BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In Re: Application for a rate increase by Tampa Electric Company.	DOCKET NO. 920324-EI ORDER NO. PSC-93-0165-FOF-EI ISSUED: 02/02/93

The following Commissioners participated in the disposition of this matter:

J. TERRY DEASON, Chairman
BETTY EASLEY
LUIS J. LAUREDO

Pursuant to duly given notice, the Florida Public Service Commission held public hearings in this docket on September 30, 1992, in Tallahassee, Florida; on October 7, 1992 in Tampa, Florida; and October 12 through 19, 1992 in Tallahassee, Florida. Having considered the record herein, the Commission now enters its final order.

APPEARANCES:

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On behalf of the Citizens of the State of Florida.

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On behalf of Florida Industrial Power Users Group.

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On behalf of Legal Environmental Assistance Foundation/John Ryan.

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On behalf of City of Tampa.

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On behalf of the Commissioners.

ORDER GRANTING CERTAIN INCREASES

CASE BACKGROUND

On May 22, 1992, Tampa Electric Company (TECO or Tampa Electric or the company or the utility) filed a Petition for an increase in its rates and charges and approval of a fair and reasonable rate of return. The petition seeks a permanent increase in TECO's rates and charges pursuant to Section 366.06, Florida Statutes. The petition cites the costs associated with building and maintaining an adequate and reliable production, transmission and distribution system; the cost of serving over 106,000 new customers expected to take service by 1993 as compared to 1984 (the test year in the company's last rate proceeding); and the effects of a 41% expected increase in inflation from the end of 1984 through 1993 as factors creating the need for higher rates.

The increases requested total 63.5 million dollars in 1993 and a step increase in 1994 of 34.4 million dollars. The company seeks a Commission determination that a 13.75% return on equity and a 9.22% overall rate of return is fair and reasonable for Tampa Electric Company. Tampa Electric Company filed new tariff schedules reflecting the proposed increases. The company did not seek an interim increase.

By Order No. PSC-92-0596-FOF-EI issued July 1, 1992, the Commission voted to suspend the permanent increase pending review. A prehearing conference was held on September 30, 1992 in Tallahassee, Florida. A customer service hearing was held on October 7, 1992 in Tampa, Florida. The final hearing was held on October 12-16, 1992 in Tallahassee, Florida.

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I. SUMMARY OF DECISION

We authorize an increase to Tampa Electric Company's annual revenues of $1,163,000 beginning February 4, 1993; an additional $17,412,000 increase beginning January, 1994; for a total increase of $18,575,000. The 1994 rate changes shall become effective with the first billing cycle of that month.

We have set the rate of return on common equity capital at 12%.

We establish an interim incentive to encourage Tampa Electric Company to maximize off-system sales of surplus capacity. We find that TECO should not be rewarded or penalized for its performance in the areas of residential rates, customer service and energy conservation.

II. TEST PERIOD

A. Test Year

The purpose of the test year is to represent the financial operations of a company during the period in which the new rates will be in effect. Based on the filing date of TECO's request for a rate increase, the first date that the new rates will be in effect is approximately February, 1993.

There are primarily two options for evaluating Tampa Electric Company's expected financial operations. The first option is to use a historical test year and make pro forma adjustments to it. The second is to use a projected test year. Both of these options have strengths and weaknesses.

The historical test year has the advantage of using actual data for much of rate base, net operating income, and capital structure; however, the pro forma adjustments usually do not represent all the changes which occur from the end of the historical period to the time new rates are in effect. Therefore, this option generally does not present as complete an analysis of the expected financial operations as a projected test year.

The main advantage of a projected test year is that it includes all information related to rate base, NOI and capital structure for the time new rates will be in effect. However, the data is projected and its accuracy depends on the company's ability to forecast. Many companies are not able to forecast accurately enough to use the forecast for setting rates.

The parties have stipulated to the use of projected calendar year 1993 as the appropriate test year upon which to base TECO's request for permanent rate relief. We accept and approve the stipulation as appropriate to the resolution of this case.

At issue is the use of the 1994 test year. TECO believes that additional revenues will be needed in 1994 and that a step increase in this case can avoid the expense of a separate case for 1994. The use of dual test periods is authorized by Section 366.076(2), Florida Statutes, and Rule 25-6.0425, Florida Administrative Code, and is consistent with Commission practice. See Order No. 13537, issued July 24, 1984 in Docket No. 830465-EI (FPL rate case). The Office of Public Counsel believes that a rate increase in 1993 cannot be justified and the 1994 data, standing alone, is too speculative to establish rates that far in the future.

The parties and the Commission staff have conducted extensive discovery concerning TECO's forecast. We believe that TECO's forecast of its 1994 financial operations, as adjusted herein, is accurate enough to use as a basis for setting rates.

B. Sales Forecast

Mr. Moore presented the forecast model and assumptions used to produce the KW, KWH, and Customer forecasts on behalf of the company. TECO's KW and KWH forecast model is an end-use model that projects on an hourly load by Revenue Class. TECO's Customer forecast is derived from its economic-demographic model. The forecasts used in this case were finalized in December 1991.

During the hearing, Mr. Moore was asked to provide the Load Forecast Variance Report for August, 1992. This report shows the year-to-date accuracy of the KW, KWH, and Customer forecasts. The report shows that Total Retail Sales are within -0.6% of forecast, and that Total Customers are within -0.2% of forecast, and that Weather Normalized System KW is within 0.3% of forecast. Mr. Moore stated that he believes that the KW, KWH, and Customer forecasts are sufficiently accurate that no modifications to the projections are required. No other party took a position on this issue.

We reviewed TECO's forecast models and assumptions, as well as compared the difference between the forecasted and actual values through August, 1992. We believe that TECO's forecast models are capable of and have produced reliable projections and that the input assumptions are reasonable. We note that the August 1992 year-to-date actual values for KW, KWH, and Customers are very close to their forecasted values. Accordingly, we approve the company's KW, KWH, and Customer forecasts.

C. Forecasted Inflation Rates

The inflation forecast is used for rate making purposes to determine the appropriate amount of projected test year expenses. As a basis for the Consumer Price Index (CPI) factors used in its MFR Schedules, Tampa Electric used forecasted data from the DRI/McGraw-Hill Forecast for the U. S. Economy published in late 1991. Late-filed Exhibit 30 provides an updated September, 1992 CPI forecast from DRI to use as a comparison. The updated CPI forecast predicts a slower growth in the consumer price index. We shall adopt the original CPI forecast to determine the level of O&M expenses in 1993 and 1994. The ultimate effect of using a lower CPI for O&M expenses in 1993 and 1994 is that the benchmark level for each functional area will be decreased. MFR Schedules C-53 and C-56 incorporate a true-up of actual CPI and customer growth multipliers to those forecasted in the company's prior rate case. Tampa Electric shall be required to true-up the forecasted CPI and customer growth numbers presented in this rate case to actual data during the company's next full requirements rate case.

D. Jurisdictional Separation

The jurisdictional separation study allocates rate base and operating expense items comprising the company's total system cost of service between those customers served under the jurisdiction of the Florida Public Service Commission (retail or jurisdictional) and those served under jurisdiction of the Federal Energy Regulatory Commission (wholesale or nonjurisdictional).

In the separation study filed as part of the MFRs by the company, only the City of Sebring and TECO Power Services were included in the nonjurisdiction. Additionally, only $3.8 million of O&M revenues from certain off-system sales were included in the company's filing.

However, Tampa Electric has commitments to sell firm capacity and energy to the Utilities Commission of the City of New Smyrna Beach, the Reedy Creek Improvement District, the City of Wauchula and the Florida Municipal Power Association in 1993. In 1994, Tampa Electric will sell firm capacity and energy to the City of Saint Cloud also.

These four systems have a firm commitment from Tampa Electric for capacity from the Big Bend Station through 1996. (Exhibit 37, Letters of Commitment) The terms and conditions of the commitment are such that these four entities have first call for their contract amount over the retail customers for Big Bend Station plants as long as the capacity from Big Bend Station is available. (Tr. 484) Seminole, through Tampa Power Services, has first call over both the firm Schedule D customers and the retail customers for up to 145 MW of the Big Bend 4 plant.

We do not believe it is fair or appropriate for nonretail customers to be buying firm capacity, particularly when the nonretail customers have first call for the capacity, at a rate which is not compensatory or cost-based, which means the retail customers are responsible for part of the revenue requirement for the plant serving the nonretail customers.

The parties have stipulated to the use of the separation studies provided which separate the cost to the four firm Schedule D customers on the basis of all generating plant. The 1994 study will be revised to include the St. Cloud contract (LF Exhibit 98). We accept and approve the stipulation.

The separation studies stipulated by the parties for use in this docket differ from those filed by the company as part of the MFRs in three respects. First, the projected MW reductions from residential load management provided by Mr. Moore, TECO's witness, in his Deposition Exhibit 1 were removed from the 12 monthly coincident peak demands (12 CP KW) for the retail class for the 12 CP allocation or separation factors for both 1993 and 1994. Second, the 1994 study is based on the projected 1994 load characteristics of the retail and the nonjurisdictional (Federal

Energy Regulatory Commission) classes and not on the 1993 separation factors. For Seminole (Tampa Power Services) the 1992 sixty-two 12 CP MW were increased for 1993 by 6.425%; the percentage increase in the Seminole's contractual allotment of the total energy use of Big Bend 4 from 1993 to 1994. Third, the three utilities (New Smyrna Beach Utilities Commission , Reedy Creek, and the City of Wauchula) and the Florida Municipal Power Association, which have Letters of Commitment for firm Schedule D sales from Tampa Electric in 1993, are included in the 1993 separation study as part of the nonjurisdictional portion. In the 1994 separation study the City of St. Cloud, which begins firm service under Schedule D in 1994, is also included in the nonjurisdiction.

If these four customers are separated into the nonjurisdictional portion, the retail ratepayers would be paying none or very little of the revenue requirement associated with these sales. The company has agreed to treat these customers as non-jurisdictional in the separation study. Accordingly, we find that the Utilities Commission of the City of New Smyrna Beach, the Reedy Creek Improvement District, the City of Wauchula and the Florida Municipal Power Association shall be treated as nonjurisdictional customers in the 1993 and 1994 jurisdictional separation studies as well as the City of Saint Cloud in the 1994 study.

Since we are making adjustments to the company's numbers contained in the MFRs to reconcile to the numbers as revised by this stipulation, the following adjustments issues are necessary:

RATE BASE
$(000)

	1993	1994
Plant in Service	(35,511)	(48,308)
Dep. Res.	14,408	19,838
CWIP	(47)	(355)
PHFU	(942)	(1,400)
Working Capital	(3,405)	(4,272)
Decrease to Rate Base	(25,497)	(34,497)

NET OPERATING INCOME
$(000)

	1993	1994
Revenue	(1,068)	(8,160)
O&M Exp.	(3,224)	(3,871)
Dep. & Amort. Exp.	(1,433)	(1,939)
Taxes Other	(569)	(776)
Cur.Inc.Tax	1,628	(551)
Def. Inc. Tax	(85)	29
ITC	13757	
Gain/Loss on Sale	1	0
Increase (Decrease) to NOI	2,477	(1,109)

We accept and approve these adjustments.

III. ACCOUNTING TREATMENT

A. FAS 106 - Methodology

The basic concept underlying FAS No. 106, titled Employers' Accounting for Postretirement Benefits Other Than Pensions, is the concept of accrual versus cash basis accounting to record other postretirement benefits (OPEB). TECO has requested that we use the accrual method of accounting for ratemaking purposes. Because accrual accounting matches the cost of employees' services, we agree. If we were to continue to use the pay-as-you-go method, future customers would pay for costs related to past years. Ultimately, the costs of retirement benefits under FAS No. 106 will not vary from costs under pay-as-you-go accounting, but the timing of the recognition of these costs will be different. The accrual accounting prescribed by FAS No. 106 appropriately recognizes the cost of retirement benefits. In fact, we have previously recognized the concept of using FAS No. 106 in two recent rate cases. In both the United Telephone Company of Florida rate case and the Florida Power Corporation rate case, the Commission approved the concept of using FAS No. 106 for ratemaking purposes. (Order No. PSC-92-0708-FOF-TL and Order No. PSC-92-1197-FOF-EI)

TECO supports the use of FAS No. 106 for ratemaking purposes. TECO testified that FAS No. 106 requires a company to recognize the costs of OPEBs during the period that employees are working and earning the benefits. Also, TECO asserts that the expense recognition method is independent of the decision to fund OPEBs. In addition, it has reduced OPEBs prospectively to reduce the impact of FAS No. 106 implementation. TECO further testified that it has implemented caps on post-retirement medical premiums for all employees retiring on or after January 1, 1990 and that these caps (or defined dollar benefits) reduced OPEB costs by 40%. The implementation of FAS No. 106, TECO maintains, will increase costs in 1993 by $4.7 million. TECO has not made a final decision regarding the prefunding of OPEBs. TECO's MFRs for the 1993 and 1994 test year reflect the implementation of FAS No. 106.

OPC argued that the current method of calculating the cost of postretirement benefits allows the company to recover the costs it has incurred. However, the SFAS methodology places the customer in jeopardy and offers no assurance that the current or future customer would not be overcharged. OPC recommended that the Commission continue its pay-as-you-go method. FIPUG argued that accounting for OPEBs for ratemaking purposes is presently the subject of a rulemaking proceeding and should be deferred. Also, the Florida Consumer Action Network argued that the current "pay-as-you-go" methodology assures workers of their other post-retirement benefits without forcing ratepayers to overpay on the basis of company "guess-timates" of potential future costs.

OPC presented the five following arguments. First, OPC testified that TECO may restructure its benefits plan to reduce costs in the future. If rates are set before the cost reductions, then the company will collect more cash than it deserves. Second, FAS 106 calculations are inherently unreliable in the rate setting environment. Third, the use of FAS No. 106 for ratemaking assigns costs of prior periods, i.e., the transition obligation, to current ratepayers, which contradicts the utility company's point that today's costs should not be assigned to future ratepayers, as would happen under the pay-as-you-go method. Fourth, as cost estimates become more reliable and cost containment measures are instituted, future ratepayers will receive the benefits of those events. Fifth, there is no assurance that funds collected through rates will be used to pay benefits.

TECO rebutted OPC's contention that TECO might restructure the benefits plan to reduce costs in the future. TECO argued that under FAS No. 106, if a company reduced or curtailed its benefits, then a resulting gain or loss is recognized in the company's income. Further, the Commission could monitor such events through a simple mechanism and ensure that the company's shareholders do not inappropriately benefit from reductions in benefits costs.

Although TECO testified that FAS No. 106 costs cannot be calculated with certainty, TECO believes that the Financial Accounting Standards Board regards a best estimate as superior to implying that no obligation exists. Even under the pay-as-you-go method, estimates would be necessary for the use of projected test years. Further, FAS No. 106 requires companies to regularly review their calculations and make adjustments. The Commission could monitor such adjustments. Moreover, long-term estimates are routinely used in rate cases.

Regarding the amortization of the transition obligation and inter-generational inequity, TECO testified that, even with the amortization of the transition obligation, there is better matching and a more equitable allocation with FAS No. 106 than with the pay-as-you-go method. Also, amortizing the transition obligation is similar to catch-up methods for underrecovery of depreciation, for changing income tax treatments, and for pension accounting.

Regarding the possibility that funds collected through rates will not go to pay benefits, we note that funding of OPEBs would eliminate this possibility though it might not be the least cost method. We also note that FAS No. 106 requires a company to review the calculations of OPEB costs and make adjustments for material changes.

Accordingly, we find that FAS No. 106 shall be used by Tampa Electric for ratemaking purposes. We believe that the accrual accounting prescribed by FAS No. 106 is appropriate for ratemaking, because it matches the cost of OPEBs to the period when employees are working and earning the benefits. Continuing the pay-as-you-go method would result in a mismatch between the cost of an employee's service and the period when the employee provides that service. We acknowledge that FAS No. 106 costs are estimates but note that many costs recognized in rate cases are based on estimates. FAS No. 106 estimates are reviewed and can be monitored and corrected.

IV. RATE BASE

To establish TECO'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, including 1) plant-in-service, 2) depreciation reserve, 3) construction work in progress (CWIP) (where appropriate), 4) property held for future use, 5) fuel inventory, and 6) working capital.

TECO requested a rate base of $1,868,787,000 ($1,970,215,000 system) for the 1993 projected and $2,073,467,000 ($2,180,246,000 system) for the 1994 projected test year. Evidence developed during the course of the proceedings has led us to reduce the jurisdictional amounts to $1,749,355,000 for 1993 and $1,850,927,000 for 1994. We therefore approve the rate base summarized in the schedules attached to this Order as Appendix 1.

A. Methodology

We find that the use of a simple average methodology is not appropriate for computing the 1994 rate base.

In the company's original filing, a 13-month average was used to compute the rate base for the 1993 Projected Test Year. TECO requested that the Commission, after making staff adjustments to the 1993 data, use TECO's financial model to determine the appropriate additional revenue increase for the 1994 Subsequent Test Year. The company submitted very little additional information for 1994 based on its request to use its model to determine the 1994 revenue increase. TECO was asked to supply a number of stand-alone MFR schedules for the 1994 Subsequent Test Year. The schedules were prepared using a simple average rather than the standard 13-month average method. A comparison of the two methods shows that TECO's 1994 revenue requirement, before any staff adjustments, is $1,383,000 higher using the 13-month average. We believe that the 1994 data used to compute a revenue increase, if any, should be comparable to the data used to compute the 1993 revenue increase. Therefore, we find that a 13-month average shall be used to determine any revenue increase for the 1994 Subsequent Test Year. A comparison of the two methodologies is shown on the following tables (000's):

RATE BASE

	Simple ave.	13-month	Diff.
Plant in Service	$2,626,092	$2,625,595	($497)
Acc. Deprec.	(996,699)	(996,434)	265
Net P-I-S	1,629,393	1,629,161	(232)
CWIP	213,831	213,831	----
PHFU	62,036	62,036	----
Net Plant	1,905,260	1,905,028	(232)
Working Capital	168,207	166,926	(1281)
Total Rate Base	$2,073,467	$2,071,954	($1513)
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NET OPERATING INCOME

Tot. Oper. Rev	$612,747	$612,747	----
Oper. Expenses:			
Operation-fuel	(7,561)	(7,561)	----
-other	(144,991)	(144,991)	----
Maintenance	(76,180)	(76,180)	----
Depre.& Amort.	(107,980)	(107,980)	----
Taxes-other	(41,960)	(41,960)	----
Curr. Inc. Taxes	(61,840)	(62,012)	172
Deferred Inc. Taxes	(2,820)	(2,821)	1
Charge/Eqiv ITC	4,214	4,214	----
Loss on Disposal	9	9	----
Total Oper. Expenses	(439,109)	(439,282)	173
Net Operating Income	$173,638	$173,465	($173)

B. Plant In Service

1. Hookers Point Generating Station

The Hookers Point units were removed from extended cold shutdown status and returned to service between October, 1990 and January, 1991. In its past expansion plans, Tampa Electric had planned to phase the five units into service between 1991 and 1993. Mr. Ramil testified that Tampa Electric accelerated the time frame for returning the units to service for three reasons: to enhance reliability of its electric system; to take advantage of an improved market for off-system sales; and to comply with the Commission's Order No. 22708, Docket No. 900071-EG, regarding the 1989 Christmas capacity shortfall. These arguments are discussed below.

a. Enhance reliability of its electric system

Mr. Ramil testified that the Hookers Point units were needed to provide enough peaking capacity to insure that the loss of load probability (LOLP) of Tampa Electric's system was not violated (Tr. 1981-7). Tampa Electric's reliability criterion, consisting of a minimum 20% reserve margin and a maximum 0.1 days/year LOLP, will be met with the inclusion of generation from the Hookers Point units. However, if such generation is not included, Tampa Electric's system LOLP will be well above 0.1 days/year between 1993 and 2000.

Mr. Stewart, Public Counsel's witness argued that Tampa Electric does not need the Hookers Point capacity. He correctly stated that the reserve margin will be reasonably adequate whether or not such capacity is included on Tampa Electric's system. However, Mr. Stewart did not discuss the possibility that such capacity was needed to meet the LOLP criteria, although he admitted that a utility should be reliable during the entire year and not just at peak times (Tr. 1273). It should be noted that, for the period from 1993 to 2000, Tampa Electric's summer reserve margin criteria is not violated, and the winter reserve margin is projected to be no lower than 16%, if Hookers Point was not returned to service.

Tampa Electric's system is over 3300 MW and the combined capacity of the five Hookers Point units is 210 MW. Tampa Electric's generating system is primarily baseloaded. Hookers Point capacity is used to meet peak and near peak loads, which occur many hours of the year thus greatly contributing to the reliability of the system. We agree that the Hookers Point units are needed for Tampa Electric to meet its reliability criteria.

b. To take advantage of an improved market for off-system sales

Exhibit 45 contains a "Summary for Appropriation Request" from June 1990 authorizing the return of the Hookers Point units to service. Tampa Electric's budget for 1990 did not include the start-up costs for all the units because it had not planned to return all five units to service at one time. Tampa Electric proposed selling 80 MW of capacity off-system between 1991 and 1994, which would generate more than enough revenue to offset the incremental cost of restarting all five units at once.

However, Public Counsel argued that the increased capacity from Hookers Point station would not be needed if Tampa Electric were not selling so much capacity off-system out of Big Bend 4. Public Counsel argued, in effect, that Tampa Electric is using more expensive generation out of Hookers Point to make cheaper generation from Big Bend 4 available to its wholesale customers, and that the retail ratepayers are subsidizing Tampa Electric's wholesale customers.

It should be noted here that the Commission imputed over $37 million of rate recovery for Big Bend 4 in Tampa Electric's last rate case in 1985, because the Commission determined that the utility did not need 145 MW of capacity from Big Bend 4 at that time. In doing so, the Commission provided an incentive for Tampa Electric to sell the excess capacity off-system.

c. To comply with the Commission's Order No. 22708, Docket No. 900071-EG, regarding the 1989 Christmas capacity shortfall

Mr. Ramil testified that Tampa Electric followed the Commission's recommendation that utilities return their long-term reserve standby units to service earlier (Tr. 1968-9, 1995-7). At page 9, section 9, of Order 22708, the Commission stated that

> Where practicable, cold standby units should be returned to service earlier, or their status should be enhanced from a state of "cold" standby to "hot" standby.

The Commission did not order Tampa Electric, or any other utility, to bring its plants back early, but only to consider doing so where practicable. Tampa Electric considered this advice and determined that it was prudent to accelerate plans to return the Hookers Point units to service. We agree with Tampa Electric's decision.

There was considerable evidence in this case concerning the prudence of returning the Hookers Point units to service. Some of the evidence, especially that concerning bringing the units back to bolster off-system sales, could imply that Hookers Point should be removed from retail rate base. However, the weight of the evidence surrounding Tampa Electric's need for the units to ensure system reliability and adequate LOLP leads us to conclude that the Hookers Point units are needed, and that their inclusion in rate base is appropriate. Accordingly, we find that the Hookers Point units shall be included as plant in service in the rate base of Tampa Electric Company.

2. Over Accrual of AFUDC on Work Order K23

Based on findings in the Staff Audit Report, Disclosure No. 8 (Exh.83,p.labeled 17), staff proposed that adjustments be made to reduce the 1993 Projected Test Year Rate Base by $95,275, to reduce Accumulated Depreciation by $16,952, and to reduce Depreciation Expense by $4,002. The report stated that the company continued to accrue AFUDC on a project for several months after all major work on the project had been completed. For the 1994 Subsequent Test Year, staff proposed to reduce Rate Base by $95,275, reduce Accumulated Depreciation by $20,954, and reduce Depreciation Expense by $4,002. The company reviewed this finding and in its response to the audit and agreed that the adjustments should be made. No other party took a position on the issue.

Therefore, we reduce the 1993 Projected Test Year Rate Base by $95,275, reduce Accumulated Depreciation by $16,952, and reduce Depreciation Expense by $4,002. For the 1994 Subsequent Test Year, we reduce Rate Base by $95,275, reduce Accumulated Depreciation by $20,954, and reduce Depreciation Expense by $4,002.

3. Compliance with Rule 25-6.0141(1)(e), Florida Administrative Code

In pertinent part, Rule 25-6.0141(1)(e), Florida Administrative Code states "Account 107, Construction Work in Progress shall be subdivided so as to segregate the cost of construction projects that are eligible for AFUDC from the cost of construction that are ineligible for AFUDC."

Audit Exception No. 1 of the Staff Audit Report states that TECO is in violation of Rule 25-6.0141(1)(e), F.A.C. The report states that the company is not subdividing Account 107 in the General Ledger and, therefore, is in violation of this section of the rule. The company responds that it has always complied with the rule that Account 107 be subdivided. TECO maintains that the rule does not specify the method of segregation.

The company prepares a monthly analysis of projects which are eligible as well as ineligible for AFUDC. These totals are included in two subsidiary ledgers (Exh.62-composite; Informal Data Request 24,p.1). Report FT003130 (p.7-10) lists all ineligible projects by project number. The general ledger contains total CWIP by month; and, the remainder, after subtracting the total of all ineligible projects, is the total of eligible projects.

The list of ineligible projects is at least four pages long. The inclusion of this level of detail in the general journal is not required. A general journal by definition need not contain a detailed breakdown of all accounts as long as there are sufficient other ledgers or subsidiary ledgers which are detailed and allow the search for, or confirmation of, specific accounting information. Part of the required audit work of TECO was an examination of projects eligible for AFUDC. There is no indication in the audit findings that suggest that the auditors had any difficulty in locating eligible or ineligible projects during their examination of construction projects. It appears that the auditor has taken the very conservative position that the rule requires that Account 107 be segregated in the general ledger itself.

The rule, however, does not say that; rather, the rule only states that Account 107 be segregated. TECO has segregated Account 107 in subsidiary ledgers rather than the general journal.

We believe that the level of detail contained in the subsidiary ledgers is adequate. Therefore, we find that TECO shall not be required to change its present method of recording and accounting for eligible and ineligible AFUDC projects in its subsidiary journals.

4. Adjustments Related to Dravo-Wellman Bucket Unloader Contract

Ms. Bouckaert, staff's witness, proposed through testimony (TR 1285) and Audit Disclosure Number 9 in the Staff Audit Report, adjustments to reduce Plant in Service $46,028 ($52,334 System) and reduce Accumulated Depreciation $4,987 ($5,670 System) for the 1993 projected test year. The recommended adjustments for 1994 are to reduce Plant in Service $45,588 ($52,334 System) and Accumulated Depreciation by $6,086 ($7,763 System) for the 1994 subsequent test year. (EX 84 Selected Audit Work Papers).

Audit Disclosure No. 9 states that TECO contracted with Dravo-Wellman to install a bucket coal unloader at the Gannon Station. The original contract price was $2,841,750 and the original budget including overhead was $3,172,000. Because of time delays and because the machine unloaded coal below the minimum unloading rate the parties entered into a settlement lowering the contract amount by $1,525,000 from $2,841,750 to $1,316,750. As a result of the reduction in contract price, TECO overpaid Dravo-Wellman by $775,000 since TECO had been making progress payments based on the original contract. The $775,000 amount related to the refund had accrued AFUDC during the construction period, but upon refund of the overpayment, no AFUDC was removed from CWIP.

TECO believes the funds were properly expended, the company was without the use of the funds, and the accrued AFUDC should remain. Audit staff's position is that the $775,000 was a refund of an overpayment and was not eligible for AFUDC.

Since the contractor agreed to accept less than one-half of the contract amount, it is clear that the contractor performed poorly on this contract. The actual cost to TECO includes the AFUDC on the overpayment. In summary, a contractor performed poorly and TECO sought and received such a large settlement that the contractor was required to make a refund.

Our rules do not specifically address AFUDC on amounts later refunded. It is preferable to address unusual events individually rather than through rule amendments. Since our rules do not address this situation we believe that it is within the discretion of the Commission to make adjustments to plant, accumulated depreciation and depreciation expense, for both the 1993 and 1994 test years. However, we make no adjustments, as TECO has taken the appropriate action to reasonably limit the cost of the unloader.

5. Adjustments Related to Planning and Pre-engineering Expenses Incurred at Big Bend 4

Concurrently with the staff financial audit, an engineering audit of expenses associated with Big Bend 4 (BB4) was also conducted. The recommendations of this Engineering Audit were contained in the Staff Audit Report. This issue was developed as a result of Audit Disclosure No. 2 in that report. Total architect\engineering costs from March, 1974 until March, 1978, when the final design of BB4 was authorized, amounted to $3,544,000. Of this total, $2,744,000 of these costs related to engineering design which had to be redone because of scope changes.

The audit opinion is that "Normally planning costs can be a part of project costs if they lead into an approved project in a reasonable span of time. In this project there were excessive delays from 1971 to 1978 due to adequate reserve capacities, and the costs do not reflect true project costs."

The report recommended that engineering costs of $2,744,000 should have been expensed rather than capitalized. Various design and scope changes caused rework which replaced $2,744,000 of original design work. The exact origin or cause of these changes cannot reasonably be determined at this time. The company in its response to the audit disclosure, points out that these changes were the proper response to variations in conditions such as economic and environmental changes which were outside the scope of their company operations. The company does not disagree that some additional costs may have been incurred; however, there is nothing in the record that suggests that these expenses might have been imprudent.

In spite of the luxury of hindsight, which does suggest that some of these expenses might properly have been expensed, we lack the detailed information to determine which expenses would appropriately be disallowed.

Overall, the record evidence in this proceeding does not support reversing Commission Order 15451, which allowed these charges in Rate Base. Therefore, we find that these charges shall remain as capitalized expenditures in TECO's Rate Base.

<u>6. Adjustments Related to Architect/Engineering Expenses Incurred at Big Bend 4 Generating Station</u>

Mr. Davis testified that the additional Architect/Engineering costs of $513,000 should have been expensed rather than capitalized in Audit Disclosure No.3. The circumstances involved in the construction of Big Bend 4 (BB4) were necessarily very complex. The record shows that numerous delays were encountered, but it is not currently reasonably possible to reconstruct the origin and circumstances of those delays. The company position states that costs for these drawings were part of the project cost accepted for capitalization in Order 15451 (TECO Brief, p.32), and there is no substantive evidence in the record to support reversal of that action.

Therefore, we find that the $513,000 expenditure for additional architect/engineering drawings related to Big Bend Unit 4 shall remain capitalized.

<u>7. Inclusion of Sebring Utilities Generating System and Associated Transmission Facilities in Rate Base</u>

In February, 1991, TECO purchased from the Sebring Utilities Commission (SUC) the generating units at the Phillips and Dinner Lake sites, associated transmission facilities, and agreed to provide full requirements service to Sebring's customers. We consider whether or not the purchase of the generating and transmission facilities is appropriate for inclusion in rate base.

Mr. Ramil, TECO's witness, stated that the SUC plants purchased "are economical sources of peaking and intermediate capacity and provide fuel savings to the Tampa Electric System." He further stated that the Phillips site is a desirable potential site for additional peaking and intermediate capacity.

TECO provided economic analyses of the SUC purchase in Late-filed Exhibits 128 and 129. Public Counsel correctly notes that in Late-filed Exhibit 128, the page entitled "Retail Jurisdictional Benefits from the Sebring Transaction" is on a system basis. The analysis shows the SUC purchase to have a positive cumulative present worth in each year for 1993-2002. However, TECO has included 1991 and 1992 fuel savings with 1993 fuel savings. This has the effect of making the transaction appear more cost-effective than it really is. A more accurate analysis would have included the costs (revenue requirements), and benefits (fuel savings and non-fuel revenues) for 1991 and 1992. Estimating these amounts shows the transaction to still be cost-effective, but with the cumulative present worth of the benefits not becoming positive until 1998.

Late-filed Exhibit 129 compares the effects on TECO's system with and without the SUC units. This analysis shows an increase in cost of approximately $28 million for the period 1993-2002 if the SUC units are excluded.

The addition of the SUC generating plants will only marginally improve TECO's reserve margin. TECO's 1992/93 winter reserve margin with the SUC units is forecasted to be 28%, but excluding the SUC units lowers the 92/93 reserve margin only to 27%. Throughout the forecasted period of 1992-2002, including the SUC units improves TECO's reserve margin by only one or two percentage points. TECO's system is primarily baseloaded, and the SUC units, which are peaking and intermediate in nature, will contribute to the reliability of the system.

We believe that the evidence in the record shows the addition of the SUC units are cost effective and will contribute to maintaining TECO's reserve margin. Also, the Phillips site provides TECO with an a site available for peaking and intermediate capacity to meet future needs. Therefore, we find that these units shall be included in rate base.

8. Appropriate Rate Base Accounting Treatment for Sebring Utilities Commission Generating and Associated Transmission Facilities

On February 28, 1991, TECO purchased some production and transmission plant assets from Sebring Utilities Commission at less than net book value, thereby creating a negative acquisition adjustment of $10,728,866.(MFR Schedule B-11, Composite EXH 3) The company paid $37,000,000 for assets having a net book value of $47,728,866. The initial entries TECO made to plant, Account 101, and reserve, Account 108, associated with this purchase were $67,367,000 and $18,461,000, respectively, with a credit of $10,728,866 to Account 114, Electric Plant Acquisition Adjustments.(Composite EXH 62, p. 19-24) Amortization of this acquisition adjustment was initiated based on a period of 23 years with a charge to Account 115, Accumulated Provision for

Amortization of Electric Plant Acquisition Adjustments and a credit to Account 406, Amortization of Electric Plant Acquisition Adjustments. (Schedule B-11, Composite EXH 3) The amortization period was based on the remaining life of facilities purchased.

In December 1991, the Federal Energy Regulatory Commission (FERC) directed TECO to treat the acquisition adjustment as a credit to the reserve, thereby restating the reserve of the purchased assets by the acquisition adjustment amount. (MFR Schedule B-11, Composite EXH 3) This may be predicated on an assumption that when plant is sold for less than book value, the market value is a better indicator than net book value. Whether net book value is reduced by an acquisition adjustment or by increasing accumulated depreciation, the result is to reduce the plant amounts to the total actually paid by TECO.

In accord with FERC's directive, TECO transferred the balances in Accounts 114 and 115 to the reserve, Account 108. (EXH 62) The acquisition adjustment is recorded and is being maintained as a separate subaccount in the reserve. (Schedule B-8b, p. 3-10, Composite EXH 3) In this respect, it has the same effect as if the amount were recorded in Account 114. We believe this treatment is satisfactory.

Accordingly, we find that the rate base accounting treatment for the Sebring Utilities Commission assets utilized by TECO in its filing for the 1993 and 1994 test years is appropriate.

9. Total Level of Plant In Service

We find that the appropriate jurisdictional Plant in Service is $2,437,233,000 for 1993 and $2,561,446,000 for 1994 based on the adjustments made concerning the overaccrual of AFUDC, the revised jurisdictional separation factors, the use of a thirteen month average for 1994, certain affiliated transactions and the over projection of plant in service discussed below.

Mr. Schultz, OPC's witness, testified in support of adjustments to plant in service and accumulated provision for depreciation based on a comparison between actual plant and accumulated depreciation for the months of December, 1991 through July, 1992. Schedule 5 of his prefiled testimony indicates that the actual plant balance for July 1992 was only $2,512,255,000 and the projected balance $2,528,129,000.

Exhibit 50, page 2 of 3, shows the projected plant in service for July 1992 (revised forecast) to be $2,529,311,000. Actual plant in service for July 1992 is only $2,512,255,000 which is $17,056,000 less. Since the revised forecast uses actual plant balances through January of 1992, this difference accumulated in only six months.

TECO did not provide any detailed explanation of the over projection of plant or any specifics showing when the growth rate of actual plant would accelerate to reduce or eliminate the over projection. Accordingly, we make adjustments to reduce plant in service, increase reserve for depreciation and amortization (adjustment to increase the reserve reduces the absolute dollar amount of the negative reserve), and reduce depreciation and amortization expense of the following:

1993 (000's)

	System	Jurisdictional
Plant	($17,056)	($15,910)
Reserve	$582	$543
Depreciation Expense	($635)	($592)

1994 (000's)

	System	Jurisdictional
Plant	($17,056)	($15,843)
Reserve	$1,217	$1,131
Depreciation Expense	($635)	($590)

These adjustments to plant, depreciation expense and the reserve are calculated based on the latest actual amounts. Actual system depreciation and amortization expense for the month of July 1992 of $7,796,000 was .3103% of the July plant balance of $2,512,255,000. That percentage applied to the $17,056,000 difference between actual plant and projected results in monthly adjustments to depreciation and amortization expense and the related reserve of $52,925.

C. Construction Work In Progress

1. Effect of Including CWIP in Rate Base on TECO's Financial Integrity

Tampa Electric proposes an amount of CWIP in rate base it believes is essential to maintain its financial integrity and credit rating. The calculations for the company are on a total company basis after adjustments for purchased power capacity and off-system sales.

Public Counsel believes the amount of CWIP proposed by the Company is inaccurate for several reasons. First, OPC believes Tampa Electric will be able to receive additional revenues if the Company asks for wholesale rate relief. OPC also points out that Tampa Electric did not include the cash flows from implementing FAS 106 when calculating the percent of funds generated internally. OPC further believes Tampa Electric has understated off-system sales for 1993, and has over projected the amount of construction it will incur during the test years. (TR 258, 598-600) In OPC's opinion, these misstatements understate the financial integrity of the company. Tampa Electric actually has more revenues available, and consequently, better financial integrity.

We based the financial integrity test on the regulated electric operations. Although Mr. Abrams testified on behalf of Tampa Electric that the rating agencies perform a credit analysis on a total company basis, the Commission can only be responsible for the regulated portion of Tampa Electric Company. The Commission considers the financial risks and strength of the regulated utility, while the wholesale operations are under the jurisdiction of the Federal Energy Regulatory Commission.

Mr. Abrams also states that only 6% of total company sales come from the wholesale business; therefore, any wholesale rate relief will have a marginal effect on the financial integrity. If we calculate Tampa Electric's financial integrity on a regulated rather than total company basis, it will alleviate OPC's concern that the financial integrity has been understated due to possible wholesale revenues.

Tampa Electric did not include the cash flows from implementing FAS 106 in its original financial integrity study. (TR 1870) The company did, however, calculate the effect of FAS 106 on financial integrity in a late-filed hearing exhibit No. 121. We considered the cash flows from FAS 106 when calculating the financial integrity for the regulated operations of Tampa Electric.

We agree with the OPC that the company may have overstated the amount of construction projected for 1993 and 1994. Overstating construction has the effect of overstating the amount of CWIP that should be included in rate base. We have adjusted the CWIP balance to reflect the over projected construction when considering the financial integrity of Tampa Electric.

OPC recommends that off-system sales be included in jurisdictional revenues, but not at the amount projected by Tampa Electric. OPC notes that the revenues collected through August 1992 are already higher than the 1993 full year forecast; therefore, the Company has understated off-system sales. If an incorrect amount of revenues is included in the regulated jurisdiction, it will affect Tampa Electric's financial integrity. As discussed at length beginning at page 82 of this Order, we have voted to remove off-system sales from jurisdictional revenues and included those revenues in the Fuel and Purchase Power Cost Recovery Clause. This eliminates the problems associated with under or over forecasting the level of off-system sales when setting base rates and when analyzing financial integrity.

Tampa Electric may not have correctly accounted for potential revenues from its wholesale business and FAS 106, or projected off-system sales precisely. In addition, we believe the proposed amount of CWIP in rate base is overstated.

Accordingly, we find that the company has not properly calculated the effects of including Construction Work in Progress in its rate base on its financial integrity.

2. Appropriate Level of Construction Work in Progress (CWIP) in Rate Base

We find that the Company has over projected its CWIP balance by $11,972,000 ($12,065,000 system) in 1993 and by $11,959,000 ($12,065,000 system) in 1994. In addition, after considering an acceptable level of financial integrity for Tampa Electric, we reduce the level of CWIP in rate base to $18,793,000 for 1993 and $48,017,000 for 1994.

A comparison of monthly CWIP amounts based on the original 1992 forecast contained in the MFRs and the revised monthly CWIP amounts for 1992 provided in Late-filed Exhibit 69 shows significant differences.

	ORIGINAL	REVISED	ACTUAL
December 1991	$13,032	$18,698	$18,698
January 1992	19,842	19,842	19,842
February 1992	26,326	20,121	23,180
March 1992	34,599	21,652	24,481
April 1992	38,868	28,024	27,541
May 1992	42,636	33,992	25,947
June 1992	44,185	36,035	21,110
July 1992	47,501	42,876	30,811
August 1992	50,567	46,725	
September 1992	56,700	54,230	
October 1992	58,771	58,121	
November 1992	65,649	67,701	
December 1992	56,194	52,818	

A review of the above figures indicates considerable variance between TECO's projections of CWIP and actual CWIP. The original 1992 was based on numbers through November, 1991. TECO's projection of CWIP for December, 1991 was $13,032,000. Actual CWIP was $18,698,000. In projecting CWIP just one month into the future, TECO had over projected the balance by $5,666,000. TECO used actual numbers through January, 1992 in projecting its revised budget for 1992. By July of 1992, the difference between TECO's second projection of CWIP for 1992 and actual CWIP was $12,065,000. Since projected plant in service for July exceeded actual plant in service by $17,056,000 the excess projected CWIP is not offset by an under projection of plant. Therefore, we reduce total projected CWIP for 1993 and 1994 by $11,972,000 ($12,065,000 system) and 11,959,000 ($12,065,000 system).

We have considered the amount of eligible CWIP needed in rate base to maintain Tampa Electric's financial integrity. The financial ratios considered include interest coverage and total debt to total capital. We note that two of the ratios calculated, funds flow interest coverage and funds from operations as a percentage of average total debt, are above the Standard & Poors standard for AA-rated companies even with no rate increase. Also, the level of net cash flow to capital expenditures set for AA-rated companies cannot be reached even after considering Tampa Electric's full rate request.

Interest coverage after AFUDC has been identified by the several witnesses as one of the most important indicators of financial integrity. We have calculated a jurisdictional interest coverage for Tampa Electric after all other Commission approved adjustments. The coverage is calculated on a jurisdictional basis rather than total company because the Commission can only be responsible for maintaining the integrity and strength of the regulated utility.

TECO's witness Mr. Abrams, who is employed by the Duff & Phelps rating agency, testifies that a 4.0 times interest coverage is appropriate for a AA-rated electric utility. Standard and Poor's, another rating agency, indicates that interest coverage for a AA-rated electric utility should be above 3.5 times. We believe the Company should be allowed enough CWIP in rate base to maintain an interest coverage of approximately 3.75 times. Therefore, in 1993, we allow only the $18,793,000 of CWIP ineligible for AFUDC in rate base. We have calculated, on a jurisdictional basis, that eliminating the remaining CWIP in 1993 will allow Tampa Electric a 4.16 times interest coverage.

In 1994, we allow $48,017,000 of CWIP in rate base. Disallowing the remaining CWIP in 1994 will jurisdictionally allow Tampa Electric a 3.75 times interest coverage. Mr. Abrams testifies that Tampa Electric will be in the peak year of its construction program in 1994. Based on this testimony, we believe that if Tampa Electric does not fall below the interest coverage standard for a AA-rated electric utility in the critical year of 1994, the financial pressure on the company caused by the construction program will begin to moderate.

Finally, a AA-rated company should maintain a debt ratio below 46%. These adjustments to the allowed level of CWIP do not affect Tampa Electric's requested debt ratios of 41% in 1993 and 42% in 1994. Therefore, Tampa Electric is within the debt ratio range needed to maintain a AA bond rating.

3. Plant Held for Future Use - Gannon Coal Yard

Tampa Electric purchased 11 acres of land in 1982 from Port Sutton, Inc. to support expansion of the Gannon Station coal yard when Gannon Station converted from oil to coal. A small part (0.66 acre) of this land, parcel B, cannot currently be used for coal storage because a large sulfur storage tank sits on the land. The sulfur tank will be used until 1999 pursuant to a pre-existing lease agreement between the tank user and Port Sutton. Tampa Electric testified that the entire land purchase was one transaction; Tampa Electric was not able to buy the land needed for Gannon's coal yard expansion without purchasing parcel B as well. Mr. Ramil testified that Tampa Electric was given a good deal on the land in exchange for allowing Port Sutton to continue receiving payments for the storage tank until expiration of the lease.

Staff's witness, Jack Hoyt, proposed in the Staff Audit Report and through testimony that $35,515 ($36,429 system) be transferred from Account 105 (Electric Plant Held for Future Use) to Account 121 (Non-Utility Plant). The Commission ordered Tampa Electric to put the dollar amount in question into Plant Held For Future Use in Order No. 17281, Docket No. 860001-EI. Mr. Ramil testified that parcel B "may indeed be useful for the plant site" once the lease on the tank expires. Therefore, we find that the level of Plant Held for Future Use for the Gannon Coal Yard is appropriate.

4. <u>Plant Held for Future Use - Port Manatee Plant Site</u>

Power plant sites in Florida are becoming increasingly more difficult to find, purchase, and permit. Tampa Electric has a potential power plant site at Port Manatee. Utilities purchase power plant sites in advance, because the value of the land will generally appreciate at a rate greater than the utility's overall rate of return. If the Commission found that the Port Manatee site was an imprudent investment and did not allow Tampa Electric to earn a rate of return on the property, Tampa Electric would be encouraged to sell the site now. Tampa Electric would then have to search for, and purchase, another site for a future power plant, at much greater cost.

Public Counsel argues that Tampa Electric has no current plans for the Port Manatee plant site. Staff agrees that, at the current time, the company has not identified a particular generating unit to be built at the site. However, as discussed before, it will be more difficult to find an alternate plant site in the future. By allowing the Port Manatee site to remain in rate base, Tampa Electric will already have a viable generating site for future power plants. The Power Plant Siting Task Force recognized that the Port Manatee location was a viable generating site, although the task force ultimately recommended the Polk County location for Tampa Electric's next plant. Accordingly, we find that the requested level of Plant Held for Future Use in the amount of $4,640,000 ($5,094,000 system) for 1993 and $4,692,000 ($5,172,000 system) for 1994 associated with the Port Manatee plant site is appropriate.

5. <u>Reclassification of Substation Sites as Non-utility</u>

The Staff Audit Report, Audit Disclosure No. 7, stated that three substation sites listed in the MFRs for the Projected Test Year ended December 31, 1993 had been transferred out of Account 105, Property Held for Future Use, to Account 121, Non-Utility

Property, in March of 1992. The Audit Report, which reported on the year ended December 31, 1991, recommended that an reduction of $86,000 be made to Account 105 to reflect this transfer which took place prior to the test year, but were still listed in the MFRs. Since the company had in fact effected the transfer in 1992, the 13-month average that was listed in the MFRs for the 1993 and 1994 Projected Test Years was $52,000. The company in its response to the audit agreed to the reduction. We accept and approve this reduction to Rate Base of $52,000. Since these sites contained no depreciable structures, there is no reduction for Accumulated Depreciation or Depreciation Expense.

6. Total Level of Plant Held for Future Use

Incorporating the adjustments made related to the reclassification of the three substation sites, the reclassification of the Jackson Road substation site and the revised jurisdictional separation, we find that the appropriate jurisdictional amounts of plant held for future use are $48,909,000 for the Projected Test Year 1993 and $60,382,000 for the Subsequent Test Year 1994.

In the past, Commission rate case decisions have reflected the importance of retaining certain properties held for future use in view of Florida's projected growth rate, the burden on the utilities to meet this growth rate, and the expense that might be incurred if the properties were sold and had to be replaced in the future at greater cost. One of the most important aspects of long range planning is the identification and acquisition of land for future system expansion requirements.

Public Counsel's witness, Mr. Schultz, applied a 10-year rule to plant held for future use, suggesting that property either owned by Tampa Electric for longer than ten years or whose projected in-service date is greater than ten years in the future should be removed from rate base. We disagree with this methodology because it arbitrarily disallows rate recovery for power plant, distribution substation, and transmission substation sites that Tampa Electric plans to use to meet future growth beyond a point in time ten years from now. It is well known that, in Florida, these sites are becoming increasingly more difficult to find, purchase, and permit. This is especially true for Tampa Electric Company, since a major part of its relatively small service territory is urban.

Another point to consider is that Tampa Electric's future system expansion plans must be coordinated with Hillsborough

County's Comprehensive Plan for future land use which extends through the year 2010. Mr. Ramil testified that Tampa Electric must anticipate its planned facility locations and coordinate its land acquisition for these facilities with the future land use elements of Hillsborough County's Comprehensive Plan .

Utilities must act prudently in acquiring properties for future use. We believe Tampa Electric Company has acted prudently in acquiring future power plant sites, transmission right-of-way, and distribution substation sites. With the exception of the adjustments discussed in this Order, we find that Tampa Electric's level of Plant Held for Future Use for the 1993 and 1994 test years is appropriate.

D. Accumulated Depreciation

1. Adjustment to Reflect Commission Approval of Depreciation Rates in Docket No. 920618-EI

The parties have stipulated to the use of the depreciation rates established in Order No. PSC-92-1205-FOF-EI. We accept and approve the stipulation. For 1993, the system reserve shall be reduced by $2,533,000; and for 1994, the system reserve shall be reduced by $4,417,000. Reflecting the agreed to jurisdictional separation, we find the appropriate jurisdictional adjustment for 1993 is a reduction of $2,278,000 and for 1994 the appropriate jurisdictional adjustment is a reduction of $3,940,000.

2. Total Amount of Accumulated Depreciation

Based on our decisions on the specific depreciation issue and incorporating the effect of other Commission decisions in this Order, we find that the appropriate amount of accumulated depreciation for the 1993 Projected Test Year is $898,968,000. The appropriate amount of accumulated depreciation for the 1994 Subsequent Test Year is $971,504,000.

E. Working Capital

1. Appropriate Treatment of Tax Refunds due from IRS

In August, 1988 and December, 1991, Tampa Electric recorded $704,000 and $946,532, respectively, as Other Accounts Receivable. These amounts represent tax refunds due from the Internal Revenue Service. The recorded receivable related to the IRS tax refunds was $1,650,532 as of December 31, 1991. $946,532 was "cleared out" in February of 1992 and the company expected the $704,000 to be "cleared out" by the third quarter of 1992.

Other Accounts Receivable is a working capital allowance component. Consequently, the 1991 and 1992 working capital allowances contain these receivables. Likewise, the 1993 and 1994 test years include corresponding projections.

Tampa Electric Company maintains that no working capital adjustment should be made for this item because the corresponding credit to this debit balance is contained in the liabilities included in working capital and removal of the two transaction balances would have zero impact on working capital for 1991 as well as the 1993-1994 test years.

Our review of the record suggests all related adjustments left the income statement with zero impact and moved the receivable, instead of being a negative payable, over into the receivable account.

We believe that Tampa Electric has shown that the receivable should be included in working capital allowance, unless the corresponding payable is also removed, in which case the impact on working capital would be zero. Therefore, we find that the 1993 and 1994 working capital allowances should not be adjusted to remove the effect of tax refunds due from the Internal Revenue Service.

2. Requested Amount of Cash in Working Capital

We find that the appropriate jurisdictional amount of cash to include in working capital is $7,014,000($7,292,000 System) for the 1993 Projected Test Year and $6,989,000 ($7,292,000 System) for the 1994 Subsequent Test Year.

Audit Disclosure No. 11 of the Staff Audit Report states that the cash balance for 1991 "seems extremely high in comparison with the years 1987 through 1990. It appears more appropriate to use a five year average." The audit recommendation was to reduce cash by approximately $3,000,000 to reflect the five year average balance.

The company stated that bank charges have increased because interest rates have dropped. TECO's banks "charge" the Company for all bank transactions by earning a return on the cash balances TECO keeps in the banks. The Late-filed Exhibit entitled "Statement of Bank Fees" details the bank charges from TECO's seven banks for the month of August, 1992. This exhibit shows that TECO has a total compensating balance requirement of over $14,000,000. The currently very low interest rates are unusual. When rates rise, TECO expects that its cash balance requirements will fall.

The audit recommendation to reduce cash would have been appropriate if the company's cash balances required by its banking institutions were less closely tied to the economy in general and interest rates specifically. It appears that the company must carry a larger balance in cash than has historically been the case, or pay out larger service charges to pay for its banking services. For these reasons we find that the cash balance in Working Capital shown in the MFRs shall not be reduced other than to reflect the new jurisdictional factors.

3. Inclusion of Unamortized Rate Case Expense in Working Capital

TECO proposed to include unamortized rate case expense of $1,050,000 ($1,078,000 System) in Working Capital in 1993, and $350,000 ($359,000 System) in 1994. Based on the agreed revised jurisdictional factors, the amounts are $1,036,000 in 1993 and $344,000 in 1994. It is the position of OPC that retail customers should not be required to pay a return on funds expended to increase their rates.

This Commission has excluded unamortized rate case expense from working capital in a number of prior cases, as demonstrated in Order 14030 in Docket No. 840086-EI, Order 16313 in Docket No. 850811-GU, Order 23573 in Docket No. 891345-EI, and Order No. PSC-92-0580-FOF-GU in Docket No. 910778-GU. (TR 1233-34) In each of these cases, the adjustment was made in an effort to reflect a sharing of rate case expense between the stockholders and the ratepayers, since shareholders benefit from rate increases. (TR 1233) In Docket No. 910778-GU, the issue was argued fully and the Commission reaffirmed its long-standing policy of excluding unamortized rate case expense from working capital. Order No. PSC-92-0580-FOF-GU states that unamortized rate case expense is excluded from working capital "in an effort to reflect a sharing of rate case expenses between the stockholders and the ratepayers since both benefit from a rate case proceeding."

We find that working capital shall be reduced by $1,036,000 ($1,078,000 System) in 1993 and by $344,000 ($359,000 System) in 1994 to exclude unamortized rate case expense, consistent with the treatment in these prior cases.

4. Effect of Net Over and Under Recoveries of Fuel and Conservation Expenditures on Working Capital

By stipulation, the company has agreed that the Commission's policy of including net over recoveries in working capital and excluding net under recoveries is the appropriate treatment. Net under recoveries, which are assets, are excluded from working capital, and net over recoveries, which are liabilities, are included. We accept and approve the stipulation. In its filing, the company incorrectly removed both over recoveries and under recoveries.

MFR Schedule B-15 shows an underrecovery in fuel for 1993, but a $12,000 overrecovery in conservation. The best information available in the record supports a finding that there is a $46,000 conservation overrecovery in 1994, on a 13-month average basis.

Therefore, we reduce working capital by $12,000 ($12,000 System) in 1993, and $46,000 ($46,000 System) in 1994 to properly reflect the effect of conservation over recoveries in both years.

5. Costs associated with Renegotiating Zeigler Coal Contract

This issue was raised by staff as a result of Audit Disclosure No. 14 in the Staff Audit Report. According to this disclosure, the company had a 13-month balance for 1991 of $381,052 in Working Capital for costs associated with re-negotiating the Zeigler Coal Contract. The company indicated in its Response to the Staff Audit Report that these costs were removed from Working Capital in 1992. Since the Staff Audit covered the period ending December 31, 1991, the company adjustment was not reflected in the Audit recommendation. Since the adjustment was made prior to the Projected Test Year and is reflected in the MFRs, we find that no additional adjustment is necessary.

6. Inclusion of Common Stock Dividends Payable as Current Liability in Working Capital

TECO's witness testified that 100% of all earnings including AFUDC earnings are paid to the parent (TECO Energy, Inc.) as dividends. Dividends declared are paid to the parent in the month following declaration.

The basic accounting entry to record dividends payable is a debit to retained earnings and a credit to dividends payable. This entry has no actual effect on cash balances or other assets. This entry through a reduction to retained earnings reduces the amount of equity on the books and increases current liabilities. Current liabilities which are not interest bearing reduce working capital allowance because they are a source of cost free capital. The Commission has consistently increased equity and the working capital allowance reversing the average balance of common stock dividends payable.

TECO has filed its request consistent with this method, treating common stock dividends as a component of capital structure. Accordingly, we find that no adjustment to Working Capital Allowance is necessary to exclude common stock dividends payable.

7. Appropriate Treatment of Success Sharing Plan in Working Capital

This issue is closely related to the question of whether all expenses associated with the Success Sharing program should be allowed in the computation of Net Operating Income, discussed beginning at page 59 of this Order. From TECO's perspective these expenses are an obligation that will be paid at the conclusion of the fiscal year to which they apply. As an obligation, it is a liability which TECO accrues monthly.

As discussed at beginning at page 59, we believe the costs associated with the Success Sharing program should be allowed. Therefore we make no adjustment to the monthly accrual in Working Capital.

8. Adjustment to Account 183, Preliminary Survey and Investigation

Through testimony, the Office of Public Counsel alleged that TECO's projected average balance for Account 183, Preliminary Survey and Investigation, is overstated. Specifically, OPC stated that the Company's budgeting process allowed for $3,357,845 in transfers from Account 183 to CWIP, but the budget did not credit Account 183 for these transfers. Therefore, the $3,357,845 amount included in the CWIP and in Account 183 projected balances represents a "double-counting" of these costs.

TECO responded that OPC's concern had been raised in the audit work papers of the Company's independent auditor and an adjustment to reduce account 183 by $2,908,195 had been made and reflected in the MFRs.

Our review of the record indicates an additional adjustment of $449,651 related to the Polk Plant should be removed from Account 183. TECO in its post hearing statement agreed to this adjustment.

Accordingly, we find that an adjustment shall be made to reduce the working capital allowance by $431,988 ($449,651 system) for the 1993 test year and by $434,901 ($454,260 system) for the 1994 test year.

9. Adjustment Related to Proper Treatment of SFAS 106 Expenses in Working Capital

Ms. Montanaro, OPC's witness, believes that the unfunded FAS 106 liability should be treated as a zero-cost source of capital if the Commission uses FAS 106 for ratemaking purposes. She states that FAS 106 provides a company with excess cash. Therefore, if the liability is treated as a reduction to working capital, the reduction is offset by an increase in cash. She further asserts that equity should also be reduced with working capital to reflect properly the revenue reducing effect of the FAS 106 liability.

Mr. McKnight, TECO's witness, states that the unfunded liability should reduce rate base. He further states that this treatment is appropriate because investors are not funding the FAS 106 liability and that it displaces the need for investor capital. This allows customers to earn a return on the liability at the rate of the company's overall cost of capital.

In its MFRs, TECO reduced working capital for the FAS 106 liability in 1993 and 1994. The company subsequently increased its estimate of FAS 106 costs. Mr. Lefler, TECO's witness, sponsored an exhibit in which he acknowledges that the FAS 106 liability should reduce working capital for both test years and that the liability should reflect the latest FAS 106 estimates. He states that the liability should be increased by the following amounts: $1,742,000 ($1,813,000 system) for 1993 and $5,318,000 ($5,555,000 system) for 1994.

We believe that the company's treatment of the unfunded FAS 106 liability as a reduction to working capital is appropriate. The Commission approved similar treatments of the FAS 106 liability in the recent United Telephone Company of Florida and Florida Power Corporation rate cases. (See Order Nos. PSC-92-0708-FOF-TL and PSC-92-1197-FOF-EI)

Therefore, we find that working capital shall be reduced by $1,742,000 ($1,813,000 system) for the 1993 projected test year and $5,318,000 ($5,555,000 system) for the 1994 projected test year to reflect the implementation of FAS 106.

10. Transactions with Affiliated Companies

Based on the findings of the Staff Audit Report, Staff has proposed two adjustments to properly reflect TECO's transactions with affiliated companies.

The first is discussed in Staff Audit Exception No. 5. As a result of the order which was issued in the 1982 TECO rate case, Order No. 11307, the company was ordered to remove the Jackson Road substation site from Rate Base. This was ordered because the company did not have a utility-related use for this property. The company transferred this property to TECO Energy, an affiliated company, in the form of a dividend. TECO Energy subsequently transferred this property as an equity contribution to another affiliated company that is now called TECO Properties, Inc. In 1988 Tampa Electric Company decided that it needed the property for utility use.

The company states that, following Commission policies, it then negotiated to purchase the property from TECO Properties at market value. TECO had the property appraised and the market value according to this appraisal was $95,000. The appraisal stated that this was the value of the property as of May 10, 1988. TECO Properties had in its possession an appraisal report issued December 9, 1987 stating that the market value was $230,000 as of that date. As a result, the Company and TECO Properties jointly requested a third appraisal. On October 14, 1988 this appraisal report stated that the property had a market value of $200,000. The parties agreed to a purchase price of $199,994. Including $2,115.08 in recording, appraisal and survey fees, it went into Plant in Service with a value of $202,109.08.

The Opinion section of Disclosure No. 5 of the Staff Audit Report states that TECO's first appraisal was based on market conditions, and most importantly, the zoning which was then currently in effect. It states that the jointly obtained appraisal value of $200,000 was arrived at by making the assumption that the property would be rezoned for office use and would probably not be built on for 4-5 years, from October 10, 1988. It was not certain that any zoning change would be granted if requested. The primary basis for the large variance between the appraisals appears to be the different assumptions used to appraise the property.

The primary concern with this transaction, however, was that it was not conducted at "arms length". The parties were all affiliated companies and as a result, there was no incentive for Tampa Electric Company to negotiate a reduced price from the price eventually agreed to. TECO Properties benefits from a high selling price to Tampa Electric even though in the year-end consolidation of financial statements any intercompany gains or losses are removed as required by generally accepted accounting principles (GAAP). As a subsidiary of a large holding company, it would benefit because the higher TECO's Rate Base was, the greater the total earnings of the company would be. Also the greater the selling price it received the greater amount of cash could be transferred from the regulated subsidiary (Tampa Electric Company) to an unregulated subsidiary (TECO Properties, Inc.). Tampa Electric also had a direct incentive to pay a high price, or at least, no incentive not to. The higher the price paid for this property, the higher the amount entered in Rate Base and the greater amount its customers would be required to pay in increased rates as a result, and for an indeterminate number of years.

We believe that the purchase price for properties sold between affiliated parties should not exceed an amount based on an independent appraisal using current market conditions and zoning. In this case, we find that the amount to be allowed in Plant in Service shall be $95,000 plus $2,115.08 in related fees for a total of $97,115.08, not $202,109.08. TECO reclassified this property from Land Held for Future Use to Plant in Service in February, 1992, but the MFRs continue to show this amount in Land Held for Future Use. Since adjustments are made to the numbers contained in the MFR's, the proper adjustments are to reduce Land Held for Future Use by $202,000, and increase Plant in Service by $97,000. This results in a net Rate Base reduction of $105,000 ($105,000 System) for both 1993 and 1994.

The second proposed adjustment is based on Disclosure No. 15 of the Staff Audit Report. The audit report states that in 1991 TECO made an adjustment to Working Capital in the amount of $4,930,000 in "Accounts Payable-TECO Energy" because it was non-utility in nature. The audit opinion says that:

> The Company gave no indication the amounts associated with payables to TECO Energy were booked to Non-Utility accounts. Since there was no evidence of the booking for non-utility accounts, the amounts for Accounts Payable to TECO Energy should be considered utility in nature and included in Accounts Payable.

The recommended reduction to working capital for 1993 is $2,920,000 ($3,039,000 System) and for 1994 is $2,602,000 ($2,718,000 System). The company, in its response to the audit, agreed to the reduction.

Accordingly, we reduce Working Capital by $2,920,000 ($3,039,000 System) for the 1993 Projected Test Year and by $2,602,000 ($2,718,000 System) for the 1994 Subsequent Test Year.

These two adjustments result in a total Rate Base reduction of $3,025,000 ($3,144,000 System) for the 1993 Projected Test Year and $2,707,000 ($2,823,000 System for the 1994 Subsequent Test Year.

11. Reasonableness of Fuel Price Forecasts Used in Calculating Working Capital

We accept Tampa Electric's forecasted fuel prices for 1993 and 1994 as reasonable for the limited purpose of establishing the appropriate inventory value of the fuel included in the working capital component of TECO's capital structure.

OPC's position is that the projected Gatliff Coal prices are overstated. Gatliff Coal Company is an affiliated company of Tampa Electric Company. The Commission's fuel procurement guidelines contained in Order No. 12645 state that all purchases from affiliated companies should be priced at levels not to exceed those available on the competitive market. As noted in Public Council's brief, the MFR coal price for the Gannon units (Gatliff coal) is 35% above the Big Bend #1-#3 MFR coal price. Including the Gatliff coal in the working capital equation does increase the working capital coal inventory amount. However, the greater weight of the evidence suggests that TECO's projected prices are more appropriate to use than any other information available to the Commission.

The question of the appropriate price for the Gatliff coal will be determined at the February 1993 hearing in Docket 930001-EI. Our approval here does not alter Tampa Electric's responsibility to justify all expense recovered through the Fuel Cost Recovery Clause.

12. Level of Heavy Oil Inventory

We find that the appropriate jurisdictional amounts of heavy oil inventory to be included in working capital are $1,704,000 ($1,800,000 system) for 1993 and $1,865,000 ($1,980,000 system) for 1994. This decision incorporates the effects of the revised jurisdictional separation and the restatement of the 1994 capital structure to a thirteen month weighted average basis.

Due to the nature in which Hookers Point and Phillips Station are dispatched, as peaking units, we believe the generic inventory policy set forth in Order 12645 does not apply in this instance. The Order set the guidelines for units burning heavy oil at 45 days projected burn plus normally unavailable oil and units burning light oil at 30 days burn at the highest average monthly rate during the most current five year period. Neither Hookers Point nor Phillips Station are dispatched as an intermediate unit. In addition, neither of the generation sites have a five year history of consistent on-line service. Therefore, we have relied on the record and to set an appropriate benchmark for Tampa Electric's heavy oil inventory.

Hookers Point was removed from cold storage and put back on line in November 1990. An account of Phillips station heavy oil use began showing up on the FPSC A-Schedules filed by Tampa Electric in March 1991.

From November, 1990 through September, 1992, Tampa Electric has had only two occurrences when the amount of heavy oil burned exceeded 81,000 BBLs [May 1991-139,725 BBLs and July 1992-117,899 BBLs]. In May, 1991 the Hookers Point generation was replacing the off-line generation of Gannon #5. In July, 1992 Hookers Point produced an increase in generation from the previous month which was consistent with all but one of Tampa Electric's coal plants.

Based on the record, we find that a heavy oil inventory level of 7 days at the maximum burn rate is appropriate. This reduces the levels requested by Tampa Electric by the amounts of 12,933 BBLs in 1993 and 12,933 BBLs in 1994.

13. Requested Level of Light Fuel Oil Inventory

We find that the appropriate jurisdictional amounts of light oil inventory to be included in TECO's working capital are $1,496,000 ($1,580,000 system) for 1993 and $1,644,000 ($1,746,000 system) for 1994. This decision incorporates the effects of the revised jurisdictional separation and the restatement of the 1994 capital structure to a thirteen month weighted average basis.

When a comparative analysis of the benefits and risks of an inventory level is not outlined by a utility, we rely on the generic fuel inventory policy found in Order No. 12645. Subsequent to Order 12645, peaking reliability is maintained by the light oil inventory established by a 30 day maximum monthly rate during the most current and five year period plus normally unavailable oil.

Comparing the level of light inventory level developed using the guidelines of Order 12645 to the amount requested by the company shows that the difference is negligible. Therefore, we find that the requested inventory levels proposed by Tampa Electric Company for both 1993 and 1994 are reasonable.

14. Requested Level of Regular and Compliance Coal Inventory in Working Capital

We find that the appropriate jurisdictional amounts of compliance and regular coal inventory to be included in the working capital of Tampa Electric Company are $90,065,174 ($95,152,603 system) for 1993 and $91,717,632 ($97,400,358 system) for 1994. This decision incorporates the effects of the revised jurisdictional separation and the restatement of the 1994 capital structure to a thirteen month weighted average basis.

Tampa Electric has offered no analysis that would indicate the level which they propose to maintain is the appropriate level which will properly balance economic risks and benefits. They rely on the 100 day previously approved commission level.

Tampa Electric is requesting 92.2 days burn of regular coal and 9.3 days of environmental testing coal or a total of 101.5 days burn to be included in the 1993 and 1994 proposed coal inventory. Staff believes Tampa Electric's coal inventory should be maintained at 95 days burn and that any special purpose coal (which could be used for emergency reliability purposes) should be included in this 95 day burn benchmark and should not be in addition to this level.

We agree with staff's recommendation of 95 days as being the appropriate amount necessary for Tampa Electric to continue reliable generation under normal circumstances. We also agree with Tampa Electric's position that some additional coal is warranted in order to perform compliance coal test burns. However, we do not feel that the entire amount requested by Tampa Electric is justified. We feel that it is more appropriate to allow Tampa Electric to maintain additional inventory equal to three days burn to conduct these tests.

This benchmark is representative of a balance between staff's recommended 95 days burn level and Tampa Electric's requested 101.5 days burn. We consider this to be a justifiable guideline for

Tampa Electric to continue both reliable generation and the necessary testing of compliance coals.

Based on information in the record, we establish Tampa Electric's total (regular and compliance) coal inventory level at 98 days burn.

15. Total Amount of Working Capital in Rate Base

Based on our decisions on these specific issues and incorporating the effect of other decisions in this Order, we find the appropriate level of Working Capital is $143,388,000 for 1993 and $152,586,000 for 1994.

F. Total Rate Base

Based on our decisions on other issues discussed in this Order, we find the appropriate jurisdictional rate base for the 1993 Projected Test Year to be $1,749,355,000. Based on our decisions on other issues discussed in this Order, we find the appropriate jurisdictional rate base for the 1994 Projected Test Year to be $1,850,927,000.

V. COST OF CAPITAL

A. Cost Of Common Equity Capital

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

Three witnesses presented testimony concerning the required rate of return on common equity (ROE) for Tampa Electric. Charles Olson, testifying on behalf of the Company, recommends an ROE of 14%. Charles Benore, also testifying on behalf of the Company, recommends an ROE of 13.5%. David Parcell, testifying on behalf of the OPC, recommends an ROE within a range of 10.5% to 12%.

Mr. Olson utilizes two methods in arriving at his estimate of a required ROE for the Company. He first performs a Discounted Cash Flow (DCF) analysis on a group of comparable electric utilities. He then performs a risk premium analysis for AA rated companies. The risk premium approach attempts to estimate the appropriate ROE by recognizing the higher return investors require on equity securities than on debt securities.

Mr. Benore utilizes three methods in arriving at his estimate of a required ROE for the Company. He first performs a risk premium model on an index of comparable companies. He then performs a DCF analysis on a group of companies with a safety rank comparable to Tampa Electric. Finally, he performs a DCF on the S&P 500 companies based on the presumption that electric utility stocks are of comparable risk to the average common stock available to investors.

Mr. Parcell testifying on behalf of the OPC, utilizes three methods in arriving at a required ROE for Tampa Electric. He first performs a DCF analysis on TECO, a comparison group of eight electric utilities, and the groups of electric utilities used by Company witnesses Olson and Benore. Next, he uses a Capital Asset Pricing Model (CAPM) for the same groups of companies considered in his DCF analysis. Finally, he conducts a Comparable Earnings (CE) test to the same groups as well.

Based upon the evidence in the record and a detailed review of the cost of equity capital methodologies presented, we have determined that the cost of common equity capital for TECO is 12% with a range of plus or minus 100 basis points (for ratemaking purposes). We believe that a return of 12% would continue to provide the company with comfortable coverage ratios that, along with its strong qualitative factors, maintain the company's present credit rating. In addition, this ROE is reasonable given the current market conditions and the relatively low risk associated with this high quality, well managed electric utility.

B. Appropriate Cost Of Short Term And Long Term Debt

Tampa Electric has filed in its MFRs a short-term debt cost rate of 6.5% for 1993 and 1994, a long-term debt cost rate of 7.86% for 1993 and 7.89% for 1994, and an Oil Backout Trust (OBO) cost rate of 5.0% for 1993 and 1994.

When considering the rate for variable cost or prospective issues of debt, the most current information available should be used. The company plans to issue short term debt and projects $50 million and $90 million issues of long term debt in 1993, and a $120 million issue of debt in 1994. The company established the cost rate for these prospective issues of debt by referring to the commercial paper rate and the AA utility bond rate in the August, 1992 edition of <u>DRI's Forecast of the U.S. Economy</u>.

We base our decision on the cost of short-term debt, variable cost long-term debt, and prospective long-term debt issues for the test years 1993 and 1994 on the September, 1992 edition of DRI's Forecast of the U.S. Economy. The cost of short-term debt, accordingly, is 4.28% for 1993 and 5.37% for 1994. The cost of the OBO debt and the issue of variable cost long-term debt is assumed to be 75% of the short-term taxable commercial paper rate, which would be 3.21% for 1993 and 4.03% for 1994. The cost of the prospective issues of long-term debt is 8.68% for 1993 and 8.91% for 1993.

After establishing the rates for the variable cost long-term debt and the prospective issues of long-term debt, the overall cost of debt to be used in the capital structure is 7.60% for 1993 rather than the company's requested 7.86%. The cost for 1994 is 7.93% rather than the company's requested 7.89%. We calculated these results by specifically changing the interest costs on line 14, 16, and 28 in MFR schedule D-4a and then recalculating the overall results.

The company's requested 7.89% long-term debt cost in 1994 is lower than our decision because the company used the 1994 simple average capital structure. If a 13 month average capital structure had been used by the company, the company's request cost would be 8.04%.

Therefore, we find that the appropriate cost of short-term debt is 4.28% for 1993 and 5.37% for 1994. We find that the appropriate cost of long-term debt is 7.60% for 1993 and 7.93% for 1994. We find that the appropriate cost of the debt associated with the Oil Backout Trust is 3.21% for 1993 and 4.03% for 1994.

C. Appropriate Capital Structure Treatment Of Gannon Conversion Assets

In Order No. PSC-92-0837-FOF-EI, Tampa Electric's petition to modify its Gannon Oil backout financing was approved. In essence, the modifications dissolved the Gannon Trust and replaced the debt of the trust with tax exempt financing. The main benefit of the modification is that the debt does not have to be paid down as quickly, thus delaying the financing needs of Tampa Electric. The decision of how to treat the modification in financing for oil backout purposes was delayed until this rate case. Tampa Electric proposes to continue to specifically identify the debt associated with the oil backout clause.

We believe that rather than specifically identifying short-term debt, the new debt should replace investor sources of capital on a pro-rata basis. We believe this will not impede the company's capital structure objectives.

In its MFRs, TECO projects a reduced amount of short-term debt. In MFR schedule D-1 page 2 and 3, the short-term debt percentage of total capital is 5.00% in 1991, 4.43% in 1992, but only 2.02% proposed for 1993 and 2.14% for 1994. At the same time the Company is specifically decreasing the low cost short-term debt, the company is proposing to issue additional long-term debt and increase its common equity position. Considering these circumstances, we find that pro-rata treatment of capital structure sources will be fairer to Tampa Electric's ratepayers.

Accordingly, we find that the debt associated with the oil backout assets that will be added to the capital structure in 1993 and 1994 shall replace investor sources on a pro-rata basis, rather than specifically replace short-term debt.

D. Accumulated Deferred Investment Tax Credits - Zero Cost Rate

In its filing, Tampa Electric's zero-cost adjusted jurisdictional ITCs after reconciliation to rate base are $395,000 for the 1993 test year, $249,000 for the simple average 1994 test year and $248,000 for the 13-month average 1994 test year

The Commission has approved the parties stipulation on revised jurisdictional separation factors. Reflecting the new jurisdictional separation factors, redistributing the Gannon Oil Backout debt, converting to a 1994 thirteen-month average capital structure and making specific adjustments for the 1994 test year results in revision of the company's pro rata adjustments.

Therefore, we find that the ITCs with a zero cost rate are $389,000 for the 1993 projected test year and $244,000 for the 1994 subsequent test year.

E. Accumulated Deferred Income Tax Credits - Cost Rated

In its filing, TECO has reflected the weighted cost adjusted jurisdictional ITCs after reconciliation to rate base as $64,868,000 at 11.17% for the 1993 test year; and $59,549,000 at 11.19% and $59,988,000 at 11.21% for the simple average 1994 test year and the 13-month average 1994 test year, respectively.

The Commission has approved the parties stipulation on revised jurisdictional separation factors. Reflecting the new jurisdictional separation factors, redistributing the Gannon Oil Backout debt, converting to a 1994 thirteen-month average capital structure and making specific adjustments for the 1994 test year results in revision of the company's pro rata adjustments. Consequently, an additional adjustment was required.

Consideration of the above actions results in net adjustments decreasing 1993 ITCs by $885,000 and decreasing 1994 ITCs by $514,000.

Additionally, as a result of adjustments to the capital structure cost rates, the appropriate weighted cost of the ITCs are 10.06% for the projected 1993 test year and 10.15% for the subsequent test year.

Therefore we find that the ITCS should be $63,983,000 at a cost rate of 10.06% for the 1993 projected test year and $59,035,000 at a cost rate of 10.15% for the 1994 subsequent test year.

F. <u>Balance Of Accumulated Deferred Income Taxes</u>

In its filing, Tampa Electric's adjusted jurisdictional accumulated deferred taxes after reconciliation to rate base are $295,258,000 for the 1993 test year; and $292,849,000, and $296,905,000 respectively, for the simple-average 1994 test year and the 13-month average 1994 test year.

The Commission has approved the parties stipulation on revised jurisdictional separation factors. Reflecting the new jurisdictional separation factors, redistributing the Gannon Oil Backout debt, converting to a 1994 thirteen-month average capital structure and making specific adjustments for the 1994 test year results in revision of the company's prorata adjustments. Consequently, an additional adjustment was required. Consideration of the above results in net adjustments decreasing 1993 accumulated deferred taxes by $4,028,000 and decreasing 1994 accumulated deferred taxes by $662,000. Furthermore, the other decisions in this order result in adjustments increasing deferred taxes by $858,000 for 1993 and $1,236,000 for 1994.

Therefore, we find that the accumulated deferred taxes are $292,088,000 for the 1993 projected test year and $293,423,000 for the 1994 subsequent test year.

G. Treatment Of SFAS 109, Accounting For Income Taxes

SFAS No. 109, which changes the method of accounting for income taxes, was issued in February, 1992. Implementation of this statement is mandatory for financial reporting for years beginning after December 15, 1992. Consequently, the company will be required to implement the accounting during the 1993 test year and its implementation will affect both the 1993 projected test year and the 1994 future test year.

Tampa Electric has not reflected implementation of SFAS 109 in its projected 1993 test year or its subsequent 1994 test year.

Because Tampa Electric failed to include in its 1993 and 1994 test years, pro forma adjustments for implementation of SFAS 109, technically the utility's treatment of SFAS 109 is not appropriate. However, because no pro forma adjustments for its implementation are included, there is no revenue impact. Revenue neutrality is the intent of proposed Rule 25-14.005, Florida Administrative Code, Accounting for Deferred Taxes Under SFAS 109, which the Commission voted to adopt at the September 15, 1992 agenda conference. Consequently, we believe that the company's MFRs reflect the intent of the Commission. Therefore, we find no adjustments are necessary.

H. Weighted Average Cost Of Capital

Based upon the proper components, amounts, and cost rates associated with the capital structure for the test years ending December 31, 1993 and December 31, 1994, we find the weighted average cost of capital is 8.20% and 8.34%, respectively.

Schedules attached to this Order as Appendix 1 show the components, amounts, cost rates, and weighted average cost of capital associated with the test year capital structure for the Projected Test Year 1993 and the Subsequent Test Year 1994.

VI. NET OPERATING INCOME

A. Operating Revenues

1. Estimated Revenues - Sales of Electricity (Sales to Ultimate Customers)

We find that TECO's estimates of billing determinants for 1993 and 1994 are reasonable. The estimates of customer growth, KW and

KWH growth are consistent with the load and customer forecasts. Further, the method used to breakdown the load and customer forecast by rate class into the respective billing determinants is acceptable. The parties have stipulated to this issue, and we accept that stipulation, with the clarification that the company's proposed billing determinants are "sales to ultimate customers" or retail customers. Accordingly, we find that the company's estimated revenues for sales of electricity (sales to ultimate customers) based upon reasonable estimates of customers, KW, and billing determinants by rate class are reasonable.

2. Adjustments Removing Fuel Revenues for 1993 and 1994

TECO has proposed adjustments removing $407,074,000 ($412,686,000 system) in fuel revenues for 1993 and $440,078,000 ($452,211,000 system) for 1994 and the related expenses recoverable through the Fuel Adjustment Clause.

Based on the Stipulated Jurisdictional Separation Factors that we approved earlier in this Order, the appropriate revenue adjustments are $395,391,000 ($412,686,000 System) for 1993 and $429,647,000 ($448,779,000 System) for 1994. Total expenses shall be reduced by $393,695,000 ($411,168,000 System) for 1993 and $426,628,000 ($446,099,000 System) for 1994. The appropriate adjustments resulting from the revised separation factors are reflected in the total adjustments.

3. Adjustments Removing Conservation Revenues

The company proposed that adjustments removing $18,195,000 ($18,195,000 system) in conservation revenues for 1993 and $18,774,000 ($18,774,000 system) for 1994 and the related expenses are recoverable through the Conservation Cost Recovery Clause.

TECO stated in its post hearing position that the adjustment removing conservation expenses in 1994 is overstated. The Company's position in the prehearing order was that the adjustments contained in its filing was appropriate. Also, no evidence was presented at the hearing to substantiate the error and no correcting adjustment was made in Late-filed Exhibit No. 106, Revised Income Statement for 1994.

We find that the adjustments made by TECO to remove conservation revenues and expenses for 1993 and 1994 are appropriate and are consistent with the Commission's treatment in prior rate cases.

4. Total Operating Revenues

The company has requested Total Operating Revenues in the amount of $548,162,000 ($571,600,000 system) for the 1993 projected test year and $612,747,000 ($636,234,000 system) for the 1994 subsequent test year.

On page 85 of this Order, we decide that all revenues from off-system sales not allocated to the wholesale jurisdictional shall be included as a credit in the Fuel and Purchased Power Cost Recovery Clause. The Capacity revenues shall be credited to the Capacity Cost Recovery Clause with O&M revenues credited to the Fuel Cost Recovery Clause. We remove projected O&M revenues from off-system sales of $2,750,000 jurisdictional in 1993 and $3,888,000 jurisdictional in 1994 from base rate revenues. The O&M revenues shall be credited to the Fuel Cost Recovery Clause serving as a net offset to total rates. We have incorporated this treatment in our determination of the appropriate operating revenues.

In projecting 1994 revenue, TECO included its proposed 1993 increase in base revenues multiplied by a customer growth factor. In order to calculate the appropriate operating revenue for 1994, it is necessary to remove this $43,305,000 from revenue and include the 1993 revenue increase of $1,190,000. ($1,163,000 X 1.023 growth factor) Therefore, the appropriate jurisdictional Total Operating Revenue is $544,344,000 for 1993 and $558,584,000 for 1994.

B. Operation And Maintenance Expense

1. Advertising Expense

The company argued that its advertising expenses budgeted for 1993 and projected for 1994 are appropriate. However, TECO argued that if an adjustment were to be made, it should not be related to the safety and security related costs at the Big Bend Manatee Viewing Facility, and that there is no evidence in the record to the contrary.

OPC and FCAN asserted that jurisdictional advertising expense should be decreased by $50,635. They argued that it is not a necessary activity related to utility operations to inform the public about a manatee viewing area, the Peter O. Knight Honeymoon Cottage, and community events such as a county fair.

Staff Audit Disclosure No. 18 provided that advertising expense should be reduced by $41,479 in 1991 related to the operation of a manatee viewing facility. (TR 1283)

In response to Audit Disclosure No. 18, the company argued that the manatee viewing facility was developed to provide a safe means for the general public to observe the manatees because, prior to the opening of the facility, the company routinely experienced problems with members of the public trespassing on the plant site in order to see the manatees. The desire of the public to observe the manatees created a hazardous situation and created a potential liability problem for the company, and plant security guards were diverted from normal duties to control the situation. A Hillsborough County sheriff was dispatched on a number of occasions to control the traffic generated by people coming to see the manatees. The opening of the manatee viewing facility reduced the unsafe situations and security problems around the plant related to manatee viewing. The company also argued that an additional use of the facility is to educate customers and the general public that power generation and the environment can co-exist. The viewing facility is staffed with company retirees who volunteer their time to serve as educators and guides. This method of staffing provides the company with a cost effective method of providing an educational service to the customers and insuring safe viewing of the manatees. (EX 60; TR 771)

Accordingly, we find that the manatee viewing facility serves a valid purpose by avoiding a potential liability problem, and therefore, we shall allow those costs. However, we find that Account 909 shall be reduced by $7,212 ($7,212 System) in 1993 and by $7,655 ($7,655 System) in 1994 for costs associated with the Peter O. Knight Honeymoon cottage and community events.

2. Industry Association Dues

Tampa Electric requested Industry Association Dues in the amount of $3,703,385 ($3,802,465 system) for the 1993 projected test year and $3,855,220 ($3,958,364 system) for the 1994 subsequent test year to comply with its perception of Commission guidelines established in previous rates cases. Based on the revised jurisdictional separation factors, the revised jurisdictional requested amount is $3,629,833 for the 1993 projected test year and $3,788,550 for the 1994 subsequent test year. In making its adjustments, TECO removed one-third of its EEI administrative dues, dues for a lobbying group (Hunton and Williams), and dues for Chambers of Commerce and other organizations. At the same time, TECO allowed its contributions to

EEI's Utility Air Regulatory Group and Utility Solid Waste Activities Group.

We find that an adjustment shall be made in the amount of $10,119 ($10,600 system) in 1993 and $10,561 ($11,034 system) for dues allocated to TECO from the parent company for community development costs, the Tampa Committee of 100, and various Chambers of Commerce. This amount, had it been spent directly by TECO, would have been disallowed.

3. <u>Outside Services Expense</u>

We find that no adjustment is necessary to Tampa Electric's Outside Services Expense of $2,242,000 (jurisdictional) and $2,302,000 (system) for the 1993 projected test year and $2,387,000 (jurisdictional) and $2,451,000 (system) for the 1994 subsequent test year. No parties to this proceeding introduced evidence to support any adjustment to Outside Services Expense. Accordingly, we find that there shall be no adjustment to Outside Services Expense.

4. <u>Adjustment To Miscellaneous General Expenses</u>

No parties in this proceeding introduced evidence to support any adjustment to Tampa Electric's Miscellaneous General Expenses in the amount of $5,930,000 (jurisdictional) for the 1993 projected and $6,316,000 (jurisdictional) for the 1994 subsequent test years. Accordingly, we find that no adjustments other than those made elsewhere in this Order shall be made.

5. <u>Requested O&M Expense Level of Salaries and Employee Benefits</u>

We find that Tampa Electric's requested O&M expense level of Salaries and Employee Benefits for the 1993 projected test year and for the 1994 subsequent test year are appropriate. We find the appropriate jurisdictional number is $91,230,000 ($94,873,000 system) and $23,567,000 ($24,553,000 system) for the 1993 Projected Test Year; and $95,928,000 ($99,901,000 system) and $25,299,000 ($26,452,000 system) for the 1994 Subsequent Test Year pursuant to the new separation study agreed to by the Stipulated Jurisdictional Separation.

OPC and PASCO argued that for the 1993 projected test year, the O&M expense level of Salaries and Employee Benefits should be reduced by $2,989,000 ($3,062,170 system) and $2,151,000 ($2,208,661 system), respectively.

Even though the record indicates that TECO tried to have its average wage level approximately 10% above its competition, OPC did not state that the **average** salary level was excessive. Based on our decision that TECO's number of employees is appropriate, we find that the requested amounts for salaries and benefits as listed above for 1993 and 1994 shall be approved.

6. Number of Employees

TECO requested 3,263 for the budgeted number of employees for 1993 and 3,285 for 1994. Based on evidence presented at the hearing, no adjustment shall be made to these figures.

OPC argued that the company's budgeted number of employees is excessive, because the budget is based on the number of authorized positions rather than the number of positions that are actually filled. In addition, OPC asserted that the customer-to-employee ratio is high in comparison to other electric utilities in Florida. PASCO also argued that TECO's forecast of employees to be hired during the 1993 projected test year is overstated and should be adjusted.

TECO argued that no adjustment should be made to the budgeted number of employees. Rather than focusing on the number of employees, TECO stated that it focuses its budgeting effort on total dollars, and as reflected in its benchmark comparisons, TECO is well below the benchmark guidelines.

Mr. Schultz (OPC's witness) recommended that the total number of TECO employees budgeted for 1993, a total of 3,364, should be reduced to the actual number of employees as of July 31, 1992. Mr. Schultz stated that on that date, TECO had 3,254 employees. The figure of 3,364 employees given by Mr. Schultz is only a assumption; the record only contains this figure as an indirectly calculated approximation. Additionally, the information upon which the approximation was calculated was obtained by OPC by Citizen's Field Data Request No. 4, which was not made part of the record of this case.

The periods that are used by Mr. Schultz and those used by TECO are not comparable. The date of July 31, 1992 is little more than half way through the fiscal year. The assumptions made by Mr.

Schultz appear to be based on year-end 1993 data, since TECO adjusts salary dollars for a known salary lag (TR 983-984). For the 1993 Projected Test Year, the average number of employees will be 3,263, or only .87% higher than the 1992 figure of 3,235. For the 1994 Subsequent Test Year, the number of employees will be 3,285. (MFR Schedule C-33) The total projected increase from 1992 through 1994 totals only a net addition of 50 employees. The MFR data submitted by TECO does not support the assumptions made by Mr. Schultz.

However, even if the year-end total of employees were accepted, the timing of these net hires affect payroll expense. It is not uncommon for adjustments in the projected number of new employees to be made, particularly when companies project the hiring of all new employees, in the first month of the year for which rates will be set. It would be highly unlikely that a company would complete all of the year's hiring even as early as the first few months. Any deviation from virtually first day of the fiscal year hiring is known as a hiring lag.

Mr. Lefler (TECO's witness) stated that TECO budgets not by position but rather by total dollars and allows for the hiring lag by including an adjustment of $355,300 to budgeted payroll dollars. (TR 945) In addition, there is an adjustment of $244,000 for disability payroll dollars, for a total payroll adjustment of $599,300. Late-filed Exhibit 72 entitled "Calculation of $355,000 Adjustment" indicates that there is an historical turnover rate of 3%.

The calculation of the lag, however, is only part of the analysis. The hiring lag adjustment is a necessary company adjustment, but only a comparison of budgeted payroll dollars to actual payroll dollars at the end of the year would be a valid indicator of the company's accuracy in predicting total salary expense for 1993 and 1994. Any significant percentage deviation, particularly if it existed year after year, or was consistently high or low, would indicate that TECO did in fact have a hiring lag which was not allowed for or would indicate that TECO's budget projections were flawed and should be adjusted.

Late-filed Exhibit 73, entitled "Five Year Actual to Budget Total and O&M Payroll", shows that TECO's budget projections are higher than actual in some years are lower than actual in others. Overall, TECO's budget projections are within approximately 1.5% of actual over the period 1987-August 1992.

Accordingly, we find that TECO's budgeted payroll projections for 1993 and 1994 are reasonable. Even if Mr. Schultz's assumption of a perceived actual to budgeted employee lag as of July 31, 1992, is correct, it has been allowed for by the payroll lag adjustment. In addition, a review of the last five years budget versus actual payroll shows that TECO is accurate for this period of time in obtaining budgeted results. Thus, we find no basis upon which to reduce the projected level of new employees.

OPC also argued that TECO's customer to employee ratios were high in comparison to other electric utilities. However, Mr. Surgenor (TECO's witness) prepared a graph indicating that, with the exception of 1989, the company has shown a continuous improvement in its customer/employee ratio since 1985. (Exh. 51) This trend is expected to continue (TR 747). In his rebuttal testimony, Mr. Lefler listed several factors to consider when comparing utilities' customer/employee ratios. (TR 839-841) These factors included fuel mix, percentage of purchased power, customer mix and density, the degree that a particular utility has subcontracted construction or maintenance, and the type of pollution control devices installed at power plants.

Since such data has not been made a part of this record, we cannot judge the overall validity of these factors on a plant to plant or company to company basis. These factors would be considered in any in-depth comparison of TECO to other utilities. We agree with the company that there is insufficient information for it to be considered over staffed.

Based on the foregoing, we find that no adjustment shall be made to TECO's budgeted number of employees for 1993 or 1994.

7. Projected Accrual for Injuries and Damages

TECO projected expenses for injuries and damages of $1.679 million for 1993 and $1.787 million for 1994. Based on evidence in the record, we find the projected accrual for injuries and damages to be appropriate.

TECO maintains an unfunded injuries and damages and worker's compensation reserve in accordance with Rule 25-6.0143, Florida Administrative Code, and the Uniform System of Accounts as prescribed by the Commission. The account has been established to meet the probable liability for deaths or injuries to employees or to others not covered by insurance.

For 1993 and 1994, the company projected expenses of $1.679 million and $1.787 respectively. The company stated on MFR Schedule C-28 that the desired balance for the reserve is based on maintaining a balance sufficient to cover all incurred liabilities both reported and unreported. Also, the desired balances are determined based on historical record and review of the status of current actions. The projected accrual to this reserve account is significantly below the expense levels in prior years.

We find that the company's projected expense for injuries and damages is reasonable. We note that this reserve is for general liability claims against the company and not for storm damage coverage. The future reserve balances shall continue to reflect a balance sufficient to cover all incurred liabilities both reported and unreported. This reserve is also consistent with a similar reserve maintained by Florida Power Corporation and addressed in its recent rate case.

8. Success Sharing Program

TECO requested costs associated with its Success Sharing Program. As a result of the stipulation reached earlier in this Order regarding the jurisdictional separation and based on evidence of record, we find the appropriate jurisdictional projected expense associated with TECO's Success Sharing Program to be $5,267,000 ($5,487,000 System) for the 1993 Projected Test Year and $8,381,000 ($8,763,000 System) for 1994.

TECO implemented an incentive program in 1990 for officers and department heads whose actions and decisions directly affected the success of the company. In 1992, this program was expanded to include all employees and became known as the "Success Sharing" program. Under this program, employees are eligible to receive compensation in addition to their regular salary, if certain company goals are obtained. Starting in 1992, the target award amount is 2% of an employee's job market value increasing to a maximum of 8% in 1995. This portion of an employee's compensation is not guaranteed but is only received when the goals of the company are obtained.

OPC believes that this program compensates employees to a far greater degree than necessary to remain competitive in the marketplace. Mr. Surgenor responded that this program takes the place of the merit program for a few years; that in fact, the total payroll costs would be less than under the traditional approach (TR 698). Late-filed Exhibit No. 55, entitled "Hypothetical Salary Performance Through 1996," compares the old pay method with scheduled 5% merit increases to the new plan in which Success Sharing dollars replace a portion of the merit increase dollars. A comparison of the new plan to the old plan shows that an employee with a hypothetical salary of $10,000 in 1992 under both plans would have a total compensation about $200 less per year for 1993 and 1994 under the Success Sharing plan. The primary reason is that the 3% merit in 1992 anticipates an additional 2% paid in early 1993 if all corporate goals are met, and the bonus for 1993 will be paid in early 1994 and so on. Part of the bonus is deferred until the next budget year. The ultimate percentage of compensation at risk is unclear. MFR C-57, page 13 of 14, indicates that 8% will be the maximum at risk under Success Sharing; the testimony indicates that 10% will be the target percentage (TR 716).

TECO plans to use a 5% factor for merit increases for years after 1995 (TR 721). However, the information in Late-filed Exhibit No. 55 indicates that the company plans to continue a policy of granting 3% merit increases at least through 1996, the last year shown on the late file. If the next year, 1997, is extrapolated from the data on Late-filed Exhibit No. 55, using a 5% merit increase for both scenarios, the Success Sharing side of the chart begins to grow larger than the straight merit increase side does beginning in 1997. For the year 1997, the $12,763 multiplied by 1.05% equals a salary of $13,400 using a straight merit system only. Using a 3% merit and an 8% bonus percentage on the $12,493 under the Success Sharing scenario, the total compensation is $14,000. Part of the reason the Success Sharing side shows fewer dollars than the straight merit side is that part of the bonus earned each year is deferred until the following budget year. Also, the base pay under the Success Sharing plan changes by only a 3% merit raise as opposed to the 5% merit raise under the old pay system. Once the percentage is stabilized at 8%, however, the total compensation under the Success Sharing scenario will be higher, beginning in 1997.

Before Success Sharing, the company would grant merit increases of approximately 5% on a yearly basis, generally but not exclusively based on company performance (TR 723). None of these salary dollars were at risk. Once an employee was granted a merit increase, the base pay was the old salary plus the new merit raise. Under the new approach, however, the bonus portion of the salary package is not guaranteed. Therefore, an employee's base pay only changes by the merit portion of any increase, which for the next several years will be 3%, rather than the existing 5%.

Initially, the Success Plan dollars replace part of the present merit pay system. However, we agree with OPC that TECO employees are in no way underpaid for the performance of their duties compared to the competition. Exhibit 57, page 4, lists various job titles and salary information obtained by TECO surveys of representative samplings of TECO job classifications. In a few job classifications, TECO appears to be below its competition. In most job classifications, however, TECO is several percentage points higher than its competition.

We do not believe that Success Sharing represents an overall higher level of compensation than present. However, we do share OPC's concern regarding TECO's total level of compensation with or without Success Sharing. Since TECO is one of the larger Tampa Bay employers with excellent fringe benefits and promotional opportunities, it would attract prospective employees even with lower levels of pay. On the other hand, TECO has an excellent record of controlling O&M costs (MFR C-53, page 1) and has an overall average yearly turnover rate of only 3% (Exh. 72, p. 2), which shows that TECO has a work force that would benefit from a Success Sharing plan. Additionally, the company has indicated that the part of compensation not at risk will gradually change to equal its competition (Exh. 57). Accordingly, we approve TECO's Success Sharing Plan and find the appropriate jurisdictional numbers associated with TECO's Success Sharing Program to be $5,267,000 ($5,487,000 System) for the 1993 Projected Test Year and $8,381,000 ($8,763,000 System) for 1994. Future approval of costs associated with this program, regardless of its general merit, may be based on the achievement of parity with the market for the not at-risk portion of compensation of TECO's employees.

9. Other Fringe Benefits

TECO requested Other Fringe Benefits in Account 926 in the amount of $24,400,000 ($25,421,000 system) for the 1993 projected test year and $25,344,000 ($25,809,000 system) for the 1994 subsequent test year. We find that no adjustment is necessary other than the adjustment related to our approval of the Stipulated Jurisdictional Separation. Thus, we find that the appropriate jurisdictional numbers shall be amount for Other Fringe Benefits in Account 926 shall be $24,400,000 ($25,421,000 system) for the 1993 Projected Test Year and $25,344,000 ($25,809,000 system) for the 1994 Subsequent Test Year.

This category of expenses is properly called Employee Pensions and Benefits. Account 926 includes costs associated with pensions, medical and life insurance premiums, workman's compensation, and other employee benefits such as educational or recreational activities. The area of medical insurance premiums is the one controllable area where expenses have grown at a much higher rate than inflation. For several years the company has aggressively pursued cost reductions through various means such as higher deductibles for employees and the promotion of HMO's for employee care. As a result, TECO compares favorably to other utilities in average medical costs per employee. (Exh. 51) Nevertheless, this expense category continues to rise at a rapid rate. However, the company appears to contain costs as well as can be expected. Life insurance costs have modestly increased. All other controllable areas are budgeted for reduced amounts for 1993 from 1992.

10. Supplemental Executive Retirement Program

OPC, FCAN and PASCO argued that since this expense increased 26% over 1992 and, as of April 1992, actual expenses were less than budgeted, an adjustment should have been made in the amount of $331,000.

OPC recommended that all of the projected costs for this program be removed because the benefit represented an additional benefit provided exclusively to executives in addition to the standard retirement benefits available to all employees. Mr. Surgenor (TECO's witness) stated in his rebuttal testimony that Supplemental Executive Retirement Plans (SERPs):

> are a common practice in industry today and are provided for those employees earning above the allowed IRS maximum limit for purposes of qualified retirement plan credit. The SERP is a component of our competitive compensation and benefits package provided to our officers. (TR 669)

In addition, he stated that in a 1991 Edison Electric Institute study 76% of participating utilities provided SERP benefits for officers and that SERPS are necessary to maintain a competitive pay package for officers.

Previously, this Commission has approved the recovery of such expenses of SERPs for other electric utilities, such as Florida Power & Light Company and Florida Power Corporation. Plans of this type increase costs of any utility which implements them. These plans were originally developed to mitigate the unfairness of the IRS regulations in capping individual employees benefits. Accordingly, we find that no adjustment to the level of expenditures for its Supplemental Executive Retirement Program is necessary other than to adjust for the Stipulated Jurisdictional Separation approved previously.

11. Non-recurring Expenses

All documentation submitted by a company during a rate case is reviewed to determine whether there are any expenses that are extraordinary in nature. Extraordinary expenses only occur periodically and are not considered a routine, annual expense when setting rates. The review did not reveal any expenses which meet the definition of a non-recurring expense, nor was there any testimony by any party in this proceeding related to non-recurring expenses. Accordingly, we find that no adjustment is necessary.

12. Level of Other Post Employment Benefits

Tampa Electric requested Other Post Employment Benefits cost level in the amount of $6,545,000 ($6,749,000 system) for the 1993 projected test year and $6,995,000 ($7,213,000 system) for the 1994 subsequent test year. However, after applying the separation factors from the Stipulated Jurisdictional Separation approved previously in this Order, we find that the appropriate amounts are $6,450,000 ($6,749,000 system) for the 1993 projected test year and $6,868,000 ($7,213,000 system) for the 1994 test year.

As discussed previously, we have decided to use FAS No. 106 for ratemaking purposes. TECO testified that its FAS No. 106 costs for 1993 are $6,749,000 with $1,035,000 capitalized and $5,714,000 assigned to O & M expenses. For 1994, FAS No. 106 costs are $7,213,000 with $1,107,000 capitalized and $6,106,000 assigned to expenses. (EXH 62) Also, the company has instituted cost savings measures to control its OPEB costs. (TR 819, 662)

In its brief, TECO states that the FAS No. 106 costs should be $6,545,000 ($6,749,000 system) for 1993 and $6,868,000 ($7,213,000 system) for 1994. OPC's position is that the costs should be reduced by $4,126,328 ($4,233,000 system). PASCO adopts the same position as OPC.

Accordingly, we find that the company's FAS 106 costs for 1993 and 1994 are appropriate.

13. Pension Expense

Tampa Electric requested Pension Expense in the amount of $2,608,000 ($2,678,000 system) for the 1993 projected test year and $2,778,000 ($2,852,000 system) for the 1994 subsequent test year. We find the pension expense for 1993 and 1994 shall be $2,570,000 ($2,678,000) and $2,728,000 ($2,852,000), respectively, using the jurisdictional factors from the Stipulated Jurisdictional Separation approved previously in this Order. No record evidence was presented that convinces us that these numbers are not appropriate.

14. Rate Case Expense

TECO requested $1,438,000 total rate case expense. Late-filed Exhibit 71 shows that by September 30, 1992, $1,144,632 had actually been spent. An additional $601,000 is expected to be incurred through January, 1993, which would bring the total actual to $1,745,632. Although actual expenditures were less than budgeted in some areas, other areas exceeded the estimates. We find it appropriate to limit recovery to the original $1,438,000 requested by the company in the MFRs.

The company proposed to amortize rate case expense over two years, consistent with the amortization period approved in the company's last rate case which was in 1985. TECO testified that it will bring the Polk unit into service in 1995, and that it foresees a need to come back in two years to get recovery of that plant in rate base.

In Order No. 23573, Docket No. 891345-EI, this Commission approved a four-year amortization period, based on the actual length of time since the company's most recent rate case, and the fact that electric companies are required by Chapter 366, Florida Statutes, to file Modified Minimum Filing Requirements every four years. Accordingly, we shall use an amortization period of four years in this case as well.

Therefore, the total amount of $1,438,000 requested in the MFRs shall be allowed, but annual expense shall be reduced by $345,156 ($359,500 System) in 1993 and by $343,970 (359,500 System) in 1994, to reflect amortization over four years rather than two.

15. Sebring Utilities Acquisition

The appropriate NOI accounting treatment for Tampa Electric's acquisition of the electric generation system and associated transmission facilities of Sebring Utilities shall include the amortization of the amount related to the acquisition adjustment in the test year depreciation and amortization expense (reduces total depreciation and amortization expense). The corresponding rate base treatment of this is discussed previously in this Order. Accordingly, no adjustment is necessary.

16. Transactions with Affiliated Companies

One of the primary items that the staff auditors reviewed was transactions of Tampa Electric with its affiliates. Other than the sale of the Jackson Road Substation and the reclassification of certain accounts payable to an affiliated company, the audit report did not reveal evidence of improper transactions with affiliated parties. No evidence was introduced at the hearing to support any adjustment to the NOI effects of transactions with affiliated companies, and therefore, we find that no adjustments are necessary.

17. Total Fossil Production O&M Expenses

Tampa Electric requested Total Fossil Production O&M expenses in the amount of $78,663,000 ($81,614,000 System) for the 1993 projected test year and $81,841,000 ($84,910,000 system) for the 1994 subsequent test year. Pursuant to the Jurisdictional Separation approved previously, however, we find that the appropriate jurisdictional amount is $77,108,000 for 1993 and $79,401,000 for 1994.

Tampa Electric's projected Fossil Production O&M expenses are below the Commission's O&M benchmark for both 1993 and 1994. Tampa Electric cites its efforts at cost containment, despite having to meet new, expanded and changed environmental regulations, as the primary reason for its production expenses to be below the benchmark by $3.52 million in 1993 and $3.67 million in 1994 (jurisdictional). The record does not contain any evidence that would warrant an adjustment to such expenses in either 1993 or 1994. We find that Tampa Electric's requested level of Fossil Production O&M expenses for both the 1993 and 1994 test year is appropriate, and that no adjustment shall be made to these expenses.

OPC and PASCO argued that Tampa Electric's level of Fossil O&M expenses should be reduced by $8 million to reflect the removal of the Hookers Point units from rate base. We disagree.

18. Fossil Production O&M Expense Associated with Hookers Point

Tampa Electric requested Fossil Production O&M expense in the amount of $7,897,627 ($8,198,981 system) associated with the Hookers Point generating plant for the 1993 and 1994 test years. We find that Tampa Electric's Fossil O&M expenses associated with the Hookers Point station were prudently incurred. However, we find the appropriate amounts are $7,613,000 ($8,101,000 system) for 1993 and $7,880,000 ($8,433,000 system) for 1994, pursuant to the Stipulated Jurisdictional Separation discussed earlier in this Order.

We have determined that Tampa Electric needs the capacity from the Hookers Point to meet the energy needs of its retail ratepayers and to ensure reliability of its electric system. Since we have previously determined that Hookers Point is needed and shall remain in rate base, we find that the accompanying O&M expenses for this plant are appropriate and that no adjustment be made.

19. Transmission O&M Expense

Tampa Electric requested Transmission O&M expenses in the amount of $7,486,000 ($7,644,000 System) for the 1993 projected test year and $7,971,000 ($8,139,000 system) for the 1994 subsequent test year. Tampa Electric's requested level of Transmission O&M expenses are below the Commission's O&M benchmark for both years. Tampa Electric notes the considerable growth of transmission-related expenses experienced since its last rate case, and cites its efforts at cost containment as the primary reason that these expenses are below the benchmark. The record does not contain any evidence that would warrant an adjustment to such expenses in either 1993 or 1994. Pursuant to the Stipulated Jurisdictional Separation, however, we find that the appropriate jurisdictional amount is $7,439,000 for 1993 and $7,906,000 for 1994.

20. Distribution O&M Expense

Tampa Electric requested Distribution O&M expenses in the amount of $28,279,000 ($28,284,000 system) in 1993 and $30,117,000 ($30,122,000 system) in 1994. We disagree. Although Tampa Electric's projected Distribution O&M expenses are below the O&M benchmark, we find that these expenses shall be reduced by $1,840,258 ($1,840,258 system) in 1993 and $1,959,553 ($1,959,553 system) in 1994 to account for our finding of excessive tree trimming expenses and for the new Jurisdictional Separation study approved previously. We found no other evidence that would warrant any other adjustment to these expenses in either 1993 or 1994. Therefore, we find that Tampa Electric's level of Distribution O&M expenses shall be $26,438,742 ($26,443,742 system) in 1993 and $28,157,447 ($28,162,447 system) in 1994.

Tampa Electric requested distribution expenses of $6,257,305 ($6,257,305 system) for tree trimming expense for the 1993 and 1994 test years. We find that Tampa Electric's tree trimming expenses shall be reduced to reflect a continuing four-year cycle. Expenses for the 1993 and 1994 test years shall be reduced by $1,840,258 ($1,840,258 system) and $1,959,553 ($1,959,553 system), respectively. These adjustments reduce Tampa Electric's tree trimming expenses in 1993 to $4,417,047 (4,417,047 system) and to $4,704,120 ($4,704,120 system) in 1994.

Tampa Electric is gradually moving from a four-year to a two-year tree trimming cycle and attempted to justify the change based on a study performed in 1983 (Tr. 846, 610). Mr. Lefler (TECO's witness) testified that it was appropriate to move to a two-year tree trimming cycle to reduce momentary outages (Tr. 959). However, Tampa Electric presented no evidence in the record to show any reduction in momentary or total outages, in spite of the additional money spent to date. Public Counsel believed that Tampa Electric's request for a two-year cycle was not supported by the low level of tree-related outages recorded by the company (Tr. 611). Mr. Lefler testified that only 600 of the 11,300 distribution circuit breaker outages in 1991 were tree-related, and that only 25% of those 600 were momentary (Tr. 957-8). Tampa Electric did not testify as to whether the number of momentary outages has increased or decreased from prior years. Because Tampa Electric failed to show any improvement in total outages to justify the additional expenditures for tree trimming, we shall refrain from approving the amounts expended.

Public Counsel argued that Tampa Electric's 1993 tree trimming budget of $6,257,305 represents an increase of 24.4% over the 1991 actual expenses of $5,029,228. The 1993 test year tree trimming budget is substantially higher than the actual tree trimming expense for the previous five years (Tr. 610). Public Counsel noted that Tampa Electric's budget variance report for 1991 explained that $742,000 of the over-budgeted actual tree trimming expense was due to additional work performed to move closer to the desired two-year trim cycle. In addition, Public Counsel stated that once the desired cycle is obtained, subsequent years' spending should be less than the average tree trimming expenses for the last two years (Tr. 610). We agree with Public Counsel's assertion that tree trimming expenses over the last two years were over budget because of Tampa Electric's attempt to convert its tree trimming activities to a two-year cycle. Tampa Electric's proposed 1993 tree trimming expense should be less than its 1990 and 1991 two-year average.

We find that Tampa Electric's move to a two-year tree-trimming cycle is not supported by the record. Even if Tampa Electric were justified in moving to a two-year cycle, subsequent years' spending should be less.

The amount of allowed Distribution O&M expense for tree trimming in 1993 and 1994 shall be calculated by escalating the 1984 actual tree trimming expenses, which we approved in Tampa Electric's last rate case, by the CPI/customer growth multiplier:

	$2,432,000	1984 O&M Benchmark for Four-Year Cycle
*	1.81622	CPI times customer growth (1984-1993)
	$4,417,047	1993 allowed tree trimming expense (system)
	$2,432,000	1984 O&M Benchmark for Four-Year Cycle
*	1.93426	CPI times customer growth (1984-1994)
	$4,704,120	1994 allowed tree trimming expense (system)

The amount of adjustment to Tampa Electric's tree trimming expenses in 1993 and 1994 shall be calculated by subtracting allowed expenses from Tampa Electric's requested level of tree trimming expense in those two years:

	$6,257,305	TECO's requested 1993 tree trimming expense
-	4,417,047	Commission-approved 1993 expense
	$1,840,258	Adjustment for 1993 (system)
*	1.00	1993 jurisdictional separation factor
	$1,840,258	1993 adjustment (jurisdictional)

	$6,663,673	TECO's requested 1994 tree trimming expense
-	4,704,120	Commission-approved 1994 expense
	$1,959,553	Adjustment for 1994 (system)
*	1.00	1994 jurisdictional separation factor
	$1,959,553	1994 adjustment (jurisdictional)

21. Miscellaneous Prepaid Items

The Statement of Facts of Audit Disclosure 13 state that the company contributed $6,412,036 to fund the retirement plan as determined by an actuary in December, 1991. By the end of 1991, $4,104,651 was charged to Miscellaneous Prepaid Items. The amount is amortized by $153,000 per month out of the prepaid account. The opinion in the Audit Disclosure is that the 1991 prepaid pension amount should be reduced to reflect only one year's prepayment. (EXH 83)

The company agrees with the Statement of Facts included in the Audit Disclosure but does not believe that the balance of prepaid miscellaneous items should be reduced to reflect only one year of pension prepayments. The actuary determined the amount to be contributed to the plan during 1991 under the ERISA guidelines. The $6,412,036 is the maximum amount that was deductible for tax purposes in 1991 and the minimum contribution required by ERISA. (EXH 60)

The company argues that the prepayment benefitted the customers in two ways. First, TECO was allowed a tax deduction. Second, the 1992 pension expense was reduced by approximately $400,000 because the asset was reflected for all of 1992 in the calculation of the pension expense. No additional funding is forecasted until December, 1993. (EXH 60)

Accordingly, we do not believe an adjustment to Miscellaneous Prepaid Items for prepaid pensions is warranted. The prepaid asset arose due to constraints placed on the contribution from tax and ERISA considerations.

22. Customer Accounts Expense

Tampa Electric requested Customer Accounts Expense in the amount of $19,050,000 ($19,053,000 system) for the 1993 projected test year and $20,289,000 ($20,292,000 system) for the 1994 subsequent test year. Customer Accounts expenses are recorded under five categories: supervision, meter reading expense, customer records and collection expense, uncollectible accounts, and miscellaneous customer accounts. TECO's projected expenses in the Customer Accounts functional area are $5,908,000 below the benchmark in 1993 and $1,000 over the benchmark in 1994.

The parties stipulated to the appropriate level of bad debt expense in the amount of $2,041,000 ($2,041,000 system) for the 1993 projected test year and $2,174,000 ($2,174,000 system) for the 1994 subsequent test year. Staff calculated a three-year average of net write-off as a percentage of sales (or .226%) which was applied to the projected sales for 1993 and 1994 for purposes of testing the reasonableness of this expense. This approach is consistent with that used in prior rate cases, including the recent Florida Power Corporation rate case in Docket No. 910890-EI. Accordingly, we accept and approve this stipulation.

Based on the Jurisdictional Separation Factors approved previously, we find that the appropriate level of Customer Accounts Expense for the 1993 and 1994 test years is $19,045,000 ($19,053,000 system) and $20,282,000 ($20,292,000 system) respectively.

23. Customer Service Expense

Tampa Electric requested Customer Service Expense in the amount of $2,923,000 ($2,923,000 system) for the 1993 projected test year and $3,112,000 ($3,112,000 system) for the 1994 subsequent test year. Other than adjustments to advertising expense discussed previously in this Order, no parties proposed any adjustments to Customer Service Expense. Accordingly, we find that no adjustment is necessary.

24. Sales Expense

Tampa Electric requested Sales Expense in the amount of $280,000 ($280,000 system) for the 1993 projected test year and $298,000 ($298,000 system) for the 1994 subsequent test year. No evidence was introduced at the hearing to support adjustment to Outside Services Expense. Accordingly, we find that no adjustment is necessary.

25. Administrative and General Expense

Tampa Electric requested Administrative and General Expense in the amount of $73,407,000 ($75,372,000 system) for the 1993 projected test year and $77,544,000 ($79,646,000 system) for the 1994 subsequent test year. Other than specific adjustments discussed elsewhere, we find no additional adjustments to the Administrative and General Expense. Accordingly, after making adjustments elsewhere, the appropriate level of Administrative and General Expense is $71,901,000 ($74,911,000 system) for 1993 and $75,728,000 ($79,180,000 system) for 1994.

26. O&M Expenses Below the Benchmark

The Commission is expressly authorized by Section 366.041, Florida Statutes, to consider a utility's costs of providing service as part of the Commission's determination of fair, just, and reasonable rates. In making this determination, it is important to keep in mind that the benchmark is simply a tool or an indicator. The benchmark is a test, not a reward or penalty mechanism. It is not a floor or a ceiling. Certain expenses may not grow at the benchmark level, while others may exceed the benchmark level. In neither case are we precluded from looking closely at O&M expenditures. The benchmark forces the company to justify any inability it experiences in holding expenses within the rate of inflation and customer growth. Allowing any expenses to be included in rates automatically, simply because they are less than a benchmark, will not give adequate consideration to the utility's cost to serve and may fail to adequately evaluate the fair and reasonable costs of rendering service.

During a rate case, the Commission Staff reviews all utility O&M expenses. When imprudent expenses are identified, we can disallow such expenses regardless of whether or not they are below the Commission's O&M benchmark. Therefore, we find that O&M expenses below the benchmark are already subject to a test of prudence.

27. Operation and Maintenance Expense

Tampa Electric requested Operation and Maintenance Expense in the amount of $217,355,000 ($222,686,000 system) for the 1993 projected test year and $228,732,000 ($234,340,000 system) for the 1994 subsequent test year. We find, however, that the appropriate

Operation and Maintenance expense is $211,842,000 for 1993 and $222,448,000 for 1994, based upon the findings in the other O&M expense areas.

C. Depreciation Expense

1. Depreciation Expense Associated with the Acquisition of Sebring Utilities

Tampa Electric proposed Depreciation Expense of $2,446,000 ($2,542,000 system) for 1993 and $2,442,000 ($2,556,000 system) for 1994 associated with the acquisition of Sebring Utilities Commission's Electric Generating System and associated transmission facilities. We find that the company has correctly calculated the depreciation expense for the generation system and transmission facilities purchased from Sebring Utilities Commission. This calculation was based on the plant in service and the depreciation rates as prescribed by the Commission in Docket No. 910868-EI. The jurisdictional amounts are the result of the Stipulated Jurisdictional Separation.

2. Dravo-Wellman Bucket Unloader Contract

We find that no adjustments shall be made to Depreciation Expense related to the Dravo-Wellman bucket unloader contract for any test year. Further discussion related to the contract is discussed previously in this Order.

3. Adjustment to Reflect New Depreciation Rates

To properly reflect the depreciation rates approved by the Commission in Docket No. 920618-EI, depreciation expense shall be reduced by $1,612,000 ($1,799,000 system) for the 1993 test year and by $1,750,000 ($1,970,000 system) for the 1994 subsequent test year.

Late-filed Exhibit No. 66 provides the depreciation expense for the test years 1993 and 1994 using the rates set forth in Order No. PSC-92-1205-FOF-EI. Late-filed Exhibit No. 96 provides the correct 1993 jurisdictional factor for determination of the jurisdictional amount of 1993 expense; and Late-filed Exhibit No. 98 provides the correct 1994 jurisdictional factor for determination of the jurisdictional amount of 1994 expense. Use of these rates and factors results in a reduction by an amount of $1,799,000 on a system basis for 1993 depreciation expense, and the corresponding jurisdictional adjustment is a reduction in the amount of $1,612,000. For test year 1994, the depreciation expense shall be reduced by $1,970,000 on a system basis, and the corresponding jurisdictional adjustment is a reduction in the amount of $1,750,000.

4. Depreciation Expense

Tampa Electric requested Depreciation Expense of $102,642,000 ($107,168,000 system) for the 1993 projected test year and $107,980,000 ($112,740,000 system) for the 1994 subsequent test year. Based on adjustments discussed in this Order, we find the appropriate calculations for depreciation to be $99,001,000 for 1993 and $103,697,000 for 1994.

D. Taxes Other Than Income Tax

1. Taxes Other than Income Taxes

Tampa Electric requested Taxes Other Than Income Taxes in the amount of $39,762,000 ($41,662,000 system) for the 1993 projected test year and $41,960,000 ($43,965,000 system) for the 1994 subsequent test year. Based on the Stipulated Jurisdictional Separation Factors, adjustments decreasing taxes other by $569,000 ($0 system) for the 1993 test year and $776,000 ($1,000 system) for the 1994 test year are appropriate (Late-filed Exhibit No. 106). No other adjustments are necessary. Consequently, we find that the taxes other than income taxes shall be $39,193,000 ($41,662,000 system) for the 1993 projected test year and $41,184,000 ($43,964,000 system) for the 1994 subsequent test year.

E. Income Tax Expense

1. Interest Synchronization

In its filing, Tampa Electric's interest synchronization adjustments decrease 1993 income tax expense by $1,418,000; decrease the simple average 1994 income tax expense by $913,000; and decrease the thirteen-month average 1994 income tax expense by $743,000.

The company's request for increased rates was based on the 1994 simple average test year; however, we have previously decided to use the 13-month average test year for 1994. Consequently, this required that an adjustment be made for the 1994 test year. Also, we have approved the Stipulated Jurisdictional Separation Factors, and, thus, adjustments for both test years are appropriate. We have also considered adjustments that have been made to the cost of capital components and rate base that have an impact on the interest synchronization adjustment.

Therefore, after the adjustments are made and interest expense is synchronized to the amount of debt in the capital structure (following reconciliation to the rate base), we find that the income tax expense shall be increased by $2,256,000 for the 1993 projected test year and increased by $3,264,000 for the 1994 subsequent test year for the effects of interest synchronization.

2. Income Tax Expense

Tampa Electric requested Income Tax Expense in the amount of $47,028,000 ($50,097,000 system) for the 1993 projected test year and $60,446,000 ($63,207,000 system) for the 1994 subsequent test. We find that jurisdictional adjusted income tax expense, including interest synchronization, shall be $51,624,000 for the projected 1993 test year and $47,726,000 for the 1994 subsequent test year.

Pursuant to the Stipulated Jurisdictional Separation Factors, we find adjustments shall increase income tax expense by $1,680,000 for 1993 and decrease income tax expense by $465,000 for 1994. Moreover, we find elsewhere in this Order other adjustments that increase income taxes for 1993 by $660,000 and decrease income taxes for 1994 by $15,519,000.

Finally, our decision regarding interest synchronization adjustments increases 1993 tax expense by $2,256,000 and increases 1994 tax expense by $3,264,000. (The 1994 interest synchronization adjustment of $3,264,000 includes an $173,000 reduction in tax expense which results from our decision to use a thirteen-month average test year, rather than the simple average test year upon which the company's request was based.)

Accordingly, we find that income tax expense (including interest synchronization) shall be $51,624,000 for the projected 1993 test year and $47,726,000 for the 1994 subsequent test year.

F. Net Operating Income

Tampa Electric requested Net Operating Income of $141,416,000 ($150,030,000 system) for the 1993 projected test year and $173,465,000 ($181,809,000 system) for the 1994 subsequent test.

Based on adjustments made elsewhere in this Order, however, we find that the appropriate Net Operating Income is $142,724,000 for 1993 and $143,538,000 for 1994.

VII. REVENUE REQUIREMENTS

A. Revenue Expansion Factors

Tampa Electric proposed revenue expansion factor of 62.1886 percent and the NOI multiplier of 1.608012 for 1993 and 1994. (Schedules 6 and 12) No evidence was introduced at the hearing to support an adjustment to the bad debt expense. Accordingly, the revenue expansion factor of 62.1886 and the NOI multiplier of 1.608012 as proposed by TECO are correct for both 1993 and 1994.

B. Annual Operating Revenue Increase

Tampa Electric requested annual operating revenue increase of $63,494,000 for the 1993 projected test year and $34,392,000 for the 1994 subsequent test year. Based on our other decisions in this Order, we find that a $1,163,000 increase is appropriate for 1993 and an increase of $17,412,000 is appropriate for 1994 for a total of $18,575,000.

VIII. COST OF SERVICE AND RATE DESIGN ISSUES

We have ascertained the company's revenue requirement and the amount of revenue increase necessary to fulfill that requirement. We now consider rate design: the rate of return currently earned by each rate class; and how each class's responsibility will be spread between the customer, energy, and demand charges.

The Prehearing Order reflects proposed stipulations on several cost of service and rate design issues. We have carefully reviewed the proposed stipulations, we approve them, and we adopt them as our decisions on the relevant cost of service and rate design issues in the case. Listed below are the stipulated resolutions to the cost-of-service and rate design issues reflected in the prehearing order:

The criteria used to allocate any increase in revenue for 1993 and 1994 among rate classes shall include: 1) cost to serve the various classes; 2) rate history; 3) public acceptance of rate structure; 4) Customer understanding and ease of application; 5) consumption and load characteristics of the classes; and 6) revenue stability and continuity.

The method used by the utility for calculating the increase in unbilled revenues by rate class is appropriate.

The Sports Field provision in Rate Schedule GS shall be eliminated, since we approve the low load factor provision for the GS rate class in this Order.

The provisions on the General Service Nondemand (GS/GST) and General Service Demand (GSD/GSDT) rate schedules that provide for 90 days notice before transferring a customer whose demand has exceeded the maximum for the rate schedule to the GSD/GSDT or GSLD/GSLDT rate schedules shall be eliminated.

The company's proposed revision to the definitions of some of the standby service billing determinants is approved.

It is appropriate to eliminate the Street Lighting Service (SL-1) and Outdoor Lighting Service (OL-2) rate schedules.

The parties who took positions on the remaining cost of service and rate design issues in the case entered into a comprehensive stipulation on those issues. We have carefully reviewed the comprehensive stipulation, we approve it, and we adopt it as our decision on all cost of service and rate design issues in the case. A copy of a spread sheets of approved rates is attached to this order as part of Appendix 1. Listed below are the stipulated resolutions to the remaining cost-of-service and rate design issues raised in this proceeding:

The treatment of interruptible service as a demand-side management program will not be pursued in this case. The company will file a cost study which allocates costs to this class(es) based on their load characteristics and a study which develops a Coincident CP KW credit based on avoided cost <u>at the same time as they file their MFR's in their next rate case.</u> The company's proposed treatment may be different from this filing.

TECO's IS-3 and IST-3 rates (or other applicable interruptible rates) shall be made available to customers with a minimum demand of 500 KW.

The existing closure and waiting list procedure associated with TECO's interruptible rates shall not be eliminated.

Tampa Electric will file the information required by Rule 25-6.0438 regarding the cost-effectiveness of its proposed interruptible rates within 60 days after the entry of the final order in this proceeding. The Commission may then take such action as it deems appropriate consistent with the purpose and intent of the rule after notice and opportunity for hearing to all affected customers.

Parties stipulate to the use of the 12 CP and 1/13th weighted average demand cost of service methodology with the scrubber portion of the environmental equipment for Big Bend 4 classified as energy related as appropriate for use in this proceeding.

As an option, GSD customers for whom it is cost-effective to take service under a non-demand rate with a non-fuel energy charge equal to 120% of the GS energy charge may do so.

The power factor shall be stated as a range of 85% to 90%, with a penalty for a power factor below 85% and a credit for a power factor above 90%. The power factor penalty shall be set at twice the level of the credit in an attempt to encourage Customers to improve their power factor to at least 85%. The power factor clause as proposed by the company and described in the company's filing sets out the calculation of the appropriate credit or penalty. The power factor should be stated as the average power factor because power factor is important at all times, not just during peak demand periods.

The appropriate transformer discount for GSLD Customers is 36 cents per KW at primary level and 59 cents per KW at subtransmission level and 23 cents for subtransmission level IS Customers.

Tampa Electric's proposed changes in the Tariff Agreements for the purchase of firm and interruptible standby and supplemental service are appropriate.

The firm and interruptible standby service rate (SBF-1) will be developed from the compliance cost of service study consistent with the methodology contained in the Commission's standby rate Order No. 17159 in Docket 850673-EU. A 12% outage rate will be used in calculating the reservation charge. There will be no adjustment of unit costs for cost of service methodology or the rate of return of the full requirements class.

The interruptible standby service rates (SBI-1 and SBI-3) will be developed from the compliance cost of service study consistent with the methodology contained in the Commission's standby rate

Order No. 17159 in Docket 850673-EU. A 12% outage rate will be used in calculating the reservation charge. There will be no adjustment of unit costs for cost of service methodology or the rate of return of the full requirements class.

The power factor clause shall apply to the standby portion as well as the supplemental portion of a standby service customer's load.

The appropriate customer charges for 1993 and 1994 are identical and are set out for each rate class in MFR Schedule E-16c.

The appropriate service charges for 1993 and 1994 are identical and are set out in MFR Schedule E-16d.

For the non-demand classes, the off-peak non-fuel energy cost should be set at the class's energy unit costs, and the on-peak energy charge should recover the balance of the class's revenue requirements less the customer charge revenue. For demand classes, the off-peak non-fuel energy charge should be set at the class's energy unit cost, the maximum demand charge should recover the distribution unit costs, the on-peak demand charge should recover transmission and production costs, and the on-peak energy charge should recover the balance of the class's revenue requirements less the customer charge revenues.

The following provisions shall be incorporated in the design of the final street and outdoor lighting rate schedule charges for 1993 and 1994:

a) The energy charges for lighting fixtures will be set at the per kwh unit cost for demand, non-fuel energy, and customer costs as developed in the final compliance cost of service studies for 1993 and 1994.

b) The monthly maintenance charges for 1993 and 1994 will be set at the monthly maintenance costs as developed in the Lighting Incremental Cost Study, which was filed by TECO as a supplement to MFR Schedule E-17.

c) The fixture charges will be adjusted to collect the additional revenue requirement for lighting fixtures and poles.

d) TECO will include in its tariff a provision indicating that the company normally will replace burned out street lights within three working days of notification by the customer.

The appropriate level of the Emergency Relay Power Service Charge is set out for the applicable rate schedules in MFR Schedule E-16c.

The CIAC shall be equal to the cost of additional facilities required to provide emergency relay power service.

The amount of CIAC a customer is required to contribute to purchase a Time-of-Day meter shall be equal to the difference in cost between a regular meter and a Time-of-Day meter.

IX. OTHER ISSUES

A. Settlement Charges By Utley-James Oakes

Concurrently with the Staff financial audit, an engineering audit of expenses associated with Big Bend 4 (BB4) was also conducted (Exh. 85). Audit Disclosure No.4 of the Staff Audit Report (Exh. 83) stated that due to resequencing of work, design interferences, and schedule accelerations, Utley-James/Oakes billed TECO for additional charges for an amount in excess of the $850,000 that through negotiations TECO agreed to pay to Utley-James/Oakes. The audit opinion stated that the charges did not represent normal costs of installation but were the result of poor performance by various vendors and TECO, and that as a result these charges should have been expensed rather than capitalized.

The construction of BB4 was very complex, and the record indicates that there were numerous delays encountered during the construction of this facility but it is not possible to determine that any adjustment is warranted. In addition, there is no explanation to support any adjustment amount, other than the fact that the $850,000 is what TECO settled for. The company stated in its response in Issue 9, that certain changes were outside its direct control and that the plant was constructed on budget and was placed in Rate Base on time. To assess TECO's judgment at this point in time would be inappropriate. The original claim against TECO amounted to $1,500,000; through negotiations this amount was reduced to little more than half of the original figure. By negotiating this settlement, TECO demonstrated that it attempted to hold the ultimate construction costs of this plant to a minimum and was not simply planning to ultimately pass through all costs of BB4 to the ratepayers without a review. Therefore, we find that these settlement charges in the amount of $850,000 by Utley-James/Oakes on contract BB4-04 were appropriate and should remain part of the capitalized costs of BB4.

B. Capacity Associated With Purchase And Sharing Of Hardee Power Station

The Commission granted a determination of need for the 295 MW Hardee Power Station capacity to Seminole Electric Cooperative (SEC). TECO Power Services (TPS) responded to the SEC Request for Proposal (RFP) for backup power to back up Seminole's existing coal fired units. The Commission bifurcated Docket No. 880309, the need determination docket, and made two findings. First, in Order No. 20930 the Commission found that SEC had established a need for 450 MW of capacity in 1993, and second, in Order No. 22335 the Commission found that the TPS proposal satisfied SEC's need in the most cost-effective manner to SEC and provides adequate electricity at a reasonable cost.

Tampa Electric's participation in the sharing of the Hardee capacity with Seminole Electric results in the deferral of 225 MW of combustion turbine capacity in the Tampa Electric Company's twenty year plan. (TR 255) Seminole will use the Hardee unit to meet its need for backup power during the spring and fall maintenance outages of its existing units, while Tampa Electric's new capacity needs are in the winter and summer months. (TR 255) Tampa Electric will pay TPS an amount equal to 40% of the Hardee capacity and energy charges, with Seminole responsible for the remaining 60% of capacity and energy charges. (TR 529)

The Commission based the need finding on the economics inherent in the wholesale contracts between TPS, SEC and Tampa Electric. (Order No. 22335) In Phase I (1993-2003) TPS will construct 295 MW of combined cycle capacity and TECO will sell 145 MW of Big Bend 4 capacity to SEC, and in Phase II (2003-2013) TPS will replace the BB-4 capacity by constructing a 70 MW heat recovery unit and one 75 MW CT at the Polk/Hardee site for sale to SEC. (TR 254) The combination of the sale of existing BB-4 capacity and constructing new TPS capacity was preferred to the option of SEC constructing two 220 MW combined cycle units in 1993. The TPS proposal resulted in projected present worth of revenue requirements savings to SEC of approximately $57 million (1987 dollars) and projected present worth revenue requirement savings of $90 million (1989 dollars) to Tampa Electric based on the deferral of 225 MW of previously planned CT capacity on Tampa Electric's system. (Order No. 22335)

The Commission also recognized the sharing of 295 MW of Hardee Power Station capacity between Tampa Electric and SEC as purchased power in Tampa Electric's determination of need proceedings for the Polk County IGCC unit. (Order No. PSC-92-0002-FOF-EI) Accordingly, we find that Tampa Electric demonstrated that capacity associated with the Hardee Power Station is needed for its retail ratepayers in 1993 and 1994.

C. Capacity Costs Associated With The Purchase Of Power From The Hardee Power Station

TECO has requested that the capacity costs associated with the purchase of power from the Hardee Power Station flow through the new Capacity Cost Recovery Factor. We find that the annual Hardee Power capacity costs shall be recovered through the Capacity Cost Recovery Clause.

The three parties to the Hardee Power Station, Tampa Electric, TECO Power Services (TPS) and Seminole Electric Cooperative, have negotiated wholesale contracts for the purchase and sale of the 295 MW of combined cycle capacity. Tampa Electric proposed to collect the capacity charges associated with the Hardee Power Station through the Capacity Cost Recovery Clause. (TR 256) The company's contractually agreed upon monthly capacity charge paid to its affiliate TPS pursuant to the wholesale contract is $1,095,932. This number does not vary and could be allocated among rate classes and recovered through base rates. We shall permit cost recovery through the Capacity Cost Recovery Clause solely to keep components of the Hardee costs together. Because of the straightforwardness of the amount, we are actually indifferent to whether recovery is through base rates or the capacity cost recovery clause. Although arrangements such as the Hardee Power station may be more complicated than what was envisioned by the decision to recovery purchased power capacity costs through the Capacity Cost Recovery Clause, we believe the contract to be monitorable for cost recovery clause purposes.

The company's witness, Mr. Ramil, testified that Tampa Electric could have built the Hardee Plant instead of TPS. (TR 536-37) If this plant were constructed and owned by Tampa Electric, it would come under traditional cost of service regulation subject to the Commission's authorized return on equity. Because the plant is an Affiliated Power Production facility, it is entirely possible that these earnings could exceed the level approved by this Commission for rate base generating plant.

In traditional regulation, the capital cost recovery of a fixed asset such as a generating plant is included in rate base with the expense reflected in base rate charges recovered on a per kilowatt hour basis. Pursuant to the traditional treatment, the earnings of the company's stockholders vary due to the seasonality and variability of sales. This results in a certain level of risk associated with capital cost recovery which is borne by the stockholder for which they are compensated through the authorized return on equity. However, in the TPS Hardee purchase power contract, stockholder earnings are guaranteed pursuant to the proposed Purchased Power cost recovery of the Hardee Power capacity. Tampa Electric proposed to recover these capacity costs on a fixed levelized basis independent of sales levels. In other words, through the proposed recovery treatment, the parent company has decoupled the cost associated with the Hardee Station from sales.

D. Capacity Charges Through Hardee Power Station

TECO proposed $13,151,184 in annual capacity charges for the Hardee Power Capacity. (Exhibit 37) In Order No. 22335 issued December 22, 1989, the Commission approved the petition of Seminole Electric, TECO Power Services (TPS) and Tampa Electric for a Determination of Need for the Hardee Power Project as well as the wholesale power sales contract between TECO, TPS and Seminole. Annual capacity charges in the amount of $13,151,184 are in accordance with the power sales contract. Tampa Electric's off-system sales revenues from the Hardee Power Station for all interchange sales shall flow through the Capacity Cost Recovery Clause.

E. O&M Costs Associated With Purchase Of Power From Hardee Power Station

TECO has requested that the fuel and O&M costs associated with the purchase of power from the Hardee Power Station flow through the Fuel Adjustment Clause. We shall allow recovery of actual Hardee Power fuel costs through the fuel cost recovery clause because these costs will vary with the amount of energy produced and the market price of fuel. If actual O&M expenses exceed projected amounts shown in Exhibit 37, Tampa Electric shall notify the Commission prior to the hearing and justify any O&M expenditures which exceed the projected amounts during the period 1993-1997. Prior to 1997, the company shall provide Staff with projected O&M costs for the remainder of Phase I through 2003. This treatment will provide the company with the opportunity to recover O&M expenditures exceeding the projected levels after providing justification for these expenditures as well as to provide the Commission with additional cost information relating to the total cost of Hardee Power Project.

Tampa Electric projects annual fixed and variable O&M costs ranging from approximately 1.45 million to 3.0 million for the period 1993-1997. (Exhibit 37) These cost vary from period to period depending on the planned outage and maintenance schedules for the Hardee Power Plant. The Commission contemplated Purchased Power Capacity clause recovery of related O&M costs in the generic investigation, Docket No. 910794-EQ. However, the Commission made no finding in the proceeding and stated that "While there may be merit in these suggestions, we do not have sufficient information at this point to determine definitively what additional items may be appropriate." The Commission indicated that inclusion of O&M expenditures would require consideration in a rate case or other generic proceeding to determine the exact nature and magnitude of such charges. (Order No. 25773)

Because the O&M benchmark is based on projections and because of the requirement for specific justifications to recover O&M costs if exceeded, we find that actual fuel and O&M costs shall be recovered through the Fuel Adjustment Clause. Tampa Electric shall be required to justify annual O&M costs exceeding those amounts projected by the Company in Exhibit No. 37 for the period 1993-1997 and provide updated projections for future periods.

F. Reward/Penalty For Corporate Performance

The issue of whether or not Tampa Electric should be given a reward or penalty for its corporate performance in the areas of residential rates, customer service, and energy efficiency programs was raised by the Commission staff. We believe that staff has an obligation to look into these matters and bring them to our attention when appropriate. However, we are reluctant, unless the conditions seem to be fairly extreme one way or the other, to grant a reward or impose a penalty.

TECO has the highest rates on a per 1000 kwh basis of the Peninsular IOU's, but its average residential revenue divided by residential sales yields a rate that is between the other two IOU's. With regard to customer complaints, Ms. Pruitt (staff's witness) testified that justified complaints per 1000 customers has been higher for TECO than the industry as a whole for three of the past five years, but TECO's individual complaints have decreased every year, but one, since 1987. (TR 1483-1484) TECO's conservation efforts have been comparable with other IOU's in that more emphasis is placed on demand reducing programs than energy reducing programs. TECO's conservation programs have been approved by the Commission and are consistent with the statutory requirement that conservation programs be cost-effective.

Therefore, we find that TECO shall not be rewarded or penalized in this rate case since it appears that TECO's management has neither excelled nor failed in its corporate performance in the areas of residential rates, customer service, and energy efficiency programs.

G. Broker Sales

We believe that Tampa Electric Company has acted appropriately in making off-system sales of excess capacity rather than as-available one hour sales transactions through the Florida Energy Broker System.

The Commission's treatment of surplus Big Bend capacity in TECO's last rate case (Docket No. 850050-EI) encouraged what we believe are appropriate actions to maximize off-system sales. In TECO's last rate case, the Commission established an off-system sales target for surplus Big Bend capacity by imputing $37.1 million in revenues for off-system sales. This gave TECO an incentive to make as many non-Broker sales as possible since 100% of non-Broker sales revenues offsets the sales revenue imputation made by the Commission in the last rate case.

TECO has not, since the last rate case, achieved $37.1 million dollars in annual off-system sales revenue. Thus, in some respects, the shareholders have been disadvantaged by the imputation of revenue.

Profits from as-available sales through the broker system are split with 80% enuring to the benefit of the ratepayers and 20% enuring to the benefit of the shareholders. It has been suggested that in making off-system sales, TECO has bypassed the Broker System so that more of the profits from these transactions would accrue to the shareholders. The testimony we heard does not support such a finding.

In its position, TECO states "If a utility can bring greater revenue to its system by selling power through another interchange agreement it should be encouraged to do so." We agree. By imputing $37.1 million in revenues for off-system sales we established an incentive for TECO to pursue off-system sales. The greater weight of the evidence suggests that TECO acted appropriately in marketing its excess capacity.

H. Appropriate Treatment Of Revenues Associated With Off-System Sales, Incentives

Staff recommended that all capacity revenues from off-system sales should be credited to the Capacity Cost Recovery Clause and that all off-system O&M revenues credited to the Purchased Power and Fuel Cost Recovery Clause. Staff proposed this treatment because of the variability of off-system revenues, which depend on the needs of Tampa Electric's neighboring utilities, the prevailing market conditions, and competing fuel prices. Uncertainty in projecting off-system revenues presents a problem when determining base rates in a rate case.

If in future years, actual revenues are greater than the forecasted amount included in base rate determination, the ratepayers are penalized and the company retains the excess revenues for its stockholders. The opposite is true if actual revenues are less than the forecasted amount benefiting the ratepayers. Since forecasting the revenue impact of future off system sales revenues is difficult because of the numerous assumptions contained in the forecast which may or may not prove accurate over time, staff recommended crediting off-system capacity revenues to the Capacity Cost Recovery Clause, and removing the projected off-system O&M revenues of $2.75 million in 1993 and $3.88 million in 1994 from base rate revenues and crediting these amounts to the Fuel Cost Recovery Clause.

Forecasting levels of off-system sales is far from an exact process. In his testimony, Tampa Electric's witness, Mr. Ramil, projects $11.9 million of off-system transactions in 1993 not including the Sebring and TECO Power Services sales. This is roughly half of the 8 month actual/4 month forecast amount of $23 million of off-system sales revenues for the current year 1992. Tampa Electric will likely have the opportunity for additional off-system sales starting in 1993 when the Hardee Power Station capacity of 295 MW comes on-line.

The revenue effect of incorrectly forecasting off-system sales from year to year will be eliminated if the revenues are credited through the Capacity Cost Recovery and Fuel and Purchased Power Clauses. Our treatment eliminates the potential inaccuracy from forecasting the level of off-system sales to be included in the calculation of base rate revenues.

All revenues and expenses associated with the firm Schedule D sales for the cities of New Smyrna Beach, St. Cloud and Wauchula, the Reedy Creek Improvement District and the Florida Municipal Power Association have been removed from the retail jurisdiction in the stipulated jurisdictional separation study.

Accordingly, we find that all revenues from off-system sales not allocated to the wholesale jurisdictional shall be included as credits in the Capacity Cost Recovery and Fuel and Purchased Power Cost Recovery Clauses. The capacity revenues shall be credited to the Capacity Cost Recovery Clause with O&M revenues credited to the Fuel and Purchased Power Cost Recovery Clause. We remove projected O&M revenues from off-system sales of $2,750,000 jurisdictional in 1993 and $3,888,000 jurisdictional in 1994 from base rate revenues.

Tampa Electric has proposed a sharing of the benefits of certain off-system sales described in Mr. Ramil's testimony (modified in accordance with the revised jurisdictional separation), in order to preserve an incentive for engaging in off-system sales which was incorporated in Tampa Electric's last full rate proceeding in Docket No. 850050-EI. TECO claims that retention of this incentive will directly benefit Tampa Electric's retail Customers.

Tampa Electric proposes to retain 60 percent of the capacity revenues from off-system sales other than those in the wholesale jurisdiction for the benefit of their stockholders and flow the remaining 40 percent of these revenues through the Capacity Cost Recovery clause for the benefit of the ratepayers.

Staff recommended that the Commission reject Tampa Electric's proposed 60/40 stockholder/ratepayer sharing of off system sales capacity revenues as unnecessary. Staff suggested that a prudently managed utility would use its best efforts to market this capacity and energy irrespective of whether it receives an additional incentive for doing so.

If the Commission decides to explore incentives, staff recommended that this issue be investigated in a generic docket. At that time, the Commission can explore the issue of off-system sales incentives as well as penalties for low levels of off-system sales or continued high levels of surplus capacity. This proceeding would allow the Commission the opportunity to adopt a uniform approach for all companies if it determines that incentives and penalties are needed for levels of off-system sales of generating capacity.

We believe that a generic proceeding to consider this issue is appropriate. We direct staff to initiate a docket to investigate and consider stockholder incentives for off-system sales.

By our decision to credit the revenues associated with off-system sales through the Capacity Cost and Fuel and Purchased Power cost recovery clauses, we have not maintained the status quo for Tampa Electric Company. In addition to the imputation of 37.1 million dollars of revenue in the last rate case, in that case we established a sharing of the annual revenues in excess of that amount. The stockholders would have received 20% of the revenue above that level and the ratepayers 80%. Since the target level of off-system sales was never achieved, no sharing ever occurred.

We believe that incentives can be useful in maximizing the level of off-system sales. Maximizing off-system sales makes the best use of the available capacity and can help minimize rates. The time necessary to conduct and decide a generic proceeding to determine an appropriate, industry-wide policy is likely to yield an effective date of October, 1993 at the earliest. This means that there will be less incentive for TECO to pursue off-system capacity sales and the carrying cost of any unused capacity will be paid by the ratepayers.

As an interim method to maximize the potential off-system revenues between the effective date of this Order and the decision in the generic proceeding, we establish the following incentive for Tampa Electric Company: We establish an $18 million dollar 1993 annual revenue target for off-system sales of excess jurisdictional capacity. Below that level, all the revenues will be credited, as discussed, through the Capacity and Fuel and Purchased Power Cost Recovery Clauses. Above $18 million dollars; 80% of the revenues shall be credited through Capacity and Fuel and Purchased Power Cost Recovery Clauses and 20% of the revenues shall be retained by the shareholders. The $18 million dollar target shall exclude TECO's commitments to the Utilities Commission of the City of New Smyrna Beach, the Reedy Creek Improvement District, the City of Wauchula and the Florida Municipal Power Association (the previously identified Schedule D sales).

I. Justifying Decisions Not To Competitively Bid Contracts For Architect/Engineering Services For Power Plant Construction

This issue was developed as a result of Audit Disclosure No. 1 in the Staff Audit Report. All of TECO's generating plants that are in rate base have been designed and engineered by Stone and Webster Engineering Corporation (SWEC) under cost plus type contracts without benefit of competitive bidding. The audit opinion section of Audit Disclosure No. 1 in the Staff Audit Report states

> The accepted industry-wide practice for selecting a contractor for needed services, is the bidding process where the owner requests proposals from qualified vendors/contractors, then makes an impartial evaluation of the bids and awards the contract to the lowest evaluated bidder. By consistently sole sourcing with the same A/E, it cannot be determined whether the company received the best value for their money and therefore provided the rate payer with the most economical rates possible.

The report recommended that TECO should reverse its practice of awarding A/E contracts to the same company, SWEC.

The Company in their response to the audit disclosure, and in Mr. Ramil's rebuttal testimony states that since 1981, the Company policy has been to competitively bid A/E services. TECO recognizes that there may be instances where sole sourcing may be prudent and would justify that approach when employed.

Accordingly we find that TECO shall be required to justify any instance when it does not competitively bid for Architect /Engineering services.

J. Implementation Of Revenue And Sales Decoupling; And Implementation Of Demand Side Management Incentives

All Parties taking positions on these issues (LEAF, FIPUG and TECO) entered in to a stipulation stating that Docket No. 920606-EG (the Conservation Goals Rule)is an appropriate docket for the Commission's consideration of decoupling, rate impact measure, and DSM incentives. We agree. Accordingly we approve the stipulation entered by the parties. We find that these issues are moot for the purposes of resolving the matters necessary to reach a decision on Tampa Electric Company's petition for a Rate Increase.

K. Use Of An Integrated Resource Plan And Development Of Least Cost Integrated Resource Planning

Tampa Electric maintains that it:

> has an integrated resource plan in place. This plan is an essential element of Tampa Electric's provision of reliable and cost-effective service to its Customers. The definition of "least cost" is critical to understanding one's position on this issue. Tampa Electric favors an analysis which provides "the least cost" to its Customers consistent with considerations of safety, reliability and Customer service standards. The company adheres to the concept of minimizing revenue requirements consistent with the maintenance of appropriate safety, reliability and Customer service standards and other strategic considerations.

The Legal Environmental Assistance believes TECO's current approach is inadequate: "The only way TECO can determine if it is providing services at lowest cost to customers is to fairly evaluate and compare the costs and benefits of all potential resources options and then plan to acquire those options on a least cost basis--that is, to engage in what the industry calls Integrated Resource Planning."

The real issue is the definition of "least cost." It was apparent from the cross examination that the focal point of these two issues was really which cost-effectiveness test should be used, the Rate Impact (RIM) or Total Resource (TRC) test. This is an issue that we believe is more appropriate for consideration in the Conservation Goals rule docket, as the parties have stipulated.

X. OTHER MATTERS

A. LEAF's Motion To Strike FIPUG's Brief

The Legal Environmental Assistance Foundation, Inc. and John Ryan (LEAF) and the Florida Industrial Power Users Group (FIPUG) are both intervenors in this docket and participated fully in the discovery, hearing and post hearing phases of the consideration of Tampa Electric Company's Application for a Rate Increase. Both parties timely filed post hearing briefs on November 3, 1992. On November 25, 1992 LEAF filed a Motion to Strike FIPUG's Post-Hearing Brief. LEAF cited Florida Rule of Civil Procedure 1.140 which provides that material which is "immaterial, impertinent or scandalous" may be stricken from any pleading at any time.

FIPUG timely filed a response to the Motion to Strike on December 7, 1992. In the response FIPUG states that it "deeply regrets that the argument in its Post-Hearing Brief is perceived as discourteous or disrespectful of any individuals comprising the Legal Environmental Assistance Foundation, Inc. and John Ryan team. (LEAF)"

While some of FIPUG's comments are clearly sarcastic and acerbic, they are not scandalous, impertinent or immaterial, within the meaning of Rule 1.140, Florida Rules of Civil Procedure. Accordingly, we deny the Motion to Strike.

B. OPC's Motion To Supplement The Record

On December 3, 1992 the Office of Public Counsel filed a Motion to Supplement the Record. The motion sought to add the Supplemental Staff Audit Report, filed November 17, 1992, to the record. No party filed a response to the motion. Having reviewed the motion, we find it should be granted. Accordingly, we grant the Office of Public Counsel's Motion to Supplement the Record.

Accordingly, it is

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

ORDERED that the stipulated issues and positions identified in the Prehearing Order in this docket (Order No. PSC-92-1163-PHO-EI; Issued October 9, 1992) and within the body of this Order are hereby approved. It is further

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

ORDERED that Tampa Electric Company is hereby authorized to submit revised rate schedules consistent herewith designed to generate $1,163,000 in additional gross revenues annually beginning February 4, 1993. It is further

ORDERED that Tampa Electric Company is hereby authorized to submit revised rate schedules consistent herewith designed to generate $17,412,000 in additional gross revenues annually beginning January, 1994. It is further

ORDERED that the rate changes authorized herein shall become effective as follows: The 1993 increase shall become effective for meters read on or after February 4, 1993, and the 1994 increase shall become effective the first billing cycle of January, 1994. It is further

ORDERED that Tampa Electric Company shall file, within 60 days after the date of the final order in this docket, a description of all entries or adjustments to its annual report, rate of return reports, and books and records required as a result of the Commission's findings in this rate case.It is further

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

XI. DISSENTING VOTES

Chairman Deason dissented as follows:

1. From the Commission's vote concerning common stock dividends payable included as current liability in Working Capital.

I disagree with the Commission's method of treating common stock dividends payable as a component of the capital structure requiring a rate of return. TECO's dividends are declared quarterly, and once declared, become a liability and a cost free source of funds to the company. Allowing the inclusion of the declared but unpaid dividends in the capital structure gives the company the opportunity to earn an equity return on cost free capital. This is results in a windfall to the company, since investors calculate (and we establish) their required return by taking into account the fact that dividends are paid quarterly. Including dividends payable as a reduction to working capital is the proper way to account for these funds.

2. From the Commission's vote concerning TECO's forecasted fuel prices included in fuel inventory for 1993 and 1994.

My concern with the majority's decision on this issue is one of burden of proof. When determining the appropriate inventory value of coal, the Commission was faced with testimony by TECO that coal from its affiliate Gatliff was priced in inventory at approximately $66 per ton, while the next highest value of coal in inventory is priced at about $49 per ton. This issue was raised by the OPC which did not offer any testimony or evidence as to the appropriate valuation for the Gatliff coal. Apparently, the majority feels constrained by the lack of other affirmative evidence as to what the price of the Gatliff coal should be. I appreciate the majority's difficulty and share their concern about the scarcity of evidence. However, I am not convinced that it is the OPC or any other intervenor's burden to affirmatively establish the valuation of TECO's coal inventory. I believe it is TECO's burden to prove to this Commission the fair valuation of its coal inventory. I am especially concerned that, where the coal is from an affiliate and our own staff has concerns about the fact that the coal is priced at 35% above non affiliate coal, we feel constrained to accept TECO's price. The Commission has plenty of latitude to fashion appropriate relief is this type of situation.

3. From the Commission's vote concerning level of coal inventory.

I dissent from the majority decision on this issue because I agree with the staff's analysis that the Commission should decide the appropriate level of inventory based on a reasonable number of days burn regardless of the type of coal that is used to meet the company's burn requirements. Whether the company is utilizing compliance coal or regular coal, they are still utilizing the coal for generation purposes. Any use of compliance coal would merely displace regular coal in meeting the company's daily generation needs. Therefore, I would concur with the staff's method of setting a target days burn, rather than treating compliance coal as a supplemental or special need in the days burn requirement.

Commissioner Lauredo dissented as follows:

1. From the Commission's vote concerning unamortized rate case expense.

By ORDER of the Florida Public Service Commission, this 2nd day of February, 1993.

STEVE TRIBBLE, Director
Division of Records and Reporting

(S E A L)

RVE/DLC/MAP/MRC:bmi

NOTICE OF FURTHER PROCEEDINGS OR JUDICIAL REVIEW

The Florida Public Service Commission is required by Section 120.59(4), Florida Statutes, to notify parties of any administrative hearing or judicial review of Commission orders that is available under Sections 120.57 or 120.68, Florida Statutes, as well as the procedures and time limits that apply. This notice should not be construed to mean all requests for an administrative hearing or judicial review will be granted or result in the relief sought.

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

XII. PROPOSED FINDINGS OF FACT

Pursuant to Rule 25-22.056, F.A.C. LEAF submitted twenty one proposed Findings of Fact and two Proposed Conclusions of Law. In compliance with Section 120.59, Florida Statutes, the Commission ruled on each proposed Finding of Fact. The Commission is not required to make a ruling on the Proposed Conclusions of Law. The Commission declines to rule on the Proposed Conclusions of Law.

1. The primary goal of TECO's resource planning process is to provide safe and reliable electric services to customers at lowest net present value of revenue requirements. T 52, lines 17-19; 84, lines 15-19; 85, lines 6-21; 89, lines 20-25; 90, lines 1-10; 94, lines 10-21; 360, lines 3-12; 1626, lines 10-12; 1631, lines 5-6; 1679, lines 23-25, 1680, lines 2-3; 1699, lines 6-8.

RULING: Rejected as unnecessary to decide the issues voted on in this docket.

2. In order to provide reliable energy services with minimum revenue requirements, the costs and benefits of all viable resource options must be evaluated with equivalent economic tests. T 94, lines 22-25; 95, lines 1-13; 99, lines 22-25; 100, lines 1-2; 1626, lines 12-14; 1627, lines 12-14.

RULING: Rejected as unnecessary to decide the issues voted on in this docket.

3. TECO's resource planning process selects supply-side options primarily on the basis of minimization of the net present value of revenue requirements. T 378, lines 24-25, PSC Order 92002-EI.

RULING: Rejected as unnecessary to decide the issues voted on in this docket.

4. TECO's resource planning process does not select demand-side resource options primarily on the basis of minimization of the net present value of revenue requirements. T 373, lines 5-25; 374, lines 1-22; 377, lines 14-25; 378, lines 1-25; 1639, lines 6-23, PSC Order 92002-EI, Rule 25-17.008, F.A.C.

RULING: Rejected as unnecessary to decide the issues voted on in this docket.

5. TECO's resource planning process rejects all demand-side resource programs that do not pass the Rate Impact ("RIM") Test set forth in Rule 25-17.008, F.A.C., without considering whether

revenue requirements would be less with those programs included in the Company's DSM portfolio. T 365, lines 19-25; 366, lines 1-6; 374, lines 1-22; 377, lines 19-25; 378, lines 1-6, 24-25; 1639, lines, 1-23; 1698, line 1; PSC Order 92002-EI.

RULING: Rejected as unnecessary to decide the issues voted on in this docket.

6. All DSM programs that pass the Total Resource Cost ("TRC") Test set forth in Rule 25-17.008, F.A.C. are less expensive (have lower revenue requirements) than new generating resources (even if said programs fail the RIM test). T 374, lines 3-10; 1639, lines 1-23; 1640, lines 1-3; Ex. 108, Part 6; Rule 25-17.008, F.A.C.

RULING: Rejected as unnecessary to decide the issues voted on in this docket.

7. TECO's planning process does not assure resource choices that minimize revenue requirements. T 52, lines 17-19; 84, lines 15-19; 85, lines 6-21; 89, lines 20-25; 90, lines 1-10; 94, lines 10-21, 22-25; 95, lines 1-13; 99, lines 22-25; 100, lines 1-2; 360, lines 3-12; 365, lines 19-25; 366, lines 1-6; 373, lines 5-24; 374, lines 1-22; 377, lines 14-25; 378, lines 1-25; 1626, lines 10-12; 1627, lines 12-14; 1631, lines 5-6; 1639, lines 1-23; 1640, lines 1-3; 1679, lines 23-25, 1680, lines 2-3; 1698, line 1; 1699, lines 6-8; PSC Order 92002-EI, Rule 25-17.008, F.A.C., Ex. 108, Part 6.

RULING: Rejected as unnecessary to decide the issues voted on in this docket.

8. The current regulatory connection between TECO's sales and revenues creates strong economic disincentives to TECO's selection of resource options that will reduce sales, even if those options would reduce total revenue requirements and customer costs. T 81, lines 11-18, 23-25; 82, lines 1-10, 13-21; 109, lines 1-9; 852, line 25; 853, lines 1-25; 854, lines 1-25; 855, lines 1-25; 856, lines 1-16; 1631, lines 16-21; 1632, lines 1-6, 10-21; 1633, lines 1-14; 1636, lines 1-8; 1643, lines 1-20; 1644, lines 1-22; 1645, lines 1-15; 1694, lines 4-6; Ex. 108, Parts 3 & 8.

RULING: Rejected as unnecessary to decide the issues voted on in this docket.

9. TECO's DSM programs reduce peak demand growth far more than they reduce growth in energy use. T 1637, lines 10-22; Ex. 108, Part 5.

RULING: Rejected as unnecessary to decide the issues voted on in this docket.

10. TECO's focus on peak demand reduction has resulted in DSM programs that have little impact on the customer group that has the highest growth rate in kWh sales, the Commercial sector. T 1637, lines 18-22; 1641, lines 20-21; 1642, lines 1-4; Ex. 108, Part 7, PSC Order 92002-EI.

RULING: Rejected as unnecessary to decide the issues voted on in this docket.

11. Decoupling revenues from sales removes a major financial disincentive to TECO's DSM programs, which otherwise would result in reductions in profits from reductions in sales. T 1627, lines 3-5. The citations in number 8, above are hereby adopted by reference.

RULING: Rejected as unnecessary to decide the issues voted on in this docket.

12. DSM Incentives can help TECO overcome the significant economic and institutional barriers to DSM that remain after decoupling revenues and sales. T 1627, lines 10-14, 20-21; 1632, lines 6-15; 1637, lines 3-8; 1642, lines 2-4; 1656, lines 8-20; 1657, lines 1-21; 1658, lines 1-21, 1659, lines 1-27; 1660, lines 1-2, Ex. 108, Part 10.

RULING: Rejected as unnecessary to decide the issues voted on in this docket.

13. Without changes in regulatory incentives, there will not be a level playing field between demand and supply resources, and TECO will not have adequate incentive to aggressively pursue those DSM programs that reduce revenue requirements. T 1626, lines 10-14; 1627, lines 3-10; 1635, lines 1-17. The citations in numbers 8 and 12, above are hereby adopted by this reference.

RULING: Rejected as unnecessary to decide the issues voted on in this docket.

14. Regulatory changes such as decoupling and DSM incentives are required to make successful implementation of a least cost plan to provide reliable energy services TECO's most profitable course of action. The citations in number 13, above are hereby adopted by this reference.

RULING: Rejected as unnecessary to decide the issues voted on in this docket.

15. A shared savings DSM incentive mechanism would provide regulatory support for TECO efforts to capture the available energy efficiency and demand savings that cost less than supply-side resources. T 1663, lines 1-22; 1664, lines 1-2; 1666, lines 3-25; Ex. 108, Part 9. The citations in number 12, above are hereby adopted by this reference.

RULING: Rejected as unnecessary to decide the issues voted on in this docket.

16. The ERAM decoupling method, as implemented in California, is an elaborate system and involves additional regulatory procedures, "mini-yearly rate cases," where a set of adjustments are made. T 1650, lines 1-21; 1652, lines 1-2.

RULING: Rejected as unnecessary to decide the issues voted on in this docket.

17. The RPC decoupling method as described in Appendix A, attached hereto and incorporated herein, is extremely simple and creates very little, if any additional administrative burden. T 1647, lines 7-21.

RULING: Rejected as unnecessary to decide the issues voted on in this docket.

18. The linkage between revenues and customers is at least as soundly based in both theory and statistics as the current regulatory linkage between revenues and sales. T 108, lines 24-25; 1647, lines 1-5.

RULING: Rejected as unnecessary to decide the issues voted on in this docket.

19. The RPC method will cause no more attrition for TECO than does current regulatory practice. T 1648, lines 16-20.

RULING: Rejected as unnecessary to decide the issues voted on in this docket.

20. DSM incentives for TECO should be designed to make TECO's least-cost resource plan its most profitable plan, provide appropriate impacts on stockholder and customers, and be simple, understandable and easy to administer (as more full described in

Appendix B, attached hereto and incorporated herein). T 1660, line 4-21; 1661, lines 1-22; 1662, lines 1-14.

RULING: Rejected as unnecessary to decide the issues voted on in this docket.

21. TECO's economic rewards from DSM investments should be limited to a percentage of the financial benefits created for its customers, and incentives should encourage both maximizing energy savings and obtaining savings at the lowest possible cost. T 1660, lines 3-21, 1661, lines 1-22; 1663, lines 1-43; 1664, lines 1-2; 1666, lines 5-25, Ex. 108, Part 11.

RULING: Rejected as unnecessary to decide the issues voted on in this docket.

APPENDIX I

Company : Tampa Electric Company
Docket No. : 920324-EI
Test Year : December 31, 1993

SCHEDULE 1
26-Jan-93

LN NO	COMPARATIVE RATE BASE (000)	COMPANY POSITION	COMMISSION
1	RATE BASE PER FILING:		
2			
3	Plant in Service	$2,488,652	
4	Depreciation Reserve	(916,214)	
5			
6	Net Plant in Service	$1,572,438	
7	Construction Work in Progress	89,609	
8	Property Held for Future Use	50,105	
9	Nuclear Fuel (Net)	0	
10	Allowance for Working Capital	156,635	
11			
12			
13	Total rate base	$1,868,787	$1,868,787
14			
15			
16	ADJUSTMENTS TO COMPANY FILING:		
17			
18	ISSUE:		
19	4. Hookers Point	0	0
20	5. Overaccrual of AFUDC	(78)	(78)
21	10. Sebring Acquisition	0	0
22	12. Plant-in-Service	0	(15,367)
23	14. CWIP Overprojection	0	(70,769)
24	16. Port Manatee Plant Site	0	0
25	17. Substation Site Reclassification	(52)	(52)
26	21. Unamortized Rate Case Expense	0	(1,036)
27	22. FAC & ECCR Overrecoveries	0	(12)
28	24. Dividends Payable	0	0
29	25. Success Sharing Plan	0	0
30	26. Acct. 183, Prelim. Survey & Invest.	(432)	(432)
31	27. SFAS 106	(1,742)	(1,742)
32	28. Affiliated Transactions	0	(3,025)
33	30. Heavy Oil Inventory	0	(206)
34	32. Coal Inventory	0	0
35	33. Additional Coal Inventory	0	(3,494)
36	35. Depreciation rates/reserves	2,278	2,278
37	36. Accum. Depreciation	0	0
38	S100. Revised Juris. Separation Factors	(25,497)	(25,497)
39	Amount to Reconcile to Brief	26	
40			
41			
42	Total Adjustment	($25,497)	($119,432)
43			
44			
45	ADJUSTED RATE BASE:	$1,843,290	$1,749,355
46			

APPENDIX I
(con't)

Company : Tampa Electric Company
Docket No. : 920324-EI
Test Year : December 31, 1993

SCHEDULE 2
26-Jan-93
Page 1 of 2

LN NO	COMPARATIVE CAPITAL	AMOUNT (000)	RATIO	COST RATE	WEIGHTED COST
1	COMPANY				
2					
3	Long Term Debt	$551,753	29.93%	7.84%	2.34%
4	Short Term Debt	37,238	2.02%	6.50%	0.13%
5	Preferred Stock	51,731	2.81%	6.49%	0.18%
6	Customer Deposits	44,918	2.44%	8.19%	0.20%
7	Common Equity	802,048	43.51%	13.75%	5.98%
8	Deferred ITC - Weighted Cost	63,983	3.47%	11.17%	0.39%
9	Accumulated Deferred Income Taxes &	291,619	15.82%	0.00%	0.00%
10	Zero Cost ITCs				
11					
12	Total Capital	$1,843,290	100.00%		9.22%
13					
14					
15					
16	COMMISSION				
17					
18	Long Term Debt	$514,895	29.43%	7.56%	2.23%
19	Short Term Debt	39,223	2.24%	4.28%	0.10%
20	Preferred Stock	48,274	2.76%	6.49%	0.18%
21	Customer Deposits	42,056	2.40%	8.19%	0.20%
22	Common Equity	748,447	42.78%	12.00%	5.13%
23	Deferred ITC - Weighted Cost	63,983	3.66%	10.06%	0.37%
24	Accumulated Deferred Income Taxes &	292,477	16.72%	0.00%	0.00%
25	Zero Cost ITCs				
26					
27	Total Capital	$1,749,355	100.00%		8.20%
28					
29					

Company : Tampa Electric Company
Docket No. : 920324-EI
Test Year : December 31, 1993

SCHEDULE 2
26-Jan-93
Page 2 of 2

LN NO	RECONCILIATION OF AVERAGE RATE BASE AND AVERAGE CAPITAL STRUCTURE (000)	LONG-TERM DEBT	SHORT-TERM DEBT	PREFERRED STOCK	CUSTOMER DEPOSITS	COMMON EQUITY	TAX CREDITS WEIGHTED COST	DEFERRED INCOME TAXES & ZERO COST ITCs	TOTAL CAPITAL
1	System Per Books	$591,455	$44,635	$54,956	$47,748	$844,451	$67,973	$307,969	$1,959,187
2	Non-Utility	0	0	0	(42)	0	(18)	1,752	1,692
3	Pro Forma Adjustments:	(5,453)	(5,086)	(14)	0	7,383	0	0	(3,170)
4	Pro Rata Adjustments	(26,617)	(1,796)	(2,496)	(2,167)	(38,692)	(3,087)	(14,068)	(88,923)
5									
6	TECO Adjusted Retail Per MFR	$559,385	$37,753	$52,446	$45,539	$813,142	$64,868	$295,653	$1,868,787
7	Post-Filing Adjustments	(7,632)	(515)	(715)	(621)	(11,094)	(885)	(4,034)	(25,496)
8									
9	Company Position	$551,753	$37,238	$51,731	$44,918	$802,048	$63,983	$291,619	$1,843,290
10									
11	Adjustments to Co. MFR Filing:								
12	Recalculate Oil Backout	(1,817)	4,654	(172)	0	(2,665)	0	0	$0
13									
14	Subtotal	$549,936	$41,892	$51,559	$44,918	$799,383	$63,983	$291,619	$1,843,290
15	ISSUE:								
16	Rate Base Adjustments (Specific)	$0	$0	$0	$0	$0	$0	$858	$858
17	Rate Base Adjustments (Pro Rata)	(35,041)	(2,669)	(3,285)	(2,862)	(50,936)	0	0	(94,794)
18									
19									
20	Total Adjustment	($35,041)	($2,669)	($3,285)	($2,862)	($50,936)	$0	$858	($93,936)
21									
22									
23	Adjusted Jurisdictional								
24	Capital Structure	$514,895	$39,223	$48,274	$42,056	$748,447	$63,983	$292,477	$1,749,355
25									

APPENDIX I
(con't)

Company : Tampa Electric Company
Docket No. : 920324-EI
Test Year : December 31, 1993

SCHEDULE 3
26-Jan-93
Page 1 of 4

COMPARATIVE NET OPERATING INCOME (000) OPERATING REVENUE	COMPANY POSITION	COMMISSION
OPERATING REVENUE PER FILING:		
Revenue From Sales of Electricity	$536,010	
Other Operating Revenue	12,152	
Total Operating Revenue	$548,162	$548,162
ADJUSTMENTS TO COMPANY FILING:		
ISSUE:		
97. Off System Retail Sales Profits	$0	($2,750)
97/98 Off-System Capacity Revenues	0	0
S100. Revised Juris. Separation Factors	(1,068)	(1,068)
Total Adjustments	($1,068)	($3,818)
ADJUSTED OPERATING REVENUE	$547,094	$544,344

APPENDIX I
(con't)

Company : Tampa Electric Company
Docket No. : 920324-EI
Test Year : December 31, 1993

SCHEDULE 3
26-Jan-93
Page 2 of 4

COMPARATIVE NET OPERATING INCOME (000) OPERATION & MAINTENANCE EXPENSE	COMPANY POSITION	COMMISSION
OPERATION & MAINTENANCE EXPENSES PER FILING:		
Operation & Maintenance	$217,355	
Total Operation & Maintenance Expense	$217,355	$217,355
ADJUSTMENTS TO COMPANY FILING:		
ISSUE:		
5. Overaccrual of AFUDC	0	0
12. Plant-in-Service	0	0
50. Advertising Expense	0	(7)
51. Industry Association Dues	0	(97)
54. Salaries and Benefits	0	0
57. Success Sharing Program	0	0
59. Supplemental Executive Retirement	0	0
60. OPEB Expense	0	0
63. Pension Expense	0	0
64. Rate Case Expense	0	(345)
65. Sebring Acquisition	0	0
69. Fossil O&M-Hookers Point	0	0
73. Tree Trimming Expense	0	(1,840)
78. Approved Depreciation Rates	0	0
S100. Revised Juris. Separation Factors	(3,224)	(3,224)
Total Adjustment	($3,224)	($5,513)
ADJUSTED OPERATION & MAINTENANCE EXPENSES	$214,131	$211,842

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LN NO	COMPARATIVE NET OPERATING INCOME (000) DEPRECIATION & AMORTIZATION EXPENSE	COMPANY POSITION	COMMISSION
71	DEPRECIATION & AMORTIZATION EXPENSES PER FILING:		
73	Depreciation & Amortization	$102,642	
76	Total Depreciation & Amortization Expense	$102,642	$102,642
79	ADJUSTMENTS TO COMPANY FILING:		
81	ISSUE:		
82	5. Overaccrual of AFUDC	(4)	(4)
83	12. Plant-in-Service	0	(592)
84	65/80 Sebring Acquisition	0	0
85	69. Fossil O&M-Hookers Point	0	0
86	78. Approved Depreciation Rates	(1,612)	(1,612)
87	S100. Revised Juris. Separation Factors	(1,433)	(1,433)
88	Amount to Reconcile to Brief	1,616	
90	Total Adjustment	(1,433)	(3,641)
93	ADJUSTED DEPRECIATION & AMORTIZATION	$101,209	$99,001

LN NO	COMPARATIVE NET OPERATING INCOME (000) TAXES OTHER THAN INCOME	COMPANY POSITION	COMMISSION
90	OTHER TAXES PER FILING	$39,762	$39,762
93	ADJUSTMENTS TO COMPANY FILING:		
94	ISSUE:		
95	Tax Effect of Revenue Adjustments	$0	$0
96	S100. Revised Juris. Separation Factors	(569)	(569)
97		0	0
98		0	0
101	Total Adjustments	($569)	($569)
104	ADJUSTED OTHER TAXES	$39,193	$39,193

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LN NO	COMPARATIVE NET OPERATING INCOME (000) INCOME TAX EXPENSE	COMPANY POSITION	COMMISSION
108	INCOME TAXES PER FILING:		
109	Current Income Taxes	$48,364	
110	Deferred Income Taxes	2,922	
111	Investment Tax Credit	(4,258)	
114	Total Income Tax	$47,028	$47,028
117	ADJUSTMENTS TO COMPANY FILING:		
118	ISSUE:		
119	Tax Effect of Other Adjustments	$0	$660
120	Interest Expense Reconciliation	0	2,256
121	S100. Revised Juris. Separation Factors	1,680	1,680
122	Amount to Reconcile to Brief	267	0
129	Total Adjustments	$1,947	$4,596
132	ADJUSTED INCOME TAXES	$48,975	$51,624

LN NO		COMPANY POSITION	COMMISSION
136	OTHER ITEMS PER FILING:		
137	(Gain)/Loss on Sale	($41)	
138	Regulatory Practices Reconcilation	0	
141	Total	($41)	($41)
143	ADJUSTMENTS TO COMPANY FILING:		
144	ISSUE:		
145	S100. Revised Juris. Separation Factors	$1	$1
148	ADJUSTED OTHER ITEMS	($40)	($40)

LN NO	COMPARATIVE NET OPERATING INCOME (000) NET OPERATING INCOME / SUMMARY	COMPANY POSITION	COMMISSION
150	NET OPERATING INCOME:		
151	Operating Revenue	$547,094	$544,344
152	Operation & Maintenance Expenses	(214,131)	(211,842)
153	Depreciation & Amortization	(101,209)	(99,001)
154	Taxes Other than Income	(39,193)	(39,193)
155	Income Taxes	(48,975)	(51,624)
156	Other Items	40	40
159	Net operating income	$143,626	$142,7[illegible]4

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	Steam Production (000)	Nuclear Production (000)	Other Production (000)	Trans-mission (000)	Distribution (000)	Customer Accounts (000)	Customer Service (000)	Sales (000)	Admin. & General (000)	Other Adjustments (000)	Total (000)
1984 FPSC Allowed O&M-System	$57,773	$0	$978	$5,618	$17,728	$13,744	$1,441	$30	$40,707	$0	$138,019
1984-1993 Compound Multiplier	1.41104	1.41104	1.41104	1.81622	1.81622	1.81622	1.81622	1.81622	1.81622	0.00000	
1993 O&M Benchmark - System	81,520	0	1,380	10,204	32,198	24,962	2,617	54	73,933	0	226,868
Add Sebring Units	869	0	1,568	0	0	0	0	0	0	0	2,437
Revised 1993 O&M Benchmark	82,389	0	2,948	10,204	32,198	24,962	2,617	54	73,933	0	229,305
1993 Adj. O&M - System	79,092	0	2,522	7,644	28,284	19,053	2,923	280	75,373	0	215,171
Benchmark Variance	(3,297)	0	(426)	(2,560)	(3,914)	(5,909)	306	226	1,440	0	(14,134
Staff Adjustments-System	0	0	0	0	(1,840)	0	(7)	0	(462)	0	(2,309
Adjusted Variance-System	(3,297)	0	(426)	(2,560)	(5,754)	(5,909)	299	226	978	0	(16,443
1993 O&M Benchmark - System	82,383	0	2,948	10,204	32,198	24,962	2,617	54	73,933	0	229,305
Juris. Separation Factors	0.9399	0.0000	0.9626	0.9732	0.9994	0.9996	1.0000	1.0000	0.9598	0.0000	
1993 Benchmark - Juris.	77,438	0	2,838	9,930	32,179	24,952	2,617	54	70,961	0	220,977
1993 Adj. O&M - Juris.	76,185	0	2,478	7,486	28,279	19,050	2,923	280	73,409	0	210,090
Juris. Benchmark Variance	(1,256)	0	(360)	(2,445)	(3,900)	(5,903)	306	226	2,445	0	(10,887
Staff Adjustments-Juris.	0	0	0	0	(1,840)	0	(7)	0	(442)	0	(2,289
Adjusted Variance-Juris.	($1,256)	$0	($360)	($2,445)	($5,740)	($5,903)	$299	$226	$2,003	$0	($13,176
New Separation Study Effect	(1,846)	0	(50)	(47)	(12)	(5)	0	0	(1,066)	0	($3,026
Adjusted Variance-Juris.	(3,102)	0	(410)	(2,492)	(5,752)	(5,908)	299	226	937	0	($16,202

Using the new separation study, TECO is $16,202,000 under the benchmark overall.

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		Fossil Production (000)	Nuclear Production (000)	Other Power Supply (000)	Trans-mission (000)	Distribution (000)	Customer Accounts (000)	Customer Service (000)	Sales (000)	Admin. & General (000)	Total (000)
50	ADVERTISING EXPENSE							(7)			(7)
51	INDUSTRY ASSOC. DUES									(97)	(97)
64	RATE CASE EXPENSE									(345)	(345)
73	TREE TRIMMING EXP.					(1,840)					(1,840)
	TOTAL JURISDICTIONAL	0	0	0	0	(1,840)	0	(7)	0	(442)	(2,289)

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		Fossil Production (000)	Nuclear Production (000)	Other Power Supply (000)	Trans-mission (000)	Distribution (000)	Customer Accounts (000)	Customer Service (000)	Sales (000)	Admin. & General (000)	Total (000)
50	ADVERTISING EXPENSE							(7)			(7)
51	INDUSTRY ASSOC. DUES									(102)	(102)
64	RATE CASE EXPENSE									(360)	(360)
73	TREE TRIMMING EXP.					(1,840)					(1,840)
	TOTAL SYSTEM	0	0	0	0	(1,840)	0	(7)	0	(462)	(2,309)

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O & M COMPOUND MULTIPLIERS

Year	Total Customers Amount	Total Customers %Increase	Total Customers Compound Multiplier	Average CPI-U (1982-1984=100) Amount	Average CPI-U (1982-1984=100) & Increase	Average CPI-U (1982-1984=100) Compound Multiplier	Inflation and Growth Compound Multiplier
1984	372,257		1.00000	103.9		1.00000	1.00000
1985	391,026	5.0419%	1.05042	107.6	3.5611%	1.03561	1.08783
1986	407,788	4.2867%	1.09545	109.6	1.8587%	1.05486	1.15555
1987	423,839	3.9361%	1.13857	113.6	3.6496%	1.09336	1.24487
1988	436,439	2.9728%	1.17241	118.3	4.1373%	1.13859	1.33489
1989	447,157	2.4558%	1.20121	124.0	4.8183%	1.19346	1.43360
1990	455,672	1.9043%	1.22408	130.7	5.4032%	1.25794	1.53982
1991	462,260	1.4458%	1.24178	136.2	4.2081%	1.31088	1.62782
1992	469,906	1.6540%	1.26232	141.2	3.7000%	1.35938	1.71597
1993	479,151	1.9674%	1.28715	146.6	3.8000%	1.41104	1.81622

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COMPARATIVE REVENUE REQUIREMENTS (000)	COMPANY POSITION	COMMISSION
Adjusted Jurisdictional Rate Base	$1,843,290	$1,749,355
Required Rate of Return	9.22%	8.20%
Required Net Operating Income	$169,951	$143,447
Adjusted Achieved Test Year Jurisdictional Net Operating Income	143,626	142,724
Jurisdictional NOI Deficiency (Excess)	$26,325	$723
Revenue Expansion Factor	1.608012	1.608012
Revenue Increase (Decrease) - Test Year	$42,331	$1.163
Penalty For High Rates	0	0
Total Base Rate Revenue Increase	$42,331	$1.163

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Revenue Expansion Factor

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REVENUE EXPANSION FACTOR	COMPANY POSITION	COMMISSION
Revenue Requirement	100.000000	100.000000
Uncollectible Rate	0.207600	0.207600
Gross Reciepts Tax	0.000000	0.000000
Regulatory Assessment Fee	0.083330	0.083330
Net Before Income Taxes	99.709070	99.709070
State Income Tax Rate	0.055000	0.055000
Amount	5.483999	5.483999
Net Before Federal Income Taxes	94.225071	94.225071
Federal Income Tax Rate	0.340000	0.340000
Amount	32.036524	32.036524
Net Operating Income	62.188547	62.188547
Net Operating Income Multiplier	1.608012	1.608012

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COMPARATIVE RATE BASE (000)	COMPANY POSITION	COMMISSION
RATE BASE PER FILING:		
Plant in Service	$2,626,092	
Depreciation Reserve	(996,699)	
Net Plant in Service	$1,629,393	
Construction Work in Progress	213,831	
Property Held for Future Use	62,036	
Nuclear Fuel (Net)	0	
Allowance for Working Capital	168,207	
Total rate base	$2,073,467	$2,073,467
ADJUSTMENTS TO COMPANY FILING:		
ISSUE:		
3. Simple Average	0	(1,513)
4. Hookers Point	0	0
5. Overaccrual of AFUDC	(74)	(74)
10. Sebring Acquisition	0	0
12. Plant-in-Service	0	(14,712)
14. CWIP Overprojection	0	(165,459)
16. Port Manatee Plant Site	0	0
17. Substation Site Reclassification	(52)	(52)
21. Unamortized Rate Case Expense	0	(344)
22. FAC & ECCR Overrecoveries	0	(46)
24. Dividends Payable	0	0
25. Success Sharing Plan	0	0
26. Acct. 183, Prelim. Survey & Invest.	(435)	(435)
27. SFAS 106	(5,318)	(5,318)
28. Affiliated Transactions	0	(2,707)
30. Heavy Oil Inventory	0	(225)
32. Coal Inventory	0	0
33. Additional Coal Inventory	0	(1,098)
35. Depreciation rates/reserves	3,942	3,940
36. Accum. Depreciation	0	0
S100. Revised Juris. Separation Factors	(34,435)	(34,497)
Amount to Reconcile to Brief	1,937	
Total Adjustment	($34,435)	($222,540)
ADJUSTED RATE BASE:	$2,039,032	$1,850,927

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COMPARATIVE CAPITAL	AMOUNT (000)	RATIO	COST RATE	WEIGHTED COST
COMPANY				
Long Term Debt	$622,827	30.55%	7.89%	2.42%
Short Term Debt	69,542	3.41%	6.50%	0.22%
Preferred Stock	51,298	2.52%	6.49%	0.16%
Customer Deposits	48,625	2.38%	8.10%	0.19%
Common Equity	899,950	44.14%	13.75%	6.07%
Deferred ITC - Weighted Cost	58,560	2.87%	11.19%	0.32%
Accumulated Deferred Income Taxes & Zero Cost ITCs	288,230	14.14%		
Total Capital	$2,039,032	100.01%		9.38%
COMMISSION				
Long Term Debt	$556,320	30.06%	7.81%	2.35%
Short Term Debt	55,934	3.02%	5.37%	0.16%
Preferred Stock	45,329	2.45%	6.49%	0.16%
Customer Deposits	43,311	2.34%	7.86%	0.18%
Common Equity	797,331	43.08%	12.00%	5.17%
Deferred ITC - Weighted Cost	59,035	3.19%	10.15%	0.32%
Accumulated Deferred Income Taxes & Zero Cost ITCs	293,667	15.87%	0.00%	
Total Capital	$1,850,927	100.00%		8.34%

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LN NO	RECONCILIATION OF AVERAGE RATE BASE AND AVERAGE CAPITAL STRUCTURE (000)	LONG-TERM DEBT	SHORT-TERM DEBT	PREFERRED STOCK	CUSTOMER DEPOSITS	COMMON EQUITY	TAX CREDITS WEIGHTED COST	DEFERRED INCOME TAXES & ZERO COST ITCs	TOTAL CAPITAL
1	System Per Books	$667,230	$74,500	$54,956	$52,092	$964,110	$62,735	$308,779	$2,184,402
2	Non-Utility	0	0	0	0	0	0	0	0
3	Pro Forma Adjustments:	0	0	0	0	0	0	0	0
4	Pro Rata Adjustments	(33,885)	(3,783)	(2,791)	(2,645)	(48,962)	(3,186)	(15,681)	(110,933)
5									
6	TECO Adjusted Retail Per MFR	$633,345	$70,717	$52,165	$49,447	$915,148	$59,549	$293,098	$2,073,467
7	Post-Filing Adjustments	(10,518)	(1,175)	(867)	(822)	(15,198)	(989)	(4,868)	(34,437)
8									
9	Company Position	$622,827	$69,542	$51,298	$48,625	$899,950	$58,560	$288,230	$2,039,032
10									
11	Adjustments to Co. MFR Filing:								
12	Recalculate Oil Backout	3,798	(6,539)	(241)	160	(1,856)	475	4,201	(2)
13									
14	Subtotal	626,625	63,003	51,057	48,785	898,094	59,035	292,431	2,039,030
15	ISSUE:								
16	Rate Base Adjustments (Specific)	0	0	0	0	0	0	$1,236	$1,236
17	Rate Base Adjustments (Pro Rata)	(70,305)	(7,069)	(5,728)	(5,474)	(100,763)	0	0	(189,339)
18									
19									
20	Total Adjustment	($70,305)	($7,069)	($5,728)	($5,474)	($100,763)	$0	$1,236	($188,103)
21									
22									
23	Adjusted Jurisdictional								
24	Capital Structure	$556,320	$55,934	$45,329	$43,311	$797,331	$59,035	$293,667	$1,850,927
25									

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COMPARATIVE NET OPERATING INCOME (000) OPERATING REVENUE	COMPANY POSITION	COMMISSION
OPERATING REVENUE PER FILING:		
Revenue From Sales of Electricity	$599,037	
Other Operating Revenue	13,710	
Total Operating Revenue	$612,747	$612,747
ADJUSTMENTS TO COMPANY FILING:		
ISSUE:		
49. 1993 Co. Revenue Increase	$0	($43,305)
49. 1993 Staff Rev. Increase/Decrease	0	1,190
97. Off System Retail Sales Profits	0	(3,888)
98. Off-System Capacity Revenues	0	0
S100. Revised Juris. Separation Factors	(8,160)	(8,160)
Total Adjustments	($8,160)	($54,163)
ADJUSTED OPERATING REVENUE	$604,587	$558,584

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COMPARATIVE NET OPERATING INCOME (000) OPERATION & MAINTENANCE EXPENSE	COMPANY POSITION	COMMISSION
OPERATION & MAINTENANCE EXPENSES PER FILING:		
Operation & Maintenance	$228,732	
Total Operation & Maintenance Expense	$228,732	$228,732
ADJUSTMENTS TO COMPANY FILING:		
ISSUE:		
5. Overaccrual of AFUDC	0	0
12. Plant-in-Service	0	0
50. Advertising Expense	0	(8)
51. Industry Association Dues	0	(101)
54. Salaries and Benefits	0	0
57. Success Sharing Program	0	0
59. Supplemental Executive Retirement	0	0
60. OPEB Expense	0	0
63. Pension Expense	0	0
64. Rate Case Expense	0	(344)
65. Sebring Acquisition	0	0
69. Fossil O&M-Hookers Point	0	0
73. Tree Trimming Expense	0	(1,960)
78. Approved Depreciation Rates	0	0
S100. Revised Juris. Separation Factors	(3,871)	(3,871)
Total Adjustment	($3,871)	($6,284)
ADJUSTED OPERATION & MAINTENANCE EXPENSES	$224,861	$222,448

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LN NO	COMPARATIVE NET OPERATING INCOME (000) DEPRECIATION & AMORTIZATION EXPENSE	COMPANY POSITION	COMMISSION
71	DEPRECIATION & AMORTIZATION EXPENSES PER FILING:		
72			
73	Depreciation & Amortization	$107,980	
74			
75			
76	Total Depreciation & Amortization Expense	$107,980	$107,980
77			
78			
79	ADJUSTMENTS TO COMPANY FILING:		
80			
81	ISSUE:		
82	5. Overaccrual of AFUDC	(4)	(4)
83	12. Plant-in-Service	0	(590)
84	65/80 Sebring Acquisition	0	0
85	69. Fossil O&M-Hookers Point	0	0
86	78. Approved Depreciation Rates	(1,750)	(1,750)
87	S100. Revised Juris. Separation Factors	(1,939)	(1,939)
88	Amount to Reconcile to Brief	1,754	
89			
90	Total Adjustment	(1,939)	(4,283)
91			
92			
93	ADJUSTED DEPRECIATION & AMORTIZATION	$106,041	$103,697

LN NO	COMPARATIVE NET OPERATING INCOME (000) TAXES OTHER THAN INCOME	COMPANY POSITION	COMMISSION
90	OTHER TAXES PER FILING	$41,960	$41,960
91			
92			
93	ADJUSTMENTS TO COMPANY FILING:		
94	ISSUE:		
95	Tax Effect of Revenue Adjustments	$0	$0
96	S100. Revised Juris. Separation Factors	(775)	(776)
97		0	0
98		0	0
99			
100			
101	Total Adjustments	($775)	($776)
102			
103			
104	ADJUSTED OTHER TAXES	$41,185	$41,184
105			
106			

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LN NO	COMPARATIVE NET OPERATING INCOME (000) OPERATION & MAINTENANCE EXPENSE	COMPANY POSITION	COMMISSION
23	OPERATION & MAINTENANCE EXPENSES PER FILING:		
25	Operation & Maintenance	$228,732	
28	Total Operation & Maintenance Expense	$228,732	$228,732
31	ADJUSTMENTS TO COMPANY FILING:		
33	ISSUE:		
34	5. Overaccrual of AFUDC	0	0
35	12. Plant-in-Service	0	0
36	50. Advertising Expense	0	(8)
37	51. Industry Association Dues	0	(101)
38	54. Salaries and Benefits	0	0
39	57. Success Sharing Program	0	0
40	59. Supplemental Executive Retirement	0	0
41	60. OPEB Expense	0	0
42	63. Pension Expense	0	0
43	64. Rate Case Expense	0	(344)
44	65. Sebring Acquisition	0	0
45	69. Fossil O&M-Hookers Point	0	0
46	73. Tree Trimming Expense	0	(1,960)
47	78. Approved Depreciation Rates	0	0
48	S100. Revised Juris. Separation Factors	(3,871)	(3,871)
66	Total Adjustment	($3,871)	($6,284)
69	ADJUSTED OPERATION & MAINTENANCE EXPENSES	$224,861	$222,448

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LN NO	COMPARATIVE NET OPERATING INCOME (000) DEPRECIATION & AMORTIZATION EXPENSE	COMPANY POSITION	COMMISSION
71	DEPRECIATION & AMORTIZATION EXPENSES PER FILING:		
72			
73	Depreciation & Amortization	$107,980	
74			
75			
76	Total Depreciation & Amortization Expense	$107,980	$107,980
77			
78			
79	ADJUSTMENTS TO COMPANY FILING:		
80			
81	ISSUE:		
82	5. Overaccrual of AFUDC	(4)	(4)
83	12. Plant-in-Service	0	(590)
84	65/80 Sebring Acquisition	0	0
85	69. Fossil O&M-Hookers Point	0	0
86	78. Approved Depreciation Rates	(1,750)	(1,750)
87	S100. Revised Juris. Separation Factors	(1,939)	(1,939)
88	Amount to Reconcile to Brief	1,754	
89			
90	Total Adjustment	(1,939)	(4,283)
91			
92			
93	ADJUSTED DEPRECIATION & AMORTIZATION	$106,041	$103,697

LN NO	COMPARATIVE NET OPERATING INCOME (000) TAXES OTHER THAN INCOME	COMPANY POSITION	COMMISSION
90	OTHER TAXES PER FILING	$41,960	$41,960
91			
92			
93	ADJUSTMENTS TO COMPANY FILING:		
94	ISSUE:		
95	Tax Effect of Revenue Adjustments	$0	$0
96	S100. Revised Juris. Separation Factors	(775)	(776)
97		0	0
98		0	0
99			
100			
101	Total Adjustments	($775)	($776)
102			
103			
104	ADJUSTED OTHER TAXES	$41,185	$41,184
105			
106			

APPENDIX I
(con't)

Company : Tampa Electric Company
Docket No. : 920324-EI
Test Year : December 31, 1994

SCHEDULE 9
26-Jan-93
Page 4 of 4

COMPARATIVE NET OPERATING INCOME (000) INCOME TAX EXPENSE	COMPANY POSITION	COMMISSION
INCOME TAXES PER FILING:		
Current Income Taxes	$61,840	
Deferred Income Taxes	2,820	
Investment Tax Credit	(4,214)	
Total Income Tax	$60,446	$60,446
ADJUSTMENTS TO COMPANY FILING:		
ISSUE:		
Tax Effect of Other Adjustments	$0	($15,519)
Interest Expense Reconciliation	0	3,264
3. Simple Average	0	0
S100. Revised Juris. Separation Factors	(88)	(465)
	0	0
	0	0
	0	0
	0	0
Total Adjustments	($88)	($12,720)
ADJUSTED INCOME TAXES	$60,358	$47,725
OTHER ITEMS PER FILING:		
(Gain)/Loss on Sale	($9)	
Regulatory Practices Reconcilation	0	
Total	($9)	($9)
ADJUSTMENTS TO COMPANY FILING:		
ISSUE:		
S100. Revised Juris. Separation Factors	$0	$0
ADJUSTED OTHER ITEMS	($9)	($9)

COMPARATIVE NET OPERATING INCOME (000) NET OPERATING INCOME / SUMMARY	COMPANY POSITION	COMMISSION
NET OPERATING INCOME:		
Operating Revenue	$604,587	$558,584
Operation & Maintenance Expenses	(224,861)	(222,448)
Depreciation & Amortization	(106,041)	(103,697)
Taxes Other than Income	(41,185)	(41,184)
Income Taxes	(60,358)	(47,726)
Other Items	9	9
Net operating income	$172,151	$143,538

APPENDIX I
(con't)

TAMPA ELECTRIC COMPANY
DOCKET NO. 920324-EI
O & M BENCHMARK VARIANCE BY FUNCTION
1994

SCHEDULE 10
Page 1 of 4
26-Jan-93

	Fossil Production (000)	Nuclear Production (000)	Other Power Supply (000)	Trans-mission (000)	Distribution (000)	Customer Accounts (000)	Customer Service (000)	Sales (000)	Admin. & General (000)	Other Adjustments (000)	Total (000)
1993 FPSC Allowed O&M-System	$79,092	$0	$2,522	$7,644	$26,444	$19,053	$2,916	$280	$74,911	$0	$212,862
1993-1994 Compound Multiplier	1.04100	1.04100	1.04100	1.06499	1.06499	1.06499	1.06499	1.06499	1.06499	0.00000	
1994 O&M Benchmark - System	82,335	0	2,625	8,141	28,163	20,291	3,106	298	79,780	0	224,739
1994 Adj. O&M - System	82,286	0	2,624	8,139	30,122	20,292	3,112	298	79,646	0	226,519
Benchmark Variance	(49)	0	(1)	(2)	1,959	1	6	(0)	(134)	0	1,780
Staff Adjustments-System	0	0	0	0	(1,960)	0	(8)	0	(466)		(2,434
Adjusted Variance-System	(49)	0	(1)	(2)	(1)	1	(2)	(0)	(600)	0	(654

	Fossil Production (000)	Nuclear Production (000)	Other Power Supply (000)	Trans-mission (000)	Distribution (000)	Customer Accounts (000)	Customer Service (000)	Sales (000)	Admin. & General (000)	Other Adjustments (000)	Total (000)
1994 O&M Benchmark - System	82,335	0	2,625	8,141	28,163	20,291	3,106	298	79,780	0	$224,739
Juris. Separation Factors	0.9369	0.0000	0.9590	0.9715	0.9998	0.9995	1.0000	1.0000	0.9564	0.0000	
1994 Benchmark - Juris.	77,139	0	2,518	7,909	28,157	20,281	3,106	298	76,301	0	215,709
1994 Adj. O&M - Juris.	79,262	0	2,579	7,971	30,117	20,289	3,112	298	77,544	0	221,172
Juris. Benchmark Variance	2,123	0	61	62	1,960	8	6	(0)	1,243	0	5,463
Staff Adjustments-Juris.	0	0	0	0	(1,960)	0	(8)	0	(445)	0	(2,413
Adjusted Variance-Juris.	$2,123	$0	$61	$62	($0)	$8	($2)	($0)	$798	$0	$3,050
New Separation Study Effect	(2,168)	0	(63)	(64)	(1)	(7)	0	0	(1,371)	0	($3,674
Adjusted Variance-Juris.	(46)	0	(1)	(2)	(1)	1	(2)	(0)	(573)	0	($624

Using the new separation study, TECO is $624,000 under the benchmark overall.

APPENDIX I
(con't)

TAMPA ELECTRIC COMPANY
DOCKET NO. 920324-EI
1994 O & M BENCHMARK VARIANCE BY FUNCTION (JURISDICTIONAL)

SCHEDULE 10
Page 2 of 4
26-Jan-93

		Fossil Production (000)	Nuclear Production (000)	Other Power Supply (000)	Trans-mission (000)	Distribution (000)	Customer Accounts (000)	Customer Service (000)	Sales (000)	Admin. & General (000)	Total (000)
50	ADVERTISING EXPENSE							(8)			(8)
51	INDUSTRY ASSOC. DUES									(101)	(101)
64	RATE CASE EXPENSE									(344)	(344)
73	TREE TRIMMING EXPENSE					(1,960)					(1,960)
	TOTAL JURISDICTIONAL	0	0	0	0	(1,960)	0	(8)	0	(445)	(2,413)

SCHEDULE 10
Page 3 of 4
26-Jan-93

TAMPA ELECTRIC COMPANY
DOCKET NO. 920324-EI
1994 O & M BENCHMARK VARIANCE BY FUNCTION (SYSTEM)

		Fossil Production (000)	Nuclear Production (000)	Other Power Supply (000)	Trans-mission (000)	Distribution (000)	Customer Accounts (000)	Customer Service (000)	Sales (000)	Admin. & General (000)	Total (000)
50	ADVERTISING EXPENSE							(8)			(8)
51	INDUSTRY ASSOC. DUES									(106)	(106)
64	RATE CASE EXPENSE									(360)	(360)
73	TREE TRIMMING EXPENSE					(1,960)					(1,960)
	TOTAL SYSTEM	0	0	0	0	(1,960)	0	(8)	0	(466)	(2,434)

APPENDIX I
(con't)

Company : Tampa Electric Company
Docket No. : 920324-EI
Test Year : December 31, 1994

SCHEDULE 11
26-Jan-93

COMPARATIVE REVENUE REQUIREMENTS (000)	COMPANY POSITION	COMMISSION
Adjusted Jurisdictional Rate Base	$2,039,032	$1,850,927
Required Rate of Return	9.38%	8.34%
Required Net Operating Income	$191,261	$154,367
Adjusted Achieved Test Year Jurisdictional Net Operating Income	172,151	143,538
Jurisdictional NOI Deficiency (Excess)	$19,110	$10,829
Revenue Expansion Factor	1.608012	1.608012
Revenue Increase (Decrease) - Test Year	$30,736	$17,412
Penalty For High Rates	0	0
Total Base Rate Revenue Increase	$30,736	$17,412

APPENDIX I
(con't)

Company : Tampa Electric Company
Docket No. : 920324-EI
Test Year : December 31, 1994

Revenue Expansion Factor

Schedule 12
26-Jan-93

LN NO	REVENUE EXPANSION FACTOR	COMPANY POSITION	COMMISSION
1	Revenue Requirement	100.000000	100.000000
2			
3			
4	Uncollectible Rate	0.207600	0.207600
5			
6	Gross Reciepts Tax	0.000000	0.000000
7			
8	Regulatory Assessment Fee	0.083330	0.083330
9			
10			
11	Net Before Income Taxes	99.709070	99.709070
12			
13	State Income Tax	0.055000	0.055000
14	Rate		
15			
16	Amount	5.483999	5.483999
17			
18			
19	Net Before Federal Income Taxes	94.225071	94.225071
20			
21	Federal Income Tax		
22	Rate	0.340000	0.340000
23			
24			
25	Amount	32.036524	32.036524
26			
27			
28	Net Operating Income	62.188547	62.188547
29			
30			
31			
32	Net Operating Income Multiplier	1.608012	1.608012
33			

TAMPA ELECTRIC COMPANY
DOCKET NO. 920324-EI
APROVED 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)

1993

(1) RATE CODE	(2) (a) PROPOSED RATE BASE	(3) (a) 1993 NOI PRESENT RATES	(4) ROR/ PRESEN INDEX	(5) (b) STIPULATED INCREASE SERVICE CHARGES	(6) (b) PROPOSED INCREASE SALES OF ELECTRICITY	(7) (b) TOTAL APPROVED INCREASED REVENUE	(8) REQUIRED NOI	(9) ROR/ PROPOSED INDEX	(10) % INCREASE IN REV FROM SALES OF ELEC W/ADJS	BASE
RS	$980,311	$69,617	7.10% / 0.87							
GS	$112,369	$11,113	9.89% / 1.21							
RS-GS	$1,092,680	$80,730	7.39% / 0.91	$1,235	$0	$1,235	$81,498	7.46% / 0.91	0.00%	0.00%
GSD	$380,013	$36,243	9.54% / 1.17	$13	$0	$13	$36,251	9.54% / 1.16	0.00%	0.00%
GSLD	$148,785	$13,164	8.85% / 1.08	$0	$0	$0	$13,164	8.85% / 1.08	0.00%	0.00%
GSD/GSLD	$528,799	$49,407	9.34% / 1.15	$0	$0	$13	$49,416	9.34% / 1.14	0.00%	0.00%
IS	$65,068	$8,049	12.37% / 1.52	$0	($85)	($85)	$7,996	12.29% / 1.50	-0.11%	-0.30%
OL-SL	$62,808	$4,538	7.23% / 0.89	$0	$0	$0	$4,538	7.23% / 0.88	0.00%	0.00%
TOT.RET	$1,749,355	$142,724	8.16% / 1.00	$1,248	($85)	$1,163	$143,447	8.20% / 1.00	-0.01%	-0.02%

Schedule E-16c

BASE REVENUE BY RATE SCHEDULE - CALCULATIONS

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: TAMPA ELECTRIC COMPANY

DOCKET NO.: 920324-EI

EXPLANATION: By rate schedule, calculate revenues under present and proposed rates for the test year. If any customers are to be transferred from one schedule to another, show revenues separately for the transfer group. Correction factors are used for historical test years only. The total base revenue by class must equal that shown in Schedule E-16a. The billing units must equal those shown in Schedules E-18a, E-18b and E-18c. Provide total number of Bills, MWH and Billing KW for each rate schedule (including Standard and Time-of-Day customers) and transfer group.

Type of data shown:
XX Projected Test Year Ended 12/31/93
__ Projected Prior Year Ended __/__/__
__ Historical Prior Year Ended __/__/__
Witness: L. R. SMITH

RATE SCHEDULE RS

TYPE OF CHARGES	PRESENT REVENUE CALCULATION			PROPOSED REVENUE CALCULATION			% INCREASE
	UNITS	CHARGE/UNIT	$ REVENUE	UNITS	CHARGE/UNIT	$ REVENUE	
Customer Charge:							
Standard	5,062,946 Bills	$7.00	35,440,622	5,062,946 Bills	$8.50	43,035,041	21.4
Time-of-Day (Co. Owned)	501 Bills	$10.00	5,010	501 Bills	$11.50	5,762	15.0
Time-of-Day (Cust. Owned)	12 Bills	$7.00	84	12 Bills	$8.50	102	21.4
Total	5,063,459 Bills		35,445,716	5,063,459 Bills		43,040,905	21.4
Energy and Demand Charge:							
Standard	5,776,482 MWH	$43.34	250,352,730	5,776,482 MWH	$41.30	238,568,707	(4.7)
Time-of-Day On-Peak	191 MWH	$104.42	19,944	191 MWH	$108.40	20,704	3.8
Time-of-Day Off-Peak	647 MWH	$14.86	9,614	647 MWH	$9.55	6,179	(35.7)
Total	5,777,320 MWH		250,382,288	5,777,320 MWH		238,595,590	(4.7)
Total Base Revenue (Calculated)			285,828,004			281,636,495	(1.5)
Correction Factor			1.000000			1.000000	
Total Base Revenue (Booked)			285,828,004			281,636,495	(1.5)

Supporting Schedules: E-18a, E-18b, E-18c

Recap Schedules: E-16a, E-17

Schedule E-16c

BASE REVENUE BY RATE SCHEDULE - CALCULATIONS

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: TAMPA ELECTRIC COMPANY

DOCKET NO.: 920324-EI

EXPLANATION: By rate schedule, calculate revenues under present and proposed rates for the test year. If any customers are to be transferred from one schedule to another, show revenues separately for the transfer group. Correction factors are used for historical test years only. The total base revenue by class must equal that shown in Schedule E-16a. The billing units must equal those shown in Schedules E-18a, E-18b and E-18c. Provide total number of Bills, MWH and Billing KW for each rate schedule (including Standard and Time-of-Day customers) and transfer group.

Type of data shown:
XX Projected Test Year Ended 12/31/93
__ Projected Prior Year Ended __/__/__
__ Historical Prior Year Ended __/__/__
Witness: L. R. SMITH

RATE SCHEDULE GS

TYPE OF CHARGES	PRESENT REVENUE CALCULATION				PROPOSED REVENUE CALCULATION				% INCREASE
	UNITS		CHARGE/UNIT	$ REVENUE	UNITS		CHARGE/UNIT	$ REVENUE	
Customer Charge:									
Standard Metered	551,774	Bills	$7.00	3,862,418	551,774	Bills	$8.50	4,690,079	21.4
Standard Unmetered	30,797	Bills	$6.00	184,782	30,797	Bills	$7.50	230,978	25.0
Sports Fields	1,128	Bills	$12.00	13,536	1,128	Bills	$42.00	47,376	250.0
Time-of-Day (Co. Owned)	707	Bills	$10.00	7,070	707	Bills	$11.50	8,131	15.0
Time-of-Day (Cust. Owned)	12	Bills	$7.00	84	12	Bills	$8.50	102	21.4
Total	584,418	Bills		4,067,890	584,418	Bills		4,976,666	22.3
Energy and Demand Charge:									
Standard	786,140	MWH	$43.34	34,071,308	786,140	MWH	$41.30	32,467,582	(4.7)
Sports Fields	4,300	MWH	$53.31	229,233	4,300	MWH	$49.56	213,108	(7.0)
Time-of-Day On-Peak	226	MWH	$104.42	23,599	226	MWH	$108.40	24,498	3.8
Time-of-Day Off-Peak	916	MWH	$14.86	13,612	916	MWH	$9.55	8,748	(35.7)
Total	791,582	MWH		34,337,752	791,582	MWH		32,713,936	(4.7)
Total Base Revenue (Calculated)				38,405,642				37,690,602	(1.9)
Correction Factor				1.000000				1.000000	
Total Base Revenue (Booked)				38,405,642				37,690,602	(1.9)

Supporting Schedules: E-18a, E-18b, E-18c

Recap Schedules: E-16a, E-17

BASE REVENUE BY RATE SCHEDULE - CALCULATIONS

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: TAMPA ELECTRIC COMPANY

DOCKET NO.: 920324-EI

EXPLANATION: By rate schedule, calculate revenues under present and proposed rates for the test year. If any customers are to be transferred from one schedule to another, show revenues separately for the transfer group. Correction factors are used for historical test years only. The total base revenue by class must equal that shown in Schedule E-16a. The billing units must equal those shown in Schedules E-18a, E-18b and E-18c. Provide total number of Bills, MWH and Billing KW for each rate schedule (including Standard and Time-of-Day customers) and transfer group.

Type of data shown:
XX Projected Test Year Ended 12/31/93
__ Projected Prior Year Ended __/__/__
__ Historical Prior Year Ended __/__/__
Witness: L. R. SMITH

RATE SCHEDULE GSD

TYPE OF CHARGES		PRESENT REVENUE CALCULATION			PROPOSED REVENUE CALCULATION			% INCREASE
		UNITS	CHARGE/UNIT	$ REVENUE	UNITS	CHARGE/UNIT	$ REVENUE	
Customer Charge:								
Standard Secondary		104,507 Bills	$35.00	3,657,745	91,973 Bills	$42.00	3,862,866	20.0
Standard Primary		1,076 Bills	$35.00	37,660	887 Bills	$42.00	37,254	20.0
T-O-D Sec. (Co. Owned)		2,747 Bills	$42.00	115,374	1,410 Bills	$49.00	69,090	16.7
T-O-D Sec. (Cust. Owned)		12 Bills	$35.00	420	0 Bills	$42.00	0	20.0
T-O-D Pri. (Co. Owned)		204 Bills	$42.00	8,568	179 Bills	$49.00	8,771	16.7
Standard Secondary	Optional				12,534 Bills	$42.00	526,428	-
Standard Primary	Optional				189 Bills	$42.00	7,938	-
T-O-D Sec. (Co. Owned)	Optional				1,337 Bills	$42.00	56,154	-
T-O-D Sec. (Cust. Owned)	Optional				12 Bills	$42.00	504	-
T-O-D Pri. (Co. Owned)	Optional				25 Bills	$42.00	1,050	-
Total		108,546 Bills		3,819,767	108,546 Bills		4,570,055	19.6
Energy Charge:								
Standard Secondary		3,152,968 MWH	$14.85	46,821,575	2,978,801 MWH	$13.98	41,643,638	(5.9)
Standard Primary		115,447 MWH	$14.85	1,714,388	109,681 MWH	$13.98	1,533,340	(5.9)
T-O-D Sec. On-Peak		55,964 MWH	$28.22	1,579,304	53,008 MWH	$22.83	1,210,173	(19.1)
T-O-D Sec. Off-Peak		162,611 MWH	$9.76	1,587,083	153,835 MWH	$10.11	1,555,272	3.6
T-O-D Pri. On-Peak		8,447 MWH	$28.22	238,374	8,444 MWH	$22.83	192,777	(19.1)
T-O-D Pri. Off-Peak		24,286 MWH	$9.76	237,031	24,273 MWH	$10.11	245,400	3.6
Standard Secondary	Optional				174,167 MWH	$49.56	8,631,717	-
Standard Primary	Optional				5,766 MWH	$49.56	285,763	-
T-O-D Sec. On-Peak	Optional				2,956 MWH	$49.56	146,499	-
T-O-D Sec. Off-Peak	Optional				8,776 MWH	$49.56	434,939	-
T-O-D Pri. On-Peak	Optional				3 MWH	$49.56	149	-
T-O-D Pri. Off-Peak	Optional				13 MWH	$49.56	644	-
Total		3,519,723 MWH		52,177,755	3,519,723 MWH		55,880,311	7.1

Continued on Page 4

Supporting Schedules: E-18a, E-18b, E-18c

Recap Schedules: E-16a, E-17

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: TAMPA ELECTRIC COMPANY

DOCKET NO.: 920324-EI

EXPLANATION: By rate schedule, calculate revenues under present and proposed rates for the test year. If any customers are to be transferred from one schedule to another, show revenues separately for the transfer group. Correction factors are used for historical test years only. The total base revenue by class must equal that shown in Schedule E-16a. The billing units must equal those shown in Schedules E-18a, E-18b and E-18c. Provide total number of Bills, MWH and Billing KW for each rate schedule (including Standard and Time-of-Day customers) and transfer group.

Type of data shown:
XX Projected Test Year Ended 12/31/93
__ Projected Prior Year Ended __/__/__
__ Historical Prior Year Ended __/__/__
Witness: L. R. SMITH

RATE SCHEDULE GSD

TYPE OF CHARGES		PRESENT REVENUE CALCULATION			PROPOSED REVENUE CALCULATION			% INCREASE
		UNITS	CHARGE/UNIT	$ REVENUE	UNITS	CHARGE/UNIT	$ REVENUE	
Continued from Page 4								
Demand Charge:								
Standard Secondary		8,989,619 KW	$6.75	60,679,928	7,736,406 KW	$7.00	54,154,842	3.7
Standard Primary		341,340 KW	$6.75	2,304,045	297,620 KW	$7.00	2,083,340	3.7
T-O-D Sec. Billing		573,891 KW	$0.00	0	443,583 KW	$2.27	1,006,933	-
T-O-D Sec. Peak		483,159 KW (1)	$6.75	3,261,323	398,618 KW (1)	$4.92	1,961,201	(27.1)
T-O-D Pri. Billing		75,853 KW	$0.00	0	75,744 KW	$2.27	171,939	-
T-O-D Pri. Peak		67,054 KW (1)	$6.75	452,615	66,958 KW (1)	$4.92	329,433	(27.1)
Standard Secondary	Optional				1,253,213 KW	$0.00	0	-
Standard Primary	Optional				43,720 KW	$0.00	0	-
T-O-D Sec. Billing	Optional				130,308 KW	$0.00	0	-
T-O-D Sec. Peak	Optional				84,541 KW (1)	$0.00	0	-
T-O-D Pri. Billing	Optional				109 KW	$0.00	0	-
T-O-D Pri. Peak	Optional				96 KW (1)	$0.00	0	-
Total		9,980,703 KW		66,697,911	9,980,703 KW		59,707,688	(10.5)
Metering Level Discount:								
Standard Primary		4,018,433 $	-1%	(40,184)	3,616,680 $	-1%	(36,167)	0.0
T-O-D Primary		928,020 $	-1%	(9,280)	767,610 $	-1%	(7,676)	0.0
Standard Primary	Optional				285,763 $	-1%	(2,858)	-
T-O-D Primary	Optional				793 $	-1%	(8)	-
Total		4,946,453 $		(49,464)	4,670,846 $		(46,709)	(5.6)

(1) T-O-D Peak KW is included in T-O-D Billing KW and is therefore excluded from total.

Continued on Page 5

Schedule E-16c

BASE REVENUE BY RATE SCHEDULE - CALCULATIONS

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: TAMPA ELECTRIC COMPANY

DOCKET NO.: 920324-EI

EXPLANATION: By rate schedule, calculate revenues under present and proposed rates for the test year. If any customers are to be transferred from one schedule to another, show revenues separately for the transfer group. Correction factors are used for historical test years only. The total base revenue by class must equal that shown in Schedule E-16a. The billing units must equal those shown in Schedules E-18a, E-18b and E-18c. Provide total number of Bills, MWH and Billing KW for each rate schedule (including Standard and Time-of-Day customers) and transfer group.

Type of data shown:
XX Projected Test Year Ended 12/31/93
__ Projected Prior Year Ended __/__/__
__ Historical Prior Year Ended __/__/__
Witness: L. R. SMITH

RATE SCHEDULE GSD

TYPE OF CHARGES		PRESENT REVENUE CALCULATION UNITS	CHARGE/UNIT	$ REVENUE	PROPOSED REVENUE CALCULATION UNITS	CHARGE/UNIT	$ REVENUE	% INCREASE
Continued from Page 4								
Transformer Owner. Discount:								
Standard Primary		192,755 KW	($0.32)	(61,682)	186,229 KW	($0.36)	(67,042)	12.5
T-O-D Primary		45,550 KW	($0.32)	(14,576)	45,550 KW	($0.36)	(16,398)	12.5
Standard Primary	Optional				6,526 KW	($0.36)	(2,349)	-
T-O-D Primary	Optional				0 KW	($0.36)	0	-
Total		238,305 KW		(76,258)	238,305 KW		(85,789)	12.5
Emergency Relay Charge:								
Standard Secondary		94,391 KW	$0.50	47,196	93,163 KW	$0.60	55,898	20.0
Standard Primary		14,029 KW	$0.50	7,015	14,029 KW	$0.60	8,417	20.0
T-O-D Secondary		37,819 KW	$0.50	18,910	36,044 KW	$0.60	21,626	20.0
T-O-D Primary		0 KW	$0.50	0	0 KW	$0.60	0	20.0
Standard Secondary	Optional				1,228 KW	$0.60	737	-
Standard Primary	Optional				0 KW	$0.60	0	-
T-O-D Secondary	Optional				1,775 KW	$0.60	1,065	-
T-O-D Primary	Optional				0 KW	$0.60	0	-
Total		146,239 KW		73,121	146,239 KW		87,743	20.0
Total Base Revenue (Calculated)				122,642,832			120,113,299	(2.1)
Correction Factor				1.000000			1.000000	
Total Base Revenue (Booked)				122,642,832			120,113,299	(2.1)

Supporting Schedules: E-18a, E-18b, E-18c

Recap Schedules: E-16a, E-17

Schedule E-16c

BASE REVENUE BY RATE SCHEDULE - CALCULATIONS

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: TAMPA ELECTRIC COMPANY

DOCKET NO.: 920324-EI

EXPLANATION: By rate schedule, calculate revenues under present and proposed rates for the test year. If any customers are to be transferred from one schedule to another, show revenues separately for the transfer group. Correction factors are used for historical test years only. The total base revenue by class must equal that shown in Schedule E-16a. The billing units must equal those shown in Schedules E-18a, E-18b and E-18c. Provide total number of Bills, MWH and Billing KW for each rate schedule (including Standard and Time-of-Day customers) and transfer group.

Type of data shown:
XX Projected Test Year Ended 12/31/93
__ Projected Prior Year Ended __/__/__
__ Historical Prior Year Ended __/__/__
Witness: L. R. SMITH

RATE SCHEDULE GSLD

TYPE OF CHARGES	PRESENT REVENUE CALCULATION			PROPOSED REVENUE CALCULATION			% INCREASE
	UNITS	CHARGE/UNIT	$ REVENUE	UNITS	CHARGE/UNIT	$ REVENUE	
Customer Charge:							
Standard Secondary	658 Bills	$170.00	111,860	658 Bills	$255.00	167,790	50.0
Standard Primary	261 Bills	$170.00	44,370	261 Bills	$255.00	66,555	50.0
Standard Subtrans.	0 Bills	$170.00	0	0 Bills	$255.00	0	-
T-O-D Secondary	424 Bills	$170.00	72,080	424 Bills	$255.00	108,120	50.0
T-O-D Primary	384 Bills	$170.00	65,280	384 Bills	$255.00	97,920	50.0
T-O-D Subtrans.	0 Bills	$170.00	0	0 Bills	$255.00	0	-
Total	1,727 Bills		293,590	1,727 Bills		440,385	50.0
Energy Charge:							
Standard Secondary	321,188 MWH	$14.85	4,769,642	321,188 MWH	$13.98	4,490,208	(5.9)
Standard Primary	175,967 MWH	$14.85	2,613,110	175,967 MWH	$13.98	2,460,019	(5.9)
Standard Subtrans.	0 MWH	$14.85	0	0 MWH	$13.98	0	-
T-O-D Sec. On-Peak	84,028 MWH	$28.22	2,371,270	84,028 MWH	$22.83	1,918,359	(19.1)
T-O-D Sec. Off-Peak	230,443 MWH	$9.76	2,249,124	230,443 MWH	$10.11	2,329,779	3.6
T-O-D Pri. On-Peak	187,757 MWH	$28.22	5,298,503	187,757 MWH	$22.83	4,286,492	(19.1)
T-O-D Pri. Off-Peak	493,124 MWH	$9.76	4,812,890	493,124 MWH	$10.11	4,985,484	3.6
T-O-D Subtrans. On-Peak	0 MWH	$28.22	0	0 MWH	$22.83	0	-
T-O-D Subtrans. Off-Peak	0 MWH	$9.76	0	0 MWH	$10.11	0	-
Total	1,492,507 MWH		22,114,539	1,492,507 MWH		20,470,341	(7.4)

Continued on Page 7

Supporting Schedules: E-18a, E-18b, E-18c

Recap Schedules: E-16a, E-17

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: TAMPA ELECTRIC COMPANY

DOCKET NO.: 920324-EI

EXPLANATION: By rate schedule, calculate revenues under present and proposed rates for the test year. If any customers are to be transferred from one schedule to another, show revenues separately for the transfer group. Correction factors are used for historical test years only. The total base revenue by class must equal that shown in Schedule E-16a. The billing units must equal those shown in Schedules E-18a, E-18b and E-18c. Provide total number of Bills, MWH and Billing KW for each rate schedule (including Standard and Time-of-Day customers) and transfer group.

Type of data shown:
XX Projected Test Year Ended 12/31/93
__ Projected Prior Year Ended __/__/__
__ Historical Prior Year Ended __/__/__
Witness: L. R. SMITH

RATE SCHEDULE GSLD

TYPE OF CHARGES	PRESENT REVENUE CALCULATION			PROPOSED REVENUE CALCULATION			% INCREASE
	UNITS	CHARGE/UNIT	$ REVENUE	UNITS	CHARGE/UNIT	$ REVENUE	
Continued from Page 6							
Demand Charge:							
Standard Secondary	801,307 KW	$6.75	5,408,822	801,307 KW	$7.00	5,609,149	3.7
Standard Primary	437,193 KW	$6.75	2,951,053	437,193 KW	$7.00	3,060,351	3.7
Standard Subtrans.	0 KW	$6.75	0	0 KW	$7.00	0	-
T-O-D Sec. Billing	644,301 KW	$0.00	0	644,301 KW	$2.27	1,462,563	-
T-O-D Sec. Peak	604,870 KW (1)	$6.75	4,082,873	604,870 KW (1)	$4.92	2,975,960	(27.1)
T-O-D Pri. Billing	1,308,387 KW	$0.00	0	1,308,387 KW	$2.27	2,970,038	-
T-O-D Pri. Peak	1,263,509 KW (1)	$6.75	8,528,686	1,263,509 KW (1)	$4.92	6,216,464	(27.1)
T-O-D Subtrans. Billing	0 KW	$0.00	0	0 KW	$2.27	0	-
T-O-D Subtrans. Peak	0 KW (1)	$6.75	0	0 KW (1)	$4.92	0	-
Total	3,191,188 KW		20,971,434	3,191,188 KW		22,294,525	6.3
Power Factor Charge:							
Standard Secondary	10,337 KVA	$6.75	69,775	15,901 MVARH	$2.00	31,802	(54.4)
Standard Primary	9,050 KVA	$6.75	61,088	13,573 MVARH	$2.00	27,146	(55.6)
Standard Subtrans.	0 KVA	$6.75	0	0 MVARH	$2.00	0	-
T-O-D Secondary	11,674 KVA	$6.75	78,800	13,173 MVARH	$2.00	26,346	(66.6)
T-O-D Primary	4,422 KVA	$6.75	29,849	8,541 MVARH	$2.00	17,082	(42.8)
T-O-D Subtrans.	0 KVA	$6.75	0	0 MVARH	$2.00	0	-
Total	35,483 KVA		239,512	51,188 MVARH		102,376	(57.3)

(1) T-O-D Peak KW is included in T-O-D Billing KW and is therefore excluded from total.

Continued on Page 8

Schedule E-16c

BASE REVENUE BY RATE SCHEDULE - CALCULATIONS

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: TAMPA ELECTRIC COMPANY

DOCKET NO.: 920324-EI

EXPLANATION: By rate schedule, calculate revenues under present and proposed rates for the test year. If any customers are to be transferred from one schedule to another, show revenues separately for the transfer group. Correction factors are used for historical test years only. The total base revenue by class must equal that shown in Schedule E-16a. The billing units must equal those shown in Schedules E-18a, E-18b and E-18c. Provide total number of Bills, MWH and Billing KW for each rate schedule (including Standard and Time-of-Day customers) and transfer group.

Type of data shown:
XX Projected Test Year Ended 12/31/93
__ Projected Prior Year Ended __/__/__
__ Historical Prior Year Ended __/__/__
Witness: L. R. SMITH

RATE SCHEDULE GSLD

TYPE OF CHARGES	PRESENT REVENUE CALCULATION UNITS		CHARGE/UNIT	$ REVENUE	PROPOSED REVENUE CALCULATION UNITS		CHARGE/UNIT	$ REVENUE	% INCREASE
Continued from Page 7									
Power Factor Credit:									
Standard Secondary				(84,217)	10,459	MVARH	($1.00)	(10,459)	(87.6)
Standard Primary				(28,068)	4,132	MVARH	($1.00)	(4,132)	(85.3)
Standard Subtrans.				0	0	MVARH	($1.00)	0	-
T-O-D Secondary				(43,812)	3,822	MVARH	($1.00)	(3,822)	(91.3)
T-O-D Primary				(189,847)	52,128	MVARH	($1.00)	(52,128)	(72.5)
T-O-D Subtrans.				0	0	MVARH	($1.00)	0	-
Total				(345,944)	70,541	MVARH		(70,541)	(79.6)
Metering Level Discount:									
Standard Primary	5,564,163	$	-1%	(55,642)	5,520,370	$	-1%	(55,204)	(0.8)
Standard Subtrans.	0	$	-2%	0	0	$	-2%	0	-
T-O-D Primary	18,640,079	$	-1%	(186,401)	18,458,478	$	-1%	(184,585)	(1.0)
T-O-D Subtrans.	0	$	-2%	0	0	$	-2%	0	-
Total	24,204,242	$		(242,043)	23,978,848	$		(239,789)	(0.9)
Transformer Owner. Discount:									
Standard Primary	390,719	KW	($0.32)	(125,030)	390,719	KW	($0.36)	(140,659)	12.5
Standard Subtrans.	0	KW	($0.42)	0	0	KW	($0.59)	0	-
T-O-D Primary	1,102,447	KW	($0.32)	(352,783)	1,102,447	KW	($0.36)	(396,881)	12.5
T-O-D Subtrans.	0	KW	($0.42)	0	0	KW	($0.59)	0	-
Total	1,493,166	KW		(477,813)	1,493,166	KW		(537,540)	12.5

Continued on Page 9

Supporting Schedules: E-18a, E-18b, E-18c

Recap Schedules: E-16a, E-17

Schedule E-16c

BASE REVENUE BY RATE SCHEDULE - CALCULATIONS

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: TAMPA ELECTRIC COMPANY

DOCKET NO.: 920324-EI

EXPLANATION: By rate schedule, calculate revenues under present and proposed rates for the test year. If any customers are to be transferred from one schedule to another, show revenues separately for the transfer group. Correction factors are used for historical test years only. The total base revenue by class must equal that shown in Schedule E-16a. The billing units must equal those shown in Schedules E-18a, E-18b and E-18c. Provide total number of Bills, MWH and Billing KW for each rate schedule (including Standard and Time-of-Day customers) and transfer group.

Type of data shown:
XX Projected Test Year Ended 12/31/93
__ Projected Prior Year Ended __/__/__
__ Historical Prior Year Ended __/__/__
Witness: L. R. SMITH

RATE SCHEDULE GSLD

TYPE OF CHARGES	PRESENT REVENUE CALCULATION UNITS	CHARGE/UNIT	$ REVENUE	PROPOSED REVENUE CALCULATION UNITS	CHARGE/UNIT	$ REVENUE	% INCREASE
Continued from Page 8							
Emergency Relay Charge:							
Standard Secondary	98,481 KW	$0.50	49,241	98,481 KW	$0.60	59,089	20.0
Standard Primary	132,295 KW	$0.50	66,148	132,295 KW	$0.60	79,377	20.0
Standard Subtrans.	0 KW	$0.50	0	0 KW	$0.60	0	-
T-O-D Secondary	193,161 KW	$0.50	96,581	193,161 KW	$0.60	115,897	20.0
T-O-D Primary	651,708 KW	$0.50	325,854	651,708 KW	$0.60	391,025	20.0
T-O-D Subtrans.	0 KW	$0.50	0	0 KW	$0.60	0	-
	1,075,645 KW		537,824	1,075,645 KW		645,388	20.0
Total Base Revenue (Calculated)			43,091,099			43,105,145	0.0
Correction Factor			1.000000			1.000000	
Total Base Revenue (Booked)			43,091,099			43,105,145	0.0

Supporting Schedules: E-18a, E-18b, E-18c

Recap Schedules: E-16a, E-17

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: TAMPA ELECTRIC COMPANY

DOCKET NO.: 920324-EI

EXPLANATION: By rate schedule, calculate revenues under present and proposed rates for the test year. If any customers are to be transferred from one schedule to another, show revenues separately for the transfer group. Correction factors are used for historical test years only. The total base revenue by class must equal that shown in Schedule E-16a. The billing units must equal those shown in Schedules E-18a, E-18b and E-18c. Provide total number of Bills, MWH and Billing KW for each rate schedule (including Standard and Time-of-Day customers) and transfer group.

Type of data shown:
XX Projected Test Year Ended 12/31/93
__ Projected Prior Year Ended __/__/__
__ Historical Prior Year Ended __/__/__
Witness: L. R. SMITH

RATE SCHEDULE SBF

TYPE OF CHARGES	PRESENT REVENUE CALCULATION UNITS		CHARGE/UNIT	$ REVENUE	PROPOSED REVENUE CALCULATION UNITS		CHARGE/UNIT	$ REVENUE	% INCREASE
Customer Charge:									
T-O-D Primary	48	Bills	$195.00	9,360	48	Bills	$280.00	13,440	43.6
T-O-D Subtrans.	24	Bills	$195.00	4,680	24	Bills	$280.00	6,720	43.6
Total	72	Bills		14,040	72	Bills		20,160	43.6
Energy Charge (Supplemental):									
T-O-D Pri. On-Peak	27,846	MWH	$28.22	785,814	27,846	MWH	$22.83	635,724	(19.1)
T-O-D Pri. Off-Peak	82,390	MWH	$9.76	804,126	82,390	MWH	$10.11	832,963	3.6
T-O-D Subtrans. On-Peak	0	MWH	$28.22	0	0	MWH	$22.83	0	-
T-O-D Subtrans. Off-Peak	0	MWH	$9.76	0	0	MWH	$10.11	0	-
Energy Charge (Standby):									
T-O-D Pri. On-Peak	4,162	MWH	$28.22	117,452	4,162	MWH	$9.79	40,746	(65.3)
T-O-D Pri. Off-Peak	10,205	MWH	$9.76	99,601	10,205	MWH	$9.79	99,907	0.3
T-O-D Subtrans. On-Peak	190	MWH	$28.22	5,362	190	MWH	$9.79	1,860	(65.3)
T-O-D Subtrans. Off-Peak	398	MWH	$9.76	3,884	398	MWH	$9.79	3,896	0.3
Total	125,191	MWH		1,816,239	125,191	MWH		1,615,096	(11.1)
Demand Charge (Supplemental):									
T-O-D Pri. Peak	208,934	KW	$6.75	1,410,305	208,934	KW	$7.00	1,462,538	3.7
T-O-D Subtrans. Peak	0	KW	$6.75	0	0	KW	$7.00	0	-
Demand Charge (Standby):									
T-O-D Pri. Peak	266,400	KW	$2.03	540,792	266,400	KW	$2.53	673,992	24.6
Reservation Chg. Pri	61,645	KW/Mo. (1)	$0.62	38,220	61,645	KW/Mo. (1)	$0.84	51,782	35.5
Reservation Chg. Pri	1,157,668	KW/Day (1)	$0.30	347,300	1,157,668	KW/Day (1)	$0.33	382,030	10.0
T-O-D Subtrans. Peak	63,096	KW	$2.03	128,085	63,096	KW	$2.53	159,633	24.6
Reservation Chg. Subtrans.	55,442	KW/Mo. (1)	$0.62	34,374	55,442	KW/Mo. (1)	$0.84	46,571	35.5
Reservation Chg. Subtrans.	26,248	KW/Day (1)	$0.30	7,874	26,248	KW/Day (1)	$0.33	8,662	10.0
Total	538,430	KW		2,506,950	538,430	KW		2,785,208	11.1

(1) Not included in total.

Continued on Page 11

Supporting Schedules: E-18a, E-18b, E-18c

Recap Schedules: E-16a, E-17

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: TAMPA ELECTRIC COMPANY

DOCKET NO.: 920324-EI

EXPLANATION: By rate schedule, calculate revenues under present and proposed rates for the test year. If any customers are to be transferred from one schedule to another, show revenues separately for the transfer group. Correction factors are used for historical test years only. The total base revenue by class must equal that shown in Schedule E-16a. The billing units must equal those shown in Schedules E-18a, E-18b and E-18c. Provide total number of Bills, MWH and Billing KW for each rate schedule (including Standard and Time-of-Day customers) and transfer group.

Type of data shown:
XX Projected Test Year Ended 12/31/93
__ Projected Prior Year Ended __/__/__
__ Historical Prior Year Ended __/__/__
Witness: L. R. SMITH

RATE SCHEDULE SBF

TYPE OF CHARGES	PRESENT REVENUE CALCULATION			PROPOSED REVENUE CALCULATION			% INCREASE
	UNITS	CHARGE/UNIT	$ REVENUE	UNITS	CHARGE/UNIT	$ REVENUE	
Continued from Page 10							
Power Factor Charge (Supp.):							
T-O-D Primary	0 KVA	$6.75	0	0 MVARH	$2.00	0	-
T-O-D Subtrans.	0 KVA	$6.75	0	0 MVARH	$2.00	0	-
Power Factor Charge (Stby.):							
T-O-D Primary				0 MVARH	$2.00	0	-
T-O-D Subtrans.				117 MVARH	$2.00	234	-
Total	0 KVA		0	117 MVARH		234	-
Power Factor Credit (Supp.):							
T-O-D Primary			(56,099)	29,913 MVARH	($1.00)	(29,913)	(46.7)
T-O-D Subtrans.			0	0 MVARH	($1.00)	0	-
Power Factor Credit (Stby.):							
T-O-D Primary				3,898 MVARH	($1.00)	(3,898)	-
T-O-D Subtrans.				0 MVARH	($1.00)	0	-
Total			(56,099)	33,811 MVARH		(33,811)	(39.7)
Meter Level Discount (Supp.):							
T-O-D Primary	3,000,245 $	-1%	(30,002)	2,931,225 $	-1%	(29,312)	(2.3)
T-O-D Subtrans.	0 $	-2%	0	0 $	-2%	0	-
Meter Level Discount (Stby.):							
T-O-D Primary	1,143,365 $	-1%	(11,434)	1,248,457 $	-1%	(12,485)	9.2
T-O-D Subtrans.	179,579 $	-2%	(3,592)	220,622 $	-2%	(4,412)	22.8
Total	4,323,189 $		(45,028)	4,400,304 $		(46,209)	2.6

Continued on Page 12

Supporting Schedules: E-18a, E-18b, E-18c

Recap Schedules: E-16a, E-17

Schedule E-16c

BASE REVENUE BY RATE SCHEDULE - CALCULATIONS

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: TAMPA ELECTRIC COMPANY

DOCKET NO.: 920324-EI

EXPLANATION: By rate schedule, calculate revenues under present and proposed rates for the test year. If any customers are to be transferred from one schedule to another, show revenues separately for the transfer group. Correction factors are used for historical test years only. The total base revenue by class must equal that shown in Schedule E-16a. The billing units must equal those shown in Schedules E-18a, E-18b and E-18c. Provide total number of Bills, MWH and Billing KW for each rate schedule (including Standard and Time-of-Day customers) and transfer group.

Type of data shown:
XX Projected Test Year Ended 12/31/93
__ Projected Prior Year Ended __/__/__
__ Historical Prior Year Ended __/__/__
Witness: L. R. SMITH

RATE SCHEDULE SBF

TYPE OF CHARGES	PRESENT REVENUE CALCULATION			PROPOSED REVENUE CALCULATION			% INCREASE
	UNITS	CHARGE/UNIT	$ REVENUE	UNITS	CHARGE/UNIT	$ REVENUE	
Continued from Page 11							
Transf. Owner. Disc. (Supp.):							
T-O-D Primary	156,934 KW	($0.32)	(50,219)	156,934 KW	($0.36)	(56,496)	12.5
T-O-D Subtrans.	0 KW	($0.42)	0	0 KW	($0.59)	0	-
Transf. Owner. Disc. (Stby.):							
T-O-D Primary	176,400 KW	($0.27)	(47,628)	176,400 KW	($0.28)	(49,392)	3.7
T-O-D Subtrans.	63,096 KW	($0.35)	(22,084)	63,096 KW	($0.46)	(29,024)	31.4
Total	396,430 KW		(119,931)	396,430 KW		(134,912)	12.5
Emergency Relay Charge (Supp.):							
T-O-D Primary	82,606 KW	$0.50	41,303	82,606 KW	$0.60	49,564	20.0
T-O-D Subtrans.	0 KW	$0.50	0	0 KW	$0.60	0	-
Emergency Relay Charge (Stby.):							
T-O-D Primary	151,200 KW	$0.50	75,600	151,200 KW	$0.60	90,720	20.0
T-O-D Subtrans.	0 KW	$0.50	0	0 KW	$0.60	0	-
Total	233,806 KW		116,903	233,806 KW		140,284	20.0
Total Base Revenue (Calculated)			4,233,074			4,346,050	2.7
Correction Factor			1.000000			1.000000	
Total Base Revenue (Booked)			4,233,074			4,346,050	2.7

Supporting Schedules: E-18a, E-18b, E-18c

Recap Schedules: E-16a, E-17

BASE REVENUE BY RATE SCHEDULE - CALCULATIONS

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: TAMPA ELECTRIC COMPANY

DOCKET NO.: 920324-EI

EXPLANATION: By rate schedule, calculate revenues under present and proposed rates for the test year. If any customers are to be transferred from one schedule to another, show revenues separately for the transfer group. Correction factors are used for historical test years only. The total base revenue by class must equal that shown in Schedule E-16a. The billing units must equal those shown in Schedules E-18a, E-18b and E-18c. Provide total number of Bills, MWH and Billing KW for each rate schedule (including Standard and Time-of-Day customers) and transfer group.

Type of data shown:
XX Projected Test Year Ended 12/31/93
__ Projected Prior Year Ended _/_/_
__ Historical Prior Year Ended _/_/_
Witness: L. R. SMITH

RATE SCHEDULE IS-1

TYPE OF CHARGES	PRESENT REVENUE CALCULATION			PROPOSED REVENUE CALCULATION			% INCREASE
	UNITS	CHARGE/UNIT	$ REVENUE	UNITS	CHARGE/UNIT	$ REVENUE	
Customer Charge:							
Standard Primary	132 Bills	$670.00	88,440	132 Bills	$1,000.00	132,000	49.3
Standard Subtrans.	12 Bills	$670.00	8,040	12 Bills	$1,000.00	12,000	49.3
T-O-D Primary	132 Bills	$670.00	88,440	132 Bills	$1,000.00	132,000	49.3
T-O-D Subtrans.	216 Bills	$670.00	144,720	216 Bills	$1,000.00	216,000	49.3
Total	492 Bills		329,640	492 Bills		492,000	49.3
Energy Charge:							
Standard Primary	50,612 MWH	$11.96	605,320	50,612 MWH	$11.34	573,940	(5.2)
Standard Subtrans.	3,387 MWH	$11.96	40,509	3,387 MWH	$11.34	38,409	(5.2)
T-O-D Pri. On-Peak	82,121 MWH	$11.96	982,167	82,121 MWH	$11.34	931,252	(5.2)
T-O-D Pri. Off-Peak	254,716 MWH	$11.96	3,046,403	254,716 MWH	$11.34	2,888,479	(5.2)
T-O-D Subtrans. On-Peak	199,092 MWH	$11.96	2,381,140	199,092 MWH	$11.34	2,257,703	(5.2)
T-O-D Subtrans. Off-Peak	613,197 MWH	$11.96	7,333,836	613,197 MWH	$11.34	6,953,654	(5.2)
Total	1,203,125 MWH (1)		14,389,375	1,203,125 MWH (1)		13,643,437	(5.2)
Demand Charge:							
Standard Primary	221,939 KW	$1.30	288,521	221,939 KW	$1.45	321,812	11.5
Standard Subtrans.	7,513 KW	$1.30	9,767	7,513 KW	$1.45	10,894	11.5
T-O-D Primary	946,527 KW	$1.30	1,230,485	946,527 KW	$1.45	1,372,464	11.5
T-O-D Subtrans.	2,115,095 KW	$1.30	2,749,624	2,115,095 KW	$1.45	3,066,888	11.5
Total	3,291,074 KW		4,278,397	3,291,074 KW		4,772,058	11.5

(1) Excludes 3,171 MWH of Optional Provision.

Continued on Page 14

Supporting Schedules: E-18a, E-18b, E-18c

Recap Schedules: E-16a, E-17

BASE REVENUE BY RATE SCHEDULE - CALCULATIONS

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: TAMPA ELECTRIC COMPANY

DOCKET NO.: 920324-EI

EXPLANATION: By rate schedule, calculate revenues under present and proposed rates for the test year. If any customers are to be transferred from one schedule to another, show revenues separately for the transfer group. Correction factors are used for historical test years only. The total base revenue by class must equal that shown in Schedule E-16a. The billing units must equal those shown in Schedules E-18a, E-18b and E-18c. Provide total number of Bills, MWH and Billing KW for each rate schedule (including Standard and Time-of-Day customers) and transfer group.

Type of data shown:
XX Projected Test Year Ended 12/31/93
__ Projected Prior Year Ended _/_/_
__ Historical Prior Year Ended _/_/_
Witness: L. R. SMITH

RATE SCHEDULE IS-1

TYPE OF CHARGES	PRESENT REVENUE CALCULATION			PROPOSED REVENUE CALCULATION			% INCREASE
	UNITS	CHARGE/UNIT	$ REVENUE	UNITS	CHARGE/UNIT	$ REVENUE	
Continued from Page 13							
Power Factor Charge:							
Standard Primary	511 MVAH	$36.50	18,652	940 MVARH	$2.00	1,880	(89.9)
Standard Subtrans.	14 MVAH	$36.50	511	30 MVARH	$2.00	60	(88.3)
T-O-D Primary	539 MVAH	$36.50	19,674	903 MVARH	$2.00	1,806	(90.8)
T-O-D Subtrans.	2,762 MVAH	$36.50	100,813	7,266 MVARH	$2.00	14,532	(85.6)
Total	3,826 MVAH		139,650	9,139 MVARH		18,278	(86.9)
Power Factor Credit:							
Standard Primary			(13,513)	2,609 MVARH	($1.00)	(2,609)	(80.7)
Standard Subtrans.			(649)	82 MVARH	($1.00)	(82)	(87.4)
T-O-D Primary			(112,941)	17,332 MVARH	($1.00)	(17,332)	(84.7)
T-O-D Subtrans.			(373,328)	100,805 MVARH	($1.00)	(100,805)	(73.0)
Total			(500,431)	120,828 MVARH		(120,828)	(75.9)
Metering Level Discount:							
Standard Subtrans.	50,276 $	-1%	(503)	49,303 $	-1%	(493)	(2.0)
T-O-D Subtrans.	12,464,600 $	-1%	(124,646)	12,278,245 $	-1%	(122,782)	(1.5)
Total	12,514,876 $		(125,149)	12,327,548 $		(123,275)	(1.5)
Transformer Owner. Discount:							
Standard Subtrans.	7,513 KW	($0.10)	(751)	7,513 KW	($0.23)	(1,728)	130.1
T-O-D Subtrans.	2,084,899 KW	($0.10)	(208,490)	2,084,899 KW	($0.23)	(479,527)	130.0
Total	2,092,412 KW		(209,241)	2,092,412 KW		(481,255)	130.0

Continued on Page 15

Supporting Schedules: E-18a, E-18b, E-18c

Recap Schedules: E-16a, E-17

Schedule E-16c

BASE REVENUE BY RATE SCHEDULE - CALCULATIONS

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: TAMPA ELECTRIC COMPANY

DOCKET NO.: 920324-EI

EXPLANATION: By rate schedule, calculate revenues under present and proposed rates for the test year. If any customers are to be transferred from one schedule to another, show revenues separately for the transfer group. Correction factors are used for historical test years only. The total base revenue by class must equal that shown in Schedule E-16a. The billing units must equal those shown in Schedules E-18a, E-18b and E-18c. Provide total number of Bills, MWH and Billing KW for each rate schedule (including Standard and Time-of-Day customers) and transfer group.

Type of data shown:
XX Projected Test Year Ended 12/31/93
__ Projected Prior Year Ended __/__/__
__ Historical Prior Year Ended __/__/__
Witness: L. R. SHITH

RATE SCHEDULE IS-1

TYPE OF CHARGES	PRESENT REVENUE CALCULATION			PROPOSED REVENUE CALCULATION			% INCREASE
	UNITS	CHARGE/UNIT	$ REVENUE	UNITS	CHARGE/UNIT	$ REVENUE	
Continued from Page 14							
Total Base Revenue (Calculated)			18,302,241			18,200,415	(0.6)
Correction Factor			1.000000			1.000000	
Total Base Revenue (Booked)			18,302,241			18,200,415	(0.6)

Supporting Schedules: E-18a, E-18b, E-18c

Recap Schedules: E-16a, E-17

BASE REVENUE BY RATE SCHEDULE - CALCULATIONS

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: TAMPA ELECTRIC COMPANY

DOCKET NO.: 920324-EI

EXPLANATION: By rate schedule, calculate revenues under present and proposed rates for the test year. If any customers are to be transferred from one schedule to another, show revenues separately for the transfer group. Correction factors are used for historical test years only. The total base revenue by class must equal that shown in Schedule E-16a. The billing units must equal those shown in Schedules E-18a, E-18b and E-18c. Provide total number of Bills, MWH and Billing KW for each rate schedule (including Standard and Time-of-Day customers) and transfer group.

Type of data shown:
XX Projected Test Year Ended 12/31/93
__ Projected Prior Year Ended __/__/__
__ Historical Prior Year Ended __/__/__
Witness: L. R. SMITH

RATE SCHEDULE SBI-1

TYPE OF CHARGES	PRESENT REVENUE CALCULATION UNITS	CHARGE/UNIT	$ REVENUE	PROPOSED REVENUE CALCULATION UNITS	CHARGE/UNIT	$ REVENUE	% INCREASE
Customer Charge:							
T-O-D Primary	0 Bills	$695.00	0	0 Bills	$1,025.00	0	-
T-O-D Subtrans.	48 Bills	$695.00	33,360	48 Bills	$1,025.00	49,200	47.5
Total	48 Bills		33,360	48 Bills		49,200	47.5
Energy Charge (Supplemental):							
T-O-D Pri. On-Peak	0 MWH	$11.96	0	0 MWH	$11.34	0	-
T-O-D Pri. Off-Peak	0 MWH	$11.96	0	0 MWH	$11.34	0	-
T-O-D Subtrans. On-Peak	32,841 MWH	$11.96	392,778	32,841 MWH	$11.34	372,417	(5.2)
T-O-D Subtrans. Off-Peak	101,205 MWH	$11.96	1,210,412	101,205 MWH	$11.34	1,147,665	(5.2)
Energy Charge (Standby):							
T-O-D Pri. On-Peak	0 MWH	$11.96	0	0 MWH	$9.56	0	-
T-O-D Pri. Off-Peak	0 MWH	$11.96	0	0 MWH	$9.56	0	-
T-O-D Subtrans. On-Peak	22,430 MWH	$11.96	268,263	22,430 MWH	$9.56	214,431	(20.1)
T-O-D Subtrans. Off-Peak	65,051 MWH	$11.96	778,010	65,051 MWH	$9.56	621,888	(20.1)
Total	221,527 MWH (1)		2,649,463	221,527 MWH (1)		2,356,401	(11.1)
Demand Charge (Supplemental):							
T-O-D Pri.	0 KW	$1.30	0	0 KW	$1.45	0	-
T-O-D Subtrans.	164,400 KW	$1.30	213,720	164,400 KW	$1.45	238,380	11.5
Demand Charge (Standby):							
T-O-D Pri.	0 KW	$0.73	0	0 KW	$0.86	0	-
Reservation Chg. Pri	0 KW/Mo. (2)	$0.06	0	0 KW/Mo. (2)	$0.08	0	-
Reservation Chg. Pri	0 KW/Day (2)	$0.03	0	0 KW/Day (2)	$0.03	0	-
T-O-D Subtrans.	1,109,664 KW	$0.73	810,055	1,109,664 KW	$0.86	954,311	17.8
Reservation Chg. Subtrans.	396,816 KW/Mo. (2)	$0.06	23,809	396,816 KW/Mo. (2)	$0.08	31,745	33.3
Reservation Chg. Subtrans.	3,562,687 KW/Day (2)	$0.03	106,881	3,562,687 KW/Day (2)	$0.03	106,881	0.0
Total	1,274,064 KW		1,154,465	1,274,064 KW		1,331,317	15.3

(1) Excludes 573 MWH of Optional Provision.
(2) Not included in total.
Continued on Page 17

Supporting Schedules: E-18a, E-18b, E-18c

Recap Schedules: E-16a, E-17

APPENDIX I
(con't)

BASE REVENUE BY RATE SCHEDULE - CALCULATIONS

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: TAMPA ELECTRIC COMPANY

DOCKET NO.: 920324-EI

EXPLANATION: By rate schedule, calculate revenues under present and proposed rates for the test year. If any customers are to be transferred from one schedule to another, show revenues separately for the transfer group. Correction factors are used for historical test years only. The total base revenue by class must equal that shown in Schedule E-16a. The billing units must equal those shown in Schedules E-18a, E-18b and E-18c. Provide total number of Bills, MWH and Billing KW for each rate schedule (including Standard and Time-of-Day customers) and transfer group.

Type of data shown:
XX Projected Test Year Ended 12/31/93
__ Projected Prior Year Ended __/__/__
__ Historical Prior Year Ended __/__/__
Witness: L. R. SMITH

RATE SCHEDULE SBI-1

TYPE OF CHARGES	PRESENT REVENUE CALCULATION UNITS	CHARGE/UNIT	$ REVENUE	PROPOSED REVENUE CALCULATION UNITS	CHARGE/UNIT	$ REVENUE	% INCREASE
Continued from Page 16							
Power Factor Charge (Supp.)							
T-O-D Primary	0 MVAH	$36.50	0	0 MVARH	$2.00	0	-
T-O-D Subtrans.	1,273 MVAH	$36.50	46,465	2,506 MVARH	$2.00	5,012	(89.2)
Power Factor Charge (Stby.)							
T-O-D Primary				0 MVARH	$2.00	0	-
T-O-D Subtrans.				1,636 MVARH	$2.00	3,272	-
Total	1,273 MVAH		46,465	4,142 MVARH		8,284	-
Power Factor Credit (Supp.)							
T-O-D Primary			0	0 MVARH	($1.00)	0	-
T-O-D Subtrans.			(11,742)	6,540 MVARH	($1.00)	(6,540)	(44.3)
Power Factor Credit (Stby.)							
T-O-D Primary				0 MVARH	($1.00)	0	-
T-O-D Subtrans.				4,268 MVARH	($1.00)	(4,268)	-
Total			(11,742)	10,808 MVARH		(10,808)	(8.0)
Meter Level Discount (Supp.)							
T-O-D Subtrans.	1,816,910 $	-1%	(18,169)	1,758,462 $	-1%	(17,585)	(3.2)
Meter Level Discount (Stby.)							
T-O-D Subtrans.	1,987,018 $	-1%	(19,870)	1,929,256 $	-1%	(19,293)	(2.9)
Total	3,803,928 $		(38,039)	3,687,718 $		(36,878)	(3.1)
Transf. Owner. Disc. (Supp.)							
T-O-D Subtrans.	164,400 KW	($0.10)	(16,440)	164,400 KW	($0.23)	(37,812)	130.0
Transf. Owner. Disc. (Stby.)							
T-O-D Subtrans.	1,109,664 KW	($0.08)	(88,773)	1,109,664 KW	($0.20)	(221,933)	150.0
Total	1,274,064 KW		(105,213)	1,274,064 KW		(259,745)	146.9

Continued on Page 18

Supporting Schedules: E-18a, E-18b, E-18c

Recap Schedules: E-16a, E-17

BASE REVENUE BY RATE SCHEDULE - CALCULATIONS

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: TAMPA ELECTRIC COMPANY

DOCKET NO.: 920324-EI

EXPLANATION: By rate schedule, calculate revenues under present and proposed rates for the test year. If any customers are to be transferred from one schedule to another, show revenues separately for the transfer group. Correction factors are used for historical test years only. The total base revenue by class must equal that shown in Schedule E-16a. The billing units must equal those shown in Schedules E-18a, E-18b and E-18c. Provide total number of Bills, MWH and Billing KW for each rate schedule (including Standard and Time-of-Day customers) and transfer group.

Type of data shown:
XX Projected Test Year Ended 12/31/93
__ Projected Prior Year Ended _/_/_
__ Historical Prior Year Ended _/_/_
Witness: L. R. SMITH

RATE SCHEDULE SBI-1

TYPE OF CHARGES	PRESENT REVENUE CALCULATION			PROPOSED REVENUE CALCULATION			% INCREASE
	UNITS	CHARGE/UNIT	$ REVENUE	UNITS	CHARGE/UNIT	$ REVENUE	
Continued from Page 17							
Total Base Revenue (Calculated)			3,728,759			3,437,771	(7.8)
Correction Factor			1.000000			1.000000	
Total Base Revenue (Booked)			3,728,759			3,437,771	(7.8)

Supporting Schedules: E-18a, E-18b, E-18c

Recap Schedules: E-16a, E-17

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: TAMPA ELECTRIC COMPANY

DOCKET NO.: 920324-EI

EXPLANATION: By rate schedule, calculate revenues under present and proposed rates for the test year. If any customers are to be transferred from one schedule to another, show revenues separately for the transfer group. Correction factors are used for historical test years only. The total base revenue by class must equal that shown in Schedule E-16a. The billing units must equal those shown in Schedules E-18a, E-18b and E-18c. Provide total number of Bills, MWH and Billing KW for each rate schedule (including Standard and Time-of-Day customers) and transfer group.

Type of data shown:
XX Projected Test Year Ended 12/31/93
__ Projected Prior Year Ended __/__/__
__ Historical Prior Year Ended __/__/__
Witness: L. R. SMITH

RATE SCHEDULE IS-3

TYPE OF CHARGES	PRESENT REVENUE CALCULATION UNITS	CHARGE/UNIT	$ REVENUE	PROPOSED REVENUE CALCULATION UNITS	CHARGE/UNIT	$ REVENUE	% INCREASE
Customer Charge:							
Standard Primary	48 Bills	$710.00	34,080	48 Bills	$1,000.00	48,000	40.8
Standard Subtrans.	0 Bills	$710.00	0	0 Bills	$1,000.00	0	-
T-O-D Primary	60 Bills	$710.00	42,600	60 Bills	$1,000.00	60,000	40.8
T-O-D Subtrans.	12 Bills	$710.00	8,520	12 Bills	$1,000.00	12,000	40.8
Total	120 Bills		85,200	120 Bills		120,000	40.8
Energy Charge:							
Standard Primary	58,159 MWH	$15.32	890,996	58,159 MWH	$15.61	907,862	1.9
Standard Subtrans.	0 MWH	$15.32	0	0 MWH	$15.61	0	-
T-O-D Pri. On-Peak	34,795 MWH	$15.32	533,059	34,795 MWH	$15.61	543,150	1.9
T-O-D Pri. Off-Peak	98,061 MWH	$15.32	1,502,295	98,061 MWH	$15.61	1,530,732	1.9
T-O-D Subtrans. On-Peak	1,676 MWH	$15.32	25,676	1,676 MWH	$15.61	26,162	1.9
T-O-D Subtrans. Off-Peak	5,206 MWH	$15.32	79,756	5,206 MWH	$15.61	81,266	1.9
Total	197,897 MWH (1)		3,031,782	197,897 MWH (1)		3,089,172	1.9
Demand Charge:							
Standard Primary	184,625 KW	$1.30	240,013	184,625 KW	$1.45	267,706	11.5
Standard Subtrans.	0 KW	$1.30	0	0 KW	$1.45	0	-
T-O-D Primary	249,324 KW	$1.30	324,121	249,324 KW	$1.45	361,520	11.5
T-O-D Subtrans.	16,036 KW	$1.30	20,847	16,036 KW	$1.45	23,252	11.5
Total	449,985 KW		584,981	449,985 KW		652,478	11.5

(1) Excludes 513 MWH of Optional Provision.

Continued on Page 20

Supporting Schedules: E-18a, E-18b, E-18c Recap Schedules: E-16a, E-17

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: TAMPA ELECTRIC COMPANY

DOCKET NO.: 920324-EI

EXPLANATION: By rate schedule, calculate revenues under present and proposed rates for the test year. If any customers are to be transferred from one schedule to another, show revenues separately for the transfer group. Correction factors are used for historical test years only. The total base revenue by class must equal that shown in Schedule E-16a. The billing units must equal those shown in Schedules E-18a, E-18b and E-18c. Provide total number of Bills, MWH and Billing KW for each rate schedule (including Standard and Time-of-Day customers) and transfer group.

Type of data shown:
XX Projected Test Year Ended 12/31/93
__ Projected Prior Year Ended __/__/__
__ Historical Prior Year Ended __/__/__
Witness: L. R. SMITH

RATE SCHEDULE IS-3

TYPE OF CHARGES	PRESENT REVENUE CALCULATION			PROPOSED REVENUE CALCULATION			% INCREASE
	UNITS	CHARGE/UNIT	$ REVENUE	UNITS	CHARGE/UNIT	$ REVENUE	
Continued from Page 19							
Power Factor Charge:							
Standard Primary	302 MVAH	$36.50	11,023	547 MVARH	$2.00	1,094	(90.1)
Standard Subtrans.	0 MVAH	$36.50	0	0 MVARH	$2.00	0	-
T-O-D Primary	1,010 MVAH	$36.50	36,865	2,164 MVARH	$2.00	4,328	(88.3)
T-O-D Subtrans.	0 MVAH	$36.50	0	0 MVARH	$2.00	0	-
Total	1,312 MVAH		47,888	2,711 MVARH		5,422	(88.7)
Power Factor Credit:							
Standard Primary			(25,532)	5,772 MVARH	($1.00)	(5,772)	(77.4)
Standard Subtrans.			0	0 MVARH	($1.00)	0	-
T-O-D Primary			(49,064)	12,594 MVARH	($1.00)	(12,594)	(74.3)
T-O-D Subtrans.			(3,948)	1,087 MVARH	($1.00)	(1,087)	(72.5)
Total			(78,544)	19,453 MVARH		(19,453)	(75.2)
Metering Level Discount:							
Standard Subtrans.	0 $	-1%	0	0 $	-1%	0	-
T-O-D Subtrans.	126,279 $	-1%	(1,263)	130,680 $	-1%	(1,307)	3.5
Total	126,279 $		(1,263)	130,680 $		(1,307)	3.5
Transformer Owner. Discount:							
Standard Subtrans.	0 KW	($0.10)	0	0 KW	($0.23)	0	-
T-O-D Subtrans.	16,036 KW	($0.10)	(1,604)	16,036 KW	($0.23)	(3,688)	129.9
Total	16,036 KW		(1,604)	16,036 KW		(3,688)	129.9

Continued on Page 21

Supporting Schedules: E-18a, E-18b, E-18c

Recap Schedules: E-16a, E-17

Schedule E-16c

BASE REVENUE BY RATE SCHEDULE - CALCULATIONS

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: TAMPA ELECTRIC COMPANY

DOCKET NO.: 920324-EI

EXPLANATION: By rate schedule, calculate revenues under present and proposed rates for the test year. If any customers are to be transferred from one schedule to another, show revenues separately for the transfer group. Correction factors are used for historical test years only. The total base revenue by class must equal that shown in Schedule E-16a. The billing units must equal those shown in Schedules E-18a, E-18b and E-18c. Provide total number of Bills, MWH and Billing KW for each rate schedule (including Standard and Time-of-Day customers) and transfer group.

Type of data shown:
XX Projected Test Year Ended 12/31/93
__ Projected Prior Year Ended __/__/__
__ Historical Prior Year Ended __/__/__
Witness: L. R. SHITH

RATE SCHEDULE IS-3

TYPE OF CHARGES	PRESENT REVENUE CALCULATION UNITS	CHARGE/UNIT	$ REVENUE	PROPOSED REVENUE CALCULATION UNITS	CHARGE/UNIT	$ REVENUE	% INCREASE
Continued from Page 20							
Total Base Revenue (Calculated)			3,668,440			3,842,624	4.7
Correction Factor			1.000000			1.000000	
Total Base Revenue (Booked)			3,668,440			3,842,624	4.7

Supporting Schedules: E-18a, E-18b, E-18c

Recap Schedules: E-16a, E-17

Schedule E-16c

BASE REVENUE BY RATE SCHEDULE - CALCULATIONS

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: TAMPA ELECTRIC COMPANY

DOCKET NO.: 920324-EI

EXPLANATION: By rate schedule, calculate revenues under present and proposed rates for the test year. If any customers are to be transferred from one schedule to another, show revenues separately for the transfer group. Correction factors are used for historical test years only. The total base revenue by class must equal that shown in Schedule E-16a. The billing units must equal those shown in Schedules E-18a, E-18b and E-18c. Provide total number of Bills, MWH and Billing KW for each rate schedule (including Standard and Time-of-Day customers) and transfer group.

Type of data shown:
XX Projected Test Year Ended 12/31/93
__ Projected Prior Year Ended __/__/__
__ Historical Prior Year Ended __/__/__
Witness: L. R. SMITH

RATE SCHEDULE SBI-3

TYPE OF CHARGES	PRESENT REVENUE CALCULATION UNITS	CHARGE/UNIT	$ REVENUE	PROPOSED REVENUE CALCULATION UNITS	CHARGE/UNIT	$ REVENUE	% INCREASE
Customer Charge:							
T-O-D Primary	0 Bills	$735.00	0	0 Bills	$1,025.00	0	-
T-O-D Subtrans.	48 Bills	$735.00	35,280	48 Bills	$1,025.00	49,200	39.5
Total	48 Bills		35,280	48 Bills		49,200	39.5
Energy Charge (Supplemental):							
T-O-D Pri. On-Peak	0 MWH	$15.32	0	0 MWH	$15.61	0	-
T-O-D Pri. Off-Peak	0 MWH	$15.32	0	0 MWH	$15.61	0	-
T-O-D Subtrans. On-Peak	17,680 MWH	$15.32	270,858	17,680 MWH	$15.61	275,985	1.9
T-O-D Subtrans. Off-Peak	53,928 MWH	$15.32	826,177	53,928 MWH	$15.61	841,816	1.9
Energy Charge (Standby):							
T-O-D Pri. On-Peak	0 MWH	$15.32	0	0 MWH	$9.56	0	-
T-O-D Pri. Off-Peak	0 MWH	$15.32	0	0 MWH	$9.56	0	-
T-O-D Subtrans. On-Peak	16,178 MWH	$15.32	247,847	16,178 MWH	$9.56	154,662	(37.6)
T-O-D Subtrans. Off-Peak	48,949 MWH	$15.32	749,899	48,949 MWH	$9.56	467,952	(37.6)
Total	136,735 MWH (1)		2,094,781	136,735 MWH (1)		1,740,415	(16.9)
Demand Charge (Supplemental):							
T-O-D Pri.	0 KW	$1.30	0	0 KW	$1.45	0	-
T-O-D Subtrans.	207,600 KW	$1.30	269,880	207,600 KW	$1.45	301,020	11.5
Demand Charge (Standby):							
T-O-D Pri.	0 KW	$0.73	0	0 KW	$0.86	0	-
Reservation Chg. Pri	0 KW/Mo. (2)	$0.06	0	0 KW/Mo. (2)	$0.08	0	-
Reservation Chg. Pri	0 KW/Day (2)	$0.03	0	0 KW/Day (2)	$0.03	0	-
T-O-D Subtrans.	1,256,304 KW	$0.73	917,102	1,256,304 KW	$0.86	1,080,421	17.8
Reservation Chg. Subtrans.	266,588 KW/Mo. (2)	$0.06	15,995	266,588 KW/Mo. (2)	$0.08	21,327	33.3
Reservation Chg. Subtrans.	5,171,827 KW/Day (2)	$0.03	155,155	5,171,827 KW/Day (2)	$0.03	155,155	0.0
Total	1,463,904 KW		1,358,132	1,463,904 KW		1,557,923	14.7

(1) Excludes 345 MWH of Optional Provision.
(2) Not included in total.
Continued on Page 23

Supporting Schedules: E-18a, E-18b, E-18c

Recap Schedules: E-16a, E-17

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: TAMPA ELECTRIC COMPANY

DOCKET NO.: 920324-EI

EXPLANATION: By rate schedule, calculate revenues under present and proposed rates for the test year. If any customers are to be transferred from one schedule to another, show revenues separately for the transfer group. Correction factors are used for historical test years only. The total base revenue by class must equal that shown in Schedule E-16a. The billing units must equal those shown in Schedules E-18a, E-18b and E-18c. Provide total number of Bills, MWH and Billing KW for each rate schedule (including Standard and Time-of-Day customers) and transfer group.

Type of data shown:
XX Projected Test Year Ended 12/31/93
__ Projected Prior Year Ended _/_/_
__ Historical Prior Year Ended _/_/_
Witness: L. R. SMITH

RATE SCHEDULE SBI-3

TYPE OF CHARGES	PRESENT REVENUE CALCULATION UNITS	PRESENT CHARGE/UNIT	PRESENT $ REVENUE	PROPOSED REVENUE CALCULATION UNITS	PROPOSED CHARGE/UNIT	PROPOSED $ REVENUE	% INCREASE
Continued from Page 22							
Power Factor Charge (Supp.)							
T-O-D Primary	0 MVAH	$36.50	0	0 MVARH	$2.00	0	-
T-O-D Subtrans.	29 MVAH	$36.50	1,059	1,095 MVARH	$2.00	2,190	106.8
Power Factor Charge (Stby.)							
T-O-D Primary				0 MVARH	$2.00	0	-
T-O-D Subtrans.				996 MVARH	$2.00	1,992	-
Total	29 MVAH		1,059	2,091 MVARH		4,182	294.9
Power Factor Credit (Supp.)							
T-O-D Primary			0	0 MVARH	($1.00)	0	-
T-O-D Subtrans.			(37,702)	8,216 MVARH	($1.00)	(8,216)	(78.2)
Power Factor Credit (Stby.)							
T-O-D Primary				0 MVARH	($1.00)	0	-
T-O-D Subtrans.				7,472 MVARH	($1.00)	(7,472)	-
Total			(37,702)	15,688 MVARH		(15,688)	(58.4)
Meter Level Discount (Supp.) T-O-D Subtrans.	1,366,915 $	-1%	(13,669)	1,418,821 $	-1%	(14,188)	3.8
Meter Level Discount (Stby.) T-O-D Subtrans.	2,085,998 $	-1%	(20,860)	1,879,517 $	-1%	(18,795)	(9.9)
Total	3,452,913 $		(34,529)	3,298,338 $		(32,983)	(4.5)
Transf. Owner. Disc. (Supp.) T-O-D Subtrans.	207,600 KW	($0.10)	(20,760)	207,600 KW	($0.23)	(47,748)	130.0
Transf. Owner. Disc. (Stby.) T-O-D Subtrans.	1,256,304 KW	($0.08)	(100,504)	1,256,304 KW	($0.20)	(251,261)	150.0
Total	1,463,904 KW		(121,264)	1,463,904 KW		(299,009)	146.6

Continued on Page 24

Supporting Schedules: E-18a, E-18b, E-18c

Recap Schedules: E-16a, E-17

Schedule E-16c | BASE REVENUE BY RATE SCHEDULE - CALCULATIONS |

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: TAMPA ELECTRIC COMPANY

DOCKET NO.: 920324-EI

EXPLANATION: By rate schedule, calculate revenues under present and proposed rates for the test year. If any customers are to be transferred from one schedule to another, show revenues separately for the transfer group. Correction factors are used for historical test years only. The total base revenue by class must equal that shown in Schedule E-16a. The billing units must equal those shown in Schedules E-18a, E-18b and E-18c. Provide total number of Bills, MWH and Billing KW for each rate schedule (including Standard and Time-of-Day customers) and transfer group.

Type of data shown:
XX Projected Test Year Ended 12/31/93
__ Projected Prior Year Ended __/__/__
__ Historical Prior Year Ended __/__/__
Witness: L. R. SMITH

RATE SCHEDULE SBI-3

TYPE OF CHARGES	PRESENT REVENUE CALCULATION			PROPOSED REVENUE CALCULATION			% INCREASE
	UNITS	CHARGE/UNIT	$ REVENUE	UNITS	CHARGE/UNIT	$ REVENUE	
Continued from Page 23							
Total Base Revenue (Calculated)			3,295,757			3,004,040	(8.9)
Correction Factor			1.000000			1.000000	
Total Base Revenue (Booked)			3,295,757			3,004,040	(8.9)

Supporting Schedules: E-18a, E-18b, E-18c

Recap Schedules: E-16a, E-17

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: TAMPA ELECTRIC COMPANY

DOCKET NO.: 920324-EI

EXPLANATION: By rate schedule, calculate revenues under present and proposed rates for the test year. If any customers are to be transferred from one schedule to another, show revenues separately for the transfer group. Correction factors are used for historical test years only. The total base revenue by class must equal that shown in Schedule E-16a. The billing units must equal those shown in Schedules E-18a, E-18b and E-18c. Provide total number of Bills, MWH and Billing KW for each rate schedule (including Standard and Time-of-Day customers) and transfer group.

Type of data shown:
XX Projected Test Year Ended 12/31/93
__ Projected Prior Year Ended __/__/__
__ Historical Prior Year Ended __/__/__
Witness: L. R. SMITH

RATE SCHEDULE TS

TYPE OF CHARGES	PRESENT REVENUE CALCULATION			PROPOSED REVENUE CALCULATION			% INCREASE
	UNITS	CHARGE/UNIT	$ REVENUE	UNITS	CHARGE/UNIT	$ REVENUE	
Customer Charge: Standard	20,181 Bills	$7.00	141,267	20,181 Bills	$8.50	171,539	21.4
Total	20,181 Bills		141,267	20,181 Bills		171,539	21.4
Energy and Demand Charge: Standard	2,422 MWH	$43.34	104,969	2,422 MWH	$41.30	100,029	(4.7)
Total	2,422 MWH		104,969	2,422 MWH		100,029	(4.7)
Total Base Revenue (Calculated)			246,236			271,568	10.3
Correction Factor			1.000000			1.000000	
Total Base Revenue (Booked)			246,236			271,568	

Schedule E-16d

REVENUE BY RATE SCHEDULE - LIGHTING SCHEDULE CALCULATION

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: TAMPA ELECTRIC COMPANY

DOCKET NO.: 920324-EI

EXPLANATION: Calculate revenue under present and proposed rates for the test year for each lighting schedule. Show revenues from charges for all types of lighting fixtures, poles and conductors. Poles should be listed separately from fixtures. Show separately revenues from customers who own facilities as well as those who do not. Annual KWH's must agree with the data provided in Schedule E-16a.

Type of data shown:
XX Projected Test Year Ended 12/31/93
__ Projected Prior Year Ended __/__/__
__ Historical Prior Year Ended __/__/__
Witness: L. R. SMITH

RATE SCHEDULE SL-2

				PRESENT REVENUE CALCULATION					PROPOSED REVENUE CALCULATION					
TYPE OF FACILITY	ANNUAL BILLING ITEMS	EST. KWH / MO.	ANNUAL KWH	FACILITY CHARGE	ENERGY CHARGE	MAINT. CHARGE	TOTAL MONTHLY CHARGE	$ TOTAL REVENUE	FACILITY CHARGE	ENERGY CHARGE	MAINT. CHARGE	TOTAL MONTHLY CHARGE	$ TOTAL REVENUE	PERCENT INCREASE
Fixture Type:														
4,000 Lumen High Pressure Sodium	215,190	20	4,303,800	$2.62	$0.54	$1.21	$4.37	$940,380	$2.68	$0.43	$1.17	$4.28	$921,013	(2.1)
5,800 Lumen High Pressure Sodium	28,344	29	821,976	2.65	0.79	1.21	4.65	131,800	2.71	0.62	1.20	4.53	128,398	(2.6)
9,500 Lumen High Pressure Sodium	293,208	51	14,953,608	3.01	1.38	1.25	5.64	1,653,693	3.08	1.09	1.22	5.39	1,580,391	(4.4)
16,000 Lumen High Pressure Sodium	42,510	70	2,975,700	3.46	1.90	1.28	6.64	282,266	3.54	1.49	0.91	5.94	252,509	(10.5)
27,500 Lumen High Pressure Sodium	58,608	110	6,446,880	4.03	2.99	1.32	8.34	488,791	4.13	2.35	0.97	7.45	436,630	(10.7)
50,000 Lumen High Pressure Sodium	12,708	170	2,160,360	4.21	4.61	1.37	10.19	129,495	4.31	3.63	1.09	9.03	114,753	(11.4)
5,800 Lumen High Pressure Sodium - Post Top	16,050	29	465,450	4.16	0.79	1.47	6.42	103,041	4.25	0.62	2.74	7.61	122,141	18.5
Additional Fixture on a Wood or Concrete Pole:														
4,000 Lumen High Pressure Sodium	330	20	6,600	2.35	0.54	1.19	4.08	1,346	2.41	0.43	1.17	4.01	1,323	(1.7)
5,800 Lumen High Pressure Sodium	132	29	3,828	2.39	0.79	1.19	4.37	577	2.44	0.62	1.20	4.26	562	(2.5)
9,500 Lumen High Pressure Sodium	3,012	51	153,612	2.73	1.38	1.24	5.35	16,114	2.79	1.09	1.22	5.10	15,361	(4.7)
16,000 Lumen High Pressure Sodium	2,274	70	159,180	3.18	1.90	1.27	6.35	14,440	3.25	1.49	0.91	5.65	12,848	(11.0)
27,500 Lumen High Pressure Sodium	1,494	110	164,340	3.76	2.99	1.31	8.06	12,042	3.84	2.35	0.97	7.16	10,697	(11.2)
50,000 Lumen High Pressure Sodium	36	170	6,120	3.94	4.61	1.35	9.90	356	4.03	3.63	1.09	8.75	315	(11.5)
Additional Fixture on an Aluminum Pole:														
4,000 Lumen High Pressure Sodium	0	20	0	2.36	0.54	1.19	4.09	0	2.42	0.43	1.17	4.02	0	-
5,800 Lumen High Pressure Sodium	0	29	0	2.38	0.79	1.19	4.36	0	2.44	0.62	1.20	4.26	0	-
9,500 Lumen High Pressure Sodium	486	51	24,786	2.68	1.38	1.24	5.30	2,576	2.74	1.09	1.22	5.05	2,454	(4.7)
16,000 Lumen High Pressure Sodium	180	70	12,600	5.12	1.90	1.27	8.29	1,492	5.23	1.49	0.91	7.63	1,373	(8.0)
27,500 Lumen High Pressure Sodium	0	110	0	5.70	2.99	1.31	10.00	0	5.83	2.35	0.97	9.15	0	-
50,000 Lumen High Pressure Sodium	0	170	0	6.16	4.61	1.35	12.12	0	6.30	3.63	1.09	11.02	0	-
Special Conditions: Energy Only	-	-	9,147,435	-	-	-	-	248,261	-	-	-	-	195,206	(21.4)

Present Energy Charge calculated @ $0.02714 per KWH

Proposed Energy Charge calculated @ $0.02134 per KWH

Continued on Page 2

Supporting Schedules: E-18c

Recap Schedules: E-16a, E-17

Schedule E-16d

REVENUE BY RATE SCHEDULE - LIGHTING SCHEDULE CALCULATION

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: TAMPA ELECTRIC COMPANY

DOCKET NO.: 920324-EI

EXPLANATION: Calculate revenue under present and proposed rates for the test year for each lighting schedule. Show revenues from charges for all types of lighting fixtures, poles and conductors. Poles should be listed separately from fixtures. Show separately revenues from customers who own facilities as well as those who do not. Annual KWH's must agree with the data provided in Schedule E-16a.

Type of data shown:
XX Projected Test Year Ended 12/31/93
__ Projected Prior Year Ended _/_/_
__ Historical Prior Year Ended _/_/_
Witness: L. R. SMITH

RATE SCHEDULE SL-2

TYPE OF FACILITY	ANNUAL BILLING ITEMS	EST. KWH / MO.	ANNUAL KWH	PRESENT REVENUE CALCULATION: FACILITY CHARGE	ENERGY CHARGE	MAINT. CHARGE	TOTAL MONTHLY CHARGE	$ TOTAL REVENUE	PROPOSED REVENUE CALCULATION: FACILITY CHARGE	ENERGY CHARGE	MAINT. CHARGE	TOTAL MONTHLY CHARGE	$ TOTAL REVENUE	PERCENT INCREASE
Continued from Page 1														
Fixture Type (C. I. A. C.):														
4,000 Lumen High Pressure Sodium	12	20	240	-	$0.54	$1.21	$1.75	$21	-	$0.43	$1.17	$1.60	$19	(9.5)
5,800 Lumen High Pressure Sodium	11,772	29	341,388	-	0.79	1.21	2.00	23,544	-	0.62	1.20	1.82	21,425	(9.0)
9,500 Lumen High Pressure Sodium	2,616	51	133,416	-	1.38	1.25	2.63	6,880	-	1.09	1.22	2.31	6,043	(12.2)
16,000 Lumen High Pressure Sodium	0	70	0	-	1.90	1.28	3.18	0	-	1.49	0.91	2.40	0	-
27,500 Lumen High Pressure Sodium	1,164	110	128,040	-	2.99	1.32	4.31	5,017	-	2.35	0.97	3.32	3,864	(23.0)
50,000 Lumen High Pressure Sodium	2,856	170	485,520	-	4.61	1.37	5.98	17,079	-	3.63	1.09	4.72	13,480	(21.1)
5,800 Lumen High Pressure Sodium - Post Top	0	29	0	-	0.79	1.47	2.26	0	-	0.62	2.74	3.36	0	-
Additional Fixture on a Wood or Concrete Pole (C. I. A. C.):														
4,000 Lumen High Pressure Sodium	0	20	0	-	0.54	1.19	1.73	0	-	0.43	1.17	1.60	0	-
5,800 Lumen High Pressure Sodium	0	29	0	-	0.79	1.19	1.98	0	-	0.62	1.20	1.82	0	-
9,500 Lumen High Pressure Sodium	0	51	0	-	1.38	1.24	2.62	0	-	1.09	1.22	2.31	0	-
16,000 Lumen High Pressure Sodium	0	70	0	-	1.90	1.27	3.17	0	-	1.49	0.91	2.40	0	-
27,500 Lumen High Pressure Sodium	0	110	0	-	2.99	1.31	4.30	0	-	2.35	0.97	3.32	0	-
50,000 Lumen High Pressure Sodium	12	170	2,040	-	4.61	1.35	5.96	72	-	3.63	1.09	4.72	57	(20.8)
Additional Fixture on an Aluminum Pole (C. I. A. C.):														
4,000 Lumen High Pressure Sodium	0	20	0	-	0.54	1.19	1.73	0	-	0.43	1.17	1.60	0	-
5,800 Lumen High Pressure Sodium	0	29	0	-	0.79	1.19	1.98	0	-	0.62	1.20	1.82	0	-
9,500 Lumen High Pressure Sodium	0	51	0	-	1.38	1.24	2.62	0	-	1.09	1.22	2.31	0	-
16,000 Lumen High Pressure Sodium	0	70	0	-	1.90	1.27	3.17	0	-	1.49	0.91	2.40	0	-
27,500 Lumen High Pressure Sodium	48	110	5,280	-	2.99	1.31	4.30	206	-	2.35	0.97	3.32	159	(22.8)
50,000 Lumen High Pressure Sodium	0	170	0	-	4.61	1.35	5.96	0	-	3.63	1.09	4.72	0	-
Total Fixtures and KWH	693,042		42,902,199											

Present Energy Charge calculated @ $0.02714 per KWH

Proposed Energy Charge calculated @ $0.02134 per KWH

Continued on Page 3

Supporting Schedules: E-18c

Recap Schedules: E-16a, E-17

Schedule E-16d

REVENUE BY RATE SCHEDULE - LIGHTING SCHEDULE CALCULATION

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: TAMPA ELECTRIC COMPANY

DOCKET NO.: 920324-EI

EXPLANATION: Calculate revenue under present and proposed rates for the test year for each lighting schedule. Show revenues from charges for all types of lighting fixtures, poles and conductors. Poles should be listed separately from fixtures. Show separately revenues from customers who own facilities as well as those who do not. Annual KWH's must agree with the data provided in Schedule E-16a.

Type of data shown:
XX Projected Test Year Ended 12/31/93
__ Projected Prior Year Ended _/_/_
__ Historical Prior Year Ended _/_/_
Witness: L. R. SMITH

RATE SCHEDULE SL-2

TYPE OF FACILITY	ANNUAL BILLING ITEMS	EST. KWH / MO.	ANNUAL KWH	PRESENT REVENUE CALCULATION					PROPOSED REVENUE CALCULATION					PERCENT INCREASE
				FACILITY CHARGE	ENERGY CHARGE	MAINT. CHARGE	TOTAL MONTHLY CHARGE	$ TOTAL REVENUE	FACILITY CHARGE	ENERGY CHARGE	MAINT. CHARGE	TOTAL MONTHLY CHARGE	$ TOTAL REVENUE	
Continued from Page 2														
Pole / Wire Type:														
Set Wood Pole - Overhead Wire (30 ft.)	39,642			$1.98	-	-	$1.98	$78,491	$2.22	-	-	$2.22	$88,005	12.1
Set Wood Pole - Overhead Wire (35 ft.)	12,672			2.23	-	-	2.23	28,259	2.50	-	-	2.50	31,680	12.1
Set Concrete Pole - Overhead Wire	15,564			4.05	-	-	4.05	63,034	4.53	-	-	4.53	70,505	11.9
Existing Pole - Underground Wire	330			3.75	-	-	3.75	1,238	4.20	-	-	4.20	1,386	12.0
Set Concrete Pole - Underground Wire (4,000 to 9,500 Lumen)	188,130			8.56	-	-	8.56	1,610,393	9.60	-	-	9.60	1,806,048	12.1
Set Concrete Pole - Underground Wire (16,000 Lumen)	19,074			11.63	-	-	11.63	221,831	13.03	-	-	13.03	248,534	12.0
Set Concrete Pole - Underground Wire (27,500 - 50,000 Lumen)	2,670			17.58	-	-	17.58	46,939	19.70	-	-	19.70	52,599	12.1
Set Aluminum Pole - Underground Wire (4,000 to 9,500 Lumen)	30,690			8.92	-	-	8.92	273,755	9.99	-	-	9.99	306,593	12.0
Set Aluminum Pole - Underground Wire (16,000 Lumen)	924			21.07	-	-	21.07	19,469	23.61	-	-	23.61	21,816	12.1
Set Aluminum Pole - Underground Wire (27,500 to 50,000 Lumen)	4,458			22.81	-	-	22.81	101,687	25.56	-	-	25.56	113,946	12.1
Set Aluminum Pole - Underground Wire (27,500 to 50,000 Lumen)	3,486			30.31	-	-	30.31	105,661	33.96	-	-	33.96	118,385	12.0
Decorative Post Top Pole - Underground Wire	16,050			5.39	-	-	5.39	86,510	6.04	-	-	6.04	96,942	12.1
Total Poles and Base Revenue	333,690							$6,716,756					$6,797,460	1.2

Supporting Schedules: E-18c

Recap Schedules: E-16a, E-17

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: TAMPA ELECTRIC COMPANY

DOCKET NO.: 920324-EI

EXPLANATION: Calculate revenue under present and proposed rates for the test year for each lighting schedule. Show revenues from charges for all types of lighting fixtures, poles and conductors. Poles should be listed separately from fixtures. Show separately revenues from customers who own facilities as well as those who do not. Annual KWH's must agree with the data provided in Schedule E-16a.

Type of data shown:
XX Projected Test Year Ended 12/31/93
__ Projected Prior Year Ended __/__/__
__ Historical Prior Year Ended __/__/__
Witness: L. R. SMITH

RATE SCHEDULE OL-1

TYPE OF FACILITY	ANNUAL BILLING ITEMS	EST. KWH / MO.	ANNUAL KWH	PRESENT REVENUE CALCULATION FACILITY CHARGE	ENERGY CHARGE	MAINT. CHARGE	TOTAL MONTHLY CHARGE	$ TOTAL REVENUE	PROPOSED REVENUE CALCULATION FACILITY CHARGE	ENERGY CHARGE	MAINT. CHARGE	TOTAL MONTHLY CHARGE	$ TOTAL REVENUE	PERCENT INCREASE
Fixture Type:														
4,000 Lumen High Pressure Sodium	163,785	20	3,275,700	$2.75	$0.54	$1.21	$4.50	$737,033	$2.82	$0.43	$1.17	$4.42	$723,930	(1.8)
5,800 Lumen High Pressure Sodium	122,626	29	3,556,154	2.78	0.79	1.21	4.78	586,152	2.84	0.62	1.20	4.66	571,437	(2.5)
9,500 Lumen High Pressure Sodium	263,302	51	13,428,402	3.16	1.38	1.25	5.79	1,524,519	3.23	1.09	1.22	5.54	1,458,693	(4.3)
16,000 Lumen High Pressure Sodium	129,637	70	9,074,590	3.63	1.90	1.28	6.81	882,828	3.72	1.49	0.91	6.12	793,378	(10.1)
27,500 Lumen High Pressure Sodium	90,053	110	9,905,830	4.22	2.99	1.32	8.53	768,152	4.32	2.35	0.97	7.64	688,005	(10.4)
50,000 Lumen High Pressure Sodium	102,960	170	17,503,200	4.42	4.61	1.37	10.40	1,070,784	4.52	3.63	1.09	9.24	951,350	(11.2)
4,000 Lumen High Pressure Sodium - Post Top	0	20	0	4.36	0.54	1.47	6.37	0	4.46	0.43	2.41	7.30	0	-
5,800 Lumen High Pressure Sodium - Post Top	30,893	29	895,897	4.36	0.79	1.47	6.62	204,512	4.46	0.62	2.74	7.82	241,583	18.1
Additional Fixture on a Wood or Concrete Pole:														
4,000 Lumen High Pressure Sodium	461	20	9,220	2.47	0.54	1.19	4.20	1,936	2.53	0.43	1.17	4.13	1,904	(1.7)
5,800 Lumen High Pressure Sodium	590	29	17,110	2.50	0.79	1.19	4.48	2,643	2.55	0.62	1.20	4.37	2,578	(2.5)
9,500 Lumen High Pressure Sodium	6,499	51	331,449	2.87	1.38	1.24	5.49	35,680	2.93	1.09	1.22	5.24	34,055	(4.6)
16,000 Lumen High Pressure Sodium	10,306	70	721,420	3.34	1.90	1.27	6.51	67,092	3.42	1.49	0.91	5.82	59,981	(10.6)
27,500 Lumen High Pressure Sodium	9,924	110	1,091,640	3.95	2.99	1.31	8.25	81,873	4.04	2.35	0.97	7.36	73,041	(10.8)
50,000 Lumen High Pressure Sodium	19,945	170	3,390,650	4.14	4.61	1.35	10.10	201,445	4.23	3.63	1.09	8.95	178,508	(11.4)
Total Fixtures and KWH	950,981		63,201,262											

Present Energy Charge calculated @ $0.02714 per KWH

Proposed Energy Charge calculated @ $0.02134 per KWH

Continued on Page 5

Supporting Schedules: E-18c

Recap Schedules: E-16a, E-17

ORDER NO. PSC-93-0165-FOF-EI
DOCKET NO. 920324-EI
PAGE 156

APPENDIX I
(con't)

Schedule E-16d

REVENUE BY RATE SCHEDULE - LIGHTING SCHEDULE CALCULATION

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: TAMPA ELECTRIC COMPANY

DOCKET NO.: 920324-EI

EXPLANATION: Calculate revenue under present and proposed rates for the test year for each lighting schedule. Show revenues from charges for all types of lighting fixtures, poles and conductors. Poles should be listed separately from fixtures. Show separately revenues from customers who own facilities as well as those who do not. Annual KWH's must agree with the data provided in Schedule E-16a.

Type of data shown:
XX Projected Test Year Ended 12/31/93
__ Projected Prior Year Ended __/__/__
__ Historical Prior Year Ended __/__/__
Witness: L. R. SMITH

RATE SCHEDULE OL-1

TYPE OF FACILITY	ANNUAL BILLING ITEMS	EST. KWH / MO.	ANNUAL KWH	PRESENT REVENUE CALCULATION: FACILITY CHARGE	ENERGY CHARGE	MAINT. CHARGE	TOTAL MONTHLY CHARGE	$ TOTAL REVENUE	PROPOSED REVENUE CALCULATION: FACILITY CHARGE	ENERGY CHARGE	MAINT. CHARGE	TOTAL MONTHLY CHARGE	$ TOTAL REVENUE	PERCENT INCREASE
Continued from Page 4														
Pole / Wire Type:														
Set Wood Pole - Overhead Wire (30 ft.)	245,031			$2.31	-	-	$2.31	$566,022	$2.59	-	-	$2.59	$634,630	12.1
Set Wood Pole - Overhead Wire (35 ft.)	148,006			2.59	-	-	2.59	383,336	2.90	-	-	2.90	429,217	12.0
Set Concrete Pole - Overhead Wire	35,057			4.51	-	-	4.51	158,107	5.05	-	-	5.05	177,038	12.0
Existing Pole - Underground Wire	4,346			4.19	-	-	4.19	18,210	4.70	-	-	4.70	20,426	12.2
Set Concrete Pole - Underground Wire (4,000 to 9,500 Lumen)	64,199			9.29	-	-	9.29	596,409	10.41	-	-	10.41	668,312	12.1
Set Concrete Pole - Underground Wire (16,000 Lumen)	34,739			12.53	-	-	12.53	435,280	14.04	-	-	14.04	487,736	12.1
Set Concrete Pole - Underground Wire (27,500 - 50,000 Lumen)	14,756			18.81	-	-	18.81	277,560	21.07	-	-	21.07	310,909	12.0
Decorative Post Top Pole - Underground Wire (4,000 Lumen)	0			5.93	-	-	5.93	0	6.64	-	-	6.64	0	-
Decorative Post Top Pole - Underground Wire (5,800 Lumen)	30,893			5.93	-	-	5.93	183,195	6.64	-	-	6.64	205,130	12.0
Total Poles and Base Revenue	577,027							$8,782,768					$8,711,841	(0.8)

Supporting Schedules: E-18c

Recap Schedules: E-16a, E-17

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: TAMPA ELECTRIC COMPANY

DOCKET NO.: 920324-EI

EXPLANATION: Calculate revenue under present and proposed rates for the test year for each lighting schedule. Show revenues from charges for all types of lighting fixtures, poles and conductors. Poles should be listed separately from fixtures. Show separately revenues from customers who own facilities as well as those who do not. Annual KWH's must agree with the data provided in Schedule E-16a.

Type of data shown:
XX Projected Test Year Ended 12/31/93
__ Projected Prior Year Ended __/__/__
__ Historical Prior Year Ended __/__/__
Witness: L. R. SMITH

RATE SCHEDULE OL-3

TYPE OF FACILITY	ANNUAL BILLING ITEMS	EST. KWH / MO.	ANNUAL KWH	PRESENT REVENUE CALCULATION: FACILITY CHARGE	ENERGY CHARGE	MAINT. CHARGE	TOTAL MONTHLY CHARGE	$ TOTAL REVENUE	PROPOSED REVENUE CALCULATION: FACILITY CHARGE	ENERGY CHARGE	MAINT. CHARGE	TOTAL MONTHLY CHARGE	$ TOTAL REVENUE	PERCENT INCREASE
Fixture Type:														
A- 100 Watt HPS Classic Post Top	2,654	51	135,354	$13.12	$1.38	$2.99	$17.49	$46,418	$12.76	$1.09	$2.11	$15.96	$42,358	(8.7)
B- 100 Watt HPS Contemp. Post Top	637	51	32,487	14.00	1.38	3.05	18.43	11,740	13.61	1.09	2.19	16.89	10,759	(8.4)
C- 100 Watt HPS Colonial Post Top	1,121	51	57,171	12.67	1.38	2.96	17.01	19,068	12.32	1.09	2.31	15.72	17,622	(7.6)
D- 100 Watt HPS Shoebox	4,393	51	224,043	8.23	1.38	1.33	10.94	48,059	8.00	1.09	1.36	10.45	45,907	(4.5)
E- 400 Watt HPS Shoebox	2,143	170	364,310	10.02	4.61	1.40	16.03	34,352	9.74	3.63	1.54	14.91	31,952	(7.0)
F- 400 Watt MH Shoebox	7,110	159	1,130,490	9.98	4.32	2.52	16.82	119,590	9.70	3.39	2.46	15.55	110,561	(7.5)
G- 400 Watt MH Floodlight	233	159	37,047	7.29	4.32	2.40	14.01	3,264	7.09	3.39	2.33	12.81	2,985	(8.5)
H-1,000 Watt MH Floodlight	2,268	381	864,108	9.15	10.34	3.61	23.10	52,391	8.90	8.13	4.56	21.59	48,966	(6.5)
I- 400 Watt HPS Floodlight	90	170	15,300	7.19	4.61	1.28	13.08	1,177	6.99	3.63	1.46	12.08	1,087	(7.6)
J- 400 Watt MH Decor. Cube	215	159	34,185	16.29	4.32	2.99	23.60	5,074	15.84	3.39	2.96	22.19	4,771	(6.0)
K- 400 Watt HPS Decor. Flat	0	170	0	23.04	4.61	2.20	29.85	0	22.40	3.63	1.75	27.78	0	-
L- 250 Watt HPS Shoebox	5,388	110	592,680	8.71	2.99	1.36	13.06	70,367	8.47	2.35	1.45	12.27	66,111	(6.0)
Additional Fixture on a Pole:														
d- 100 Watt HPS Shoebox	215	51	10,965	7.45	1.38	1.33	10.16	2,184	7.24	1.09	1.36	9.69	2,083	(4.6)
e- 400 Watt HPS Shoebox	3,990	170	678,300	9.23	4.61	1.40	15.24	60,808	8.98	3.63	1.54	14.15	56,459	(7.2)
f- 400 Watt MH Shoebox	2,627	159	417,693	9.20	4.32	2.52	16.04	42,137	8.94	3.39	2.46	14.79	38,853	(7.8)
g- 400 Watt MH Floodlight	233	159	37,047	6.95	4.32	2.40	13.67	3,185	6.76	3.39	2.33	12.48	2,908	(8.7)
h-1,000 Watt MH Floodlight	2,376	381	905,256	8.81	10.34	3.61	22.76	54,078	8.57	8.13	4.56	21.26	50,514	(6.6)
i- 400 Watt HPS Floodlight	54	170	9,180	6.85	4.61	1.28	12.74	688	6.66	3.63	1.46	11.75	635	(7.7)
j- 400 Watt MH Decor. Cube	0	159	0	16.63	4.32	2.99	23.94	0	16.16	3.39	2.96	22.51	0	-
k- 400 Watt HPS Decor. Flat	0	170	0	22.02	4.61	2.20	28.83	0	21.41	3.63	1.75	26.79	0	-
l- 250 Watt HPS Shoebox	421	110	46,310	7.93	2.99	1.36	12.28	5,170	7.71	2.35	1.45	11.51	4,846	(6.3)
Total Fixtures	36,168		5,591,926											

Present Energy Charge calculated @ $0.02714 per KWH

Proposed Energy Charge calculated @ $0.02134 per KWH

Continued on Page 7

Supporting Schedules: E-18c

Recap Schedules: E-16a, E-17

APPENDIX I
(con't)

Schedule E-16d

REVENUE BY RATE SCHEDULE - LIGHTING SCHEDULE CALCULATION

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: TAMPA ELECTRIC COMPANY

DOCKET NO.: 920324-EI

EXPLANATION: Calculate revenue under present and proposed rates for the test year for each lighting schedule. Show revenues from charges for all types of lighting fixtures, poles and conductors. Poles should be listed separately from fixtures. Show separately revenues from customers who own facilities as well as those who do not. Annual KWH's must agree with the data provided in Schedule E-16a.

Type of data shown:
XX Projected Test Year Ended 12/31/93
__ Projected Prior Year Ended __/__/__
__ Historical Prior Year Ended __/__/__
Witness: L. R. SHITH

RATE SCHEDULE OL-3

TYPE OF FACILITY	ANNUAL BILLING ITEMS	EST. KWH / MO.	ANNUAL KWH	PRESENT REVENUE CALCULATION FACILITY CHARGE	ENERGY CHARGE	MAINT. CHARGE	TOTAL MONTHLY CHARGE	$ TOTAL REVENUE	PROPOSED REVENUE CALCULATION FACILITY CHARGE	ENERGY CHARGE	MAINT. CHARGE	TOTAL MONTHLY CHARGE	$ TOTAL REVENUE	PERCENT INCREASE
Continued from Page 6														
Pole Type:														
1 Post Top, DB Alum., Painted Plain	2,591			$20.85	-	$0.74	$21.59	$55,940	$20.27	-	0.99	$21.26	$55,085	(1.5)
2 Post Top, DB Fiberglass	439			32.27	-	0.03	32.30	14,180	31.37	-	0.85	32.22	14,145	(0.2)
3 Post Top, AB Cast Iron, Painted	0			44.81	-	0.74	45.55	0	43.57	-	0.99	44.56	0	-
4 Post Top, DB Concrete	126			21.42	-	0.03	21.45	2,703	20.83	-	0.06	20.89	2,632	(2.6)
5 Post Top, DB Alum., Spun	1,237			14.83	-	0.03	14.86	18,382	14.42	-	0.06	14.48	17,912	(2.6)
6 Post Top, AB Alum., Painted Plain	0			19.98	-	0.03	20.01	0	19.43	-	0.85	20.28	0	-
7 Post Top, AB Alum., Painted Decorativ	1,345			20.37	-	0.74	21.11	28,393	19.81	-	0.85	20.66	27,788	(2.1)
8 Post Top, DB Alum., Painted Vintage	0			25.14	-	0.74	25.88	0	24.44	-	0.99	25.43	0	-
9 Shoebox, DB Concrete, 35 ft.	14,139			20.72	-	0.03	20.75	293,384	20.14	-	0.06	20.20	285,608	(2.7)
10 Shoebox, AB Steel, Painted	1,596			38.40	-	1.56	39.96	63,776	37.34	-	2.05	39.39	62,866	(1.4)
11 Shoebox, AB Alum.	0			46.14	-	0.03	46.17	0	44.86	-	2.05	46.91	0	-
12 Shoebox, DB Concrete, Octagonal	1,031			25.12	-	0.03	25.15	25,930	24.42	-	0.06	24.48	25,239	(2.7)
13 Floodlight, DB Concrete	690			20.55	-	0.03	20.58	14,200	19.98	-	0.06	20.04	13,828	(2.6)
14 Floodlight, AB Steel, Painted	0			34.04	-	1.56	35.60	0	33.09	-	2.05	35.14	0	-
15 Decor. Area, AB Steel, Painted	215			37.23	-	1.56	38.79	8,340	36.20	-	2.05	38.25	8,224	(1.4)
16 Shoebox, DB Concrete, 30 ft.	2,654			18.77	-	0.03	18.80	49,895	18.25	-	0.06	18.31	48,595	(2.6)
17 DB Concrete, 45 ft.	0			-	-	-	-	0	23.48 *	-	0.06	23.54	0	-
Total Poles and Base Revenue	26,063							$1,154,873					$1,101,299	(4.6)

Pole Types 09 + 13 - Combine into " 9 DB Concrete, 35 ft. " under proposed rates.
Pole Types 10 + 15 - Combine into " 10 AB Steel, Painted " under proposed rates.
Pole Type 17 - No customers presently. Add rate under proposed rates.