefore reduce O&M expenses by $ 339,407.

17. Employee Relocation

Gulf's employee relocation plan covers a variety of costs involved in moving an employee and his family. These costs include appraisals, inspections, insurance, closing costs, broker expenses, moving expenses, and living expenses until a new home is purchased.

Relocation expenses cannot be neatly extrapolated from year to year. Unlike salaries or plant maintenance relocation expenses vary, as shown below:

Year	Actual Amount
1984	$ 263,066
1985	121,536
1986	113,552
1987	285,361
1988	205,287
1989	468,246

Relocation expense increased in 1989 primarily due to company reorganization. Gulf budgeted $ 324,100 for test year 1990. We believe that $ 324,100 is too high because of the extensive changes which occurred in 1989 are unlikely to recur soon. We believe a more reasonable approach is to allow $ 268,112, the amount of the 1986-1989 average yearly expense [*61] for relocation. Therefore, Gulf's 1990 budget for relocation expense should be reduced by $ 55,988 from $ 324,100 to $ 268,112.

18. Management Perks

Gulf's ratepayers should not pay for tax services and fitness programs for executives. These expenses should be borne by the stockholders. Expenses are reduced by $ 65,100.

19. Caryville Subsurface Study

As we have previously discussed, the subsurface study was a geological study of the Caryville site to determine if the land could support the weight of a power plant and supporting facilities. Since Caryville remains in Rate Base, this study ($ 568,000) should be allowed, however we will require that this amount be amortized to expense over a 10 year period. Amortization of the subsurface study over ten years results in a $ 57,000 increase in O&M expense. In addition, we have previously made a $ 28,000 adjustment in working capital for 1/2 year in 1990.

20. Pension Expense

Gulf presented three projections for pension expense in 1990. First, the company budgeted $ 0 for pension expense and included this in its petition for a rate increase.

The second amount presented by Gulf was on MFR Schedule C-66, Pension Cost. This [*62] MFR reports projected net periodic pension cost to be ($ 11,020). This is an early projection of pension cost under SFAS 87.

The third amount presented by Gulf to project pension expense for 1990 is a letter dated June 1, 1990, from the actuary retained by Southern Company. The letter indicates that the revised estimate of pension cost under SFAS 87 for 1990 is $ 199,000.

Historically, Gulf's pension expense has been on the decline for the past three years. For 1987, 1988, and 1989; Gulf's pension expense was $ 1,538,000, $ 1,385,000, and $ 47,000, respectively. These are the amounts recorded under SFAS 87.

Consistent with the utility's treatment of pension expense for 1987-1989, we believe that pension expense should be recorded under SFAS 87; however, the estimates of pension cost vary from ($ 11,020) to $ 199,000. Although the $ 199,000 is the most current estimate available, it is not supported by a full actuarial valuation. Because of the new estimate provided, we believe that the pension cost will probably be greater than ($ 11,020). Since the 1990 pension costs are still estimates and the 1987-1989 trend of pension expense is downward, we approve a pension expense [*63] of $ 0 as originally filed by Gulf. We are not approving $ 0 because we are certain that Gulf won't contribute to the pension fund. Rather, $ 0 is our estimate of what pension expense will be under SFAS 87, based upon the three different projections submitted by Gulf.

21. Post Retirement Medical and Life Insurance

We made no adjustments to Gulf's budgeted post retirement medical and life insurance benefits. However, we will require that Gulf's retirement medical and life insurance benefits be recognized using the accrual basis of accounting. Accrual accounting more accurately charges the cost of providing service to the customer who is receiving service. At this time, we do not believe that Gulf should be required to follow the exposure draft for accounting for post retirement benefits that has been released by the Financial Accounting Standards Board. The exposure draft will not be implemented until some future date.

B. Depreciation and Amortization

The Company has proposed test year depreciation expense of $ 47,701,000. As a result of our adjustments we have reduced depreciation and amortization expense by $ 1,893,000 to an approved amount of $ 45,808,000 as follows: [*64]

(000's)	
Depreciation and Amortization Expense Per Company	$ 47,701
Adjustments:	
1. Appliance Division	(12)
2. Tallahassee Office	(1)
3. Leisure Lakes	(5)
4. Plant Scherer	(1,774)
5. New Corporate Headquarters	(101)
Total Adjustments	(1,893)
Adjusted Depreciation & Amortization Expense	$ 45,808

C. Taxes Other than Income Taxes

Gulf has projected taxes other than income taxes to be $ 20,822,000 for test year 1990. We have made adjustments of $ 274,000 and reduced taxes other than income to $ 20,548,000.

The exclusion of Plant Scherer from rate base will result in a reduction of $ 245,000 in taxes other than income. In addition, a reduction in taxes other than income of $ 30,000 must be made to remove the effect of vacancies in Gulf's labor complement. Finally, an increase in taxes other than income in the amount of $ 1,000 should be made as a result of the additional revenue imputed for 1990 due to a PXT customer being misbilled by Gulf (as previously discussed in the rate base section of this order). These adjustments total $ 274,000 and reduce taxes other than income to $ 20,548,000 as set forth above.

D. Income Taxes Currently [*65] Payable

We have decreased current income tax expense by $ 143,000 for the net tax effect of other adjustments we have made to net operating income. We made a combined interest reconciliation adjustment and investment tax credit interest synchronization adjustment, increasing income tax expense by $ 672,000. The effect of these adjustments results in an increase of $ 529,000 in income taxes currently payable.

E. Deferred Federal Income Taxes (Net)

The company has projected $ 1,621,000 in deferred Federal Income Tax expense for test year 1990. Our elimination of Plant Scherer from rate base increases deferred Federal Income Taxes by $ 668,000. In addition, our previous adjustment to depreciation for test year 1990 increases deferred Federal Income Taxes by $ 45,000. These two adjustments totalling $ 712,000 result in total deferred Federal Income Tax expense of $ 2,333,000.

F. Investment Tax Credit

Gulf's budgeted investment tax credit amortization for test year 1990 was $ 2,041,000. As a result of our exclusion of Plant Scherer 3 from rate base we have decreased this by $ 96,000, resulting in a remaining amortization of $ 1,945,000.

G. Total Operating Expenses

Total [*66] operating expenses, as adjusted are $ 194,603,000.

H. Total Net Operating Income

The net operating income is determined by subtracting total operating expenses from operating revenues. For 1990 Gulf's net operating income is $ 61,085,000 ($ 255,688,000 - $ 194,603,000). For a complete breakdown of Gulf's net operating income see Attachment 3.

X. REVENUE EXPANSION FACTOR

The purpose of the revenue expansion factor (NOI multiplier) is to gross up or expand the Company's net operating income deficiency to compensate for income taxes and revenue taxes that the Company will incur as the result of any revenue increase. All parties agree that the appropriate revenue expansion factor in this case is 1.631699 developed as follows:

Revenue Requirement	100.000000
Uncollectible Accounts	(0.113300)
Gross Receipts Tax	(1.500000)
Regulatory Assessment Fee	(0.125000)
Net Before Income Taxes	98.261700
State Income Tax Rate	5.5000%
State Income Tax	5.404394
Net Before Federal Income Taxes	92.857307
Federal Tax Rate	34.000%
Federal Income Tax	31.571484
Net Operating Income	61.285822
Net Operating Income Multiplier	1.631699

XI. REVENUE REQUIREMENTS

Having determined [*67] the Company's rate base, the net operating income applicable to the test period, and the overall fair rate of return, it is possible to calculate any excess/deficiency of revenues. Multiplying the rate base value for 1990 of $ 861,159,000 by the fair overall rate of 8.10% yields an NOI requirement for 1990 of $ 69,746,000. The adjusted net operating income for the test year amounted to $ 61,085,000 resulting in an NOI deficiency of $ 8,660,000. Applying the appropriate NOI multiplier of 1.631699 to this figure yields a deficiency of $ 14,131,000 in gross annual revenues.

As discussed earlier, we have reduced Gulf's return on equity by fifty (50) basis points for a two year period as a penalty for corporate mismanagement. After applying the fifty basis point penalty, Gulf's authorized annual revenue increase is reduced to $ 11,838,000 the calculation of which is detailed below:

(000s)

		After 50 Basis Point Reduction
Adjusted Jurisdictional Rate Base	$ 861,159	$ 861,159
Required Rate of Return	8.10%	7.94%
Required Net Operating Income	69,746	68,341
Adjusted Achieved Test Year Jurisdictional Net Operating Income	61,085	61,085
Jurisdictional NOI Deficiency	8,660	7,255
Revenue Expansion Factor	1.631699	1.631699
Revenue Increase	14,131	11,838

[*68]

In view of the above, we authorize Gulf an increase in gross annual revenues of $ 11,838,000 for two years beginning September 13, 1990. Thereafter, we authorize Gulf an increase in gross annual revenues of $ 14,131,000.

XII. INTERIM INCREASE

Order No. 22681 issued on March 13, 1990, granted Gulf an interim rate increase of $ 5,751,000 pursuant to Section 366.071, Florida Statutes. The interim increase was calculated based on a test year consisting of the twelve (12) month period ending September 1989 (October 1988 - September 1989). We approved the interim rate increase for collection, subject to refund, pending the outcome of further evaluation of the Company's request for permanent rates. Now that the evaluation is complete, the appropriate level of interim relief must be calculated.

Under Section 366.071, Florida Statutes, a refund of interim rates should be ordered if it is necessary to reduce the utility's rate of return during the pendency of the rate case proceedings to the level of the newly authorized rate of return which is found fair and reasonable on a prospective basis.

In this docket, the interim increase was calculated using an 8.26% rate of return, which [*69] is higher than the 8.10% rate of return approved herein. Therefore, we will require a refund of $ 2,052,000 on an annual basis, the calculation of which is detailed below:

	(000s) Interim at 8.26% Rate of Return	Interim at 8.10% Rate of Return	Amount to be Refunded
Jurisdictional Adjusted Rate Base	$ 785,912	$ 785,912	
Required Rate of Return	8.26%	* 8.10%	
Required Net Operating Income	64,916	63,659	
Jurisdictional Adjusted NOI	61,392	61,392	
NOI Deficiency (Excess)	3,524	2,267	
NOI Multiplier	1.631699	1.631699	
Revenue Deficiency (Excess)	5,751	3,699	$ 2,052
Required Return on Equity	13.00%	12.55%	

* Without 50 Basis Point ROE Reduction

XIII. FUEL NEUTRALITY

A. Top Gun Video

The "Top Gun" video was produced in 1987 and shown to a group of contractors and builders at Gulf's annual awards seminar. The video shows fighter aircraft shooting gas appliances out of the air and indicates that the contractors could be top guns in their areas. One has to wonder at the overall intent of not only the video but Gulf's entire seminar presentations.

Our fuel neutrality policy can be summarized by stating that a utility should not [*70] promote its product by showing a competitive fuel in a bad light. This policy objective is set forth in Order Nos. 9974 and 12179 which were issued in 1981 and 1983.

Gulf's Top Gun video is clearly in violation of our fuel neutrality policy, and Gulf's management should be held accountable for its production and distribution.

B. Gas Busters "T" Shirt

A total of 559 of the tee-shirts in question were distributed in 1985 to Gulf Power employees. Gulf states that "[t]he shirts were made available to employees during a series of meetings during 1985 and were intended to explain and gain commitment to the Company's strategic marketing plan titled EMPACT (employee action). The shirts themselves were an inappropriate reaction to the promotional efforts of other energy suppliers that was very much in the public focus during this timeframe."

The production and distribution of these shirts having a "Gas Busters" logo, was contrary to our policy regarding fuel neutrality.

C. Good Cents Incentive

The Good Cents Incentive programs were in existence during 1987 through 1989. These programs were specifically tailored to reward customers for the replacement of gas furnaces with heat pumps. [*71] The contractors were paid anywhere from $ 25 to $ 100, in cash or merchandise, for each installation. In addition "electropoints" were awarded to contractors which were redeemable for trips, awards, and merchandise.

These programs not only provided incentives for the replacement of gas heat but also increased the Company's winter peak demand and annual energy. The good cents incentive programs clearly promoted electric over gas appliances and were contrary to our policy regarding fuel neutrality.

D. Withholding Good Cents Certification

In 1987, a commercial building received energy awards from both the U.S. Department of Energy and the Governor's Energy Office yet did not receive Good Cents certification because of a small amount of backup gas power. This practice was contrary to the Commission's policy regarding fuel neutrality.

Gulf has contended all along that the Good Cents logo is synonymous with energy efficiency. Why then wouldn't a highly efficient building that received other awards be granted Good Cents certification? Gulf is not practicing what it preaches; the promotion of the most energy efficient building for its ratepayers.

E. Misleading Advertising

Gulf [*72] ran a series of advertisements in which it compared the energy efficiency of its all electric "Good Cents" home to other homes which contained gas appliances. According to the ads, the "Good Cents" homes were consistently more energy efficient. The ads did not point out however that the homes had different levels of insulation and sizes of equipment. Both of these attributes will affect the energy usage of the home that is modeled, yet the advertisements did not mention this fact. If the general public were to read these ads, they would believe that the homes were identical. This is misleading to Gulf's general body of ratepayers.

The Company's justification for these ads is that they were responding to advertising by local gas companies that Gulf thought was misleading. We do not find this justification acceptable.

We believe that the preceding five subsections demonstrate that Gulf has consistently and blatantly violated our policy regarding fuel neutrality. Although at this time we will not make an adjustment based on these violations, we warn Gulf and other utilities under our jurisdiction that in the future such violations will not be tolerated.

XIV. COST OF SERVICE [*73] AND RATE DESIGN

Having ascertained the Company's revenue requirement and the amount of revenue increase necessary, we now turn our attention to rate design. We must determine the rate of return currently earned by each rate class, the increase in revenue requirement to be allocated to such class, and how each class's revenue responsibility will be spread between the customer, energy, and demand charges. In this rate proceeding, we have also reviewed the continued appropriateness of several aspects of the company's rate structure. We begin first with the cost of service studies presented in this case.

A. Cost of Service Methodology

Several methodologies were put forth for consideration as follows:

Gulf Power - 12 month Coincident Peak and 1/13 Energy Methodology; Public Counsel - Equivalent Peaker Cost Methodology; and Industrial Intervenors - Near Peak Methodology. The equivalent peaker methodology implies a refined knowledge of costs which is misleading, particularly as to the allocation of plant costs to hours past the break-even point. The near peak method includes too narrow a spread of peak hours in our view. We heard extensive testimony on each of these methodologies [*74] and believe that the Gulf Power proposed methodology is appropriate with the following revisions:

1) All of Account 364 will be classified as demand-related and allocated on class NCP.

Commission policy has been that no distribution system costs other than service drops (Account 369) and meters should be classified as customer-related. In addition, for customers served at primary or higher voltage only the meter is classified as customer-related. (O'Sheasy, TR 1863-1864) Therefore, we believe it was inequitable to the secondary voltage customers to classify secondary wire in Account 364 as customer-related when there was no similar classification of wire for higher voltage customers.

2) Uncollectable expense will be allocated to all classes on the basis of revenue and be classified as revenue-related. It will not be classified as customer-related or included in the customer charge.

3) Fuel inventory (stock) should be allocated on energy and classified as energy-related.

4) The coincident and noncoincident demands should be developed using the same methodology used for all other rate classes. The SEP KWH should not be excluded in the development of the CP KW and NCP KW.

5) [*75] The revenues, billing determinants and development of the 12 CP and NCP demands for the Standby Service Class will be based on the assumption that the PXT customer that is not migrating from PXT has a Standby Service Capacity of 7959 KW for the test year.

6) Service drops will be allocated to the OS classes for at least recreational lighting and advertisement or billboard customers. Meter costs, which reflect the current level of metering will be allocated to the recreational lights.

All the recreational lights have meters. (Exhibit 508) There are probably service drops for each of these installations. (O'Sheasy 1858-1860) Therefore, the cost will be allocated to the class for these customers.

7) The rate base for additional facilities for OS-I/OS-II and the expenses [associated] with these facilities will be allocated to OS-I/OS-II.

In his prefiled testimony on how a cost of service study is performed, Mr. O'Sheasy stated that "Certain costs are directly associated with one particular group of customers and are, therefore, assigned to that group." (TR 1807) This assignment was not done with respect to the additional facilities for OS-I/OS-II. The class has been credited with [*76] revenues of $ 424,653 but the rate base and expenses associated with the facilities except for those booked in Account 373 were not assigned to the class. (See TR 1861 and Exhibits 500, 231 and 501.) The rate of return in the revised study is 5.96 percent compared to 7.43 percent in the company's study in Exhibit 231. We believe the expenses should be matched with the costs so that the class' rate of return will not be significantly overstated to the detriment of the other rate classes.

8) Expenses for maintenance of cooling towers and coal pulverizers (grinding mills) will be allocated on energy and classified as energy-related.

The company has changed the classification of some O&M expenses from energy to demand in the cost of service study compared to that of Docket No. 840086-EI. In Docket No. 881167-EI, Mr. Haskins stated that maintenance for both coal grinding mills and cooling towers vary with the KWH to be generated. (TR 1763) In response to cross examination Mr. Lee agreed that operation and maintenance expenses for coal pulverizers and the operation expenses for cooling towers vary with KWH generated but that the amount of maintenance varies little with KWH. (TR 1468) [*77]

9) The test year expenses for the four conservation (Good Cents New Home, Good Cents Improved Home, and Commercial Presentations/Energy Education Seminars) programs which were denied conservation cost recovery by the Commission on May 2, 1989 will be classified as energy-related and allocated on energy to the rate classes in the revenue class to which the cost has been assigned by Gulf Power.

The test year expenses for these programs have been classified as customer-related by the company and included in the customer unit costs. Thus, the same amount of program cost is allocated to and recovered from a small RS customer as a large RS customer. (O'Sheasy, TR 1861-1863) Therefore, we believe it is more equitable to continue to recover these costs on a per KWH basis rather than on a per customer basis. Demand-related costs are collected through the energy charge for the residential class. Therefore, if there is less demand-related cost allocated to the class due to demand reductions from class participation, the customers with large usage will benefit more from the conservation program than customers with small bills.

Unfortunately we do not have a 12 CP and 1/13th cost study [*78] incorporating this combination of revisions. Because two of these problems significantly impact the rate of return of the rate classes directly involved, the company's 12 CP and 1/13th cost study (no migration study Ex. 231) has been adjusted for the two problems. One problem is the crediting of the revenues for additional facilities without the assignment of the cost for some of these facilities for OS-I and II. The second is the exclusion of the SE KWH in developing the 12 CP demands of the PXT and LPT classes. For example, a comparison of the rates of return in column 1 of Schedule 1 to those in column 3 shows that there is a 1.47 percentage point difference (7.43 percent versus 5.96 percent) for OS-III.

For the PXT and LP/LPT classes, rate base was increased by 6.84 percent ($ 2,778,000) and .79 percent ($ 592,000), respectively, of the transmission and demand-related production net plant and the demand-related production materials and supplies. The NOI for these classes was reduced by 6.84 percent ($ 316,000) and .79 percent ($ 68,000), respectively, of the total transmission and demand-related production O&M expenses, production plant A&G expenses and transmission and demand-related [*79] depreciation expenses. These are the major items allocated on the 12 CP KW. For OS-1/OS-II, the rate base and NOI from the staff-requested 12 CP and 1/13th cost of service study (Exhibit 501), which reflect the assignment of the cost to the class for all its additional facilities, was substituted for the values in Exhibit 231. All classes' rate base and NOI were adjusted proportionately to equal the company's filed levels of rate base and NOI.

1. Distribution System Costs

Our policy since the early 1980s has been to classify only the service drop and meter portion of the distribution system as customer-related. The Industrial Intervenors (II) and the utility advocate classifying a significant portion of the remainder of the distribution system, including poles, conductors, and transformers, as customer-related. This method is often referred to as the Minimum Distribution System concept. There is a fundamental flaw in this proposal in that only part of the distribution system is classified as customer-related. None of the subtransmission and transmission system would be classified as customer-related. Hence, customers served at primary voltage through dedicated substations, [*80] and customers served at higher voltages would not pay for any of this network path.

We believe this minimum distribution system approach should be rejected because it is inequitable and inconsistent to apply the concept to only those customers served at secondary voltage or at primary voltage through common substations when the network path must be there to serve each and every customer.

In our opinion distribution facilities that function as service drops or dedicated tap lines should be directly assigned to the classes whose members the facilities serve. No distribution costs other than service drops and meters should be classified as customer-related. Demand-related cost should be allocated on a demand allocator, and customer-related cost on a customer allocator.

2. Uncollectible Expense

The company assigned uncollectible accounts expense to the RS, GS and GSD classes on average number of customers and classified the expense as customer-related. The result of this classification and assignment or allocation of uncollectible accounts expense is that the expense is included in the customer charge unit cost. If the customer charges for these classes have been and are set [*81] at or near unit cost, all customers in the RS, GS and GSD rate classes pay an equal amount for uncollectible expense each month, regardless of the size of their bills. Commission policy has been to allocate uncollectible expense on revenues and not include it in the customer unit cost.

Our policy of not classifying uncollectible expense as customer-related should be continued. The company's classification of the cost as customer-related is inequitable because it results in a small customer paying as much uncollectible expense as a large customer (within and between the RS, GS and GSD classes), if customer charges are set at unit cost. However, if the account of a customer becomes uncollectible, a customer with a large bill would cause the company to incur much more uncollectible expense than a customer with a small bill.

Uncollectibles should be classified as revenue-related so that cost responsibility for uncollectible expense would be proportional to the size of a customer's bill.

3. Fuel Stock

The company has allocated fuel inventory in rate base on the 12 CP and 1/13th average demand, the same allocator they have used to allocate production plant investment. Thus, 12/13ths [*82] or 92.3 percent of the inventory has been classified as demand-related and allocated on each class's estimated demands during the system's 12 monthly peak hours. The other 7.7 percent has been classified as energy-related and allocated on energy.

In the company's last rate case we approved projected daily burn for 107.5 days as the basis for the calculation of the appropriate level of fuel inventory to be included in working capital. Since projected average daily burn is a function of KWH projected to be generated and used in the test year, fuel stock should be classified as energy-related and thus allocated on energy. The energy classification and allocation of fuel more closely track cost causation than the company's 92.3 percent allocation on 12 CP demands.

Since we have based the level of fuel stock allowed in rate base on a specific number of days burn which is a function of the KWH projected to be generated in the test year, fuel stock should be classified as energy-related and allocated on energy.

4. Estimate of CP and NCP Demands

The twelve monthly coincident peak hour demands (12 CP) are used to allocate demand-related production plant and transmission plant costs [*83] in all but the near-peak cost of service study. These demands must be estimated for all classes when using a projected test year. The 12 CP and class peak demands were estimated by class by dividing the 1990 KWH by 1987 KWH and multiplying that ratio times the 1987 12 CP for rate classes RS, GS and GSD. Under this method each class' 12 CP KW for the test year are increased over the historic load research data by the same percentage their KWH are projected to increase in the same time period, i.e., each class's 12 CP load factor is assumed to be the same as it was in the year of the historic load research data. Thus, each class's demand or use in the 12 monthly coincident peak hours relative to total KWH usage is projected to be the same in the test year as the historic load research year.

For those customers taking service on the SE rider, "supplemental energy" KWH were excluded from this calculation. The resulting 12 CP demand of 104,728 KW for the PXT class would have been 6.8 percent higher if the KWH had been included (111,893 KW). The effect on the estimated demands of the LP/LPT class was insignificant (.79 percent) because the LP/LPT customers' response to the SE rider [*84] was minimal. The 104,728 KW represents a 12 CP load factor of 107 percent in the test year for PXT. Thus, the PXT class would have been allocated about 6.8% more demand related production and transmission plant cost if these KWH had not been excluded. The effect of this adjustment or methodology is to reduce the costs allocated to the PXT class and thereby avoid or reduce a rate increase by inflating the class's rate of return.

The company's reason for excluding these KWH apparently is that it expects the SE customers to have a higher 12 CP load factor in the test year, i.e., to use less energy in the 12 monthly peak hours relative to their total usage. However, the data below shows the 12 CP load factor for 1989 for the three groupings of PXT customers decreases instead of increases in 1989. The significant decrease from 101 percent to 91 percent for PX/PXT customers on the SE rider was inconsistent with the company's assumed increased load factor for the class.

12 CP LOAD FACTORS

	Actual 1987	Actual 1989	Projected 1990
PXT Class as a whole	101	95	107
PX/PXT Customers on the SE Rider	101	91	
PX/PXT Customers not on the SE Rider	100	97	
LP/LPT Class as a whole	83	83	84
LP/LPT Customers on the SE Rider	80	83	
LP/LPT Customers not on the SE Rider	84	84	

[*85]

If the company's projection of a 107 percent 12 CP load factor for PXT due to an assumed changing usage pattern of SE customers is to be realistic or representative of 1990, it is only reasonable to expect the load factor for the PX/PXT SE customers would have been higher in 1989 than 1987.

Other data indicating that it is unreasonable to expect the 12 CP load factor for the PXT class to increase from 95 percent in 1989 to 107 percent in 1990 includes:

(1) The number of supplemental energy KWH projected for 1990 is 20 percent less than 1989. (Exhibit 486)

(2) The number of hours projected to be designated as SE hours in 1990 is less than either 1988 or 1987. (Exhibit 487)

(3) The SE rider has been in effect since 1985 without revision. (Order No. 17568)

Therefore, one would not expect a markedly different response to the rider in 1990 than in 1989.

The company has not presented any data or evidence supporting the use of a load factor higher than the historic value. All of the PX/PXT customers have time-recording meters so that their 12 CP values are actual metered numbers and not estimates. Therefore, the company had the 12 CP load factor data for the first four or five [*86] months of 1990 and could have entered it into the record during the hearing as evidence supporting the increased load resulting from their methodology. The company did not enter the data. It is reasonable to assume that the data would have been entered if it corroborated the assumptions behind their methodology.

It was also unreasonable to use 104,728 12 CP KW for 1990 for PXT because the 1989 actual (not estimated) value was 119,448 KW and the PXT KWH were projected to decrease only 1% from 1989 to 1990. (Data on Exhibits 488 and 209)

We are concerned about Gulf's departure from the policy (MFR Schedule E-14) of using the load characteristics determined from the load research collected pursuant to the Commission's Rule 25-6.0437 Cost of Service Load Research in developing various peak demands by class for the test year. The policy assumes the load characteristics, including load factor, are the same in the test year as the historic load research year. The primary purpose of the rule is "to require that load research that supports cost of service studies used in ratemaking procedures is of sufficient precision to reasonably assure that tariffs are equitable and reflect the [*87] true costs of serving each class of customers." The utilities have spent large amounts of money to collect the load research required by this rule. Gulf's departure from the use of historical load characteristics for the PXT class undermines the purpose of the Commission's Cost of Service Load Research Rule. It is inequitable and should not be allowed.

The company's exclusion of "supplemental energy" KWH in the development of the 12 monthly coincident peak hour demands and the class noncoincident peak demand for PX/PXT and LP/LPT underestimated these demands and resulted in an underallocation of production and transmission cost to the two classes. The PXT 12 CP KW should have been 6.8 percent higher and the LP/LPT's .79 percent higher. The exclusion of these KWH was inappropriate. The method employed by the company to develop its estimates by class of the 12 monthly coincident peak hour demands and the class noncoincident peak hour demands is inappropriate and Gulf's use of the methodology is denied.

B. Allocation of Revenue Increase

The revenue increases that we have authorized should be spread among the rate classes in a manner that moves class rate of return indices closer [*88] to parity. In so allocating the revenue increases we adhere to the following guidelines:

No class will receive an increase greater than 1 and 1/2 times the system percentage increase of 2.79 percent with adjustments.

The classes below parity will be given the maximum increase (RS and OS-II).

The GS class will be brought to 1.45 times parity. The approved reduction to the GS class is $ 1,655,000.

The OS-III class will be brought down to 2.34 times parity.

The balance of the increase will be spread across the remaining classes to retain as closely as possible their existing relationships.

Attachment 4 sets forth the approved spread of revenue increase by class. Attachment 5 provides the approved rates by class.

C. Seasonal Rates

The company currently has seasonal rates for the RS and GS rate classes. These seasonal rates do not track the company's cost of capacity when Gulf buys power from the Southern pool. These costs represent a significant portion of Gulf's cost of service during those hours Gulf buys power. Thus, the price signal sent by the present seasonal differential under the RS and GS rate classes may not represent the true cost to the ultimate consumer on [*89] Gulf's system, thereby tempering the reduction in peak-related costs, improvement of system load factor, and conservation of summer consumption sought by the seasonal design. A flat charge per KWH based on average costs for the RS and GS classes may produce a clearer price signal than the seasonal rate design proposed by the company.

We therefore eliminate seasonal rates for the RS and GS classes because the seasonal pricing differential does not appear to be cost-based and may not be sending the appropriate price signal during the hours Gulf buys power from the Southern pool.

D. Customer Charges

Customer charges are designed to recover costs associated with the number of customers served. These costs include primarily the costs of billing and metering and customer service. Given that costs are properly allocated to the customer component, the charge for each class should reflect the cost to provide such services. The customer charges are set as follows:

Rate Class	Unit Cost	Current Charges	Approved Charges
RS	$ 7.94	$ 6.25	$ 8.00
RST		9.25	11.00
GS	17.34	7.00	10.00
GST		10.00	13.00
GSD	41.47	27.00	40.00
GSDT		32.40	45.40
LP/LPT	447.83	51.00	225.00
PX/PXT	1,222.21	146.00	570.00

[*90]

E. Transformation Ownership Discounts

Gulf currently offers a discount to customers who own their transformation equipment and for the losses absorbed by the customer metered at primary or transmission level. Gulf proposed adjusting these credits by any variance of the demand and energy charges from unit costs. FEA proposed substantial increases in the transformation discounts to include the costs of poles, overhead/underground conductors, lines, and transformers.

We agree with staff that such a large discount could encourage uneconomic duplication of facilities to the detriment of the general body of ratepayers. Further, we agree that the adjustment for variance from unit costs proposed by Gulf is an unnecessary complication. Therefore we approve a transformer ownership credit for primary level customers of $ 0.35/KW/Month for GSD/GSDT and $ 0.42/KW/Month for LP/LPT. The transformer ownership credit for transmission level customers should be set at $ 0.41/KW/Month for GSD/GSDT, $ 0.52/KW/Month for LP/LPT, and $ 0.11/KW/Month for PX/PXT customers.

Such transformation credits should also be applied to the SS and ISS classes and should be based on 100 percent ratcheted billing [*91] demand in order to match the calculation of the local facilities demand charge applicable to standby service. Metering voltage discounts should be set equal to the otherwise applicable rate schedule for SS and ISS customers and apply to both the KW and KWH charges.

F. Time of Use Rates

Two methodologies were presented at the hearing for the design of time of use rates. Gulf's testimony supports use of the load factor methodology approved by the Commission in the company's last three rate cases. We believe that the major drawback to the load factor methodology is that it does not track costs as well as the time of use methodology (TOU) proposed by OPC.

OPC supports the use of a methodology which would recover distribution-related plant costs from the maximum demand charge; production and transmission-related demand costs through the on-peak demand charge; and energy-related production plant and operations and maintenance expenses through the energy charge. This approach also includes a ratchet for recovery of local distribution plant costs. We believe the rate design for the maximum demand charge should be based on actual metered demand and not ratcheted KW as proposed by [*92] OPC.

We therefore calculate time of use rates as follows:

1) The on-peak and off-peak non-fuel energy charges would be set equal to the energy unit cost from the cost study. (This would include the energy-related production plant and operations and maintenance expenses).

2) The maximum billing demand charge (which is applied to the customer's maximum demand whenever it occurs) would be equal to the distribution plant unit cost.

3) The on-peak demand charge would be an amount sufficient to recover the remaining revenue requirement including the transmission plant and the demand-related production plant.

G. Standby Service

1. Determination of Daily Standby Service Billing Demand

The following formula is Gulf's current formula for calculating daily standby service demand on Gulf's firm standby service (SS) tariff:

Daily Standby Service (KW) =

Maximum totalized customer generation output occurring in any interval between the end of the prior outage and the beginning of the current outage.

Minus the customer's daily generation output (KW) occurring during the on-peak period of the current outage.

Minus the daily on-peak load reduction (KW) that is a direct result of the customer's [*93] current generation outage.

The customer's daily generation output (KW) and daily on-peak period load reduction (KW) that are used in the formula must occur during the same 15 minute interval as the daily Standby Service (KW) that is used for billing purposes.

The language in the above formula for calculating daily standby service demand should be changed from:

Maximized totalized customer generation output occurring in any interval between the end of the prior outage and the beginning of the current outage

to:

The amount of load in KW ordinarily supplied by the customer's generation.

This change would satisfy the Industrial Intervenors' request for adjustment for seasonal variation in generation output in calculating daily standby service demand. It would also ensure that self-generating customers (SGCs) are not billed for standby power when they reduce generation for purely economic reasons. We believe that this change in the formula will result in a more accurate determination of standby power used.

The Industrial Intervenors proposed formula would result in standby power used by SE rider customers not being properly billed as standby power.

The language in the formula [*94] in the interruptible standby service (ISS) should be replaced with the language in the formula we are approving herein for firm standby service.

2. Design of Standby Service Charges

The present standby service rates are based on system and class unit costs from Docket No. 840086-EI. We believe the standby rate schedule (SS and ISS) charges should be adjusted to reflect unit costs from the compliance cost of service study for this rate case and the 1990 IIC capacity charge rates.

The SS charges should be designed using this compliance cost of service study and the rate design specified in Order No. 17159. The forced outage rate to be used to calculate the reservation charge would be that approved herein. If the resulting charges generate either more or less revenue than the class' revenue responsibility as approved herein, all charges except the customer charge should be decreased or increased by the (same) percentage required to generate the class' revenue requirement. The ISS charges should be the same as the SS charges except for the reservation and daily demand charges. The sum of the CP KW transmission unit cost plus an average IIC monthly charge rate of $ 6.69 should [*95] be used as the unit cost to develop these charges. Having decided herein to bill SE customers for distribution system costs on their maximum metered KW whenever it occurs, the billing KW in Exhibit 510 should be used to calculate the local facilities charges.

The customer charge should be the LP/LPT customer charge plus $ 25 except for those standby customers taking service on PX/PXT for whom the charge should be the PX/PXT charge plus $ 25.

The company should provide the staff a compliance cost of service study and the SS rates calculated in accordance with this decision. A spread sheet of component costs by function (retail revenue requirements) for the compliance study should also be provided.

With respect to the definition of the capacity used to determine the applicable local facilities and fuel charges, we are denying Gulf's proposed changes because they are not in conformance with the terms and conditions prescribed in Order No. 17159 for standby service.

3. SS Rate Forced Outage Factor

In the Standby Order No. 17159, a 10 percent forced outage rate was specified as the outage rate to be used in the calculation of the Reservation Charge. The overall reliability of the [*96] forced outage data in the record is questionable, however, in that the company was apparently accepting without review the forced outage data provided by self-generating customers (SGCs) and the SGCs may not have understood they were to report these outages, even if they signed up for zero standby power. Additionally, data was provided by only three of the four SGCS.

While we are tempted to rule that the assumed 10 percent forced outage rate should not be continued, there appears to be no practical alternative in the absence of sound, reliable data to support an alternative value for the forced outage rate.

Therefore, in the absence of reliable data to support a different value for the forced outage rate used to develop the reservation charge, the 10 percent forced outage rate prescribed in Order No. 17159 should continue to be used.

4. SE Rider Availability in Lieu of Standby Service

This issue is whether self-generating customers who are experiencing a forced outage or an outage for scheduled maintenance of their generating system can be billed on the SE rider rather than the standby service rate for standby power taken during the outage if the customer has another generator [*97] with which he could generate but chooses not to use for economic reasons. In other words, the issue is whether a self-generating customer can have standby power billed under a different rate tariff than the standby service if he has additional generating capacity available but which is less economic. Under the current standby service rate schedules, self-generating customers may reduce generation for economic reasons and take additional capacity and energy as supplementary service, including supplementary service with the SE rider applied.

Order No. 17159 at page 6, in addressing the issue of whether non QF standby customers would be entitled to the same service as QFs, requires the standby tariff resulting from that proceeding to be mandatory for all self-generating customers unless there is evidence to demonstrate that their load characteristics resemble those of normal full requirements customers. To allow such a customer to choose a different rate because it would result in a lower bill would allow that customer to escape costs properly assigned to him.

There is also a basic cost recovery problem if standby service is allowed to be billed on the provisions of the SE rider. [*98] The standby service rates have been developed by dividing the utility's full demand-related production and transmission unit cost per coincident peak kilowatt of demand by the average number of days per month that contain on-peak hours (21). Using this rate requires a standby customer who imposes load every day to pay the full demand-related unit cost per coincident peak KW because it is virtually certain that his load was on at the time of the system's peak.

The average number of days in 1988 and 1989 for which a self-generating customer would be billed daily demand charges if standby power was taken and billed pursuant to the SE rider is six. Thus, if a customer were using standby power for maintenance every day in a given month, the customer would be paying, on average, 6/21ths of the full demand-related unit cost per coincident peak KW even though it was virtually certain that his load was on at the time of the system's peak. In this scenario, the rates for standby service should be recovering the full demand-related unit cost.

Additionally, to allow standby power to be taken under the terms and conditions of the SE rider if the customer had generating capacity available [*99] but less economic would discriminate against self-generating customers with only one generator versus those with multiple generators.

KWH and capacity purchased to replace energy and capacity normally generated by a customer's generator which is experiencing a forced outage or an outage for scheduled maintenance, is clearly standby power and should be billed as standby power. However, to ensure that power taken to replace reduced generation for purely economic reasons is billed as supplemental power, the definitions of backup service and maintenance service should be more specific. Two sentences should be added to the definition (in the tariff) of backup service and maintenance service, the two forms of standby service, to indicate more clearly what constitutes scheduled and unscheduled outages. In the definition of backup service, an unscheduled outage should be defined as the loss or reduction of generation output due to equipment failure(s) or other condition(s) beyond the control of the customer. Similarly, under maintenance service a scheduled outage should be defined as the loss or reduction due to maintenance activities of any portion of a customer's generating system. [*100]

5. Waiver of Ratchet Provision for Reservation Charge

All demands registered during any maintenance outage of a self-generating customer, regardless of whether the maintenance outage is fully coordinated with Gulf, should be subject to the ratchet provision of the SS rate for the local facilities charge. The ratchet provision is appropriate because the scheduling of the outage does not affect the capacity of the local facilities to serve the customer. Scheduling the outage will not enable Gulf to avoid local facilities cost as the capacity of the local facilities, particularly dedicated substations, must be sufficient to serve the customer's maximum demand whenever it occurs. An increase in demand should properly result in an increase in the billing demand for the local facilities charge.

The Company should excuse demands registered during such periods from the ratchet provision applicable to the reservation charge if (1) the maintenance outage is usefully coordinated with Gulf and (2) the maintenance is used in hours that do not include a peak hour(s) that determines Gulf's IIC payments or revenues. The ratchet provision should not be waived for maintenance power used during [*101] the peak hours that determine Gulf's IIC payments or revenues because the cost impact continues for three years.

H. Supplemental Energy (SE) Rider

1. No Separate SE Rate Class

Order No. 17568, Docket No. 850102-EI, approved the experimental Supplemental Energy (SE) (Optional) Rider as a permanent rate schedule on the condition that it become a separate rate class in the company's next rate case. In this docket however, Gulf has not provided separate cost of service analyses for the two rate classes employing the SE Rider, LPT-SE and PXT-SE.

The necessity for a separate rate class depends on the differences between billing KW and peak demand KW characteristics of SE customers, as opposed to these in the general LP/LPT and PX/PXT classes and considerations of local facilities costs. From the record in this docket it appears that there is a large dissimilarity in the ratios of billing KW to 12 CP KW and maximum metered KW between PXT-SE and LPT-SE classes and that these customers should not be grouped into a single class. The data implies that to put all SE customers into one class would create a serious cost recovery problem between the LPT-SE and the PXT-SE customers. Therefore, [*102] a separate rate class consisting of LPT and PXT customers on the SE rider should not be implemented in this rate class.

It does, however, appear that there may be sufficient dissimilarity between the ratios of billing KW and 12 CP KW and maximum metered KW to warrant separate rate classes for the LP/LPT SE customers and for the PX/PXT-SE customers. Since we do not have a cost of service study with LP/LPT-SE and PX/PXT-SE each as a separate rate class, the question of whether a separate rate class(es) should be implemented for either PX/PXT-SE or LP/LPT-SE customers should be considered in the next rate case. Gulf is instructed to file its cost of service study in that case with LP/LPT and PX/PXT each broken into SE and non-SE classes and with totals for LP/LPT and PX/PXT.

2. Distribution System Costs for SE Customers

The SE rider presently provides forgiveness of the demands incurred during SE periods both with respect to on-peak and off-peak billing KW. Five of the six SE customers have dedicated substations (Exhibit 517). The sum of the average billing KW for the three SE customers for whom dedicated substations were built in 1989 is only 53 percent of the capacity of these [*103] substations. However, the PXT-SE customers are billed on only 59 percent of their maximum metered KW. Therefore, to ensure that the SE customers pay for the dedicated facilities that have been sized to serve their maximum demands whenever they occur, SE customers should be billed for distribution system costs on their maximum metered demand whenever it occurs. The provision of the SE rider for forgiveness of demand in the SE period would continue to apply to on-peak demand.

Therefore, Gulf shall bill SE customers for distribution system costs on their maximum metered KW whenever it occurs as per these guidelines.

I. Applicability Clause, GSD, LP and PX Classes

The applicability clause of the three demand classes (GSD, LP and PX) is stated in terms of the amount of KW demand for which the customer contracts. This is not an appropriate basis for determining applicability.

In the past, contracts have not been required of all these customers, and contract demand often bears little relationship to actual measured demand. As a part of this docket, tariffs should be modified to state that the applicability for both demand and the PX/PXT 75 percent load factor should be based on [*104] measured maximum billing demand. For SE customers, this would be the actual measured billing demand in non-SE periods. Customers whose annual load factor is less than 75 percent should not be allowed to opt for PXT because the PX/PXT rate is based on the costs of high load factor customers.

J. Minimum Charge Provisions for GSD/GSDT and LP/LPT

The current GSD/GSDT and LP/LPT rate schedules have minimum charges equal to the customer charge plus the demand charge for the minimum KW to take service on the rate schedule for customers opting for the rate schedule. This minimum charge provision is not appropriate. This provision unduly penalizes customers who opt for this higher rate class because they pay for the minimum KW to qualify for the class even if their usage falls below this level. Customers who meet the class minimum even once in every 12 month period, do not pay a minimum but pay only for their actual demand, even if it falls below the minimum.

We therefore eliminate the minimum charge provisions of the GSD/GSDT and LP/LPT rate schedules.

K. No Local Facilities Charge

The company proposed the implementation of a local facilities demand charge for LP/LPT and PX/PXT [*105] customers, which would be applied when the customer's actual demand does not reach at least 80 percent of the Capacity Required to be Maintained (CRM) specified in the Contract for Electric Power. We are denying the implementation of this charge because it is inequitable to apply the charge to the contract capacity because the contract demand for many customers bears little relationship to measured demand. Furthermore, it is an ineffective charge because no customers would have to pay the charge in the test year.

L. Service Charges

The following service charges are approved:

Initial Service	$ 20.00
Reconnect a subsequent subscriber	16.00
Reconnect of existing customer after disconnect for Cause	16.00
Collection Fee	6.00
Installing and Removing Temporary Service	60.00
Minimum Investigation Fee	55.00

M. Outdoor Service (OS)

1. Elimination of OS General Provisions

The company proposes to eliminate the general provisions pertaining to replacement of lighting systems on the Outdoor Service Rate Schedule (OS). We believe this is appropriate and that the present general provisions relating to the replacement of mercury vapor lighting fixtures with [*106] high pressure sodium fixtures should be removed.

The current provisions pertaining to replacement of lighting systems on the OS schedule are deleted as proposed by the company and no new provisions are adopted.

2. Street and Outdoor Lighting Rate

We approve the methodology used in developing the Street (OS-I) and Outdoor (OS-II) lighting rates. This entails setting the energy charges at levels which will collect the total non-fuel energy, demand, and customer-related costs at the class-approved rate of return. Maintenance charges were set so as to recover the total maintenance and administrative and general expenses allocated to OS-I and II in the cost of service study. The fixture charges were set at a level to collect the remaining revenue requirement after subtracting the energy, maintenance and additional facilities revenues. Attachment 6 sets forth the approved street and outdoor lighting rates for Gulf.

Gulf at present does not have records indicating the number of poles and other facilities in place which are dedicated to additional facilities. Because of this, it was not possible to develop cost-based rates for additional facilities in this rate case. We are directing [*107] Gulf to take the steps necessary to obtain this information so that cost-based additional facilities charges can be developed when the next rate case is filed.

3. Applicability of OS-III

The language in the OS-III (Other Outdoor Service) tariff will be modified to reflect that only customers with fixed wattage loads operating continuously throughout the billing period, such as traffic signals, cable TV amplifiers and gas transmission substations, will be allowed to take service on the OS-III rate.

N. Sports Fields Rate

Since the company's last rate case, sports fields taking service on Rate Schedules GS and GSD were allowed to transfer to the OS-III rate schedule. The company has now proposed an OS-IV rate for sports fields.

In deriving the 12 CP and NCP allocators for OS-IV, the company assumed that all recreational lighting customers would require service at a constant rate every day of the year from sunset to 10:00 p.m. A review of the customer accounting memo sheets for the sports fields customers indicates that approximately 36% of the billing months showed zero kwh usage. The company has no load data for sports fields, and does not intend to obtain such data using [*108] load research meters. The OS-IV rate was thus designed in the absence of reliable load research data.

In 1981 and 1982 the Commission eliminated special rates for sports fields, poultry farms and other uses. Addition of a special rate for sports fields is philosophically at odds with these past actions.

In spite of these problems, we will allow the rate design for OS-IV to be implemented. This is because the estimated OS-IV kilowatt hours have not been broken down into summer and winter components, and thus cannot be added to the kilowatt hours for GS and GSD to determine an accurate energy rate for those classes. In addition, the OS-IV as designed will not vary significantly from the GS rate. However, when the company files its next rate case they will be required to transfer their sports field customers to the appropriate GS or GSD rate schedules.

XV. CONCLUSIONS OF LAW

1) Gulf Power Company is a public utility within the meaning of Section 366.02, Florida Statutes, and is subject to the jurisdiction of the Commission.

2) This Commission has the legal authority to approve and use a projected test period for ratemaking purposes. Calendar year 1990 is an appropriate base [*109] test period.

3) The adjustments to rate base made herein are reasonable and proper. The value of the Company's 1990 rate base for ratemaking purposes is $ 861,159,000.

4) The adjustments made to the calculation of net operating income are proper and appropriate. For ratemaking purposes, Gulf's net operating income for 1990 is $ 61,085,000.

5) The fair rate of return on the equity capital of Gulf is 12.55%.

6) As a result of our finding of corporate mismanagement, Gulf's return on equity has been reduced by fifty (50) basis points for a two year period. This results in a return on equity of 12.05% for two years beginning September 13, 1990.

7) Gulf Power Company should be authorized to increase its rates and charges by $ 11,838,000 in annual gross revenues effective September 13, 1990. Gulf Power Company should be authorized to increase its rates and charges by $ 14,131,000 beginning September 13, 1992.

8) The rate schedules prescribed and approved herein are fair, just and reasonable within the meaning of Chapter 366, Florida Statutes.

9) The new rate schedules shall be reflected upon billings rendered for meter readings taken on or after September 13, 1990.

Accordingly, [*110] it is

ORDERED by the Florida Public Service Commission that the findings of fact and conclusions of law set forth herein are approved. It is further

ORDERED that the petition of Gulf Power Company for authority to increase its rates and charges is granted to the extent delineated herein. It is further

ORDERED that Gulf Power Company is hereby authorized to submit revised rate schedules consistent herewith designed to generate $ 11,838,000 in additional gross revenues annually for two years beginning September 13, 1990. The Company shall include with the revised rate schedules all calculations and workpapers used in deriving the revised rates and charges. It is further

ORDERED that the revised schedules authorized herein for the $ 11,838,000 revenue increase shall be reflected upon billings rendered for meter readings taken on or after September 13, 1990. It is further

ORDERED that Gulf Power Company is hereby authorized to submit revised rate schedules consistent herewith designed to generate $ 14,131,000 in additional gross revenues annually for two years beginning September 13, 1992. The Company shall include with the revised rate schedules all calculations and workpapers [*111] used in deriving the revised rates and charges. It is further

ORDERED that the revised schedules authorized herein for the $ 14,131,000 revenue increase shall be reflected upon billings rendered for meter readings taken on or after September 13, 1992. It is further

ORDERED that Gulf Power Company shall return to its ratepayers on a "per KWH basis" that portion of its interim increase set forth in the body of this order. It is further

ORDERED that Gulf Power Company shall include in each customer's bill, in the first billing of which the increase is effective, a bill stuffer explaining the nature of the increase, average level of the increase, a summary of tariff charges, and the reasons therefore. The bill stuffers shall be submitted to the Division of Electric and Gas of the Florida Public Service Commission for approval before implementation. It is further

ORDERED that in its next rate case Gulf Power Company shall file a cost of service study with LP/LPT and PXT each broken into SE and non-SE classes, with totals calculated for LP/LPT and PX/PXT. It is further

ORDERED that when Gulf Power Company files its next rate case that it transfer its sports fields customers from [*112] the OS-IV rate to the appropriate GS or GSD rate schedules. It is further

ORDERED, Gulf shall take the steps necessary to determine the quantity of street and outdoor lighting facilities dedicated to additional facilities prior to the filing of the next rate case, in order that cost-based rates can be developed for these facilities.

ORDERED that this docket be closed should no petition for reconsideration or notice of appeal be timely filed.

By ORDER of the Florida Public Service Commission, this 3rd day of OCTOBER, 1990.

ATTACHMENT 1

SCHEDULE 1

COMPANY: GULF POWER COMPANY

TEST YEAR: DECEMBER 31, 1990

COMPARATIVE RATE BASES

				COMPANY FILING	
LINE NO.	CO. ADJ. NO.	ISSUE NO.	DESCRIPTION	SYSTEM PER BOOKS	JURISDICTIONAL PER BOOKS
1			PLANT IN SERVICE		$ 1,275,624
2		2	PLANT IN SERVICE		
3		3	SCHERER TAX ADDER ADJUSTMENT		
4		4	SCHERER ACQUISITION ADJUSTMENT		
5		5	NEW CORPORATE HEADQUARTERS		
6		7	NAVY HOUSE		
7		8	APPLIANCE DIVISION		
8		9	TALLAHASSEE OFFICE		
9		10	BONIFAY/GRACEVILLE		
10		12	LEISURE LAKES		
11		16	UNIT POWER SALES		
12		25	PLANT DANIEL		
13		27	PLANT SCHERER		
14		29	REBUILDS & RENOVATIONS		
15		30	NETWORK PROTECTORS		
16					

17		Total plant in service	0	1,275,624
18				
19				
20		ACCUMULATED DEPRECIATION	454,964	
21	3	SCHERER TAX ADDER ADJUSTMENT		
22	5	NEW CORPORATE HEADQUARTERS		
23	8	APPLIANCE DIVISION		
24	9	TALLAHASSEE OFFICE		
25	11	JDITC UNDERSTATEMENT		
26	16	UNIT POWER SALES		
27	25	PLANT DANIEL		
28	27	PLANT SCHERER		
29	29	REBUILDS & RENOVATIONS		
30	30	NETWORK PROTECTORS		
31				
32		Total depreciation reserve	0	454,964
33				
34		Net plant in service	0	820,660
35				
36				
37		CONSTRUCTION WORK IN PROGRESS	14,949	
38	13	LEVEL OF CWIP		
39	14	NON-AFUDC CWIP		
40				
41		Total CWIP	0	14,949
42				
43				
43				
44		PROPERTY HELD FOR FUTURE USE	3,925	
45	6	CARYVILLE SOD FARM		
46	15	LEVEL OF PHFFU		
47				
48		Total prop. held for future use	0	3,925
49				
50				
51				
52		ACQUISITION ADJUSTMENT	2,317	
53	4	SCHERER ACQUISITION ADJUSTMENT		
54				
55		Total acquisition adjustment	0	2,317
56				
57				
58		Net utility plant	0	841,851
59				
60				
61		WORKING CAPITAL	81,711	
62	16	UNIT POWER SALES		
63	18	PREPAID PENSIONS		
64	19	RATE CASE EXPENSES		
65	20	FUEL/CONSERVATION OVERRECOVERIES		
66	21	TEMPORARY CASH INVESTMENTS		
67	22	HEAVY OIL INVENTORY		

68		23	LIGHT OIL INVENTORY		
69		24	COAL INVENTORY		
70		25	PLANT DANIEL		
71		27	PLANT SCHERER		
72		28	CANCELED SCS BUILDING		
73		31	OTHER INVESTMENTS		
74		32	OTHER ACCOUNTS RECEIVABLE		
75		33	MATERIALS & SUPPLIES		
76		34	OTHER CURR. ASSETS & MISC. DEF. DEBITS		
77		35	CARYVILLE SUBSURFACE STUDY		
78		36	EXPENSE ADJUSTMENTS		
79					
80					
81			Total working capital	0	81,711
82					
83					
84			TOTAL RATE BASE	0	923,562

[*113]

				COMPANY FILING	
LINE NO.	CO. ADJ. NO.	ISSUE NO.	DESCRIPTION	ADJUSTMENTS	JURISDICTIONAL ADJUSTED
1			PLANT IN SERVICE		
2		2	PLANT IN SERVICE		
3		3	SCHERER TAX ADDER ADJUSTMENT		
4		4	SCHERER ACQUISITION ADJUSTMENT		
5		5	NEW CORPORATE HEADQUARTERS		
6		7	NAVY HOUSE		
7		8	APPLIANCE DIVISION		
8		9	TALLAHASSEE OFFICE		
9		10	BONIFAY/GRACEVILLE		
10		12	LEISURE LAKES		
11		16	UNIT POWER SALES		
12		25	PLANT DANIEL		
13		27	PLANT SCHERER		
14		29	REBUILDS & RENOVATIONS		
15		30	NETWORK PROTECTORS		
16					
17			Total plant in service	0	1,275,624
18					
19					
20			ACCUMULATED DEPRECIATION		
21		3	SCHERER TAX ADDER ADJUSTMENT		
22		5	NEW CORPORATE HEADQUARTERS		
23		8	APPLIANCE DIVISION		
24		9	TALLAHASSEE OFFICE		
25		11	JDITC UNDERSTATEMENT		
26		16	UNIT POWER SALES		
27		25	PLANT DANIEL		
28		27	PLANT SCHERER		
29		29	REBUILDS & RENOVATIONS		
30		30	NETWORK PROTECTORS		

31				
32		Total depreciation reserve	0	454,964
33				
34		Net plant in service	0	820,660
35				
36				
37		CONSTRUCTION WORK IN PROGRESS		
38	13	LEVEL OF CWIP		
39	14	NON-AFUDC CWIP		
40				
41		Total CWIP	0	14,949
42				
43				
43				
44		PROPERTY HELD FOR FUTURE USE		
45	6	CARYVILLE SOD FARM		
46	15	LEVEL OF PHFFU		
47				
48		Total prop. held for future use	0	3,925
49				
50				
51				
52		ACQUISITION ADJUSTMENT		
53	4	SCHERER ACQUISITION ADJUSTMENT		
54				
55		Total acquisition adjustment	0	2,317
56				
57				
58		Net utility plant	0	841,851
59				
60				
61		WORKING CAPITAL		
62	16	UNIT POWER SALES		
63	18	PREPAID PENSIONS		
64	19	RATE CASE EXPENSES		
65	20	FUEL/CONSERVATION OVERRECOVERIES		
66	21	TEMPORARY CASH INVESTMENTS		
67	22	HEAVY OIL INVENTORY		
68	23	LIGHT OIL INVENTORY		
69	24	COAL INVENTORY		
70	25	PLANT DANIEL		
71	27	PLANT SCHERER		
72	28	CANCELED SCS BUILDING		
73	31	OTHER INVESTMENTS		
74	32	OTHER ACCOUNTS RECEIVABLE		
75	33	MATERIALS & SUPPLIES		
76	34	OTHER CURR. ASSETS & MISC. DEF. DEBITS		
77	35	CARYVILLE SUBSURFACE STUDY		
78	36	EXPENSE ADJUSTMENTS		
79				
80				

81			Total working capital	0	81,711
82					
83					
84			TOTAL RATE BASE	0	923,562

[*114]

				COMMISSION VOTE	
LINE NO.	CO. ADJ. NO.	ISSUE NO.	DESCRIPTION	ADJUSTMENTS	JURISDICTIONAL ADJUSTED
1			PLANT IN SERVICE		
2		2	PLANT IN SERVICE	(55)	
3		3	SCHERER TAX ADDER ADJUSTMENT	0	
4		4	SCHERER ACQUISITION ADJUSTMENT	0	
5		5	NEW CORPORATE HEADQUARTERS	(3,892)	
6		7	NAVY HOUSE	(23)	
7		8	APPLIANCE DIVISION	(214)	
8		9	TALLAHASSEE OFFICE	(24)	
9		10	BONIFAY/GRACEVILLE	0	
10		12	LEISURE LAKES	(142)	
11		16	UNIT POWER SALES	0	
12		25	PLANT DANIEL	0	
13		27	PLANT SCHERER	(52,987)	
14		29	REBUILDS & RENOVATIONS	0	
15		30	NETWORK PROTECTORS	0	
16					
17			Total plant in service	(57,337)	1,218,287
18					
19					
20			ACCUMULATED DEPRECIATION		
21		3	SCHERER TAX ADDER ADJUSTMENT	0	
22		5	NEW CORPORATE HEADQUARTERS	(338)	
23		8	APPLIANCE DIVISION	(7)	
24		9	TALLAHASSEE OFFICE	(11)	
25		11	JDITC UNDERSTATEMENT	0	
26		16	UNIT POWER SALES	0	
27		25	PLANT DANIEL	0	
28		27	PLANT SCHERER	(6,557)	
29		29	REBUILDS & RENOVATIONS	0	
30		30	NETWORK PROTECTORS	0	
31					
32			Total depreciation reserve	(6,913)	448,051
33					
34			Net plant in service	(50,424)	770,236
35					
36					
37			CONSTRUCTION WORK IN PROGRESS		
38		13	LEVEL OF CWIP	0	
39		14	NON-AFUDC CWIP	0	
40					
41			Total CWIP	0	14,949
42					
43					
43					

44		PROPERTY HELD FOR FUTURE USE		
45	6	CARYVILLE SOD FARM	(135)	(135)
46	15	LEVEL OF PHFFU	0	0
47				
48		Total prop. held for future use	(135)	3,790
49				
50				
51				
52		ACQUISITION ADJUSTMENT		
53	4	SCHERER ACQUISITION ADJUSTMENT	(2,317)	
54				
55		Total acquisition adjustment	(2,317)	0
56				
57				
58		Net utility plant	(52,876)	788,975
59				
60				
61		WORKING CAPITAL		
62	16	UNIT POWER SALES	0	
63	18	PREPAID PENSIONS	0	
64	19	RATE CASE EXPENSES	(765)	
65	20	FUEL/CONSERVATION	0	
		OVERRECOVERIES	0	
66	21	TEMPORARY CASH INVESTMENTS	(576)	
67	22	HEAVY OIL INVENTORY	(123)	
68	23	LIGHT OIL INVENTORY	(6,017)	
69	24	COAL INVENTORY	0	
70	25	PLANT DANIEL	(2,187)	
71	27	PLANT SCHERER	0	
72	28	CANCELED SCS BUILDING	0	
73	31	OTHER INVESTMENTS	0	
74	32	OTHER ACCOUNTS RECEIVABLE	0	
75	33	MATERIALS & SUPPLIES	0	
76	34	OTHER CURR. ASSETS & MISC. DEF. DEBITS	0	
77	35	CARYVILLE SUBSURFACE STUDY	(28)	
78	36	EXPENSE ADJUSTMENTS	169	
79				
80				
81		Total working capital	(9,527)	72,184
82				
83				
84		TOTAL RATE BASE	(62,403)	861,159

[*115]

ATTACHMENT 2

13-Month Average Capital Structure

Test Year Ending 12/31/90

COMMISSION VOTE	LONG TERM DEBT	LONG TERM NOTE	SHORT TERM DEBT	PREFERRED STOCK
Company Per Book	439,734	42,089	4,432	67,432

Company Adjustments (Specific)	(98,837)	(42,089)		(10,278)
Subtotal	340,897	0	4,432	57,154
Commission Adjustments (Specific)	7,282	0	0	169
Subtotal	348,179	0	4,432	57,323
Prorata (Other Sources) n1	(23,159)	0	(295)	(3,813)
Subtotal	325,020	0	4,137	53,510
Prorata Adjustments	(13,070)	0	(166)	(2,152)
TOTAL	311,950	0	3,971	51,358
Ratio	36.22%	0.00%	0.46%	5.96%
Cost Rate	8.72%	0.00%	8.00%	7.75%
Weighted Cost	3.16%	0.00%	0.04%	0.46%
50 basis pt reduction to equity	8.72%	0.00%	8.00%	7.75%
Weighted Cost With Reduction	3.16%	0.00%	0.04%	0.46%

COMMISSION VOTE

	COMMON EQUITY	CUSTOMER DEPOSITS	DEFERRED TAXES	ITC's Zero Cost
Company Per Book	367,404	15,775	203,823	858
Company Adjustments (Specific)	(63,994)		(14,785)	
Subtotal	303,410	15,775	189,038	858
Commission Adjustments (Specific)	(7,793)	0	(5,877)	0
Subtotal	295,617	15,775	183,161	858
Prorata (Other Sources) n1	(19,663)	(1,049)	0	0
Subtotal	275,954	14,726	183,161	858
Prorata Adjustments	(11,097)	(592)	(7,365)	(35)
TOTAL	264,857	14,134	175,796	823
Ratio	30.76%	1.64%	20.41%	0.10%
Cost Rate	12.55%	7.65%	0.00%	0.00%
Weighted Cost	3.86%	0.13%	0.00%	0.00%
50 basis pt reduction to equity	12.05%	7.65%	0.00%	0.00%
Weighted Cost With Reduction	3.71%	0.13%	0.00%	0.00%

[*116]

COMMISSION VOTE

	ITC's Wtd. Cost	TOTAL
Company Per Book	48,068	1,189,615
Company Adjustments (Specific)	(5,793)	(235,776)
Subtotal	42,275	953,839
Commission Adjustments (Specific)	(2,402)	(8,621)
Subtotal	39,873	945,218
Prorata (Other Sources) n1	0	(47,979)
Subtotal	39,873	897,239
Prorata Adjustments	(1,603)	(36,080)
TOTAL	38,270	861,159
Ratio	4.44%	100.00%
Cost Rate	10.26%	
Weighted Cost	0.46%	8.10%
50 basis pt reduction to equity	10.04%	
Weighted Cost With Reduction	0.45%	7.94%

n1 Deferred taxes and ITCs have been specifically identified for these items.

Calculation of JDIC Rate

Capital Components	Adjusted Amount	Ratio	Cost Rate	Wtd. Cost
Common Equity	264,857	42.16%	12.55%	5.29%
Preferred Stock	51,358	8.18%	7.75%	0.63%
Long-Term Debt	311,950	49.66%	8.72%	4.33%
Total	628,166	100.00%		10.26%

Calculation of JDIC Rate with 50 basis pt reduction on the equity cost rate.

Capital Components	Adjusted Amount	Ratio	Cost Rate	Wtd. Cost
Common Equity	264,857	42.16%	12.05%	5.08%
Preferred Stock	51,358	8.18%	7.75%	0.63%
Long-Term Debt	311,950	49.66%	8.72%	4.33%
Total	628,166	100.00%		10.04%

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ATTACHMENT 3

SCHEDULE 3

COMPARATIVE NET OPERATING INCOME

				COMPANY FILING	
LINE NO.	CO. ADJ. NO.	ISSUE NO.	DESCRIPTION	SYSTEM PER BOOKS	JURISDICTIONAL PER BOOKS
1			REVENUE FROM SALES OF ELECTRICITY		249,813
2		48	PXT / STANDBY RATES		
3		49	NON-UTILITY ELECTRIC BILLINGS		
4					
5			Total sales of electricity	0	249,813
6					
7					
8			OTHER OPERATING REVENUES		5,767
9		6	CARYVILLE SOD FARM		
10		47	APPLIANCE DIVISION - USE OF LOGO		
11					
12			Total other operating revenues	0	5,767
13					
14					
15			Total operating revenues	0	255,580
16					
17					
18			OPERATING EXPENSES:		
19			OPERATION & MAINTENANCE		113,382
20		7	NAVY HOUSE		
21		27	PLANT SCHERER - NET OF IIC OFFSET		
22		29	REBUILDS & RENOVATIONS		
23		30	NETWORK PROTECTORS		
24		35	CARYVILLE SUBSURFACE STUDY		
25		50	SALARIES & BENEFITS		
26		51	BAD DEBT EXPENSE		
27		52	FUEL REVENUE & EXPENSES		

28	53	CONSERVATION REVENUE & EXPENSES
29	54	OUT-OF-PERIOD, NON-RECURRING, etc.
30	55	INDUSTRY ASSOCIATION DUES
31	56	CURRENT RATE CASE EXPENSES
32	57	881167-EI RATE CASE EXPENSES
33	58	BANK FEES & LINES OF CREDIT
34	59	OUTSIDE SERVICES
35	60	CUSTOMER ACCOUNTS
36	61	COGENERATION & INDUSTRIAL PROGRAMS
37	62	GOOD CENTS INCENTIVE PROGRAM
38	63	GOOD CENTS IMPROVED & NEW HOME PROGRAMS
39	64	ESSENTIAL CUSTOMER SERVICE PROGRAM
40	65	ENERGY EDUCATION PROGRAM
41	66	PRESENTATION / SEMINARS PROGRAM
42	67	SHINE AGAINST CRIME
43	68	ECONOMIC DEVELOPMENT
44	69	PRODUCTION RELATED A&G
45	70	OTHER A&G
46	71	LOBBYING EXPENSES
47	73	SCS EXPENSES
48	74	IRS, GRAND JURY, etc.
49	75	PENSION EXPENSE
50	76	STEAM PRODUCTION PERSONNEL
51	77	RESEARCH & DEVELOPMENT PROJECTS
52	78	EPRI / SCS DOUBLE COUNTING
53	79	PLANT DANIEL ASH HAULING
54	80	TRANSMISSION RENTS
55	81	PUBLIC SAFETY INSPECTION & MAINT.
56	86	EMPLOYEE RELATIONS PLANNING UNIT
57	87	LABOR COMPLEMENT VACANCIES
58	88	TURBINE & BOILER INSPECTIONS
59	89	PLANT DANIEL
60	90	1989 UNCOLLECTIBLES CREDIT
61	91	EMPLOYEE SAVINGS PLAN
62	92	PRODUCTIVITY IMPROVEMENT PLAN
63	93	PERFORMANCE PAY PLAN
64	94	EPRI NUCLEAR RESEARCH
65	95	PLANT SMITH ASH HAULING
66	96	EMPLOYEE RELOCATION & DEVELOPMENT PROGRAMS
67	97	OBSOLETE MATERIAL
68	98	MANAGEMENT PERKS
69	99	DUCT & FAN REPAIRS
70	100	CUSTOMER SERVICES &

		INFORMATION				
71	101	MARKETING EXPENSES				
72	102	O&M BENCHMARK				
73						
74						
75						
76						
77		Total operation & maintenance		0		113,382
78						
79						
80		DEPRECIATION AND AMORTIZATION			47,701	
81	3	SCHERER TAX ADDER ADJUSTMENT				
82	4	SCHERER ACQUISITION ADJUSTMENT				
83	5	NEW CORPORATE HEADQUARTERS				
84	8	APPLIANCE DIVISION				
85	9	TALLAHASSEE OFFICE				
86	12	LEISURE LAKES				
87	27	PLANT SCHERER				
88	82	REASONABLENESS				
89						
90		Total depreciation and amortization		0		47,701
91						
98		TAXES OTHER THAN INCOME			20,822	
99	27	PLANT SCHERER				
100	48	PXT / STANDBY RATES				
101	83	REASONABLENESS				
102	87	LABOR COMPLEMENT VACANCIES				
103						
104						
105		Total taxes other than income		0		20,822
106						
107						
108		INCOME TAXES CURRENTLY PAYABLE	0		13,185	
109	84	REASONABLENESS				
110	85	Interest expense reconciliation				
111	N/A	Effect of other adjustments				
112						
113		Total income taxes - current		0		13,185
114						
115						
116		DEFERRED INCOME TAXES (NET)	0		1,621	
117	N/A	EFFECT OF ADJS. TO DEPRECIATION				
118	27	PLANT SCHERER				
119						
120						
121						
122						
123		Total deferred income taxes (net)		0		1,621
124						
125						
126						

127			INVESTMENT TAX CREDIT (NET)		(2,041)	
128		27	PLANT SCHERER			
129						
130						
131			Total investment tax credit (net)		0	(2,041)
132						
133						
134			(GAIN)/LOSS ON SALE		0	
135						
136						
137			Total (gain)/loss on sale		0	0
138						
139						
140			TOTAL OPERATING EXPENSES	0	194,670	
141						
142						
143			NET OPERATING INCOME	0	60,910	
144						

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				COMPANY FILING	
LINE NO.	CO. ADJ. NO.	ISSUE NO.	DESCRIPTION	ADJUSTMENTS	JURISDICTIONAL ADJUSTED
1			REVENUE FROM SALES OF ELECTRICITY		
2		48	PXT / STANDBY RATES		
3		49	NON-UTILITY ELECTRIC BILLINGS		
4					
5			Total sales of electricity	0	249,813
6					
7					
8			OTHER OPERATING REVENUES		
9		6	CARYVILLE SOD FARM		
10		47	APPLIANCE DIVISION - USE OF LOGO		
11					
12			Total other operating revenues	0	5,767
13					
14					
15			Total operating revenues	0	255,580
16					
17					
18			OPERATING EXPENSES:		
19			OPERATION & MAINTENANCE		
20		7	NAVY HOUSE		
21		27	PLANT SCHERER - NET OF IIC OFFSET		
22		29	REBUILDS & RENOVATIONS		
23		30	NETWORK PROTECTORS		
24		35	CARYVILLE SUBSURFACE STUDY		
25		50	SALARIES & BENEFITS		
26		51	BAD DEBT EXPENSE		
27		52	FUEL REVENUE & EXPENSES		

28	53	CONSERVATION REVENUE & EXPENSES
29	54	OUT-OF-PERIOD, NON-RECURRING, etc.
30	55	INDUSTRY ASSOCIATION DUES
31	56	CURRENT RATE CASE EXPENSES
32	57	881167-EI RATE CASE EXPENSES
33	58	BANK FEES & LINES OF CREDIT
34	59	OUTSIDE SERVICES
35	60	CUSTOMER ACCOUNTS
36	61	COGENERATION & INDUSTRIAL PROGRAMS
37	62	GOOD CENTS INCENTIVE PROGRAM
38	63	GOOD CENTS IMPROVED & NEW HOME PROGRAMS
39	64	ESSENTIAL CUSTOMER SERVICE PROGRAM
40	65	ENERGY EDUCATION PROGRAM
41	66	PRESENTATION / SEMINARS PROGRAM
42	67	SHINE AGAINST CRIME
43	68	ECONOMIC DEVELOPMENT
44	69	PRODUCTION RELATED A&G
45	70	OTHER A&G
46	71	LOBBYING EXPENSES
47	73	SCS EXPENSES
48	74	IRS, GRAND JURY, etc.
49	75	PENSION EXPENSE
50	76	STEAM PRODUCTION PERSONNEL
51	77	RESEARCH & DEVELOPMENT PROJECTS
52	78	EPRI / SCS DOUBLE COUNTING
53	79	PLANT DANIEL ASH HAULING
54	80	TRANSMISSION RENTS
55	81	PUBLIC SAFETY INSPECTION & MAINT.
56	86	EMPLOYEE RELATIONS PLANNING UNIT
57	87	LABOR COMPLEMENT VACANCIES
58	88	TURBINE & BOILER INSPECTIONS
59	89	PLANT DANIEL
60	90	1989 UNCOLLECTIBLES CREDIT
61	91	EMPLOYEE SAVINGS PLAN
62	92	PRODUCTIVITY IMPROVEMENT PLAN
63	93	PERFORMANCE PAY PLAN
64	94	EPRI NUCLEAR RESEARCH
65	95	PLANT SMITH ASH HAULING
66	96	EMPLOYEE RELOCATION & DEVELOPMENT PROGRAMS
67	97	OBSOLETE MATERIAL
68	98	MANAGEMENT PERKS
69	99	DUCT & FAN REPAIRS
70	100	CUSTOMER SERVICES &

		INFORMATION		
71	101	MARKETING EXPENSES		
72	102	O&M BENCHMARK		
73				
74				
75				
76				
77		Total operation & maintenance	0	113,382
78				
79				
80		DEPRECIATION AND AMORTIZATION		
81	3	SCHERER TAX ADDER ADJUSTMENT		
82	4	SCHERER ACQUISITION ADJUSTMENT		
83	5	NEW CORPORATE HEADQUARTERS		
84	8	APPLIANCE DIVISION		
85	9	TALLAHASSEE OFFICE		
86	12	LEISURE LAKES		
87	27	PLANT SCHERER		
88	82	REASONABLENESS		
89				
90		Total depreciation and amortization	0	47,701
91				
98		TAXES OTHER THAN INCOME		
99	27	PLANT SCHERER		
100	48	PXT / STANDBY RATES		
101	83	REASONABLENESS		
102	87	LABOR COMPLEMENT VACANCIES		
103				
104				
105		Total taxes other than income	0	20,822
106				
107				
108		INCOME TAXES CURRENTLY PAYABLE		
109	84	REASONABLENESS		
110	85	Interest expense reconciliation		
111	N/A	Effect of other adjustments		
112				
113		Total income taxes - current	0	13,185
114				
115				
116		DEFERRED INCOME TAXES (NET)		
117	N/A	EFFECT OF ADJS. TO DEPRECIATION		
118	27	PLANT SCHERER		
119				
120				
121				
122				
123		Total deferred income taxes (net)	0	1,621
124				
125				
126				

LINE NO.	CO. ADJ. NO.	ISSUE NO.	DESCRIPTION	ADJUSTMENTS	JURISDICTIONAL ADJUSTED
127			INVESTMENT TAX CREDIT (NET)		
128		27	PLANT SCHERER		
129					
130					
131			Total investment tax credit (net)	0	(2,041)
132					
133					
134			(GAIN)/LOSS ON SALE		
135					
136					
137			Total (gain)/loss on sale	0	0
138					
139					
140			TOTAL OPERATING EXPENSES	0	194,670
141					
142					
143			NET OPERATING INCOME	0	60,910
144					

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COMMISSION VOTE

LINE NO.	CO. ADJ. NO.	ISSUE NO.	DESCRIPTION	ADJUSTMENTS	JURISDICTIONAL ADJUSTED
1			REVENUE FROM SALES OF ELECTRICITY		
2		48	PXT / STANDBY RATES	16	
3		49	NON-UTILITY ELECTRIC BILLINGS	95	
4					
5			Total sales of electricity	111	249,924
6					
7					
8			OTHER OPERATING REVENUES		
9		6	CARYVILLE SOD FARM	(3)	
10		47	APPLIANCE DIVISION - USE OF LOGO	0	
11					
12			Total other operating revenues	(3)	5,764
13					
14					
15			Total operating revenues	108	255,688
16					
17					
18			OPERATING EXPENSES:		
19			OPERATION & MAINTENANCE		
20		7	NAVY HOUSE	(8)	
21		27	PLANT SCHERER - NET OF IIC OFFSET	4,070	
22		29	REBUILDS & RENOVATIONS	0	
23		30	NETWORK PROTECTORS	0	
24		35	CARYVILLE SUBSURFACE STUDY	57	
25		50	SALARIES & BENEFITS	0	
26		51	BAD DEBT EXPENSE	0	
27		52	FUEL REVENUE & EXPENSES	0	

28	53	CONSERVATION REVENUE & EXPENSES	0
29	54	OUT-OF-PERIOD, NON-RECURRING, etc.	(190)
30	55	INDUSTRY ASSOCIATION DUES	(20)
31	56	CURRENT RATE CASE EXPENSES	(250)
32	57	881167-EI RATE CASE EXPENSES	0
33	58	BANK FEES & LINES OF CREDIT	0
34	59	OUTSIDE SERVICES	0
35	60	CUSTOMER ACCOUNTS	0
36	61	COGENERATION & INDUSTRIAL PROGRAMS	(426)
37	62	GOOD CENTS INCENTIVE PROGRAM	(50)
38	63	GOOD CENTS IMPROVED & NEW HOME PROGRAMS	0
39	64	ESSENTIAL CUSTOMER SERVICE PROGRAM	0
40	65	ENERGY EDUCATION PROGRAM	0
41	66	PRESENTATION / SEMINARS PROGRAM	(55)
42	67	SHINE AGAINST CRIME	(92)
43	68	ECONOMIC DEVELOPMENT	(687)
44	69	PRODUCTION RELATED A&G	0
45	70	OTHER A&G	0
46	71	LOBBYING EXPENSES	(264)
47	73	SCS EXPENSES	0
48	74	IRS, GRAND JURY, etc.	(5)
49	75	PENSION EXPENSE	0
50	76	STEAM PRODUCTION PERSONNEL	0
51	77	RESEARCH & DEVELOPMENT PROJECTS	(32)
52	78	EPRI / SCS DOUBLE COUNTING	0
53	79	PLANT DANIEL ASH HAULING	0
54	80	TRANSMISSION RENTS	(423)
55	81	PUBLIC SAFETY INSPECTION & MAINT.	0
56	86	EMPLOYEE RELATIONS PLANNING UNIT	0
57	87	LABOR COMPLEMENT VACANCIES	(403)
58	88	TURBINE & BOILER INSPECTIONS	0
59	89	PLANT DANIEL	0
60	90	1989 UNCOLLECTIBLES CREDIT	0
61	91	EMPLOYEE SAVINGS PLAN	0
62	92	PRODUCTIVITY IMPROVEMENT PLAN	(339)
63	93	PERFORMANCE PAY PLAN	0
64	94	EPRI NUCLEAR RESEARCH	0
65	95	PLANT SMITH ASH HAULING	0
66	96	EMPLOYEE RELOCATION & DEVELOPMENT PROGRAMS	(56)
67	97	OBSOLETE MATERIAL	0
68	98	MANAGEMENT PERKS	(65)
69	99	DUCT & FAN REPAIRS	0
70	100	CUSTOMER SERVICES &	

		INFORMATION	0	
71	101	MARKETING EXPENSES	0	
72	102	O&M BENCHMARK	0	
73				
74				
75				
76				
77		Total operation & maintenance	762	114,144
78				
79				
80		DEPRECIATION AND AMORTIZATION		
81	3	SCHERER TAX ADDER ADJUSTMENT	0	
82	4	SCHERER ACQUISITION ADJUSTMENT	0	
83	5	NEW CORPORATE HEADQUARTERS	(101)	
84	8	APPLIANCE DIVISION	(12)	
85	9	TALLAHASSEE OFFICE	(1)	
86	12	LEISURE LAKES	(5)	
87	27	PLANT SCHERER	(1,774)	
88	82	REASONABLENESS	0	
89				
90		Total depreciation and amortization	(1,893)	45,808
91				
98		TAXES OTHER THAN INCOME		
99	27	PLANT SCHERER	(245)	
100	48	PXT / STANDBY RATES	1	
101	83	REASONABLENESS	0	
102	87	LABOR COMPLEMENT VACANCIES	(30)	
103				
104				
105		Total taxes other than income	(274)	20,548
106				
107				
108		INCOME TAXES CURRENTLY PAYABLE		
109	84	REASONABLENESS	0	
110	85	Interest expense reconciliation	672	
111	N/A	Effect of other adjustments	(143)	
112				
113		Total income taxes - current	529	13,714
114				
115				
116		DEFERRED INCOME TAXES (NET)		
117	N/A	EFFECT OF ADJS. TO DEPRECIATION	45	
118	27	PLANT SCHERER	668	
119				
120				
121				
122				
123		Total deferred income taxes (net)	712	2,333
124				
125				
126				

127		INVESTMENT TAX CREDIT (NET)				
128	27	PLANT SCHERER		96		
129						
130						
131		Total investment tax credit (net)		96		(1,945)
132						
133						
134		(GAIN)/LOSS ON SALE				
135						
136						
137		Total (gain)/loss on sale		0		0
138						
139						
140		TOTAL OPERATING EXPENSES	(67)		194,603	
141						
142						
143		NET OPERATING INCOME	175		61,085	
144						

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ATTACHMENT 4

AUGUST 10, 1990

APPROVED REVENUE INCREASE BY CLASS

BASED ON COMPANY'S 12 CP AND 1/13TH COST OF SERVICE STUDY

SUMMARY OF CLASS ROR'S AND % INCREASE (000 DOLLARS)

(1) RATE CODE	(2) APPROVED RATE BASE	(3) APPROVED PRES.NOI	(4) PRESENT ROR/ INDEX	(5) INCREASE FROM SERVICE CHARGES	(6) INCREASE FROM SALES OF ELECTRICITY	(7) TOTAL INCREASE IN REVENUE
RS	$ 475,918	$ 29,345	6.17% / 0.87	$ 47	$ 8,652	$ 8,699
GS	$ 33,448	$ 4,835	14.46% / 2.04	$ 47	($ 1,655)	($ 1,608)
RS-GS	$ 509,366	$ 34,180	6.71% / 0.95	$ 94	$ 6,997	$ 7,091
GSD	$ 176,009	$ 13,846	7.87% / 1.11	$ 1	$ 1,817	$ 1,818
LP/LPT	$ 104,427	$ 7,435	7.12% / 1.00	$ 0	$ 2,351	$ 2,351
PX/PXT	$ 54,208	$ 4,363	8.05% / 1.13	$ 0	$ 395	$ 395
OSI-II	$ 13,431	$ 872	6.49% / 0.92	$ 0	$ 202	$ 202
OS-III	$ 613	$ 143	23.33% / 3.29	$ 0	($ 48)	($ 48)
SS	$ 3,105	$ 246	7.92% / 1.12	$ 0	$ 29	$ 29
TOT.RET	$ 861,159	$ 61,085	7.09% / 1.00	$ 95	$ 11,743	$ 11,838

(1) RATE CODE	(8) REQUIRED NOI	(9) RECOMMENDED ROR/ INDEX	(10) % INCREASE IN REV FROM SALES OF ELEC W/ADJ	BASE
RS	$ 34,676	7.29% / 0.92	4.19%	6.58%
GS	$ 3,850	11.51% / 1.45	-8.39%	-11.04%
RS-GS	$ 38,526	7.56% / 0.95	3.10%	4.77%
GSD	$ 14,960	8.50% / 1.07	2.00%	3.50%

LP/LPT	$ 8,876	8.50% / 1.07	3.91%	8.06%
PX/PXT	$ 4,605	8.50% / 1.07	1.03%	2.41%
OSI-II	$ 996	7.42% / 0.93	4.19%	5.38%
OS-III	$ 114	18.60% / 2.34	-9.58%	-14.29%
SS	$ 264	8.50% / 1.07	3.30%	3.68%
TOT.RET	$ 68,340	7.94% / 1.00	2.79%	4.72%

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ATTACHMENT 5

PROPOSED RATES FOR GULF POWER COMPANY

	CURRENT RATES	COMPANY PROPOSED
INCREASE IN REVENUES		$ 26,137,000
RATE CLASS		
RESIDENTIAL		
CUSTOMER CHARGE	$ 6.25	$ 8.00
ENERGY		
Oct - May	$ 0.03148	$ 0.03489
June - Sept	$ 0.03716	$ 0.04114
NON SEASONAL		
RESIDENTIAL TOU		
CUSTOMER CHARGE	$ 9.25	$ 11.00
ENERGY		
ON PEAK	$ 0.07797	$ 0.08623
OFF PEAK	$ 0.01378	$ 0.01608
GENERAL SERVICE		
CUSTOMER CHARGE	$ 7.00	$ 10.00
ENERGY		
Oct - May	$ 0.06174	$ 0.05441
June - Sept	$ 0.06348	$ 0.06423
NON SEASONAL		
GENERAL SERVICE TOU		
CUSTOMER	$ 10.00	$ 13.00
ENERGY		
ON PEAK	$ 0.14727	$ 0.14324
OFF PEAK	$ 0.02296	$ 0.02188
GS-DEMAND		
CUSTOMER CHARGE	$ 27.00	$ 40.00
KW DEMAND	$ 6.25	$ 4.52
ENERGY	$ 0.00641	$ 0.01424
GS DEMAND TOU		
CUSTOMER	$ 32.40	$ 45.40
KW DEMAND		
MAXIMUM	$ 2.96	$ 2.17
ON PEAK	$ 3.42	$ 2.44

ENERGY		
ON PEAK	$ 0.01395	$ 0.03269
OFF PEAK	$ 0.00302	$ 0.00692
LP		
CUSTOMER CHARGE	$ 51.00	$ 225.00
KW DEMAND	$ 6.25	$ 8.52
SE MAXIMUM CHARGE		
ENERGY	$ 0.00861	$ 0.00568
LP TOU		
CUSTOMER CHARGE	$ 51.00	$ 225.00
KW DEMAND		
MAXIMUM	$ 2.97	$ 4.15
ON PEAK	$ 3.35	$ 4.52
ENERGY		
ON PEAK	$ 0.01928	$ 0.01211
OFF PEAK	$ 0.00390	$ 0.00300
PX		
CUSTOMER CHARGE	$ 146.00	$ 570.00
KW DEMAND	$ 7.50	$ 8.25
SE MAXIMUM CHARGE		
ENERGY	$ 0.00521	$ 0.00445
PX TOU		
CUSTOMER CHARGE	$ 146.00	$ 570.00
KW DEMAND		
MAXIMUM	$ 3.56	$ 3.97
ON PEAK	$ 3.99	$ 4.32
ENERGY		
ON PEAK	$ 0.01299	$ 0.00984
OFF PEAK	$ 0.00242	$ 0.00262

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	COMMISSION VOTE	AFTER EXPIRATION OF MANAGEMENT PENALTY
INCREASE IN REVENUES	$ 11,838,000	
RATE CLASS		
RESIDENTIAL		
CUSTOMER CHARGE	$ 8.00	$ 8.07
ENERGY		
Oct - May		
June - Sept		
NON SEASONAL	$ 0.03487	$ 0.03518
RESIDENTIAL TOU		
CUSTOMER CHARGE	$ 11.00	$ 11.10
ENERGY		
ON PEAK	$ 0.10218	$ 0.10308
OFF PEAK	$ 0.00529	$ 0.00534

GENERAL SERVICE		
CUSTOMER CHARGE	$ 10.00	$ 10.09
ENERGY		
Oct - May		
June - Sept		
NON SEASONAL	$ 0.05086	$ 0.05131
GENERAL SERVICE TOU		
CUSTOMER	$ 13.00	$ 13.11
ENERGY		
ON PEAK	$ 0.15711	$ 0.15849
OFF PEAK	$ 0.00511	$ 0.00515
GS-DEMAND		
CUSTOMER CHARGE	$ 40.00	$ 40.35
KW DEMAND	$ 4.52	$ 4.56
ENERGY	$ 0.01289	$ 0.01300
GS DEMAND TOU		
CUSTOMER	$ 45.40	$ 45.80
KW DEMAND		
MAXIMUM	$ 2.15	$ 2.17
ON PEAK	$ 4.97	$ 5.01
ENERGY		
ON PEAK	$ 0.00445	$ 0.00449
OFF PEAK	$ 0.00445	$ 0.00449
LP		
CUSTOMER CHARGE	$ 225.00	$ 226.98
KW DEMAND	$ 8.50	$ 8.57
SE MAXIMUM CHARGE	$ 1.81	$ 1.83
ENERGY	$ 0.00528	$ 0.00533
LP TOU		
CUSTOMER CHARGE	$ 225.00	$ 226.98
KW DEMAND		
MAXIMUM	$ 1.81	$ 1.83
ON PEAK	$ 7.21	$ 7.27
ENERGY		
ON PEAK	$ 0.00417	$ 0.00421
OFF PEAK	$ 0.00417	$ 0.00421
PX		
CUSTOMER CHARGE	$ 570.00	$ 575.01
KW DEMAND	$ 8.25	$ 8.32
SE MAXIMUM CHARGE	$ 0.68	$ 0.69
ENERGY	$ 0.00409	$ 0.00413
PX TOU		
CUSTOMER CHARGE	$ 570.00	$ 575.01
KW DEMAND		
MAXIMUM	$ 0.68	$ 0.69

ON PEAK	$ 7.66	$ 7.73
ENERGY		
ON PEAK	$ 0.00406	$ 0.00410
OFF PEAK	$ 0.00406	$ 0.00410

[*123]

ATTACHMENT 6

APPROVED STREET AND OUTDOOR LIGHTING RATES

TYPE OF FACILITY	FIXTURE CHARGE	MAINTENANCE CHARGE	ENERGY CHARGE	TOTAL MONTHLY CHARGE
HIGH PRESSURE SODIUM (OS-I)				
5,400 LUMEN	$ 1.95	$ 1.34	$ 0.74	$ 4.03
8,800 LUMEN	$ 1.96	$ 1.06	$ 1.05	$ 4.07
20,000 LUMEN	$ 2.26	$ 1.56	$ 2.13	$ 5.95
25,000 LUMEN	$ 2.81	$ 2.03	$ 2.68	$ 7.52
46,000 LUMEN	$ 3.17	$ 1.61	$ 4.24	$ 9.02
20,000 LUMEN *	$ 4.31	$ 1.79	$ 2.13	$ 8.23
46,000 LUMEN **	$ 9.09	$ 2.00	$ 4.24	$ 15.33
20,000 LUMEN **	$ 10.79	$ 1.79	$ 2.13	$ 14.71
8,800 LUMEN ***	$ 6.14	$ 1.56	$ 1.05	$ 8.75
MERCURY VAPOR (OS-I)				
3,200 LUMEN	$ 1.44	$ 1.40	$ 1.03	$ 3.87
7,000 LUMEN	$ 1.43	$ 1.04	$ 1.76	$ 4.23
9,400 LUMEN	$ 1.91	$ 1.66	$ 2.50	$ 6.07
17,000 LUMEN	$ 2.22	$ 1.73	$ 4.00	$ 7.95
48,000 LUMEN	$ 6.03	$ 3.16	$ 9.79	$ 18.98
HIGH PRESSURE SODIUM (OS-II)				
5,400 LUMEN	$ 1.95	$ 0.84	$ 0.74	$ 3.53
8,800 LUMEN	$ 1.75	$ 0.79	$ 1.05	$ 3.59
20,000 LUMEN	$ 2.26	$ 1.05	$ 2.13	$ 5.44
25,000 LUMEN	$ 2.80	$ 1.50	$ 2.68	$ 6.98
46,000 LUMEN	$ 3.17	$ 1.10	$ 4.24	$ 8.51
20,000 LUMEN #	$ 4.27	$ 1.92	$ 2.21	$ 8.40
46,000 LUMEN #	$ 3.81	$ 1.79	$ 4.39	$ 9.99
8,800 LUMEN ***	$ 6.15	$ 0.76	$ 1.05	$ 7.96
MERCURY VAPOR (OS-II)				
7,000 LUMEN	$ 1.41	$ 0.65	$ 1.76	$ 3.82
17,000 LUMEN	$ 2.21	$ 1.29	$ 4.00	$ 7.50
17,000 LUMEN #	$ 4.11	$ 1.84	$ 4.29	$ 10.24

[*124]

* NEW OFFERING, DIRECTIONAL, COASTAL

** NEW OFFERING, DIRECTIONAL

*** NEW OFFERING, DECORATIVE

DIRECTIONAL

APPROVED STREET AND OUTDOOR LIGHTING RATES

ENERGY RATES ($ PER KWH)

RATE CLASS	RATE
OS-I AND OS-II	$ 0.02631
OS-III	$ 0.03751
OS-IV	$ 0.03711
OS-IV CUSTOMER CHARGE:	$ 10.00
ADDITIONAL FACILITIES CHARGES	
30-FOOT WOOD POLE	$ 2.00
30-FOOT CONCRETE POLE	$ 4.50

DISSENTBY: BEARD; WILSON; EASLEY; GUNTER

DISSENTING VOTES

Commissioner Beard dissented as follows:

1) From the Commission's allowance of the total cost of Gulf's Bonifay and Graceville Offices in rate base.

2) From the Commission's allowance of 90% of the Caryville site as land held for future use. Commissioner Beard would have disallowed the amount budgeted for the Caryville site because there are no plans to use the site for 20 years.

3) From the Commission's approval of $ 457,390 for the Good Cents Improved and $ 1,023,995 for the Good Cents New Home Programs. Commissioner Beard would have disallowed these expenses as an unnecessary cost to ratepayers to assure compliance with the state building code.

4) I respectfully dissent from the majority opinion on the mismanagement issue. My disagreement [*125] stems from a different interpretation of evidence before the Commission. This interpretation results in my belief that the reduction to the return on equity should have been greater than fifty basis points. I would reduce the return on equity to 11.75%, the minimum amount necessary for Gulf Power Company to achieve a fair rate of return according to the record.

At page 19, the majority states that there is no record evidence to indicate that the president of Gulf Power knew that illegal or unethical conduct was taking place as it happened. (Emphasis in original) The Order then goes into various incidents from 1983 through 1988 involving the president and Mr. Jacob Horton, Executive Vice President of Gulf Power. There is no need to recount those incidents again here. Suffice to say that in this case repeated instances of unethical/illegal activity over the years by a close business associate give rise to knowledge in my view. This is particularly true in light of the warnings Mr. McCrary had received concerning Mr. Horton's mode of operation and the repeated warnings given by Mr. McCrary to Mr. Horton. I also have serious reservations concerning disparate disciplinary treatment [*126] between executives and lower-level employees. See majority opinion at pages 23-24.

The unfortunate pattern of conduct present in this case should not be analyzed in terms of legal abstractions, but rather how a utility conducts its business in the real world. In my mind, the proper analysis holds Gulf Power management responsible for the activities here and then reduces the return on equity in conformity with that responsibility. I would set the return on equity at 11.75%.

Commissioner Wilson dissented as follows:

1) From the Commission's approval of Gulf's 1990 material and supply level. Commissioner Wilson would leave materials and supplies at the 1989 level.

2) From the Commission's approval of a 12.55% return on equity. Commissioner Wilson favored a 12.8% ROE.

3) From the Commission's reduction of the GS class to 1.45 times parity. Commissioner Wilson favored a greater reduction.

4) From the Commission's vote to eliminate seasonal rates for the RS and GS rate classes. Commissioner Wilson favored retaining seasonal rates.

Commissioner Easley dissented as follows:

1) From the Commission's vote setting the coal inventory as the lesser of 90 days burn or the [*127] amount maintained at the plant.

2) From the Commission's classification of fuel stock as energy-related. Commissioner Easley would classify fuel stocks as demand-related.

Commissioner Gunter dissented as follows:

1) From the Commission's disallowance of $ 31,813 for acid rain research.