In re: Petition of Tampa Electric Company for authority to increase its rates and charges;
In re: Petition of Tampa Electric Company for closure of its existing interruptible rate schedules to new businesses and for approval of new interruptible rate schedules, IS-3 and IST-3

DOCKET NO. 850050-EI, DOCKET NO. 850246-EI; ORDER NO. 15451

Florida Public Service Commission

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December 13, 1985

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PANEL:

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

OPINION: Pursuant to Notice duly issued, the Florida Public Service Commission held public hearings in Tampa, Florida, on June 19, 1985, and in Tallahassee, Florida on August 14-16, 19, 21-23, 1985. Having considered the record herein, the Commission now enters its final order.

ORDER AUTHORIZING CERTAIN INCREASES

BY THE COMMISSION:

I. SUMMARY OF DECISION

In this Order, we have determined that Tampa Electric Company (TECO, Tampa Electric, the Utility or the Company) shall receive an increase in gross revenues of $45,663,000 annually which will give the Company the opportunity to earn the fair and reasonable overall rate of return of 9.81%. In reaching this decision we have determined that TECO should have an opportunity to earn a 14.5% rate of return on common equity capital.

This increase is based upon an approved working capital allowance of $106,353,000, a total rate base of $1,513,368,000 and an NOI of $125,525,000, each of which is based upon a historic 1984 test year as adjusted for the inclusion of TECO's Big Bend Unit 4 (BB4).

We have rejected the Florida Industrial Power Users Group's (FIPUG) proposed phase-in of BB4. We have also rejected TECO's proposed Big Bend Power Sales Credit Clause and substituted a mechanism we believe will equitably address both the expenses and revenues of BB4, while also offering a reasonable incentive for TECO to make additional off-system sales of BB4 capacity. This mechanism also resulted in the award of subsequent year revenue increases of $10,408,000 and $7,688,000 for 1987 and 1988, respectively.

We have adopted a new cost of service methodology, the Equivalent Peaker Cost (EPC), which we believe allocates costs more logically and equitably than previous methodologies used. An index to this order appears on Appendix A and summary statements of our adjustments are set forth on Appendices B and C.

II. BACKGROUND OF PROCEEDINGS

By petition filed on April 5, 1985, Tampa Electric sought approval of rate schedules which were designed to generate approximately $136,518,000 in additional annual gross revenues and which would give the Company an opportunity to earn the fair and reasonable rate of return of 10.42%. The requested overall rate of return of 10.42% is based on Tampa Electric's 1984 average capital structure as adjusted for the effects of Big Bend Unit Four (BB4), average cost rates and 16% as the Company's cost of common equity capital.

The primary factor causing an immediate need for an adjustment in Tampa Electric's prices is BB4 which was placed in service on February 25, 1985. The need for BB4 was determined by this Commission in Order No. 9749, issued January 16, 1981, in Docket No. 800595-EU. The unit was completed ahead of schedule, at a capacity of 427 MW rather than its originally projected capacity of 417 MW, and is within 3% of the cost estimate made five years earlier in the certification proceeding.

In order to reduce the impact of placing this new unit in rate base, Tampa Electric, in 1979, entered into a contract with Florida Power and Light Company (FPL) for the sale of a portion of BB4 capacity during the first three years of operation of the new unit. At a minimum, the contract requires FPL to purchase 70% of the capacity of BB4 from April 1, 1985 through December 31, 1985. Thereafter, FPL's capacity commitment decreases to 50% in 1986 and to 25% in 1987. Under the Company's proposal, the amount of the credit would change each six months at the same time as changes occur in the fuel adjustment factor.

The Company has proposed the Big Bend Power Sales Credit Clause which will take into consideration the non-fuel revenues received from the FPL contract. The credit factor would have the effect of passing 100% of the non-fuel contract revenues from the FPL contract directly to TECO's customers through the fuel cost recovery clause, while all BB4 expenses would be included in base rates. When the new permanent rates are placed in effect, the operation of the credit, had it been approved, would have initially reduced the base rate increase by $57,830,000 and provided a net increase of $76,643,000.

On May 28, 1985 the Commission voted to grant an interim increase of $21,446,000, effective for meter readings taken on or after June 28, 1985 (see Order No. 14538 issued July 8, 1985).

Public hearings were held in Tampa, Florida on June 19, 1985 and in Tallahassee, Florida on August 14-16, 19, 21-23, 1985, during which time all interested parties, including the Company, specific classes of Customers and the public, had an opportunity to present their views. The record consists of all notices and pleadings, certain Orders officially noticed, together with 2,371 pages of transcript, numerous exhibits, and requests for specific information by the various parties.

III. THE PARTIES

The Company

Tampa Electric, a wholly-owned subsidiary of TECO Energy, Inc., is an investor-owned public utility, subject to the jurisdiction of this Commission. It was originally incorporated in 1899 but was reincorporated in 1949 and became a subsidiary of TECO Energy, Inc., on April 14, 1981. Tampa Electric has provided electric service to the public within its service area for some 85 years and presently serves over 383,000 Customers in Hillsborough and portions of Polk, Pasco and Pinellas Counties. The Company serves Customers within the municipal limits of the cities of Tampa, Plant City, Temple Terrace, Winter Haven, Auburndale, Lake Alfred, Eagle Lake, Mulberry, Dade City, San Antonio and Oldsmar.

The Company presented ten witnesses who testified to the Company's revenue requirement, the effects of BB4, the FPL contract, cost allocation and rate design. The Company contends that the revenues received from presently established rates and charges are insufficient to cover its revenue requirement considering the effects of BB4.

Florida Public Service Commission Staff

The Commission Staff participated in this proceeding and presented the testimony of three witnesses dealing with the Company's service, cost of service and the cost of capital.

Public Counsel

The Office of Public Counsel (Public Counsel) presented testimony of three witnesses during the final hearing and urged that no increase be granted. Public Counsel proposed a return on common equity of 14.5%.

Florida Industrial Power Users Group

Several industrial customers intervened in this proceeding. These intervenors comprise an ad hoc group entitled Florida Industrial Power User's Group (FIPUG) and will be referred to collectively by that name. FIPUG presented the testimony of five witnesses in the areas of cost of service, rate design, and a proposed phase-in of BB4.

Florida Retail Federation, Inc.

Florida Retail Federation, Inc. (FRF), an organization primarily representing large commercial customers, intervened and presented the testimony of one witness and raised issues regarding cost of service and rate design affecting its members.

Federal Executive Agencies

The Federal Executive Agencies (FEA) intervened in this proceeding and sponsored one witness on the subjects of CWIP, O&M, coal inventory and cost allocation.

IV. REVENUE REQUIREMENTS FORMULA

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

V. THE TEST YEAR

The function of a test year is to provide a set period of utility operations that may be analyzed so as to allow the Commission to set reasonable rates for the period the new rates will be in effect. A test period may be based upon a historical test year with various adjustments to make it reasonably representative of expected operations. Alternatively, a test period may be based upon a projected test year.

The test period approved by the Commission for use in this proceeding is the calendar year 1984 adjusted for the effects of placing BB4 in commercial service in 1985.

VI. THE RATE BASE

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

TECO has submitted a proposed jurisdictional rate base of $1,606,753,000. Evidence developed during the course of the proceeding has led us to reduce that amount to $1,513,368,000. Our adjustments are set forth as follows:

	Original Filing	Adjustments	Adjusted Rate Base
A. Plant-In-Service	$1,796,136,000	$ (40,249,000)	$1,755,887,000
B. Accumulated Depreciation and Amortization	(361,470,000)	(858,000)	(362,328,000)
C. Net Plant-In-Service	1,434,666,000	(41,107,000)	1,393,559,000
D. CWIP	20,888,000	(18,333,000)	2,555,000
E. Property Held for Future Use	13,020,000	(2,119,000)	10,901,000

F. Net Utility Plant	1,468,574,000	(61,559,000)	1,407,015,000
G. Total Working Capital	138,179,000	(31,826,000)	106,353,000
H. Total Rate Base	$1,606,753,000	$ (93,385,000)	1,513,368.000

A. Plant-In-Service

The amount of plant-in-service originally proposed by TECO was $1,796,136,000, which included $591 million for BB4. Subsequent to its filing, TECO revised its total project cost for BB4 to $575,300,000, thereby reducing its proposed plant-in-service to $1,780,411,000. We have made certain adjustments, described below, which reduce plant-in-service to $1,755,887,000.

1. Big Bend Unit Four (BB4)

After extensive hearings held in December 1980, the Commission, in Order No. 9749 dated January 16, 1981, certified the need for BB4 and approved its construction.

BB4 was completed ahead of schedule, at a capacity of 427 MW rather than its originally projected capacity of 417 MW, and is within 3% of the cost estimate made five years earlier in the certification proceeding. On a dollar per kilowatt basis, the ultimate cost will be less than 1% different from the estimate made in 1980.

The inclusion of BB4 in rate base is the central issue in this case. Prior to the revised projections reducing its total cost, BB4's inclusion in rate base comprised all but approximately $14.9 million of the total $136.5 million in increased revenues initially requested.

Various parties in this proceeding have argued for the exclusion from current recovery of at least a portion of the cost of BB4. Public Counsel has recommended that the 1985 year-end investment in BB4 of $572.5 million be included in rate base, with the establishment of a separate spin-off hearing to consider the prudence of the total cost of BB4. The FEA have argued for the disallowance of the estimated 1985 and 1986 expenditures for BB4, and FIPUG has proposed a phase-in plan, under which BB4 would not be fully recognized in rates until 1990. As is more fully discussed below, we find no merit in any of these proposals and shall include in rate base the full $575.3 million proposed by TECO.

Public Counsel's proposal to include the 1985 year-end investment in BB4 in rate base and establish a spin-off investigation to examine the total cost of BB4 is not warranted. All parties to this docket, including Public Counsel, have been aware that BB4 would be the central issue in these hearings since the Company's case was filed on April 5, 1985. We believe that Public Counsel has had adequate time to address the reasonableness and prudence of the cost of BB4 during the course of this proceeding and decline his invitation to establish a spin-off investigation.

Of the $591,025,000 TECO originally proposed to include in rate base for BB4, $524,422,000 was expended through December 31, 1984, plus additional estimated construction expenditures for 1985 and 1986 of $59,765,000 and $6,838,000, respectively. When TECO revised its total project cost for BB4, it did so by reducing its 1985 estimated BB4 expenditures to $48,900,000 and the estimated 1986 expenditures to $2,000,000. FEA has taken the position that the additional $50,900,000 of capital costs projected to be spent subsequent to December 31, 1984 should not be included in rate base because: 1) these amounts represent estimated construction work in progress for two years into the future, the inclusion of which TECO failed to demonstrate was necessary for the maintenance of the utility's financial integrity; and 2) because the amounts are not known and measurable.

We think FEA's concerns regarding the measurability of the 1985 and 1986 BB4 expenditures are overstated. Specifically, the evidence in this case reveals that TECO had expended $541.9 million on BB4 by its in-service date on February 25, 1985 and a total of $557.7 million by July 31, 1985, several weeks prior to the start of the hearings in this case. Thus, of the revised $50.9 million estimate for 1985 and 1986, $33.3 million had been expended prior to hearing. Additionally, TECO's Witness William N. Cantrell testified that it was common for 10% to 15% of the total cost of a unit to be incurred during the year following its in-service date. In the case of BB4 the $33.3 million expended between the in-service date and the beginning of the hearings represents 6.2% of the total project cost, which is well within the standard testified to by Mr. Cantrell.

The test period in this case was calendar year 1984 adjusted for the effects of BB4, which we find includes the projected 1985 and 1986 expenditures necessary to complete BB4. Accordingly, we find no necessity for treating these amounts as CWIP and requiring that TECO demonstrate the inclusion is necessary for the maintenance of the Company's financial integrity.

FIPUG's "phase-in" proposal was the most extreme of the intervenor adjustments proposed. As testified to by FIPUG Witness Maurice Brubaker, the phase-in would only include in the rates resulting from this proceeding the revenue requirement associated with 150 MW of BB4's capacity. In 1988 TECO's rates would be increased to include the revenue requirement associated with 250 MW of BB4 and, finally, in 1990 the rates would be increased to reflect the revenue requirement associated with all of BB4's 427 MW of capacity. Under FIPUG's proposal, that portion of BB4 not in current rates would earn a deferred return, which would be capitalized and begin earning an actual cash return in 1990. FIPUG argues that TECO, because of poor planning, coupled with the effects of conservation, will have capacity in excess of that necessary to serve its native load until 1990. By implementing its proposal, FIPUG states that the recovery of the revenue requirements for the "excess" capacity will be better matched with the group of future customers who will actually need that capacity.

TECO has characterized the phase-in proposal as an attempt to "bolt the check" by FIPUG members who did not oppose the certification or construction of BB4, but who are now attempting to avoid paying for the unit by: 1) transferring from firm to interruptible service after BB4 went on line when the chances of interruption are reduced and 2) then advocating a phase-in of the unit so that its full costs are avoided until after these large customers leave TECO's system through cogeneration.

Although the "matching concept" espoused by FIPUG's phase-in has a certain basic appeal, the proposal contains flaws requiring that it be rejected. First, FIPUG's proposal ignores the economies of scale inherent in building a 427 MW coal unit now, as opposed to building three units of 150 MW, 100 MW and 177 MW capacity between now and 1990. FIPUG makes no attempt at shifting the implied higher cost/MW for the smaller plants to present customers. Second, FIPUG's plan does not adequately recognize the benefits of current fuel savings to current customers associated with the entire capacity of BB4. Third, the proposed phase-in would result in higher costs to future customers through the capitalization of the deferred return on that portion of the plant not in current rates. As testified to by Witness Francis E. Jeffries, this aspect of the proposal increases risks, which may be reflected in higher capital costs. Lastly, the phase-in could result in a "windfall" to TECO if it were able to both collect a deferred return on the capacity not in current rates, while also collecting a current return through the sale of that capacity off-system.

With the exception of certain specific disallowances that will follow, we find that all of the total project cost of BB4 was reasonably and prudently incurred and should be included in rate base. As will be more fully discussed in the NOI section of this order, we believe that TECO has done an excellant job of marketing that portion of BB4's capacity that is not presently needed to serve its current customers. We also believe that the mechanism we have established for treating future off-system sales of TECO's generating capacity will meet the laudable objectives of FIPUG's proposal while avoiding its inherent pitfalls.

2. Big Bend Coal Blending Equipment

TECO's plant additions in 1984 were $120,980,000, $40,294,000 of which was for Big Bend coal blending and handling equipment. This project, which serves all the units at TECO's Big Bend Station, went to service in August, 1984. Utilizing a 13-month average balance in plant-in-service for the 1984 test year results in only five months or $15,343,594 of the total project cost being included in rate base. Arguing that this project is now in-service and involves a known change of a significant amount, TECO has reclassified $22,838,000 of CWIP associated with the coal blending and handling equipment to plant-in-service. The result, of course, is that a year-end amount of this asset is included in rate base and earns a return.

While we have made pro forma or annualizing adjustments related to the inclusion of BB4, we shall not make such adjustments for other units. As noted, this equipment serves the entire Big Bend Station and not just BB4. Accordingly, as with all other plant additions not specifically related to BB4, we shall include in rate base only the 13-month average for the 1984 test year. The necessary adjustment is to reduce plant-in-service by $22,838,000 and increase CWIP by a like amount.

3. BB4 Limerock

Included in the total cost of BB4 that TECO is requesting in rate base in this case is $72,000 for limerock purchased for the testing of BB4's scrubber. The limerock proved unsuitable due to material handling problems and its inability to produce the proper chemical balance. TECO maintains that costly down-time was avoided by the knowledge gained through the testing and that the cost should be capitalized.

We shall not allow the cost of the limerock in rate base because it is not used and useful in the provision of electric service and because TECO has contracted to sell the limerock at an expected price of $23,000. Consistent with our policy involving a loss on the disposition of an asset, we shall authorize TECO to amortize the net loss of $49,000 over five years beginning January 1, 1984. Accordingly, we have removed $72,000 from plant-in-service, added the unamortized balance of $44,000 to Account 186, Miscellaneous Deferred Debits, and have added the first year's amortization expense of $10,000 to test year operating expenses.

4. Survey Benchmark Elevation Variance

Big Bend Units 1, 2 and 3 were built according to survey benchmarks set by other parties in the 1960's. BB4 was designed to line up with the adjacent Big Bend Unit 3 (BB3) but its construction began with pile driving in locations surveyed from more recent TECO survey benchmarks. Ultimately, it was discovered that the two surveys did not have a common base elevation, which would cause BB4 not to be in line with the other three units. Correcting the problem cost TECO $214,000, which it has included in rate base.

We believe that TECO either knew, or should have known, of discrepancies in the two surveys that should have allowed the problem to be avoided. Accordingly, we find that the $214,000 associated with this issue should be removed from plant-in-service.

5. Vendor Back Charges

During the construction of BB4, additional costs in the amount of $1,026,000 were incurred as a result of late and out-of-sequence deliveries of structural steel, misfabrications, and vendor design changes. While TECO made a claim against Tampa Steel Erecting Company for this amount, Tampa Steel pressed its claim against TECO in the amount of $2,600,000, it said resulted from design, engineering and scheduling changes not originally contemplated in the contract. A negotiated settlement was reached whereby Tampa Steel was paid $1,600,000 in settlement of its claim.

Our Staff originally took the position that this amount should be included in rate base but subsequently reversed itself after the hearing on the basis of a document not placed in the record. Public Counsel took the position, at the prehearing conference that, $2.6 million of construction costs related to this issue should be disallowed, but neither he nor any other party cross-examined TECO witnesses on the subject. The issue was raised subsequent to the filing of TECO's prepared testimony and TECO had no opportunity to defend its position through re-direct examination because no cross-examination addressed the topic.

On this particular issue we believe that there is not sufficient evidence to disallow the recovery of the settlement amount because it was either unreasonable or imprudent. On the other hand, while we believe TECO should be allowed to recover the monies expended, we do not believe it should, under these circumstances, earn a return on this amount over the life of BB4. Accordingly, we shall remove the $1,600,000 from plant-in-service and allow TECO to amortize this amount over five years beginning January 1, 1984. Further, the Company shall not earn a return on the unamortized balance.

While we do not presently intend to establish a specific procedure for dealing with the evidentiary problem we are confronted with here, we caution all parties that the record must be adequately developed on all issues that are raised and included in the prehearing order.

6. Big Bend Ash Settling Pond

In order to obtain an Environmental Protection Agency (EPA) construction permit for BB3, TECO was required to construct a closed-loop cooling system which would have been extremely costly to operate and maintain. TECO sought EPA approval of a less costly, alternate cooling system, which it ultimately obtained, but not before it had spent over $13 million on the construction of the first system. The cooling site was ultimately used as an ash settling pond. This issue is concerned with $2,110,000 of fencing, pipe and excavation costs for a U-shaped cooling pond, which were part of the cancelled system and classified as electric plant held for future use (PHFFU). Of the $2,110,000, TECO was able to utilize $397,000 of pipe and fencing materials in the construction of BB4. TECO has, correctly we think, taken the position that the $397,000 utilized in BB4 should be reclassified to plant-in-service. However, TECO also argues that the remaining $1,713,000 associated with the excavation and other costs incurred for the cooling pond were clearly a necessary cost of obtaining a construction permit for BB3 and should, therefore, be included in rate base.

While we agree that the $1,713,000 was a reasonable and prudent expenditure necessary to secure the EPA construction permit, we find that it is not used and useful in the provision of electric service and should not be included in rate base. Accordingly, since we believe it is appropriate that TECO should recover its investment in the first cooling system, we authorize it to amortize the $1,713,000 over five years beginning January 1, 1984 and to earn a return on the unamortized balance. Working capital is increased by $1,542,000, PHFFU is decreased by $2,110,000 and loss on disposal is increased by $343,000.

7. Rate Base Stipulation No. 3

TECO and the Staff stipulated that production plant-in-service for the 1984 test year is overstated as a result of retirements in 1985 that should have been made in 1984. The necessary adjustments, which we approve, are to reduce plant-in-service by $115,000, reduce the depreciation reserve by $175,000, and reduce depreciation expense by $4,000.

8. Transformer Purchase

During the planning and engineering for BB4, TECO accepted bid proposals for a large transformer designed to take the entire load of the unit and step it up to the transmission voltage level. Three bids were received and analyzed by Company engineers pursuant to the utility's procedures for handling competitive bids. Based upon the review process, which considered a combination of factors, including cost, reliability and engineering and performance specifications, the engineers ranked the proposals and recommended that the order be given to the bidder with the lowest evaluated price. TECO's management, desiring to secure the most reliable unit, rejected the engineers' recommendation and elected to purchase a transformer that cost an additional $82,000, but which had a better reliability rating.

We believe the decision to purchase a more reliable transformer is a proper one for management, even if the unit selected is more expensive. In this case, however, the decision appears to have been made solely on the basis of reliability indices and without the benefit of a comprehensive cost-benefit analysis. Although we do not find that the Company was imprudent in purchasing the higher cost unit, we shall remove from plant-in-service the $82,000 difference between the transformer purchased and the one recommended pursuant to the Company's competitive bid procedures. We do so on the conviction that TECO will ultimately recover the $82,000 through Generating Performance Incentive Factor (GPIF) rewards in the Fuel Cost Recovery docket, if the selected transformer, in fact, proves to operate more reliably and, thereby, increases the overall reliability of BB4.

B. Accumulated Depreciation and Amortization

The amount of, accumulated depreciation and amortization proposed by TECO was $361,470,000. We have made certain adjustments, described below, which result in approved accumulated depreciation and amortization of $312,328,000.

1. BB4 Depreciation Rate

TECO has used a 4.2% depreciation rate in this case for BB4, which is the depreciation rate prescribed for new additions to the entire Big Bend Station in the Company's most recent (1982) depreciation study. Notwithstanding its use of the 4.2% rate, TECO recognizes in its brief that this rate is conservative and that a higher depreciation rate may be appropriate. Public Counsel, on the other hand, argues that the 4.2% rate is excessive because it reflects an expected life of only 25 years, which is unrealistic in light of the substantially, longer expected lives of the other three Big Bend units. Public Counsel argues that the Commission should use a 35-year life and 5% negative salvage value for BB4, which would result in a 3% composite depreciation rate.

Our Staff takes the position that the 4.2% depreciation rate, which was based on the remaining lives of BB1-3, is inappropriately low for BB4 when considering that BB4 has only recently been placed into service and, more importantly, the fact that only it, of the Big Bend units, has a Flue Gas Desulfurization Unit (FGD). As demonstrated by Exhibit 9U, the FGD, or "scrubber" as they are commonly called, accounts for approximately 27% of the entire investment in BB4. Exhibit 9U also demonstrates that the scrubber is expected to have a shorter service life than the main plant due to the corrosive and abrasive materials it is exposed to.

We agree with the Staff that estimating an overall life for the entire plant is inappropriate in view of the more detailed information provided in Exhibit 9U. By recognizing and quantifying the various components of the plant that can reasonably be expected to have differing service lives, we believe that a more accurate assessment of capital recovery needs can be made. Accordingly, we approve the Staff-proposed depreciation rates for BB4 that appear in Appendix D. The rate base effect of this adjustment is to increase accumulated depreciation by $1,041,000.

2. Rate Base Stipulation No. 2

TECO replaced a BB1 turbine low-pressure rotor in 1984 and retained the old rotor as a spare. No retirement was booked because such spare parts are capitalized upon initial purchase and not retired until junked or otherwise finally disposed of. There was an $18,000 cost of removal associated with the spare rotor.

Our Staff took the position, and TECO has stipulated, that the $18,000 cost of removal should have been charged to O&M rather than being charged to the depreciation reserve. We approve this stipulation and the corresponding adjustments, which are to increase the depreciation reserve by $18,000 and to increase test year O&M by a like amount.

3. Rate Base Stipulation No. 3

As previously discussed in the plant-in-service section, our approval of this stipulation requires that the depreciation reserve be reduced by $175,000.

4. Effect of Other Plant-In-Service Adjustments

The net effect of the other plant-in-service adjustments is to reduce accumulated depreciation by $26,000.

C. Net Utility Plant-In-Service

Net utility plant-in-service is comprised of utility plant-in-service, less accumulated depreciation and amortization. We find that the appropriate amount of net utility plant-in-service for test year 1984, as adjusted for the addition of BB4, is $1,393,559,000.

D. Construction Work In Progress (CWIP)

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

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

In our more recent electric rate cases, we have included in rate base CWIP related to the utilities' investments in projects in service, but not yet closed to plant and short-term construction projects where the utility concerned provided sufficient evidence to document and justify its inability to earn either an AFUDC or rate base return on those projects.

In this case, TECO has requested that $20,888,000 should be included in rate base as CWIP. The Company states that this amount of CWIP represents its investment in CWIP for projects which have relatively short construction periods and will be in service by the time the rates approved in the proceeding are in place. TECO neither states that this amount of CWIP in rate base is necessary to maintain its financial integrity nor does it allege that it represents projects in service upon which it would otherwise earn no return. Instead, TECO states that it finds the inclusion of this CWIP in rate base to be a preferable alternative to accruing AFUDC on these investments.

We have determined that it is not necessary to include any CWIP in rate base in order to maintain TECO's financial integrity and we shall not include those amounts that TECO asserts represent projects which will be in service by the time the permanent rates become effective. Of the $20,888,000 of CWIP requested, we find that $2,555,000 is related to projects in service or short-term construction projects on which TECO would otherwise not earn an AFUDC or rate base return and should, therefore, be included in rate base. The remaining $18,333,000 is not entitled to rate base treatment and has been adjusted out.

E. Property Held For Future Use

TECO has requested that $13,020,000 of property held for future use be included in rate base. Of this amount, $2,110,000 is related to the BB4 Ash Settling Pond, which has previously been discussed and removed from rate base so that it could be amortized over five years. In addition to the $2,110,000, $397,000 of which was reclassified to plant-in-service, we also remove $9,000 to reflect the cancellation or reclassification of four proposed substation sites. The remaining $10,901,000 represents potential sites for generating units, transmission line rights-of-way and substations, which we find to presently represent reasonable and realistic acquisitions of property for future use. The total of our adjustments is to reduce plant held for future use by $2,119,000.

F. Net Utility Plant

Based upon the adjustments discussed above, total net utility plant for test year 1984, as adjusted for the inclusion of BB4, is $1,407,015,000.

G. Working Capital

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

TECO has proposed a working capital allowance of $138,179,000. We have determined that the appropriate working capital allowance for 1984, as adjusted for BB4, is $106,353,000. Our adjustments to working capital, which total $31,826,000 are discussed below.

1. BB4 Limerock

As previously duscussed, our decision to remove the $72,000 of BB4 limerock from rate base results in a $44,000 deferred debit which increase working capital by that amount.

2. Big Bend Ash Settling Pond

Our previously discussed decision to remove $1,713,000 associated with this item from rate base and to allow it to be amortized over five years and to earn a return on the unamortized amount results in a deferred debit, which increases working capital by $1,542,000.

3. Fuel Inventory

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

In its filing in this case, TECO requested a $100,187,000 fuel inventory in rate base consisting of 1,952,771 tons of coal, 264,728 barrels of No. 6 oil and 43,021 barrels of No. 2 oil. During the hearing, the Company agreed that an additional adjustment of $6,094,000 should be made for BB4 coal inventory. This would reduce the total fuel inventory requested by the Company to $94,093,000. For the reasons that follow, we find that the requested fuel inventory is excessive and must be further reduced to $84,890,445.

We have reviewed the positions of the parties and the evidence supporting those positions and find that the Public Counsel's position, with one exception, represents what we consider to be the appropriate fuel inventory levels to be included in the working capital on which the Company should be allowed to earn a return.

The Company originally requested a coal inventory equal to a 118-day burn level plus an adjustment of 320,954 tons for BB4, or a total of 1,952,771 tons. The Public Counsel and Staff have recommended authorization for only a 90-day burn. The evidence reveals that the Company's average coal inventory level during the last five years was 101 burn days. This includes a buildup for a possible strike in the coal industry every three years. Although it is difficult to quantify the exact level of buildup necessary to provide reasonable protection against strike-related service interruptions, we consider a 100-day burn level rather than the 90-day burn level recommended by Staff and Public Counsel for coal to be appropriate based upon the evidence presented. Insofar as the oil inventory is concerned, we agree with the position taken by Public Counsel that TECO should be entitled to maintain oil inventory levels of 25,014 barrels and 122,707 barrels for No. 2 and No. 6 oil, respectively. In determining these amounts, Public Counsel reduced No. 6 oil inventory by 142,021 barrels because Gannon Units 1 and 2 were converted from oil to coal, and will, therefore, no longer burn oil. Public Counsel also reduced No. 2 oil inventory by 18,007 barrels on the theory that this inventory should be limited to a level necessary for boiler light-off plus the highest single monthly consumption during the test year. We agree with both adjustments and have reduced the Company's oil inventory accordingly.

Having determined the appropriate levels of fuel inventory for TECO, we must now establish the price at which the various fuel inventories should be calculated in order to arrive at a dollar amount to be included in working capital. We find that the prices which appear in Public Counsel's recommendation best reflect the test year prices and should be approved. We, therefore, find that the fuel inventory volumes, unit prices and amounts in the following table should be approved:

Fuel Type	Volume	Price ($ /Unit)	Amount($)
Big Bend 4 Coal	356,615 tons	$49.14	$17,524,089
Coal-Other	1,364,400 tons	$46.14	$62,953,416
no. 2 Oil			
25,014 bbls	$35.63	$ 891,249	
No. 6 Oil	122,707 bbls	$28.70	$ 3,521,691
Total			$84,890,445

The necessary adjustment is to reduce TECO's original request of $100,187,000 to $84,890,000 and to reduce working capital by $15,297,000.

4. Accounts Receivable from FPL Sales

In calculating its requested working capital allowance, TECO has included as accounts receivable $6,664,000 in accounts receivable from its sales of BB4 capacity to FPL. TECO used 1985 revenues of $6,664,000 per month, which it says is the average amount outstanding when utilizing month-end balances. Public Counsel also used 1985 revenues but argues that we should remove two-thirds of the receivables from working capital (as we did in setting interim rates) to teflect a more realistic working capital effect for this item.

We agree with the Public Counsel and our Staff that including only one-third of the month-end balances more accurately reflects the realities of the TECO/FPL contract, which specifies a ten-day payment cycle, than the scheme proposed by TECO. Furthermore, we agree with our Staff and find that using the projected 1986 FPL revenues of $56,163,000, which yields a 13-month average, month-end balance of $6,966,000, including fuel revenues, more accurately and fairly represents the impact of including BB4 in this case. Including one-third of this amount in accounts receivable equals $2,322,00 and results in an adjustment reducing working capital by $4,342,000.

5. Amortization of Computer Loss

TECO has included $191,000 in working capital for a loss on the sale of an IBM 3031 computer, the amortization of which was stipulated to and approved in TECO's last rate case. The Company began the amortization of the loss in December, 1982, but our Staff has taken the position that, for ratemaking purposes, the unamortized balance should be adjusted to reflect the amortization beginning in November, 1982. TECO and Public Counsel have stipulated to the $4,000 reduction in working capital necessitated by this adjustment. We accept this stipulation and make the necessary adjustment.

6. Amortization of MacInnes Preliminary Site Studies

In its last rate case, we ordered TECO to begin amortizing, over five years, beginning January 1, 1982, the $6,357,000 of projected costs associated with MacInnes preliminary site studies that it attempted to include in property held for future use. Now, TECO states that it incurred additional costs of $147,000 through 1983 and early 1984, which bring the total cost of the studies to $6,747,471. TECO urges that it should be allowed to amortize the full amount, which would leave an unamortized balance for the test year of $3,352,000.

We find that TECO has presented no justification for costs in excess of the $6,357,000 approved in its last case and, accordingly, reduce working capital by $175,000.

7. Work Orders

TECO has included in working capital $193,000 of accounts receivable related to work orders recorded in Account 143.01 - Accounts Receivable Miscellaneous. Work orders are related to jobs performed for individual customers and Public Counsel takes the position that the general body of ratepayers will subsidize these individuals unless the associated accounts receivable and inventory is removed from working capital.

Our Staff agrees with Public Counsel that TECO's ratepayers should not be asked to bear any of the expenses involved in providing special services for individual customers and that the $193,000 should be removed from working capital. Staff also agrees that related inventory should be removed, but states that such inventory has not been sufficiently isolated to do so in this case.

We agree with the Staff and Public Counsel that the $193,000 should be removed from working capital. As demonstrated at the hearing, TECO has requested in excess of $40,000 in annual rates to support an activity for which they booked approximately $15,000 of revenues during the test year. We also agree with the Staff that work order-related inventory is not sufficiently identified to be disallowed. We shall, however, remove $15,000 of test year revenues in addition to reducing working capital by $193,000.

8. Accounts Payable

TECO has included in this case an amount of $26,021,000 for all Accounts Payable - Account 232. Public Counsel has taken the position that accounts payable are significantly understated and argues that they should be increased by $16,809,000. Public Counsel's total adjustment consisted of three parts:

1. As acknowledged by the Company, the ratio of accounts payable to fuel expense and to materials and supplies expense has been declining since 1980. Public Counsel states that in the five years preceding the adoption of the balance sheet approach (1976-1980) TECO's accounts payable averaged approximately 30% of its materials and supplies inventories, but that in test year 1984 this ratio had decreased to approximately 20%. Public Counsel suggests that the Company may not be as aggressive as it once was in taking full advantage of this cost-free source of capital and states that if we used the 1976-1980 average ratio of accounts payable to inventory, the payables should be

$37,840,000 instead of $26,021,000, which requires an adjustment increasing accounts payable by $11,819,000.

2. Public Counsel states that the $2,301,000 TECO included as accounts payable arising out of fuel purchases for BB4 represents only one-third of the average fuel expense for the unit, of only a ten-day lag in payment. He states that a more realistic lag of 30 days should be used, resulting in accounts payable of $6,904,000 for the addition of BB4 fuel, or an additional increase in payables of $4,603,000.

3. Public Counsel states that the Company has not included any accounts payable associated with the O&M expense added for the operation of BB4. He states that one-half the average monthly O&M expense equals a reduction in working capital of $387,000, which would be a reasonable adjustment.

TECO states that it takes full advantage of payment terms on all transactions in accordance with contract and purchase order terms. It states that contract negotiations resulting in payment terms of less than 30 days have been given in return for other benefits provided to the Company. Additionally, TECO states that the primary reason for the changing ratio of accounts payable to expense and inventory levels is declining fuel prices.

Our Staff agrees with Public Counsel that an increase in payables equal to one-half of one month of BB4's O&M budget is warranted. We agree and increase accounts payable by $387,000.

TECO's increase in payables of $2,301,000 related to BB4 fuel was based on the assumption that one-third of the coal purchases for the plant would be unpaid at the end of the month, while the full amount of coal transportation costs would be unpaid. Our Staff has recommended an additional increase of $1,010,000 based on its calculation that one-half of the coal purchases for BB4 and 92% of the coal transportation costs for that unit would be unpaid at the end of the month. Under the facts and circumstances of this case, we find our Staff's position to be the most reasonable and shall increase accounts payable associated with the provision of fuel to BB4 by $1,010,000, resulting in a total increase to accounts payable of $1,397,000.

While we have not adopted the bulk of Public Counsel's suggested adjustments, we note that he has highlighted a troublesome issue that will merit greater attention and detail in future cases. Specifically, he has highlighted what appears to be a trend of utilities reducing their cost-free accounts payable since we moved from the one-eighth formula approach to the balance sheet approach. TECO's response in this case is that it has received other benefits in return for shorter payment terms. While this may very well be true, we are troubled by the lack of evidence demonstrating that shortening payment schedules has resulted in the receipt of benefits that are cost-effective, both to the Company and its ratepayers. In future cases we shall expect analyses demonstrating that the overall benefits received from such tradeoffs are greater than the costs borne.

9. Taxes Payable

TECO originally included $1,355,000 of accrued taxes payable in working capital, which it subsequently agreed should be increased $2,470,000 to reflect revised depreciation rates, a change in depreciation expense due to the revised cost of BB4, and an accrual related to property taxes payable for BB4.

Public Counsel takes the position that the amount of accrued taxes should be $11,551,000 for 1984 operations and $4,946,000 for BB4 operations, for a total of $16,497,000. His calculation of BB4's taxes rests, in part, on his assumption that his proposed 3% depreciation rate for BB4, as well as his proposed elimination of the $1,947,000 annual outage cost for BB4 would be adopted.

As pointed out by Staff and Public Counsel, income taxes are normally accrued monthly and paid quarterly. In computing the taxes payable effect of adjustments to income tax expense, TECO used a percentage of 34.36% of the income tax adjustment amount, which resulted in TECO reducing its income taxes payable by a total of $10,340,000 to $1,355,000, whereas, correctly using a 13-month average of income taxes accrued monthly and paid quarterly results in a much smaller reduction of $4,566,000. The necessary adjustment to correct TECO's error is to increase taxes payable by $5,630,000.

Taxes payable should also be increased an additional $1,761,000 as a result of the tax effect of other NOI adjustments.

As also noted by both Public Counsel and Staff, TECO made an adjustment to increase its property tax expense for BB4, but made no corresponding adjustment to increase taxes payable. TECO has acknowledged in its brief that an adjustment is appropriate and we find that the necessary adjustment is to increase taxes payable by an additional $3,544,000. The total of our adjustments is to increase taxes payable by $10,935,000.

H. Total Rate Base

Based upon total test year net utility plant of $1,407,015,000 and working capital of $106,353,000, the total rate base for test year 1984, including the addition of BB4, is $1,513,368,000.

VII. FAIR RATE OF RETURN

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

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

The establishment of a utility's capital structure serves to identify the sources of capital employed by a utility, together with the amounts and cost rates associated with each. After identifying the sources of capital, the weighted average cost of capital is determined by multiplying the relative percentages of the capital structure components by their associated cost rates and then summing the weighted average costs. The net utility rate base multiplied by the weighted average cost of capital produces an appropriate return on rate base, including a return on the equity-financed portion. The return is also sufficient to recover the annual costs of other types of capital, including debt.

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

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

We have decided to use the average capital structure and average cost rates for the thirteen-month period ended December 31, 1984 adjusted for the effects of BB4.

Approved Capital Structure and Fair Rate of Return

Based upon our review of the record, we approve the following capital structure components, amounts, and cost rates:

Tampa Electric Company

Capital Structure

Thirteen-Month Average for the Period Ended 12/31/84

(As Adjusted for BB4)
(000)

Component	Amount	Percent of Total Capital	Cost Rate	Weighted Avg. Cost Rate
Long Term Debt	$ 503,992	33.30%	8.41%	2.80%
Short Term Debt	54,722	3.62	11.08	.40
Preferred Stock	88,960	5.88	7.64	.45
Customer Deposits	17,293	1.14	7.89	.09
Common Equity	578,372	38.22	14.50	5.54
Tax Credits-Zero Cost	2,870	.19	0	0
Tax Credits-Wtd. Cost	80,783	5.34	9.81	.53
Accumulated Deferred Income Taxes	186,376	12.32	0	0
	$1,513,368	100.00%		9.81%

The range on the return on equity is 13.5% to 15.5%.

The range on the overall required return is 9.40% to 10.21%.

Cost of Common Equity Capital

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

Mr. Francis E. Jeffries, testifying on behalf of the Company, presented three cost of equity analyses in arriving at a fair rate of return on common equity: a discounted cash flow model; a comparable earnings analysis; and a risk premium analysis. Based on his analyses, Mr. Jeffries concluded that a fair return on common equity for Tampa Electric Company is in the range of 16% - 17% and recommended 16% as an appropriate rate.

Mr. David Parcell, testifying on behalf of the Public Counsel, recommended a return of 14.50% on common equity. Mr. Parcell relied on a discounted cash flow analysis and a comparable earnings analysis in arriving at his recommended cost of common equity.

Mr. Steven F. Clinger, testifying on behalf of the Commission Staff, presented four cost of equity analyses: a discounted cash flow analysis; a capital asset pricing model; an earnings price analysis; and a risk premium regression analysis. Mr. Clinger's estimate of Tampa Electric's cost of common equity was based on the midpoint of a range defined by the Company's current cost of equity and the Company's twelve month average forecast cost of equity. Based on his analyses, Mr. Clinger determined Tampa Electric's cost of common equity to be within a range of 14.12% to 14.27% with a midpoint of 14.20%.

TECO has requested an allowed return on common equity of 16.00%. This requested allowed return represents an increase of 50 basis points over the return allowed in TECO's last rate case, Docket No. 830012-EU in 1983. As evidenced in the record, market conditions have improved dramatically since TECO's last rate case. We have found no evidence in the record to suggest that interest rates, inflation, or other market conditions are expected to be significantly different in the near future than they are currently. Therefore, based on the evidence presented, we believe a 14.50% return on common equity will allow TECO the opportunity to raise capital on fair and reasonable terms and to maintain its financial integrity.

VIII. NET OPERATING INCOME (NOI)

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

TECO has proposed a test year net operating income of $99,051,000. Evidence developed during these proceedings has led us to increase this amount to $125,525,000.

Our adjustments are set forth as follows:

Tampa Electric Company

1984 Net Operating Income

(000's)

	TECO	Adjustments	As Adjusted
I. Operating Revenues	$379,352	$ 55,834	$435,186
II. Operating Expenses			
A. Operation and Maintenance	$144,510	$ (1,586)	$142,924
B. Depreciation and Amortization	66,908	2,026	68,934
C. Taxes Other Than Income Taxes	29,694	907	30,601
D. Income Taxes Currently Payable	645	7,268	7,913
E. Deferred Income Taxes (Net)	17,931	21,231	39,162
F. Investment Tax Credit (Net)	19,902	(1,085)	18,817
G. Loss On Disposal of Plant	711	599	1,310
H. Total Operating Expenses	$280,301	$ 29,360	$309,661
III. Net Operating Income	$ 99,051	$ 26,474	$125,525

I. Operating Revenues

The Company proposed test year operating revenues for 1984 of $379,352,000. We have made certain adjustment, totalling $55,834,000, that increase the approved revenue to $435,186,000.

Weather Normalization

Public Counsel proposed to impute additional base revenues of $2,957,563 as a weather normalization adjustment. In support of this adjustment, Public Counsel offered the testimony of Mr. Daniel Reed, who performed a weather normalization study of the RS and GS classes based on his analysis of the consumption data for the period 1980 through 1984. As an alternative adjustment, Mr. Reed recommended imputing $1,320,976 of additional base revenue for the RS class based on the results of a weather normalization analysis TECO performed at his request.

We believe that weather normalization is desirable when sufficiently reliable studies are available to support an adjustment. In recent cases involving projected test years, the utilities have consistently promoted their test year data as being weather normalized. When accurate data and reliable studies show that an historic test year is not "weather normal," it is both proper and desirable that that test year be normalized. In this case, Mr. Reed's $2,692,906 adjustment is based upon his review of only two of the Company's rate classes, while he acknowledged during cross-examination that weather affected the consumption of other classes. The only variable he included in his calculation was weather measured in degree days, while there were other variables that affect usage that he did not consider. While Mr. Reed's calculation of normal weather was derived from a regression analysis, he failed to calculate the confidence intervals necessary to determine if the difference between the actual 1984 sales were statistically different from his "calculated normal" sales for 1984. In sum, Mr. Reed's study contains inaccuracies and omissions that require us to reject its use for the purpose of setting rates in this proceeding.

The TECO weather normalization study prepared at Mr. Reed's request utilizes a method developed for use in tracking the Company's performance in achieving its conservation goals. While it contains limitations that may affect its accuracy, we find that it is superior to Mr. Reed's study and adequate for imputing additional revenues of $1,321,000. While approving this adjustment, we note that it would be preferable in future cases to see the same caliber of weather normalization study in historic test years as the companies have recently used in justifying projected test years. Operating Revenues are increased by $1,321,000.

Big Bend Power Sales Credit Clause

As discussed at the beginning of this order, TECO has entered into a contract with FPL whereby the latter will purchase 70% of the capacity of BB4 from April 1, 1985 through December 31, 1985; 50% in 1986; and 25% in 1987. TECO has included the full revenue requirement of BB4 in its regquest for increased rates, but, pursuant to its proposed Big Bend Power Sales Credit Clause, has requested that we treat the contract revenues from FPL as a credit on its customer's bills, rather than include them in base revenues. For the reasons stated below, we have decided to disapprove the sales credit approach and, instead, include in base revenues the $55,222,000 of BB4 sales to FPL projected for 1986.

TECO's proposed treatment included the full revenue requirement of BB4 in base rates, with a credit to ratepayers through the Big Bend Power Sales Credit Clause for all of the non-fuel revenue received under the contract sale to FPL. The Company further proposed that any additional capacity sales during the period the clause is in effect should be treated in the same manner as sales of economy energy, with ratepayers receiving 80% of the benefit and the Company retaining 20%.

Under the Company's proposal, the credit to ratepayers would decline over time as the sale to FPL declines, despite a corresponding increase in surplus capacity on the Company's system. Furthermore, while the ratepayers' credit was declining, TECO could be earning additional profits on off-system sales of capacity made available by FPL's reduced commitment. While we believe that it is worthwhile to provide TECO with an economic incentive for selling as much capacity as is presently not required for its system, we believe our methodology accomplishes that purpose and does so with more reasonable protections for the ratepayers.

The BB4 contract sale to FPL is based on a higher rate than TECO's average embedded cost rates. As the sale to FPL declines we believe a realistic target for the Company is to sell this capacity to another wholesale buyer at a regular wholesale rate. We believe the GSLD rate best approximates the expected wholesale rate. Accordingly, to insure that TECO is not penalized for having negotiated a favorable contract with FPL, we are granting subsequent year adjustments (SYA) of $10,408,000 and $7,688,000 for 1987 and 1988, respectively, which recognize the difference between the FPL revenues included in the initial award, and the wholesale revenue which should be available to TECO on the capacity made available as the FPL contract expires.

(000's)

1986	1987	1988

Amount Initially Incl.			
In Base Rates	$55,222	$55,222	55,222
SYA - 1987	0	(10,408)	(10,408)
- 1988	0	0	(7,688)
Net Amount Incl. in BR	$55,222	$44,814	$37,126
Sales to FPL	(55,222)	(26,251)	0
Amount of Additional			
Sales Needed to Breakeven	$ 0	$18,563	$37,126

As may be seen in the above table, TECO is projected to receive $26,251,000 from the FPL contract sales in 1987 for the 25% of BB4 committed to FPL. We assume that TECO will be able to sell the 25% or 107 MW of BB4 released from FPL at the end of 1986 at a rate equal to its newly-approved GSLD rate, which should earn it annual revenues of $18,563,000. The total revenues from the BB4 FPL contract and Additional Sales would equal $44,814,000 or $10,408,000 less than the $55,222,000 we included in base rates for the FPL contract in 1986. Again, so as to not penalize TECO for its success in selling BB4 to FPL at a rate higher than its own GSLD rate, we award the Company a subsequent year adjustment of $10,408,000, which will be collected through new rates effective January 1, 1987. Similarly, in 1988, when TECO should receive no revenues pursuant to the FPL contract, we have assumed that TECO will have resold all 214 MW or 50% of BB4's capacity released from FPL. Assuming, once again, that TECO will sell the 214 MW at at least its 1986 GSLD rate, should result in it receiving $37,126,000 in annual revenues. So as to not penalize TECO for negotiating the favorable FPL contract, we authorize a 1988 subsequent year adjustment of $7,688,000 ($44,814,000 - $37,126,000), which shall be collected through new rates effective January 1, 1988.

As a result of the above adjustments, the amount of revenue for off-system sales included in base revenues effectively declines from $55,222,000 in 1986, to $44,814,000 in 1987, and to $37,126,000 from 1988 forward. Under our methodology, TECO is entitled to retain the full proceeds of the current FPL contract sale, as well as any revenues from additional capacity sales up to the total level included in base revenues.

To provide an incentive for TECO to exceed these capacity sales targets, we are permitting it to retain 20% of the proceeds of any additional sales (other than those under the existing FPL contract) above the level included in base rates for that year. Any such sales in 1986 will be applied to the 1987 total. The remaining 80% of such additional sales will be credited back to ratepayers through the fuel clause, since the ratepayers are bearing the revenue requirements for the capacity being sold. So, for example, if TECO recognized $8,563,000 of additional off-system BB4 sales in 1986, that amount would be credited toward its 1987 off-system target of $18,563,000. After TECO sold an additional $10,000,000 off-system in 1987 and, thereby, met its target, it would retain 20% of all additional off-system sales in 1987, while returning 80% to its ratepayers as is currently the practice in sales of economy energy.

In summary, we disapprove TECO's proposed Big Bend Power Sales Credit Clause and implement the methodology described above. The necessary adjustment is to increase test year revenues by $55,222,000.

Reasonableness of BB4/FPL Contract

As discussed above, TECO contracted with FPL to sell 70% of BB4's capacity in 1985, 50% in 1986, and 25% in 1987. Pursuant to that contract, TECO agreed to a $410 million construction cost cap plus the potential cost of off-stream cooling, which cost approximately $10.6 million. The current total cost of BB4 is expected to be $575.3

million. One of the issues in this case is whether TECO adequately protected the interests of its ratepayers through this contract.

TECO takes the position that its contract with FPL represents the maximum amount it could have obtained from any party for the sale of BB4's capacity. The Company states that the contract provides an extremely valuable offset to the unit's revenue requirements during its first three years of operations and results in significant benefits to its customers.

Public Counsel takes the position that TECO did not adequately protect its ratepayers from the cost of construction overruns which exceeded the Company's preliminary cost estimate by more than 10%. Furthermore, Public Counsel says that while TECO and FPL originally discussed a four-year contract, it was at TECO's request that the term of the contract was reduced to three years. Public Counsel maintains that, with there being excess capacity into 1990, TECO's ratepayers would have benefited from the extended contract. Lastly, while acknowledging that it may not be proper to second-guess TECO on the contract negotiations, Public Counsel maintains that it would be proper to attempt to rectify the existing situation by instructing TECO to offset the cost of the excess capacity with additional capacity sales as soon as possible.

While Public Counsel is correct that it may not be proper to second-guess TECO on its negotiations, it is certainly proper and, indeed, our responsibility to determine whether the terms of the contract were reasonable and prudent, when considering the information known or reasonably knowable at the time the contract was entered into.

The TECO/FPL BB4 contract was entered into in September, 1979 after almost three years of negotiations, and FPL was only one of many utilities TECO contacted about purchasing portions of BB4 capacity. Economies of scale dictate that base load generating units be built in sizes greatly exceeding the additional demand imposed by TECO's system during BB4's first year of operations. Attempting to market the excess of BB4's capacity was clearly a prudent and reasonable strategy on TECO's part. There is no evidence that TECO failed to aggressively seek the maximum price for the BB4 capacity it thought, in 1979, that it would not require for the needs of its own customers. To the contrary, the record demonstrates that TECO did aggressively seek customers for BB4's temporarily unused capacity and that it only concluded a contract after protracted negotiations.

While we could speculate endlessly on whether TECO could have or should have secured a higher price for the sale of BB4's capacity, we believe the fact that it is receiving more from FPL than it would from its own GSLD customers, under the newly-approved rates, clearly evidences that the Company adequately protected the interest of its ratepayers. Lastly, we believe that we have supplied TECO with adequate incentives for marketing temporarily unnecessary BB4 capacity through the methodology we adopted for treating BB4's revenues and expenses.

Unbilled Revenues

TECO, Public Counsel and the Staff are in agreement that the Company's test year unbilled revenue adjustment should be decreased by $284,000, which has the effect of increasing test year revenues by $284,000. We accept the stipulation on this point and make the adjustment required.

Interchange Revenues

Interchange revenue and expenses result from the purchase of energy from third parties and the sales of his energy to interruptible customers in lieu of those customer having service interrupted. The Company charges interruptible customers the actual cost of the purchased power plus an administrative charge for wheeling. In this case, TECO has included $1,213,000 of interchange revenue related to third-party sales and $978,000 of interchange expense related to capacity payments.

Public Counsel has proposed the removal of the $1,186,000 of expense related to interchange sales without removing the related revenues of $1,214,000. This position is based upon the assumption that the Company will still have these interchange sales but will not have to purchase this power because of additional capacity from BB4.

Theoretically, the inclusion of BB4 capacity should eliminate some of the need for third-party purchases of energy. However, Witness William Campbell testified that the Company had already purchased 23,760 MW hours for interruptible customers from January through July 1985 compared to 13,570 MW hours purchased during 1984. Thus, even with the additional capacity of BB4, the Company has had to purchase energy from third parties to continuously serve interruptible customers.

We are of the opinion that to include revenues and eliminate expenses related to sales to interruptible customers would penalize the Company for serving these customers. Since this is essentially a wash of revenues and expenses, we find that neither the expenses nor the revenues equal to the amount of the expenses should be included for ratemaking. We include only the revenues associated with the wheeling of power and reduce both the revenues and expenses associated with interchange sales by $1,186,000.

The Company also included revenues of $208,000 from emergency sales of power as a reduction of interchange expense. We believe it would be more appropriate to include revenues from emergency sales as revenue instead of as a reduction of an expense. The effect of this adjustment is to increase both expenses and revenues by $208,000.

The net effect of our adjustments is to reduce both operating revenues and interchange expenses by $978,000.

Work Orders

As previously discussed in the Working Capital section of this order, our removal of $193,000 of work orders from working capital necessitates a $15,000 reduction in test year revenues.

II. Operating Expenses

A. Operating and Maintenance Expense (O&M)

The Company has proposed test year operating and maintenance expenses of $144,510,000. Based upon the record in this case, we have determined that O&M should be reduced by $1,586,000 to an allowed amount of $142,924,000.

Our adjustments to O&M are as follows:

(000's)

	1984
Operating and Maintenance Expenses Per Company	$144,510
Adjustments:	
1. O&M Reasonableness	(1,572)
2. BB4 O&M	(1,947)
3. Fuel Adjustment/Base Rate Expenses	3,011
4. Industry Association Dues	(61)
5. Rate Case Expense	(57)
6. Interchange Expense	(978)

7. Rate Base Stipulation 2	18
Total Adjustments	(1,586)
Adjusted O&M Expenses	$142,924

1. O&M Reasonableness

In this case, as in TECO's last rate case and our most recent series of electric rate cases, we determined to check the reasonableness of the Company's O&M request by comparing it to a benchmark year compounded for inflation, as measured by the Consumer Price Index (CPI), and customer growth. As a base year we accepted our Staff's recommendation that we utilize the 1983 test year from TECO's last rate case in Docket No. 830012-EU. Because the 1983 test year was projected, we adjusted it for actual CPI and customer growth before including amounts specifically allowed above the benchmark. We then escalated those amounts by CPI and customer growth in all FERC functional accounts, except Production, which we escalated by CPI only. The resulting O&M benchmark for test year 1984 is shown in the following table.

Function	1983 1983 Benchmark (A)	1983 ADJ for Actual CPI/Growth (B)	Specific Allow. Over Benchmark (A)	1983 Allowed Restated	ADJ for Res. Chost. (E)
Production	$ 53,883	$ 54,165	$ 0	$ 54,165	$ 0
Transmission	4,838	4,863	0	4,863	0
Distribution	16,216	16,301	0	16,301	0
Cust. Accts.	18,314	10,871	0	18,871	0
Cust. Serv.	1,768	1,777	0	1,777	(616)
Sales	70	78	0	70	0
Admin. & Gen.	29,951	30,108	2,756	12,864	0
	$117,540	$118,155	$2,756	120,311	($616)

Function	1983 ADJ O&M	Compound Illegible Word (C)	1984 Benchmark	O&M Requested (D)	Benchmark Variance
Production	$ 54,165	1.04254	$ 56,470	$ 49,469	($7,000)
Transmission	4,863	1.0928	5,314	5,645	371
Distribution	16,261	1.0928	17,814	17,728	(46)
Cust. Accts.	16,871	1.0928	11,838	14,155	2,275
Cust. Serv.	1,161	1.0938	1,249	1,479	210
Sales	70	1.0928	76	30	(46)
	32,864	1.0928	15,914	41,761	5,849
	$120,295		128,717	$130,109	$1,572

(A) Exhibit 16A

(B) 1983 assumed CPI of 3.3% and customer growth of 3.1%. 1983 actual CPI was 3.217% and customer growth was 3.722%.

(C) production expense is escalated by CPI only from 1983 to 1984.

(D) Total O&M requested is less 064 with IBM cost reallocated per MFR C-16g (p. 3 of 31).

(E) Conservation cost recoverable through conservation clause (MFR C 16c)

As we have stated in the past, our use of the CPI and customer growth benchmark is not a statement that all expenses above CPI and customer growth are prima facie unreasonable or imprudent. Likewise, it does not imply that all expenses increasing at a rate below CPI and customer growth are automatically reasonable and prudent. Rather, we use this standard to "flag" certain expenses that, because of their dramatic rates of growth, demand a greater level of scrutiny.

As may be seen from the above table, TECO's requested O&M amounts for the 1984 test year exceed the 1984 benchmark by a net amount of $1,572,000. Consistent with our prior practice, our Staff analyzed specific components of the Company's O&M request and recommended adjustments totalling $5,114,000.

While our Staff has properly attempted to analyze the individual components of TECO's requested O&M, we find that the record in this case is not sufficiently complete to fully utilize the process of examining individual O&M components. Accordingly, we shall approve that amount of O&M indicated by the O&M benchmark and disallow the $1,572,000 the Company has requested in excess of that amount.

We stress that our decision on this point is warranted by the particular facts and circumstances of this case and that we shall continue to expect that all utilities will be able to justify the prudence and reasonableness of all of their expenses.

2. BB4 O&M

Included in its overall O&M request, TECO has included $11,229,000 of O&M specifically related to BB4. Of this amount, TECO has requested $1,947,000 for "annual outage" expense for that unit.

we find that TECO has failed to adequately prove that the requested $1,947,000 for annual outage expense for this new unit is justified for inclusion in test year expenses. Boiler and turbine maintenance are cyclical in nature and the Company has a traveling maintenance crew that moves from plant to plant to handle portions of the boiler and turbine maintenance. TECO has not demonstrated that this maintenance crew will have to be increased to handle the addition of BB4 and we believe including the $1,947,000 may result in the potential for double-counting certain labor expense. Accordingly, we disallow $1,947,000 of expense associated with BB4 O&M.

3. Expenses Transferred from Fuel Cost Recovery Clause to Base Rates

In Docket No. 850001-EI-B we identified certain expense categories to be removed from base rate recovery and placed in fuel adjustment recovery and vice versa. As a result of that determination we decided that if the Big Bond Power Sales Credit Clause were approved, we would increase base rates by $3,152,546, deflated to 1984 dollars using revenue growth from 1984 to 1985. Although we have disapproved the Big Bend Power Sales Credit Clause, we shall still include the FPL power sales revenues and related expenses in base rates. When deflated by a factor of 1.047, which reflects the anticipated revenue growth of 4.7% from 1984 to 1985, the necessary adjustment to O&M expense is an increase of $3,011,000.

4. Industry Association Dues

TECO has budgeted $560,174 for industry association dues of which it has removed $170,569 to comply with its perception of Commission guidelines established in previous rate cases. In making its EEI adjustment, TECO removed one-third of all of its EEI payments of $338,558, whereas the adjustment we are making involves disallowing one-third of TECO's EEI membership dues, and disallowing all of its EEI Media Communications Program contributions, while allowing its contributions to EEI's Utility Solid Waste Group and Utility Area Regulatory Group Programs. The net effect of our adjustments is to reduce O&M expense by $51,560.

Additionally, we have removed from O&M $9,200 related to interest earnings obtained by EEI on dues that should have been forwarded to EPRI sooner than they were. EEI's tardiness should ultimately result in higher EPRI member dues, the effect of which we will not allow to be borne by TECO's ratepayers. Our total adjustments are to reduce O&M of $61,000.

5. Rate Case Expense

The Company has included $636,000 for rate case expenses. In the Company's last rate case (Docket No. 830012-EU), the Company was allowed approximately $628,000. That amount represented $290,000 for legal fees, $286,000 for consultant fees and $52,000 for other expense (travel, materials, supplies, etc.). Exhibit 10H prepared by the Company indicates a revised budget for this case totalling $722,000 consisting of $494,000 for legal fees, $182,000 for consultant fees and $46,000 of other. A comparison of what was allowed in the Company's last rate case to the Company's revised budget shows an increase in legal fees of 70%, and a decrease in consultant fees and other of 57% and 13%, respectively. The decrease in consultant fees and other is justified since the last rate case was based on a projected test year and required studies not necessary using a historic test year as in this rate case. An increase in the cost of legal services may be expected, however, a 70% increase seems to be excessive. Inflating the amount of legal fees allowed in the last rate case by CPI (1.04256) results in legal fees of $302,000. Adding this to the amounts projected in Exhibit 10H for consultant fees and other results in a total rate case expense of $530,000. This amount is only $9,000 above the Company's original rate case budget.

We find that TECO should be allowed to recover $521,000 of rate case expense as it had originally budgeted. Amortizing this amount over two years results in an annual expense of $261,000, which requires a $57,000 reduction from the O&M requested.

6. Interchange Expenses

As previously discussed in the Operating Revenues section, we determined to remove from this case the revenues and expenses associated with third-party energy purchases for interruptible customers. The necessary adjustment is to reduce operating expenses by $978,000.

7. Rate Base Stipulation No. 2

As previously discussed in the Accumulated Depreciation and Amortization section, our decision to increase the depreciation reserve by $18,000 for the BB1 spare turbine rotor necessitates an $18,000 increase to O&M expense.

B. Depreciation and Amortization

The Company proposed test year depreciation and amortization expense of $66,908,000. The effect of using the approved Staff-proposed depreciation rates for BB4 is an increase in depreciation and amortization of $2,081,000, while our remaining plant-in-service adjustments and acceptance of Rate Base Stipulation No. 3 require a $55,000 reduction. Our total adjustments are to increase depreciation and amortization expense by $2,026,000 to an approved amount of

$68,934,000.

C. Taxes Other Than Income Taxes

TECO proposed Taxes Other Than Income Taxes expense of $29,694,000. The cumulative effect of our adjustments require that this amount be increased by $907,000 to $30,601,000.

D. Income Taxes - Current

1. Interest Synchronization

Due to adjustments we made to the Company's requested rate base, the amount of debt in the allowed capital structure is less than that contained in the Company's filing. This adjustment results in less interest expense being reflected in the Company's capital structure, which requires an adjustment increasing current income tax expense by $1,414,000.

2. Effect of Other Adjustments

This adjustment is mechanical in nature and serves to reflect the effect on income tax expense of the various other adjustments we have made to the Company's proposed operating income. The necessary adjustment is to increase income tax expense $5,768,000.

3. Change in State Income Tax Rate

In tax years beginning on or after September 1, 1984, the Florida corporate income tax rate increased from 5% to 5.5%. Since TECO is on a calendar year basis for tax purposes, the new 5.5% rate became effective for them on January 1, 1985.

TECO made no adjustment to reflect the change in rates as required by Rule 25-14.05, Florida Administrative Code, but does not object to that change being made. We believe that recognizing the change is required and find that the five-year period mentioned in the rule would begin on January 1, 1985. The necessary adjustments are to increase the state deferred tax balances annually by $160,200 and reduce the federal deferred tax balance by $73,692 on an annual basis. The necessary adjustment for ratemaking purposes is to increase income tax expense by $86,000.

TECO originally proposed current income tax expense of $645,000. Our adjustment increase that amount by $7,268,000 to an approved amount of $7,913,000.

E. Deferred Taxes (Net)

1. BB4 1984 Depreciation

Subsequent to its filing in this case, TECO received a private letter ruling, which essentially said that the Company could begin depreciating BB4 in 1984 for tax purposes.

For book purposes, depreciation began for BB4 when placed in service in 1985. As a result of timing differences for depreciation between the tax return and the books, deferred taxes arise. Since in this rate case BB4 is being treated for book purposes as though it had been in service for a full year, the deferred taxes should reflect the difference in two years of tax depreciation (1984 and 1985) versus one year of book depreciation (1985).

The Company states that the pro rata addition of BB4 in the filing compensates for the deferred taxes that result from the letter ruling. While this is true, the Company also makes reference to the requirements found in Section 1.167(1)-1(h)(6)(ii) of the IRS Regulations, which set limitations on the level of deferred taxes. This section states, in part, that if a determination of the reserve must be made for ratemaking in "reference both to a historical portion and to a future portion of a period, the amount of the reserve account for the period is the amount of the reserve at the end of the historical portion of the period and a pro rata portion of the amount of any projected increase to the credited or decrease to be charged to the account during the future portion of the period." Based upon this Regulation, the amount of deferred taxes that would have been recorded at December 31, 1984, $11,227,000 should be the starting point for the thirteen-month average of deferred taxes related to BB4. The deferred tax balance should then be increased $10,836,000 in equal increments over the twelve months of 1985 based upon the deferred taxes arising from depreciation allowed in this ratemaking proceeding versus the depreciation on the tax returns for 1985. This results in a balance at December 31, 1985 of $22,063,000. The thirteen-month average of $16,645,000 conforms with the limitations set forth in the IRS Regulations.

Deferred tax reserve is increased $16,645,000 to specifically identify the appropriate adjustments for BB4. Also, deferred taxes are excluded in the pro rata allocation of BB4 to the capital structure as opposed to the Company's pro rata allocations of BB4 to the overall components of the capital structure.

As a result of the deferred tax adjustment, there will be a switch between current and deferred taxes. The amount switched equals the deferred taxes created as of December 31, 1985 of $21,204,000, which is the amount we increase deferred taxes and decrease current taxes for the test year.

2. Effect of Other Adjustments

This adjustment is mechanical in nature and reflects the effect on deferred income tax expense of the various other adjustments that we have made to the Company's proposed net operating income. The adjustment increases deferred income taxes by $27,000.

F. Investment Tax Credits (Net)

In this case, as in the past, Public Counsel has proposed that, for the purposes of calculating taxes, a portion of the investment tax credit should be treated as though it were interest-bearing debt. This method, which has come to be known as "interest imputation", would thus reduce the tax expense on investment credit revenues by calculating the allowable tax as though there were an offsetting interest deduction involved. In past cases, the regulated public utilities have argued that interest imputation would violate Section 46(f) of the Internal Revenue Code, as amended, and result in the loss of all investment tax credits.

Out of a sense of caution, we have, in past cases, declined to adopt Public Counsel's proposal for fear that it would jeopardize the utilities' ability to utilize those credits. We did, however, recognize that Public Counsel's proposed treatment was more beneficial to the ratepayers and directed several utilities to submit revenue ruling requests to the Internal Revenue Service (IRS). Several other utilities voluntarily sought IRS revenue rulings.

The IRS has chosen to deal with the entire question of interest imputation on a generic basis by issuing proposed regulations. On June 26, 1985, it issued proposed regulation Section 1.46-6 amending the existing regulation paragraphs (b)(2)(i), (3), and (4)(ii) to permit interest imputation. Although interest imputation has been determined to be permissible, the proposed regulations have raised new issues.

One major issue raised concerns the method of calculating the cost of capital for establishing the return on investment credits and for purposes of interest imputation. In our calculation of the cost of capital, and for purposes of determining the adjustment under the interest imputation concept, we have considered all sources of capital supporting rate base. These included not only long-term debt but deferred taxes, included at a zero cost rate, and customer deposits. TECO has argued that the cost of capital calculated on this basis does not comport with the requirements of the proposed regulations, which refers only to common equity, preferred stock, and debt capital obtained from long-term creditors.

We do not agree that only long-term debt, preferred stock and common equity may be considered in calculation the cost of capital applied to investment credits. We further do not agree that only the weighted cost of long-term debt may be adjusted for the interest imputation calculation. We believe it is wholly consistent with both existing and proposed regulations to apply the weighted cost of capital derived from a calculation involving all sources of capital, including deferred taxes and customer deposits. To use only the weighted cost of long-term debt, preferred stock and common equity, as has been suggested, may result in an increase in the overall cost of capital with an increase in allowed not operating income. We do not believe that this was the intent of the proposed regulations. The proposed regulations contain a "facts and circumstances" test for determining the composition of a utility's capital structure. We believe that under this test the Commission's method of determining capital structure would be upheld as consistent with the regulations.

While it is unlikely that the IRS will withdraw its approval of interest imputation, the final regulations may embody key provisions, such as the cost rate to be assigned the investment credits, which would have a significant impact on permissible methods of calculating the adjustments. If the final regulations are violated by our methodology of calculating the interest imputation adjustment, the investment credits for all open years of TECO might be jeopardized.

Accordingly, we shall, as in the past, treat the ITC as common equity for purposes of determining the Company's income tax expense allowed for ratemaking purposes. However, the revenues related to the increased taxes allowed on the debt portion of ITC are to be collected under bond or corporate undertaking and be subject to refund with interest. Final resolution of this issue will wait until the IRS releases its final regulations on this topic. If a refund is necessitated by the new IRS regulations, such a refund, or other adjustment deemed appropriate by this Commission, will be made with interest. Accordingly, we shall hold $2,749,000, on an annual basis, subject to refund with interest until this issue is resolved.

G. Loss on Disposal of Plant

As discussed earlier in this order, TECO's actual costs for the MacInnes preliminary site studies were $6,747,471. The Company has included $1,346,000 in NOI as loss on disposal of utility property in order to amortize its actual costs. Because we have approved only the amortization of the projected costs of the site studies, it is necessary to reduce TECO's proposed amortization for this item by $74,000.

Additionally, as discussed previously, we increase amortization expense by $10,000 for the BB4 limerock issue, $320,000 for the vendor backcharge issue, and $343,000 for the BB4 ash settling pond issue. Our net adjustments increase operating expense by $599,000 to $1,310,000.

H. Total Operating Expenses

Total operating expenses, as adjusted, are $309,661,000.

III. Net Operating Income

The net operating income is derived by subtracting total operating expenses from operating revenues. In this case, net operating income is $125,525,000 ($435,186,000-$309,661,000).

IX. NOI MULTIPLIER

The purpose of the NOI multiplier is to gross up or expand the Company's net operating income deficiency to compensate for income taxes and revenue taxes that the Company will incur as the result of any revenue increase.

All parties agree that the appropriate NOI multiplier for this proceeding is 1.996670, which is calculated as follows:

%

Revenue Requirement	100.000000
Gross Receipts Tax	(1.500000)
Regulatory Assessment Fee	(0.125000)
Uncollectible Accounts	(0.230000)
Net Before Income Taxes	(98.145000)
State Income Tax (5.5%)	(5.397975)
Net Before Fed. Income Tax	92.747025
Fed. Income Tax (46%)	(42.663632)
Revenue Expansion Factor	50.083394
NOI Multiplier	1.996670

X. REVENUE REQUIREMENTS

Having determined the Company's rate base, the net operating income applicable to the test period, and the overall fair rate of return, it is possible to calculate any excess or deficiency of revenues. Multiplying the rate base amount for the test year of $1,513,368,000 by the fair overall rate of return of 9.8056% yields an NOI requirement of $148,395,000. The achieved NOI for the test year amounted to $125,525,000, which results in an NOI deficiency of $22,870,000. Applying the appropriate NOI multiplier of 1.996670 to this figure yields a necessary revenue increase of $45,663,000.

In view of the above, we find and conclude that TECO should be authorized to increase its rates and charges so as to generate $45,663,000 in additional revenues annually.

XI. INTERIM RATE AWARD

By Order No. 14538 entered in this docket, TECO was granted interim rate relief in the amount of $21,446,000. Section 366.071(4), Florida Statutes, prescribes a "rate of return" standard for determining the propriety of an interim rate award by which the newly established rate of return is used to gauge whether any portion of the amount collected on an interim basis should be refunded. Applying the test to the interim award in this case, we find that the interim increase of $21,446,000 on an annual basis did not result in a return greater than that authorized here, and that, therefore, no refund of the amounts collected pursuant to the authority of Order No. 14538 is required.

XII. RATE STRUCTURE AND RATE DESIGN

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

Cost of Service Methodology

Five cost of service studies were introduced into evidence in this case. In its initial filing, the Company submitted a study based on the 12 CP and 1/13 average demand method with the cost of environmental control equipment at BB4 and the cost of coal blending and handling equipment for Big and Bend Station classified as energy related and allocated on the basis of the classes' MWH consumption at the generation level. Pursuant to recommendations made by the Staff following their initial analysis of the Company's original study, the Company prepared a new cost of service study, which came to be known in the hearings as the "Meyer Rerun" study. Inasmuch as the Company's Witness William H. Meyer termed this revised study "a better study" than the original, we considered this to be the Company's primary cost study. FIPUG filed a study based on the Company's original study but with all production plant classified as demand related and allocated on the basis of the classes' contributions to the four summer and three winter monthly peaks. The Staff's Witness sponsored a study based on the Meyer Rerun study called the Equivalent Peaker Cost (EPC) study. In classifying production plant costs in this study, only the estimated cost of equivalent peaking capacity is classified as demand related; these costs are allocated on the basis of the classes' contributions to the 10 summer and 10 winter hourly peaks. The remaining production plant costs are classified as energy related and allocated on the basis of the classes' MWH use at the generation level. Finally, a study called the Average Off-Peak Demand Production Stack study was prepared in response to a Staff interrogatory. In this study, the production plant necessary to serve the Company's average demand measured during off-peak hours was identified and its costs were classified as energy related. Remaining production plant costs were classified as demand related and allocated on the basis of the classes' contributions to the ten summer and ten winter hourly peaks. The pertinent differences between the four main studies presented in this case (excluding the Company's originally filed study in favor of the Meyer Rerun study) are shown in Exhibit 204, which is attached hereto to this order as Appendix E.

The Company supported its study by relying on its traditional use of, and this Commission's historic support for, the 12 CP and 1/13 average demand method and by arguing that the environmental control and coal handling equipment is properly energy related because it was necessitated by the Company's decision to build a baseload coal plant and because it operates only when the plant is operating. While we approved a similar classification and allocation in Tampa Electric's last rate case, we believe that better methods for determining the appropriate classification of production plant costs as between demand and energy have been introduced in this case, and thus we shall not accept the Company's cost of service study as our guide to cost allocation and rate design in this case.

FIPUG supports the cost of service study sponsored by its witnesses. They argue that peak demand, not energy consumption, drives the utility's decision to incur costs for additional generating capacity. We disagree. While we agree that peak demand drives the utility's decision to incur costs for additional generating capacity, we believe that it is clear that the amount of investment made in generating plant it determined by the type of plant built, which is in turn determined by the number of hours per year that a unit is expected to run. Apparently recognizing this, despite his position that all production plant costs are driven by peak demand, FIPUG's Witness Jeffry Pollock suggested that a breakeven point, in terms of annual unit running time, could be calculated beyond which a utility would always build a baseload unit, so long as the annual operating hours were expected to exceed the breakeven number of hours. Witness Pollock went on to suggest that allocators based on class usage in the highest use hours up to the breakeven point could be used to allocate the energy related production plant costs. This may be a reasonable suggestion, but because significant doubt was raised regarding what constitutes an appropriate breakeven point analysis, and because of our belief for it, we do not accept this suggestion in this case.

The Average Off-Peak Demand Production Stack cost of service study was prepared by the Company in response to Staff's Interrogatory No. 246. Witness Scheffel Wright testified under cross examination that this method embodies a reasonable attempt to assign production plant costs to those customers and classes who use the plant in both off-peak and on-peak periods. We believe that this method has merit but, noting the marked similarity of results between this method and the Staff's recommended Equivalent Peaker Cost method in this case, we choose to use the EPC method as our primary guide to cost allocation and rate design.

For this case, we adopt the Equivalent Peaker Cost study sponsored by the Staff's Witness Scheffel Wright and recommended by Staff as our primary guide to cost allocation and rate design. We find that this method is logically sound in its classification of the cost of equivalent peaking capacity (the amount that the utility would have spent to serve only peak demands) as demand related, and in its classification of additional production plant costs, which the utility incurred to obtain fuel savings over longer periods of operation, as energy related.

Specific Application of Equivalent Peaker Cost Method in This Case

The Equivalent Peaker Cost (EPC) Method was applied to TECO's generating plant as follows. The ratio of the cost per KW of a new combustion turbine (CT) peaking unit, excluding AFUDC, to the cost of BB4 per KW, also excluding AFUDC, was calculated and multiplied by the total in-service cost of BB4 to obtain the estimated cost of peaking capacity equivalent to the 427 MW of BB4. This amount, $122,495,000, was classified as demand related, and the remaining $468,530,000 of the in-service cost of BB4 was classified as energy related. Since BB4 is the only one of TECO's fossil steam units that has a flue gas desulfurization system (scrubber), a different ratio was calculated for use in classifying the cost of TECO's other fossil steam units between the demand and energy components. The ratio used in this step of the analysis was the ratio of the cost per KW of a new CT, excluding AFUDC, to the estimated cost per KW of a new, un-scrubbed, baseload coal-fired unit. Applying this ratio resulted in $179,843,000 of TECO's other steam generating plant-in-service being classified as demand related and in $422,667,000 of that plant being classified as energy related. TECO's actual peaking units, representing a total plant-in-service amount of $21,692,000, were classified as demand related. In total, $891,197,000 of TECO's generating plant-in-service was classified as energy related and $324,030,000 was classified as demand related. This means that, had TECO only planned to serve its peak demands, without regard to operating cost savings, it would have spent approximately $324,000,000 for its generating plant. The remaining $891,000,000 was spent to achieve operating cost savings for the large volume of KWH the utility serves.

Our adoption of the EPC approach is not entirely new since we have previously endorsed a similar approach in the classification and allocation of the costs of a baseload nuclear generating unit in Docket No. 830465-EI. Additionally, as described below, we reject FIPUG's allegations that the EPC method suffers from "double counting" and "fuel symmetry" problems, as well as its argument that the EPC method is invalid because it fails to pass a simple stand-alone test proposed by FIPUG's Witness Jeffry Pollock. These concerns are addressed below.

Alleged Double Counting

FIPUG alleges that the Equivalent Peaker Cost method suffers from a double counting problem in that the classes' energy loads or average demands are used to allocate the energy classified component of production plant costs and their average demands are also included within their peak demands in developing the allocator for the demand classification portion of production plant costs. We agree with the Staff that there is no double counting problem because those costs that the utility incurred because of energy loads to be served are allocated on the basis of the classes' proportions of energy use, and a separate pot of dollars, the amount that would have been spent to serve peak loads, is allocated using an appropriate summer-winter peak demand allocation factor.

Fuel Symmetry

FIPUG defines fuel symmetry as the principle that a class that pays a higher than average amount per KW of demand should pay lower than average fuel costs. Staff Witness Wright defined fuel symmetry as the principle that customer classes should not pay for a greater share of baseload plant capital costs than they receive or implicitly purchase as a percentage of the relatively low-cost energy that the baseload plant generates. We agree with Witness Wright. Under cross-examination, he demonstrated that, under a system of average cost fuel princing, a class implicitly buys a system average proportion of baseload generated KWH at the system average baseload fuel cost. He then compared these shares of baseload KWH implicitly purchased to the classes' proportions of baseload plant cost responsibility. This analysis demonstrated to our satisfaction that the EPC and Average Off-Peak Demand Production Stack methods come closest to achieving fuel symmetry, while the four summer-three winter CP method advocated by FIPUG results in the greatest disparities between baseload plant cost responsibility and cheap baseload energy implicitly purchased.

Stand-Alone Test

A stand-alone test was proposed by FIPUG's Mr. Pollock that purported to compare the production plant costs assigned to a class by a cost of service method to the production plant costs that would be incurred were the class to be served by a separate, stand-alone, lowest-cost generation system. If the costs assigned by the cost of service study exceed the stand-alone costs, then, it was argued, the method failed the stand-alone test. Interestingly, despite the wide range of cost of service methodology advocated in this case, no cost study passed the stand-alone test for all customer classes, including the study sponsored by Witness Pollock. Considering this fact, and considering specific doubts raised as to the specification of the proposed stand-alone test, we will leave further consideration of stand-alone tests and their proper specification and applicability to future proceedings, including our generic investigation of cost of service methods and time of use rates in Docket No. 830085-EI.

Load Research

Staff and the Company agree and we acknowledge that the load research data utilized by TECO in its Cost of Service Study is adequate with the exception of the estimate of the GS winter peak demand. The precision of the estimate of this demand is +/- 15.5% at the 90% confidence level. This precision is poorer than the design level specified in Rule 25-6.437, Florida Administrative Code, Cost of Service Load Research, which was implemented on February 23, 1984. On August 20, 1984, pursuant to Rule 25-6.437, Staff approved a load research sampling plan, filed by TECO, that is expected to produce estimates that will meet the standards specified. However, insufficient time was available to implement this sampling plan to provide data for use in this case.

Allocation of Revenue Increase

As discussed previously, the revenue from FPL for the sale of capacity and energy from BB4 has been included as operating revenue in calculating the revenue increase. It is appropriate that this revenue be spread to the rate classes in the same manner as BB4 was allocated to them. This revenue serves to reduce the increase needed from the rate classes to $45,663,000, effective for meter readings on and after December 4, 1985. Staff recommended, and we approve, that the increase be allocated among customer classes so that each class moves toward parity in rate of return to the greatest extent practical with no class receiving an increase greater than 1.5 times the system average including base revenue, fuel, conservation and oil backout. In accordance with this policy, the class farthest from parity, IS, shall receive the maximum allowed increase of 1.5 times the system average. The remainder of the increase shall be distributed to the other rate classes so that they all earn the same rate of return. The RS and GS classes' and GSD and GSLD classes' rates of return were viewed in total because we have determined that the rates of the RS and GS classes and the demand and energy charges for the GSD and GSLD classes should be set equal.

The rates of return for 1985-86, by customer class, with the revenue increase we have approved are:

Rate Code	ROR/Index
RS	9.95/1.01
GS	11.08/1.13
RS-GS	10.09/1.03
GSD	10.33/1.05
GSLD	9.83/1.00
GSD-GSLD	10.09/1.03
IS	7.13/ .73
SL & OL	10.09/1.03
TOTAL	9.81/1.00

Subsequent Year Adjustments

As discussed previously, we have also approved additional increases for 1987 and 1988. These increases have been allocated to the classes by adding the subsequent year amount to the original increase and reallocating the total amount to move class rates of return toward parity as described above. Each class's share of the subsequent year increases will be collected through the non-fuel energy charge. TECO is authorized to timely file new tariffs consistent herewith designed to generate $10,408,000 in additional revenue in 1987 and $7,688,000 in 1988. These tariffs shall be first reviewed and approved by the Commission and shall become effective for meter readings taken on and after January 31, 1987, and January 31, 1988, respectively.

Unbilled Revenue

Unbilled revenue is that revenue applicable to electric energy consumed but not yet billed. Unbilled revenue occurs because meters are read on a cycle basis. At the end of any period, there will be some power consumed but not yet billed out by the Company. The Commission adopted Rule 25-6.14(2), Florida Administrative Code, stating that for ratemaking purposes, each investor-owned electric utility shall accrue unbilled base rate revenue. Thus, unbilled revenue is a part of the Company's Other Operating Revenue. The amount of unbilled revenue at any point in time is a product of the estimated unbilled KWH times the per KWH rate.

Staff and the Company stipulated that the change in unbilled revenue due to the rate increase should be estimated and reflected in the base rate revenue authorized in this case. They further agreed that the system change in unbilled revenue should be allocated to the rate classes in the same proportion that the base revenue increase is allocated excluding the interruptible class and the GSLD phosphate customers, who are not cycle-billed. We concur with this stipulation.

Customer Charges

We approve the customer charges in the following table. The charges for RS and GSLD are lower than unit cost because we received no adequate explanation as to why the reported unit costs are generally higher than those of the other investor-owned utilities. The GS customer charge is set the same as RS's, consistent with our decision to have the rates for the two classes the same.

		Unit Cost	
Rate	Present	at Recommended	Approved
Class	Charge	Class ROR	Charge
RS	$6.50	$8.82	$7.00
GS Metered	6.50	9.99	7.00
GS Unmetered	6.00		6.00
GSD	35.00	34.40	35.00
GSLD	115.00	435.07	170.00
IS-1 - IS-2	450.00	669.02	670.00
IS-3	N/A	n(1) 711.50	710.00

n(1) Unit cost at the system approved rate of return

Demand Charges

We find that standard demand charges for GSD and GSLD should remain at their present level of $6.75/KW even though the unit costs for both classes from the Equivalent Peaker cost of service study are less than $5.75/KW. This decision is based on the need to continue the current level of incentive to hold down peak load.

We approve the Staff recommended demand charge of $1.30/KW for interruptible classes which was based on the unit cost from the cost of service study.

Equal GSD and GSLD Demand and Energy Charges

Presently, general service customers with maximum billing demands between 50 and 999 KW take service on the GSD rate schedule. Those with maximum billing demands of 1000 KW or more take service on GSLD. An issue in this case is whether the schedules should be combined for ratemaking purposes. The Company has no objection to setting the demand and non-fuel energy charges equal as long as the classes are kept separate and have different customer charges to adequately recover the cost of metering the two groups. Staff and FIPUG argue hat separate classes should be maintained in this case until a more extensive analysis of rate reclassification and restructuring can be done.

These parties assert that the key factor in customer groupings should be homogeneous load characteristics, including load factor, coincidence factor, delivery voltage and customer size. TECO's general service rates are basically defined by customer size even though this characteristic has less bearing on cost causation than other factors such as load factor and coincidence factor. Thus, they agree that the current rate classes do not adequately group customers by similar load characteristics, which leads to inequities within classes. However, Staff contends that, in spite of the inadequacies, the current rate classifications at least serve to recognize the differences between average load factors and coincidence factors of the classes. In Staff's opinion, combining the GSD and GSLD classes may exacerbate the inequities.

We believe that it is unfair to set rates based on the different load factors and coincidence factors of the GSD and GSLD classes. Under the current rate classifications and Staff recommended rates, a GSD customer would pay less than a GSLD customer with exactly the same load factor. This is due to the greater diversity of the GSD class. By diversity we mean the ratio of the class billing demand to class demand at the time of the system peak. We believe it is unfair to charge one demand-metered customer more than another customer with the same load factor simply because he was arbitrarily assigned to a particular class. We think the benefits of diversity should be spread among the entire body of ratepayers as much as practical. Therefore, we are combining the GSD and GSLD rate classes for purposes of this rate determination. This means they will have the same demand and non-fuel energy charges. However, consistent with the Staff and Company recommendations, separate GSD and GSLD rate schedules will be maintained with different customer charges to recognize the higher costs of metering large demands and high voltage customers and with a power factor clause applicable to GSLD customers only.

Elimination of GSD Minimum Demand Charge

Presently, the GS customers are billed on a two-part (customer, energy) rate structure. They can elect to be billed on the GSD rate schedule, which contains a separate demand charge, if they agree to pay a 25 KW minimum demand charge. The Florida Retail Federation (FRF) has recommended that this 25 KW minimum be removed in an effort to reduce what it perceives as considerable discrimination within the GS class, which contains a very diverse group of customers. This action would allow more of the higher load factor GS customers to opt for the GSD rate schedule, thus lowering their bills. The Company does not object to this proposal as long as the expected revenue loss due to the migration of customers from GS to GSD is considered. Staff contends that if the barrier for GS customers moving to GSD is eliminated, then the GSD customers should also be allowed to migrate to the GS rate schedule. They believe that both high load factor GS customers and low load factor GSD customers may be overcharged under the current situation, and that allowing migration both ways could result in rate classes which would be more homogeneous with respect to load factor and coincidence factor.

We agree with the FRF that the 25 KW minimum billing demand should be eliminated from the GSD rate schedule.

However, we do not think that the GSD customers should be allowed to migrate to the GS rate schedule. As a matter of policy, a large demand customer should not be given the option of taking a non-demand rate. We feel that a properly designed TOU rate containing no demand charge in the off-peak period will offer these GSD customers a viable alternative for reducing their bills. We agree with Staff that no GS customer should be allowed to transfer from one rate schedule to another more than once in any 12-month period and that any GS customer requesting demand metering to determine whether it is to its advantage to migrate to GSD should pay the GSD customer charge to cover the higher metering cost.

Service Charges

The Company's proposal for service charges is summarized as follows:

	Present	Cost	Company Proposed
Initial Connection	$15.00	$20.08	$20.00
Normal Reconnection	7.00	6.18	7.00
Reconnection After Dis-			
connection for Cause	15.00	17.90	18.00
Field Credit Visit	7.00	5.11	5.00
Temporary Service	42.00	71.63	70.00

We find that the Company's proposed service charges are cost based and should be approved with the exception of the normal reconnection charge which is presently set at $7.00. Comparing the charge to that assessed by other investor-owned utilities in the State, we find that the fair and reasonable normal reconnection charge is $16.00.

Interruptible Rates

The Company presently has two interruptible rate schedules, IS-1 and IS-2. The IS-2 schedule is a specific end use tariff applicable only to electric arc furnace customers with demands of at least 10,000 KW. The Company has also filed tariffs for a new IS-3 customer class. In addition, several issues relating to the terms and conditions of interruptible service were raised in this case, as well as in Docket No. 850246-EI. We have consolidated the cases and shall address all issues here.

Disposition of Docket No. 850246-EI

On August 5, 1985, we held a hearing to determine the resolution of the opposing claims in Docket No. 850246-EI, which had earlier been consolidated with the rate case docket.

APPEARANCES: Lee L. Willis, Esquire and James D. Beasley, Esquire, Post Office Box 391, Tallahassee, Florida 32303, for Tampa Electric Company.

John W. McWhirter, Jr., Esquire, 201 East Kennedy Boulevard, Suite 821, Post Office Box 3350, Tampa, Florida 33601-3350, for International Minerals and Chemical Corporation, W. R. Grace Company and Farmland Industries, Inc.

Max Williams, General Counsel's Office, W. R. Grace Company, Post Office Box 27, Memphis, Tennessee, for W. R. Grace Company.

Michael B. Twomey, Esquire, 101 East Gaines Street, Tallahassee, Florida 32301, for the Commission Staff.

Prentice P. Pruitt, Esquire, 101 East Gaines Street, Tallahassee, Florida 32301, Counsel for the Commission.

As is more specifically described in Order No. 14550, entered in Docket No. 850246-EI on July 9, 1985, TECO, on June 7, 1985, filed a document entitled "Emergency Petition of Tampa Electric Company," which sought the "modification of certain of its interruptible rate schedules in order to freeze the application of those schedules to new customers and to provide a new, more equitably priced interruptible rate schedule for new interruptible customers and for existing firm customers seeking to transfer to interruptible service." TECO alleged that it and its ratepayers did not now need additional generation capacity that would be made available by transfers of existing firm customers to interruptible rate schedules and that, in fact, no such new generating capacity or the purchase of such capacity was contemplated before 1992. TECO stated that its interruptible customers were now receiving what amounted to firm service and alleged that the availability of virtually firm service at discounted interruptible rates was creating considerable interest by existing firm customers in taking service under existing interruptible rate schedules. TECO concluded that if current firm customers were allowed to switch to the existing interruptible rates, they would not provide sufficient revenue to cover the generating capacity installed to serve them when they were firm customers, which would work to the detriment of both the utility and the other ratepayers.

To provide for a transition from firm power rates to interruptible service, TECO proposed to close its existing interruptible schedules to new customers, while adopting new interruptible rate schedules which would reduce the effective interruptible discount from 28.2% to 10.4% and would also require new interruptible customers to sign a contract requiring them to take interruptible service over a period of ten years, as opposed to the five-year period now required. TECO filed affidavits supporting its petition, which quantified the number of firm service customers that potentially would seek to shift to interruptible service and the size of the load that would be shifted.

On June 17, 1985, W.R. Grace and Company, Farmland Industries, Inc. and I.M.C./New Wales Operations (Intervenors) filed a Petition to Intervene and a Motion to Deny Emergency Relief. The Petition to Intervene alleged that Intervenors were industrial customers of TECO who had applied and were qualified for service under TECO's existing interruptible rate schedules.

We determined that the issue of what amount of interruptible load is appropriate and beneficial for TECO, the duration of interruptible contracts and what price should be charged for interruptible service could more appropriately be addressed in the Company's rate case and consolidated the two dockets for that purpose. In order to maintain the status quo, we closed TECO's existing interruptible rate schedules (IS-1, IST-1 IS-2 and IST-2) to new business effective June 18, 1985.

On August 5, 1985, we held a separate hearing to determine whether the Intervenors were entitled to service under the existing interruptible rate schedules. As a result of that hearing, we determined that each of the Intervenors had complied with the Company's procedures for applying for interruptible service and that, pursuant to TECO's tariffs, they were entitled to begin receiving interruptible service six months after the effective date of their applications. In the case of W.R. Grace and Company, this meant that they were entitled to interruptible service on September 15, 1985, while Farmland Industries, Inc. and I.M.C./New Wales Operations were entitled to that service on November 14, 1985.

Closure of IS-1 to New Business

We reaffirm our decision closing IS-1, IST-1, IS-2 and IST-2 to new business, with the exception of the above-described Intervenors, effective June 18, 1985. As described below, we have eliminated the end-use rates IS-2 and IST-2 by combining them with IS-1 and IST-1. Additionally, while allowing the existing IS-1 and IST-1 customers to retain service at a class rate of return below parity for purposes of rate continuity and due to our policy of limiting increases to 1.5 time the system average increase, we have opened new IS-3 and IST-3 rates, with charges set at the unit costs at the approved system rate of return.

Mr. G. Pierce Wood, a TECO Senior Vice President, testified that TECO's decision to seek closure of its interruptible rate schedules was prompted by the threat of significant transfer of load from firm to interruptible rate schedules by a number of large industrial customers. He stated that, while interruptible load was of value to the utility because it offered both an opportunity to sell reserve capacity and postpone generating capacity additions, the need for interruptible load was not infinite. Specifically, Mr. Wood said that significant amounts of firm load attempting to switch to interruptible service caused two significant problems. First, such transfers would immediately increase the Company's already adequate reserve capacity, a portion of which was expressly planned and built to serve those firm customers attempting to switch. Second, TECO would suffer a significant loss of revenues, which in the normal regulatory process would ultimately be borne by all other ratepayers. Mr. Wood testified that new interruptible load should be added on a limited basis and at a price higher than the average rate for economy interchange. He stated that the existing interruptible customers should gradually receive rate increased at a level that would ultimately allow the IS-1 and proposed IS-3 classes to be merged.

Mr. George D. Jennings presented TECO's Assessment of Need Procedure by which it would determine the allowable amount of new interruptible load to be added each year. According to Mr. Jennings, a target interruptible load would be established by considering the Company's targeted maximum non-firm load, the year in which additional generating capacity would be required if the Company's maximum non-firm load was achieved, the benefits expected from load management, and the forecast of annual firm load reserve margins. Under the Company's proposal it would seek a 20% capacity reserve factor, which equates to a 25% load reserve margin. Twenty percent of TECO's present committed system capacity, including cogeneration, of 3,071 MW would equal a targeted capacity reserve factor of 614 MW, which Mr. Jennings testified represented a reasonable target for non-firm load, including load management and interruptible service. Jennings said that TECO expected 246 MW of load management reductions by 1995, which, when subtracted from the 614 NW figure, results in a targeted peak coincident interruptible load of 368 MW. In any year in which the Company's actual projected reserve margin was expected to exceed 1.5 times the target reserve margin (i.e., when the projected reserve margin was expected to exceed 37.5%), no additional interruptible load would be allowed on the system. Jennings proposed reaching the targeted amount of 368 MW by adding interruptible load in annual increments so that the total interruptible load would gradually build to the targeted level by the year in which the new capacity is forecast to be needed. present forecasts project additional capacity being required in 1995. Subtracting the existing interruptible load of 241 MW from the target of 368 MW and dividing that amount by the eight years (in which the reserve margin criterion is not expected to be binding) to 1995 results in 16 MW of additional interruptible load per year being added from 1986 through 1994, except in 1988, when the reserve margin criterion is expected to preclude the addition of interruptible load.

We find that the Company's proposed Assessment of Need Procedure strikes a reasonable balance between the benefits associated with serving interruptible load and the adverse costs of serving too much. Additionally, we approve the priority treatment proposed by the Company under which applications to transfer to interruptible would be administered on a first come first served basis with customers applying for service for the first time at a given service location being given priority. If a customer who is applying for a transfer from firm to interruptible service has not received service in three years, then that customer would be given equal priority with first time customers. Once the amount of new interruptible load indicated by application of the approved Assessment of Need Procedure was added in a given year, no additional interruptible load would be allowed in that year.

Combining the IS-1 and IS-2 Rate Schedules

Presently, there is only one customer in TECO's service area taking service on the IS-2 schedule. The Company knows of no other customers who would qualify for IS-2 service. There appears to be no good reason for maintaining this separate end use rate schedule; therefore we find that IS-1 and IS-2 should be combined into IS-1.

New IS-3 Rate Schedule

As proposed by TECO, the new IS-3 rate schedule would be open to customers with a measured demand of 1,000 KW or more, would include a demand ratchet and a minimum KWH use per billing KW. We disapprove the last two features. We will permit the Company to place in effect an IS-3 tariff without these features and with rates set at the unit costs at the approved system rate of return for the combined IS-1 and IS-2 classes. The tariff must also include a provision which allows new load on the IS-3 rates in accordance with the Assessment of Need Procedure proposed by Company Witness Jennings.

There shall be an annual review of the Company's assessed need for additional interruptible load in accordance with the Company procedure sponsored by Mr. Jennings. The 1987 assessment shall be filed with the Commission by October 1, 1986. As discussed above, we approve the 16 MW limitation of additional interruptible load calculated for 1986.

Notice to Transfer from Firm to Interruptible Service

We find that our approval of the Company's proposed Assessment of Need Procedure for new interruptible load eliminates the need for a notice requirement for customers to transfer from firm to interruptible service.

Notice to Transfer from Interruptible to Firm Service

The Company has proposed, and Staff has recommended, that the notice required to transfer from IS to firm service be increased from five years to ten years in order to provide the Company with adequate time to make optimal generation expansion planning decisions. We believe that five years notice is sufficient and, therefore, we deny the Company's proposal.

Minimum Term of Service

The Company has proposed to implement a minimum term of service for new IS-3 customers by requireing a minimum contract demand and a minimum hours use of the contract demand for a specified period of time (ten years). These proposals appear primarily designed to address problems of customers asking to receive IS service for a relatively short period of time, then leaving the utility's system or installing self-service generation. We agree trhat these problems need to be addressed, but we find that minimum term of service provisions are not appropriate means to do so. We will defer further treatment of these problems and their potential remedies and consider them in our generic docket on non-firm rates (Docket No. 830512-EI).

Penalty for Early Transfer from IS to Firm Service

The Staff has recommended that a penalty be collected from customers who transfer from IS to firm service with less than the approved minimum notice of five years. Staff recommends that any customer choosing to transfer to firm service from interruptible service without giving full notice must pay a charge amounting to the difference between the IS and GSLD rates for the period of time immediately prior to the changeover that is equal to the period that the changeover will be less than the required notice period.

We approve this recommendation with the modification that the Company may waive the penalty in the event that the following two conditions can be demonstrated:

(1) The customer has been on the IS tariff for at least five years.

(2) There is sufficient capacity to provide firm service to the customer and that allowing the customer to receive firm service would have no adverse effect on the Company generation expansion planning.

Provision of IS Service at the Secondary Voltage Level

The Company presently provides IS service only at the primary and subtransmission voltage levels. Customers who take at the secondary level must provide their own transformation. The Company proposes to continue this practice, but the Staff proposes that customers be allowed to obtain IS service at the secondary level, paying an appropriate surcharge to cover the cost of primary to secondary transformation. Considering the Company's belief that it is a necessary control requirement for IS customers to take service at primary voltage, and our own concern that the Company should be able to recover the cost of equipment installed to serve IS customers, we find that secondary level customers who desire IS service should be required to provide their own primary to secondary transformation.

Power Factor Clause

The Company proposes to reduce the cost factor used in the Power Factor Clause by 50% in this case. The Staff proposes raising the Power Factor Percentage Goal from 85% to 90%. However, the Company and Staff have stipulated that a power factor optimization study should be performed and filed in this docket by July 1, 1987. Accordingly, we shall not make any change in the current Power Factor Clause before the study is completed.

The study should provide information to assess the following:

(1) The optimum amount of power factor correction on the transmission and distribution system;

(2) The optimum type of monitoring devices and controls;

(3) The proper size and placement of capacitor banks on the distribution system; and

(4) The avoided system costs or savings when customers correct their power factor.

Voltage Level Differentiation of the GSLD and IS Rates

The Company proposed that a voltage level differentiation of rates by the level at which service is taken be approved for the IS-1 class, with primary level customers assessed an additional 70 per KW more than subtransmission level customers. FIPUG proposed that a similar voltage level differentiation be made for the GSLD class. We reject these proposals because no credible evidence was supplied by any party documenting or supporting any differentiation of rates by level of service other than credits for transformer ownership and transformation energy or demand losses.

Transformer Ownership Credit

Transformer Ownership discounts are credits applied to the demand charge for those customers who take service at primary or subtransmission voltage and provide their own transformation. This discount is appropriate because demand charges include costs associated with the transformation necessary to provide service from the production plant down to the secondary distribution level. If a customer takes service at primary or subtransmission voltage, and provides his own transformation, a credit is warranted to cover those transformation costs included in the rates which are related to transformation not required. The transformer ownership credit shall be 32 per KW for primary and 42 for subtransmission level customers. We feel these credits as derived under the Company's formula are fair and equitable for each level of transformation avoided.

Time of Use Rates (TOU)

In the Company's last rate case, time-of-use rates were made mandatory for customers with monthly demands in excess of 2000 KW. At issue in this case is whether such rates should be continued for these customers. Staff favors mandatory TOU rates because TOU rates provide a more accurate price signal than standard rates. Staff maintains that TOU rates should be mandatorily implemented where practical. The Company proposed to eliminate mandatory TOU rates, stating that mandatory TOU rates wrongly eliminate the customer's freedom of choice. We agree with the Company and have approved the elimination of mandatory TOU rates.

The next question is how should the optional TOU rates be designed? The Company's current TOU rates were designed under the load factor method, which incorporates on-peak and maximum billing demand charges and separate charges for on-peak and off-peak KWH usage. The Company proposes to maintain the load factor method for this rate case. Staff recommended the use of a method based on the results of the approved cost of service methodology. Staff's proposal incorporates a maximum billing demand charge designed to recover distribution plant and an on-peak demand charge designed to recover transmission plant and that portion of production plant cost necessary to serve the total system peak demand. The on-peak and off-peak non-fuel energy charges would be set at the energy unit cost, which includes the production plant costs in excess of the amount necessary to serve the peak as well as O&M expenses. FIPUG contends that TOU rates should be cost-based. They state that the anomalous situation wherein the Company's proposed maximum demand charge exceeds the on-peak demand charge should be corrected. FIPUG suggests that this could be done by eliminating the maximum demand charge, or altering the relationship so that the on-peak demand charge is higher than the maximum demand charge.

Having reviewed all of the evidence on this issue, we believe that the load factor method of designing TOU rates should not be used in this case. We agree with Staff and FIPUG that the TOU rates should be as cost-based as practical. Further, we believe that rates should be designed such that customers more off-peak than average will benefit from TOU rates. Under the Staff proposed rate design, the breakeven point above which a residential customer using 1000 KWH will benefit from TOU rates is 75% off-peak usage. However, on average, the residential class consumes approximately 70% of its KWH's off-peak. Therefore, we are approving non-demand TOU rates that result in a breakeven point of approximately 70% off-peak, 30% on-peak consumption. We are setting the off-peak KWH charge approximately equal to the energy unit cost from the approved cost of service study. The on-peak charge will then be set to recover the class revenue requirement with a breakeven point of 70% off-peak, 30% on-peak usage.

With respect to demand-metered TOU rates, we disagree with Staff's position that distribution plant be collected through a maximum demand charge. We believe all demand-related costs should be recovered through an on-peak demand charge, and we are setting this charge equal to the standard demand charge of $6.75 per KW. We also disagree with Staff's recommendation that there be no differential in the on-peak and off-peak non-fuel energy charges. We believe these charges should be set such that the breakeven point for a typical customer is approximately 70% off-peak, and 30% on-peak consumption. This results in a differential between the on-peak and off-peak KWH charges of approximately 2.6 to 1.0.

The final issue related to this subject is how to treat the revenue shortfall due to optional TOU rates. Standard non-time-differentiated rates are based on average cost. Under the optional TOU rates, those customers who use more off-peak and who are less costly to serve than average will opt for the TOU rate. Those customers who are more on-peak will remain on standard rates. In order to properly reflect the costs of the standard and TOU customers, the revenue shortfall from those customers who will opt for TOU rates should be added back to the standard KWH rate for that class.

Rate Design Stipulations

Stipulation Number 3 - The Company proposes to retain equal RS and GS rates but keep the two as separate rate classifications. We approve this proposal so as to avoid administrative problems that may arise if the GS rate is lower than the RS rate.

Stipulation Number 4 - The Company proposes that sports fields remain on the GS non-demand rate rather than being transferred to the GSD rate because if sports fields were transferred to the GSD rate, they would receive an increase of 251%, without fuel, based on the approved rates. We approve this proposal and find that the sports field customers should receive an increase equal to the system average increase with fuel.

Stipulation Number 5 - The Company presently has a 1% metering discount on the KW and KWH charge of customers served above the secondary voltage level to recognize the fact that those customers are metered at a higher voltage level and must absorb losses during transformation. Staff and the Company agree that the Credits should be 1%

for primary service and 2% for subtransmission service and applied to both energy and demand. We approve the credits as agreed to by Staff and the Company.

Stipulation Number 7 - Presently, some customers, at their option, have a secondary feeder from a substation source to their location. The Company proposes to institute a relay service charge of 50 per KW to recover operations and maintenance expenses. The Company and Staff both agree that this charge is appropriate. We approve a 50 per KW charge for relay service.

Street and Outdoor Lighting

The Company proposes that rather than allocating cost between mercury vapor and high pressure sodium fixture classes on the basis of cost data, the aggregate of all mercury vapor customers and the aggregate of all high pressure sodium customers each get the average rate increase of the class. Additionally, the Company proposes to use the current facilities charges for mercury vapor classes, which are not cost-based, to prorate to the proposed facilities charges, rather than using current cost data. Based upon the record in this case, we approve the following rate design changes recommended by Staff.

First, the non-fuel energy charge for all fixture types should be set at the unit cost from the approved cost of service study at the rate of return approved for this class.

Second, the full maintenance cost of $1,450,000, identified by the Company in the cost of service study, should be recovered through a maintenance charge, as prorated by Staff from the Company's cost study. These two adjustments must be made to prevent subsidies between customers who do versus those who do not provide their own fixtures or maintenance.

Third, the remaining revenue requirement should be recovered through the facilities charges, with the facilities charges for high pressure sodium fixture classes separated into separate fixture and pole charges using the Company cost study as a basis for proration. The Company's proposal, unlike the current tariffs of the other major IOU's, does not separate the facilities charge into a pole charge and a fixture charge. Since the proposed facilities charges are not based on cost data, this means that customers with the same pole type but different fixture types would be charged considerably different amounts for use of the same type of pole. Staff advocated using the pole cost given in Exhibit 14N for both high pressure sodium fixtures and for mercury vapor fixtures since there is no evidence that pole cost is different for the same type of pole. Staff indicated they also prefer separate pole and fixture charges for mercury vapor classes. However, since current rates for mercury vapor classes are not cost-based and considerable differences from cost exist, this would produce very large rate increases for some customers. Thus, for rate continuity purposes, Staff favors and we approve the previously discussed treatment of facilities charges with separate pole and fixture charges for high pressure sodium fixture classes. However, we continue the current Company format for mercury vapor class facilities charges using costs from the Company cost study, with the exception that no customer's rate increase more than 40% due to a change in facilities.

Additionally, the Company and Staff stipulated that the Company be allowed to recover costs for additional poles and wire used in serving outdoor lighting classes through a CIAC payment in lieu of a separate pole charge for additional poles. We approve this cost recovery methodology. However, for those customers who have not made a CIAC and presently are paying an additional pole charge, the additional pole charge should be continued.

XIII. CONCLUSIONS OF LAW

1. Tampa Electric Company is a public utility within the meaning of Section 366.02, Florida Statutes, and is subject to the jurisdiction of this Commission.

2. This Commission has the legal authority to authorize incremental adjustments in rates for subsequent periods, pursuant to Section 366.076(2), Florida Statutes.

3. The adjustments to rate base made herein are reasonable and proper. The cost of the Company's 1984 rate base for ratemaking purposes, as adjusted for the inclusion of BB4, is $1,513,368,000.

4. The adjustments made to the calculation of net operating income are proper and appropriate. For ratemaking purposes, TECO's net operating income for 1984, as adjusted for the inclusion of BB4, is $125,525,000.

5. The fair rate of return on equity capital of TECO lies in a range of 13.5% to 15.5%. A return of 14.5% should be used to determine revenue requirements.

6. The range of reasonableness for the overall fair rate of return for the Company is 9.40% to 10.21%, with a focus on 9.81% for ratemaking purposes.

7. TECO is authorized to increase its rates and charges bu $45,663,000 in annual gross revenues effective November 4, 1985 to provide it with an opportunity to earn a fair rate of return of 9.81%.

8. TECO is authorized to increase its rates and charges by an additional $10,408,000, effective January 1, 1987 and by an additional $7,688,000, effective January 1, 1988.

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

10. The new rate schedules shall be reflected upon billings rendered for meter readings taken on or after December 4, 1985. The subsequent year rate schedules for 1987 and 1988 shall be reflected upon billings rendered for meter readings taken on or after January 31, 1987 and 1988, respectively.

In view of the record of this case and our considered judgment of the same, it is

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

ORDERED that the petition of 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 $45,663,000 in additional gross revenues annually. The Company shall include with the revised rate schedules all calculations and workpapers used in deriving the revised rates and charges. It is further.

ORDERED that Tampa Electric Company is hereby authorized to timely submit rate schedules consistent herewith designed to generate $10,408,000 of additional gross annual revenues in 1987 and $7,688,000 of additional gross annual revenues in 1988. The Company shall include with these rate schedules all calculations and workpapers used in deriving the revised rates and charges. It is further

ORDERED that the revised schedules authorized herein for the initial revenue increase shall be reflected upon billings rendered for meter readings taken on or after December 4, 1985. It is further

ORDERED that the revised schedules authorized herein for the subsequent year revenue increases for 1987 and 1988 shall be reflected upon billings rendered for meter readings taken on or after January 31, 1987 and 1988, respectively. It is further

ORDERED that $2,749,000 representing twelve months of revenue related to the interest imputation of investment tax credits shall be collected under bond or corporate undertaking on an annual basis, subject to refund with interest, until the final Internal Revenue Service regulations on the subject are released and this issue is resolved. A refund, if any, shall be calculated and refunded in the manner described in the body of this order. It is further

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

ORDERED that the Company file the power facotor optimization study as discussed herein no later than July 1, 1987. It is further

ORDERED that W.R. Grace and Company, IMC/New Wales and Farmland Industries are entitled to receive service under TECO's IS-1 rate schedule as of September 15, November 14 and November 14, 1985, respectively. It is further

ORDERED that any party adversely affected by the Commission's final action in this matter is entitled to request: 1) reconsideration of the decision by filing a motion for reconsideration with the Commission Clerk within 15 days of the issuance of this order in the form prescribed by Rule 25-22.60, Florida Administrative Code, or 2) judicial review by the Florida Supreme Court by the filing of a notice of appeal with the Commission Clerk and the filing of a copy of the notice and the filing fee within the Supreme Court. This filing must be completed within 30 days after the issuance of order, pursuant to Rule 9.110, Florida Rules of Appellate Procedure. The notice of appeal must be in the form specified in Rule 9.900(a), Florida Rules of Appellate Procedure.

By ORDER of the Florida Public Service Commission, this 13th day of DECEMBER, 1985.

APPENDIX A

INDEX

APPENDIX B

TAMPA ELECTRIC COMPANY
COMPARATIVE AVERAGE RATE BASES
TYE 12/31/84
$ (000)

	COMPANY			COMMISSION VOTE	
	Juris. Per Bks. As Filed	Juris. Adj. As Filed	Adj. Juris As Filed	Juris. Adjs.	Adj. Juris.
PLANT IN SERVICE	$1,182,273				

1A BB4		591,025		0	
1A BB4		0		(15,725)	
1B BB COAL BLENDING					
EQUIP		22,838		(22,838)	
1C LIMEROCK BB4		0		(72)	
1F VARIANCE BB4		0		(214)	
1G VENDOR BACKCHARGE		0		(1,600)	
1H SOFTWARE		0		0	
3A BB ASH SETTLING					
POND		0		397	
RS3 PRODUCTION PLANT		0		(115)	
TRANSFORMER PUR-CHASE		0		(82)	
TOTALS	1,182,273	613,863	1,796,136	(40,249)	1,755,887
ACCUM. DEPR. &					
AMORT.	(349,059)				
C BB 4		(12,411)		0	
1E ACCUM DEPREC BB4		0		(1,041)	
EFFECT OF OTHR PIS					
ADJ		0		26	
RS2 COST OF REMOVAL		0		(18)	
PR3 PRODUCTION PLANT		0		175	
TOTALS	(349,059)	(12,411)	(361,470)	(858)	(362,328)
NET PLANT IN SERVICE	833,214	601,452	1,434,666	(41,107)	1,393,559
CWIP	491,281				
C BB4		(447,555)		0	
1B BB COAL BLENDING					
EQUIP		(22,838)		22,838	
2 CWIP		0		(41,171)	
TOTALS	491,281	(470,393)	20,888	(18,333)	2,555
PLANT HELD FOR					

FUTURE USE	13,020				
3 PHFFU		0		(9)	
3A BB ASH SETTLING POND		0		(2,110)	
TOTALS	13,020	0	13,020	(2,119)	10,901
NET UTILITY PLANT	1,337,515	131,059	1,468,574	(61,559)	1,407,015
WORKING CAPITAL	110,295				
C GAIN ON SALE		(1,122)		0	
C A/P BB4 FUEL		(2,301)		0	
4B3 TAXES ACCRUED					
- O&M		1,889		0	
- DEPREC		4,073		0	
- PROP TAX		1,410		0	
- DEF TAX		295		0	
- ITC CR.		2,529		0	
1C LIMEROCK BB4		0		44	
3A1 BB ASH SETTLING POND		0		1,542	
4A1 FUEL INVENTORY LEVEL		15,771		(15,297)	
4A2 UNBILLED REVENUES		0		0	
4A3 A/R FPL REVENUES		6,664		(4,342)	
4A4 IBM COMPUTER LOSS		0		(4)	
4A5 MACINNES AMORTIZATION		(1,324)		(175)	
4A6 WORK ORDERS		0		(193)	
4B1 A/P LEVEL		0		(1,397)	
4B2 A/P GANNON TRUST		0		0	
4B3 TAXES ACCRUED		0		(10,935)	
4B4 INJURIES & DAMAGES RES.		0		0	
AMOUNT TO BALANCE		0		(1,069)	
TOTALS	110,295	27,884	138,179	(31,826)	106,353

TOTAL RATE BASE	$1,447,810	$158,943	$1,606,753	($93,385)	$1,513,368

TAMPA ELECTRIC COMPANY
WORKING CAPITAL
13 NO. AVG. 12/31/84
(000'S)

LINE NO.	ACCT.	DESCRIPTION	COMPANY AS FILED	COMMISSION VOTE
		CURRENT ASSETS		
1	131	CASH	$3,388	$3,388
2	134	OTHER SPECIAL DEPOSITS	182	182
3	135	WORKING FUNDS	(1,383)	(1,383)
4	142	CUSTOMER DEPOSITS	52,594	52,594
5	143	OTHER ACCTS. REC.	9,769	5,234
6	144	PROVISION FOR BAD DEBT	(530)	(530)
7	151	FUEL STOCK	100,187	84,890
8	154	MATERIALS & SUPPLIES PLNT	24,655	24,655
9	163	STORE EXP. UNDIST.	14	14
10	165	PREPAYMENTS	522	522
11	173	UNBILLED UTILITY REV.	13,803	13,803
12		TOTAL CURR. ASSETS	203,201	183,369
		DEFERRED DEBITS		
13	182	LOSS ON SALE OF PLANT	3,518	3,339
14	183	PRELIM. SURVEY & INVEST.	1,184	1,184
15	184	CLEARING ACCTS.	49	49
16	186	MISC. DEF. DEBITS	1,202	2,788
17	188	RESEARCH & DEVELOP.	12	12
18		AMOUNT TO BALANCE		(1,069)
19		TOTAL DEF. DEBITS	5,965	6,303
20		TOTAL ADJUSTED ASSETS	209,166	189,672

		CURRENT LIABILITIES		
21	232	ACCOUNTS PAYABLE	26,021	27,418
22	234	ACCTS. PAY. ASSOC. CO.	8,346	8,346
23	236	TAXES ACCRUED	1,355	12,290
24	237	INTEREST ACCRUED	10,280	10,280
25	238	DIVIDENDS DECLARED	499	499
26	241	TAX COLLEC. PAY.	2,247	2,247
27	242	MISC. CURR. & ACC. LIAB.	10,365	10,365
28		TOTAL CURR. LIABILITIES	59,113	71,445
		DEF. CR. & OPER. RESERVES		
29	253	OTHER DEF. CREDITS	9,922	9,922
30	256	DEF GAINS FM DISP OF PLNT	1,122	1,122
31	262	INU & DMG RESERVE	830	830
32		TOT. DEF CR & OPER RESV	11,874	11,874
33		TOTAL LIABILITIES	70,987	83,319
34		TOTAL WORKING CAPITAL	$138,179	$106,353

APPENDIX C

TAMPA ELECTRIC COMPANY

COMPARATIVE NOIS

TYE 12/31/84

$ (000)

	COMPANY			COMMISSION VOTE	
	Juris. Per Bks. As Filed	Juris. Adj. As Filed	Adj. Juris As Filed	Juris. Adjs.	Adj. Juris.
OPERATING REVENUES	$693,527				
C FUEL REVENUE		(289,707)		0	
C GPIF REVENUE		(610)		0	

C CONSERVATION					
REVENUE		(13,537)		0	
C FRANCHISE FEES		(12,745)		0	
C ECONOMY SALES		2,424		0	
10 OPERATING REVENUES		0		56,543	
10A UNBILLED REVENUES		0		284	
10B INTERCHANGE					
REVENUE		0		(978)	
4A6 A/R WORKORDERS		0		(15)	
TOTALS	693,527	(314,175)	379,352	55,834	435,186
OPERATING EXPENSES:					
OPERATION & MAINTENANCE	429,259				
C FUEL		(298,820)		0	
C CONSERVATION		(12,714)		0	
C STOCKHOLDER					
RELATIONS		(53)		0	
C CIVIC CLUB MEALS		(6)		0	
C SOLARIS & WATERFALL		(13)		0	
C ADVERTISING		(18)		0	
C ECONOMY SALES		2,599		0	
C BAD DEBT EXPENSE		(203)		0	
10 OPERATING REVENUE		0		0	
11A O&M LEVEL		0		(1,572)	
11B BB4 O&M		11,229		(1,947)	
11C FAC - BASE RATES		0		3,011	
11D INDUSTRY DUES		(171)		(61)	
11E EPRI DUES		0		0	
11F RATE CASE EXPENSES		0		(57)	
11G INTERCHANGE		13,421		(978)	
RS2 COST OF REMOVAL		0		18	
TOTALS	429,259	(284,749)	144,510	(1,586)	142,924
DEPRECIATION &					
AMORTIZATION	42,085				
11H BB4		24,823		2,081	

EFFECT OF OTHR PIS ADJS		0		(51)	
PS3 PRODUCTION PLANT		0		(4)	
TOTALS	42,085	24,823	66,908	2,026	68,934
TAXES OTHER THAN INCOME	38,987				
C FUEL		(4,708)		0	
C CONSERVATION		(220)		0	
C FRANCHISE FEES		(12,774)		0	
C GPIF		(10)		0	
C BB 4		8,380		0	
C ECONOMY SALES		39		0	
EFFECT OF ADJS		0		907	
TOTALS	38,987	(9,293)	29,694	907	30,601
INCOME TAXES-CURRENT	34,035				
C BB 4		(32,268)		0	
30 INTEREST SYNCH		0		1,414	
31 JDIC INTEREST SYNCH		0		0	
32 PRIOR YEAR TAX ADJ		0		0	
34 CHANGE IN STATE TAX RATE		296		36	
30 TAX EFFECT OF ADJS		(1,418)		5,768	
30 INCOME TAX ADJ.		0		0	
TOTALS	34,035	(33,390)	645	7,268	7,913
DEFERRED TAXES (NET)	21,992				
C CWIP		21,022		0	
C CHANGE IN STATE TAX RATE		102		0	
30 BB 4		859		21,204	
32 PRIOR YEAR TAX ADJ		0		0	
30 EFFECT OF ADJS		0		27	
TOTALS	21,992	(4,061)	17,931	21,231	39,162

INVESTMENT TAX CR.					
(NET)	14,310				
30 BB 4		5,592		(1,085)	
TOTALS	14,310	5,592	19,902	(1,085)	18,817
LOSS ON DISPOSAL OF					
PLANT	1,338				
C AMORT. OF GAIN ON					
SALE		(589)		0	
C GAIN ON REACQUIRED					
BNDS		(46)		0	
11I AMORTIZATION OF					
LOSS		8		(74)	
1C LIMEROCK BB4		0		10	
1G VENDOR BACKCHARGE		0		320	
3A1 BB ASH SETTLING					
POND		0		343	
TOTALS	1,338	(627)	711	599	1,310
TOTAL OPERATING					
EXPENSES	582,006	(301,705)	280,301	29,360	309,661

APPENDIX D

LIFE CATEGORIES FOR BIG BEND UNIT 4

	COMMISSION VOTE		
ACCOUNT	LIFE	SAL-VAGE	RATE
MAIN PLANT	(yrs.)	(%)	(%)
311 Structures and Improvements			
Buildings and Roads, Railroads and	40	(25)	3.1
Landscaping and Disposal and Storage Ponds			
Piping and Valves	34	(25)	3.7

312 Boiler Plant Equipment			
Boiler and Ductwork	23	(3)	4.5
Precipitatior and Ductwork	27	(3)	3.8
Pumps, Motors, Engines, Etc.	20	(3)	5.2
Equipment Foundations and Structures	40	(3)	2.6
Piping and Valves	34	(3)	3.0
314 Turbogenerator Units			
Turbine Generator and Condenser	23	(2)	4.4
Pumps, Motors, Engines, Etc.	20	(2)	5.1
Equipment Foundations and Structures	40	(2)	2.6
Piping and Valves	34	(2)	3.0
315 Accessory Electric Equipment			
Equipment Foundations and Structures	40	(8)	2.7
Instrumentation, Cable, Electrical Equipment	20	(8)	5.4
Computer	10	(8)	10.8
316 Miscellaneous Power Plant Equipment			
Station Equipment (Pumps, Etc.)	20	(9)	5.5
Instrument Piping, Cranes, Hoists	40	(9)	2.7
Communications	12	(9)	9.1

LIFE CATEGORIES FOR BIG BEND UNIT 4

	COMMISSION VOTE		
ACCOUNT	LIFE	SAL-VAGE	RATE
	(yrs.)	(%)	(%)
FGD (SCRUBBER)			
311 Structures and Improvements			
Building Structures and Foundations	35	(25)	3.6
Building Services	32	(25)	3.9
Piping and Valves	32	(25)	3.9
Roads, Railroads and Landscaping	39	(25)	3.2

312 Boiler Plant Equipment			
FGD Equipment and Ductwork	14.9	(3)	6.9
Equipment Foundations and Structures	25	(3)	4.1
Piping and Valves	12.4	(3)	3.0
315 Accessory Electric Equipment			
Equipment Foundations and Structures	28	(8)	3.9
Instrumentation	15	(8)	7.2
Cable, Raceway, Etc.	13.6	(8)	7.9
Electrical Equipment	21	(8)	5.1
316 Miscellaneous Power Plant Equipment			
Instrument Piping	35	(9)	3.1
Communications	12	(9)	9.1
Cranes and Hoists	23	(9)	4.7
TRANSMISSION			
353 Transmission Station Equipment	33	10	2.7

APPENDIX E

EXHIBIT 204

COMPARISON OF COST OF SERVICE STUDIES FILED IN TAMPA ELECTRIC COMPANY RATE CASE, DOCKET NO. 850050-EI

	"Meyer Rerun" Study	Wright Equivalent Peaker Cost Study	Average Off-Peak Demand Production Stack Method	Knoblock/Pollock 7 CP Method
Demand Allocator	Average of the 12 Monthly CPs	20 CP (10 highest summer and 10 highest winter CPs)	20 CP (10 highest summer and 10 highest winter CPs)	7 CPs (4 summer monthly CPs and 3 winter monthly CPs)
Production	Environmental	Cost of	Rate base of	All Production

Plant Classification method	control equipment classified as energy related, all other production plant classified as demand related	equivalent peaking capacity classified as demand related, all other production plant rate base classified as energy related	production stack needed to serve average off-peak demand of 1,272 MW (1,590 MW including provision for reserve margin) classified as energy related, balance classified as demand related	Plant classified as demand related
Percent of Production Plant Demand and Energy Related	66.2% Demand 33.8% Energy	25.5% Demand 74.5% Energy	21.5% Demand 78.5% Energy	100% Demand 0% Energy
Voltage Level Differentiation	No	No	No	Yes, for GSLD and IS Classes
Secondary Services	Appropriate Correction Made of error in Original TECO Cost Of Service Study	Correction Made	Correction Made	Correction Made

Legal Topics:

For related research and practice materials, see the following legal topics:
Energy & Utilities LawAdministrative ProceedingsPublic Utility CommissionsGeneral OverviewEnergy & Utilities LawUtility CompaniesRatesRatemaking FactorsRate BaseEnergy & Utilities LawUtility CompaniesRatesRatemaking FactorsRate of Return