BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for rate increase by Tampa Electric Company.	DOCKET NO. 080317-EI ORDER NO. PSC-09-0283-FOF-EI ISSUED: April 30, 2009

The following Commissioners participated in the disposition of this matter:

MATTHEW M. CARTER II, Chairman
LISA POLAK EDGAR
KATRINA J. McMURRIAN
NANCY ARGENZIANO
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APPEARANCES:

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On behalf of AARP

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On behalf of the Florida Retail Federation (FRF)

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On behalf of the Florida Public Service Commission (Staff)

FINAL ORDER GRANTING IN PART AND DENYING IN PART PETITION FOR RATE INCREASE

BY THE COMMISSION:

BACKGROUND

This proceeding commenced on August 11, 2008, with the filing of a petition for a permanent rate increase by Tampa Electric Company (TECO or Company). The Company is engaged in business as a public utility providing electric service as defined in Section 366.02, Florida Statutes (F.S.), and is subject to our jurisdiction. TECO provides electric service in all of Hillsborough County and parts of Polk, Pasco and Pinellas Counties, serving over 667,000 residential, commercial and industrial customers.

TECO requested an increase in its retail rates and charges to generate $228.2 million in additional gross annual revenues. This increase would allow the Company to earn an overall rate of return of 8.82 percent or a 12.00 percent return on equity (range 11.00 percent to 13.00 percent). The Company based its request on a projected test year ending December 31, 2009. TECO stated that this test year is the appropriate period to be utilized because it best represents expected future operations. TECO did not request any interim rate relief.

Pursuant to Section 366.06, F.S., Order No. PSC-08-0693-PCO-EI, issued October 20, 2008, we suspended TECO's proposed permanent rate schedules pending review.

The Office of Public Counsel (OPC), Office of Attorney General (OAG), AARP, Florida Industrial Power Users Group (FIPUG) and the Florida Retail Federation (FRF) intervened in this proceeding.

Customer service hearings were held in Tampa and Winter Haven on October 21, 2008, and October 22, 2008, respectively. A total of 40 customers presented testimony at the two customer service hearings. The technical hearing was held January 20, 21, 27-29, 2009, in Tallahassee. At the start of the hearing, we approved the following stipulated issues as listed in Prehearing Order No: PSC-09-0033-PHO-EI; 1, 25, 40, 42, 43, 44, 45, 81, 82, 85, 89, 90, 92, 96, 106, 108, 111 and 113.

We have jurisdiction pursuant to Sections 366.06(2) and (4), and 366.071, F.S.

TEST PERIOD

The parties and our staff stipulated that TECO's projected test period of the 12 months ending December 31, 2009 is the appropriate test year to be utilized in this docket, with appropriate adjustments.

The Company's load and customer forecast supporting the rate case petition were sponsored by TECO witness Lorraine L. Cifuentes. Witness Cifuentes offered direct testimony and supporting exhibits that summarized the forecasts and the historical data, forecast assumptions, and the regression models used to create the projected system peaks. No other witness offered an alternative forecast. We have reviewed TECO's customer and load forecast assumptions, regression models, and the projected system peak demands, and we find that they are appropriate for use in this docket. The forecast assumptions were drawn from independent sources[1] that we have relied upon in prior proceedings.[2] The regression models used to calculate the projected peak demands conform to accepted economic and statistical practices. The projected peak demands produced by the models appear to be a reasonable extension of historical trends.

QUALITY OF SERVICE

TECO witness Black testified that "[s]ince the company's last base rate increase, Tampa Electric has experienced tremendous customer growth while providing cost-effective, reliable service." He stated that the approximately 667,000 customers that TECO currently serves is almost 200,000 (42 percent) more than in 1992. None of the intervenors presented testimony concerning the quality of service provided by TECO. A total of 40 customers testified at the customer service hearings held in Tampa and Winter Haven. The customers that testified at the customer service hearings represent .006 percent of TECO's total customer base. Although some of the customers did have issues with the service provided by TECO, the reported problems were not widespread or systemic.

FRF is the only intervenor to take a position on this issue. Citing the testimony that was presented at the customer service hearings, FRF urged us to "find that the Company's service is no better than adequate." We disagree; based on the record, we find that TECO's quality of service is adequate.

RATE BASE

Non-Utility Activities Removed from Rate Base

No party filed specific testimony regarding whether non-utility activities have been removed from rate base. OPC stated in its brief that it disagrees with the inclusion of Account 146, Accounts Receivable from Associated Companies, in the amount of $6,309,000. Because

[1] University of Florida's Bureau of Economic and Business Research and Moody's Economy.com.
[2] TECO Ten-Year Site Plans, undocketed; FPL Need Determination, in Docket No. 080203-EI, In re: Petition to determine need for West County Energy Center Unit 3 electrical power plant, by Florida Power & Light Company.

we specifically address Account 146 below, the adjustment will be discussed in that context. Otherwise, we find that no adjustments to rate base for non-utility activities are needed.

Pro Forma Adjustment

Company witness Hornick testified that TECO's Ten Year Site Plan (TYSP) indicated the need for additional peaking capacity in the near term and that projects were underway to add two simple cycle combustion turbines (CTs) in 2009, each with a nominal capacity of 60 megawatts (MW). According to witness Hornick, two of the CTs will go in service in May 2009 and three of the CTs will go in service in September 2009.

Company witness Chronister testified that because these units will be generating electricity for customers for the period of time covered by new rates, it is appropriate for the revenue requirement requested to reflect the significant investment and operating costs associated with these assets. According to witness Chronister, these adjustments bring the Company's total cost profile to an amount that reflects a full year of operation for these units.

The Company's pro forma adjustment to annualize the May CTs (two units) increases Utility Plant in Service and Accumulated Depreciation Reserve by $38,672,000 and $1,163,000, respectively. The Company's pro forma adjustment to annualize the September CTs (three units) increases Utility Plant in Service and Accumulated Depreciation Reserve by $100,915,000 and $2,730,000, respectively. The pro forma adjustments combined increase Utility Plant in Service and Accumulated Depreciation Reserve by $139,587,000 and $3,894,000, respectively, for all five CT units. The effects on Net Operating Income of the Company's pro forma adjustments to annualize these CTs are discussed later.

OPC witness Larkin testified that the Company is treating these facilities as if they were in-service as of January 1, 2009, and not the actual in-service dates of May and September. According to witness Larkin, the projected test year is supposed to result in a matching of the Company's projected investment with its projected earnings on a month-to-month and annual basis. The projected test year methodology uses forecasted data for a 12-month period and matches average rate base investment to average expenses and revenues. As testified to by witness Larkin, under TECO's annualization proposal, the cost of the new plant would be put in rates without accounting for the new customer growth that would otherwise support those costs. This type of allowance will create a mismatch between the projected test year revenues and expenses and the projected investment related to assets that generated the test period revenues.

Witness Larkin noted that we moved away from using historical test years with pro forma adjustments early in 1981 and began using projected test years. TECO's use of pro forma adjustments for selected changes that occur during a projected test period as if they occur on the first day of the period creates something other than a projected test year. As we noted in TECO's last rate case, ". . . pro forma adjustments usually do not represent all the changes which occur from the end of the historical period to the time new rates are in effect. Therefore, this option generally does not present as complete an analysis of the expected financial operations as a projected test year."[3]

We acknowledge that different test periods can be used in determining a utility's revenue requirement. An appropriate test year can be historical, historical with pro forma adjustments, or projected. While it is true that that most electric utility companies base their increase requests on a fully-projected test year, the use of a projected test year is not required by rule or statute. Other Commission-regulated industries often structure their rate increase requests using historical data.

In this case, TECO requested the budgeted calendar year 2009 as its projected test year. Witness Chronister testified that the Company's 2009 budget process resulted in a fair and reasonable projection of amounts necessary for the Company to provide safe and reliable service. By proposing selected pro forma adjustments to a projected test year, and not recalculating all elements of the Company's operations that make up the test year, the Company has produced a year that does not include "all information related to rate base, NOI and capital structure for the time new rates will be in effect."[3]

The May CT units will go into service at approximately the same time the new rates from this case go into effect. However, if the pro forma adjustment for the three CTs scheduled to go into service in September 2009 is included in the revenue requirement, it will result in customers being charged new rates in May several months before the operating costs are recognized on the Company's books. Company witness Hornick stated that these peaking units, as the description suggests, will serve the demand of customers at peak periods of time. During his deposition, witness Hornick agreed that customer demand is what creates the sales of electricity. During the hearings, Company witness Black testified that not all of the five CTs may be needed in 2009. Witness Black indicated that some of the later CTs might be pushed out. After the hearings, the Company affirmed that all five CTs will be placed in service during 2009.

We agree with OPC's argument that the Company's pro forma adjustments to annualize the five simple CTs as if they were in service on January 1, 2009, violates the principle of matching revenue, expenses, and rate base for a projected test year. The use of pro forma adjustments to annualize selected changes that occur several months after the beginning of the test year as if they occur on the first day of the test year ignores all of the other components that change during the test year such as employees, customers, usage, maintenance, and financing.

That being said, we also recognize the need for the five CTs and the resulting cost to place them into commercial service in 2009. If TECO places these five combustion turbine in service units as planned, it may experience a significant adverse impact on earnings in 2010. The estimated revenue requirement effect of excluding the pro forma adjustments associated with these units is about $28.3 million. This includes rate base and expense effects. Depending on other factors such as electricity consumption, this impact could drive TECO's achieved ROE to a level below the bottom of its authorized range within a year of the establishment of rates in this proceeding.

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[3] Order No. PSC-93-0165-FOF-EI, issued February 2, 1993, in Docket No. 920324-EI, In re: Application for a rate increase by Tampa Electric Company.

Under normal circumstances, the Company's pro forma adjustments for the five simple cycle combustion turbine units would have been eliminated from the test year results because we believe it violates the principle of matching revenue, expenses, and rate base for the projected test year. We do not want consumers paying for items that are not in commercial service during the test year. However, the five simple cycle combustion turbine units represent a significant expenditure for the Company if placed into service in the 2009 test period. Thus, as stated, TECO may experience a significant adverse impact on earnings in 2010, and would most likely lead to it petitioning the Commission for a limited proceeding within a very short period of time after our decision herein.

To avoid a significant cost to the consumers and significant length of time to conduct a limited proceeding, we have decided to grant TECO a step increase in rates, effective January 1, 2010, for the cost of the five CT units. We authorize an increase in base rates to a maximum of $28.3 million for the five CT units in a manner consistent with the cost allocation methodology we have approved in this Order with the condition that these investments are completed and in commercial operation by December 31, 2009. In the event one or more of these projects are not completed by December 31, 2009, TECO shall submit a revision of the revenue requirement impact for these projects. This step increase is based upon the condition that the units must be needed for load generation.

The decision to complete any or all of these projects by year end, considering changed circumstances such as, but not limited to, decreased electricity consumption, shall be subject to our staff's review and approval. There is testimony in the record that TECO may not stay on schedule with the CTs because of the downturn in the economy. TECO shall only move forward with the units if the capacity is needed. This condition will help ensure that TECO will only move forward with its plans for the CTs if it is justified in terms of load requirements.

Therefore, based on the discussion above, we grant TECO a step increase in rates, effective January 1, 2010, for the cost of the five CT units, provided that the conditions as stated above are met.

Adjustment for the Credit from CSX

Company witness Hornick testified that rail facilities for unloading coal at Big Bend Power Station will be constructed in 2008 and 2009 for deliveries to begin by January 1, 2010. TECO is a wholly owned subsidiary of TECO Energy, Inc. Under TECO Energy, Inc.'s policy, certain expenditures require a capital allocation approved by TECO Energy, Inc., but they must first be recommended by the Capital Leadership Team (CLT). The rail facilities at Big Bend Power Station required such a recommendation by the CLT, called a Project Review, which was dated July 23, 2008. The Project Review document stated in part:

> To mitigate the cost associated with the construction of a facility to accommodate rail, CSXT has offered $45 million in discounted rates as a part of the transportation RFP. Tampa Electric included a $45 million capital project as part of the pro-forma used to develop the 2009 rate case request. Tampa Electric proposes that the CSXT discount would first be used to fund the additional $15

> million of project cost and once the deficit has been met (approximately 2 years …) the remaining $30 million of discounts would be flowed through to customers through the fuel clause. The discount is valid through the 5 year life of the delivery contract. It is expected that TEC and its customers will receive the full $45 million value offered by CSXT.

Company witness Wehle confirmed the CLT position in her rebuttal testimony. Witness Wehle proposed that TECO use the refund to first offset the capital costs associated with the facilities that are in excess of those granted in base rates, with any remainder credited to customers through the fuel and purchase power cost recovery clause. In other words, the Company would like to use the refunds to first cover any construction costs associated with the Big Bend Rail Facilities that are over its original forecast of $45,205,000 ($46,937,000 system). The $45,205,000 is the amount included in the development of the Company's revenue requirement. Any freight discounts or refund amounts left over would then be credited to the fuel accounts and subsequently flowed through the fuel cost recovery clause and reduce customer fuel rates.

Under Rule 25-6.014, F.A.C., TECO is required to maintain its accounts and records in conformity with the Uniform System of Accounts (USOA) as found in the Code of Federal Regulations. According to Company witness Chronister, under the USOA, whenever the Company receives a construction reimbursement, it is required to book it against the capital account where it spent the money. Explaining how some of the refund could be flowed to the fuel accounts, witness Chronister testified:

> Well, it would be based on the Commission's decision. FAS 71 allows you to do regulatory accounting, which is to say that you have the Uniform System of Accounts, you have your debits and credits the way they are supposed to go, but if the Commission makes a decision for a treatment, then you would follow -- your debits and credits would follow the treatment the Commission told you to use.
>
> So in this particular case, if the Commission said, yes, we agree, take the first part of the construction reimbursement against the capital costs, then take the rest of it through the fuel clause to help our ratepayers, then we would book it against the fuel clause based on the Commission's directive.

As stated, the Company included $45,205,000 ($46,937,000 system) in its original forecast for the construction costs associated with the Big Bend Rail Facilities. The same original Big Bend rail facilities' construction costs was discussed by Company witness Hornick. The Company has provided no justification for updating the original forecasted amounts, and did not ask to update the original forecast. Although the Project Review developed by the CLT discussed a higher number of $60,000,000, no Company witness supported it. During his deposition, witness Hornick provided an updated estimate of a $64,000,000 system cost for the rail project. The Company did not use the $64,000,000 because its proposal is to use the ultimate final cost of the project. The final cost of the project will be offset by the credit to cover the amount that exceeds the $46,000,000 included in the original rate case filing. TECO did not present any evidence or reasoning why the refund from CSX should be used "to first offset the capital costs associated with the facilities that are in excess of those granted in base rates."

There is no evidence in the record supporting the application of the refund from CSX against the costs that exceeded the original projection. Therefore, the entire refund shall be applied to the fuel accounts and subsequently flowed through the fuel adjustment clause and on to customers in the form of lower rates. Under this approach, customers will receive the benefit of the refund during the first five years of operation of the rail facilities, as opposed to a much longer period, by including the credit to plant in service.

We find that no adjustments for the CSX refunds or credits are necessary in this case. All of the CSX refunds or credits TECO receives during the first five years of service of the rail facilities shall be recorded in the fuel accounts and subsequently flowed through to customers in the fuel and purchase power cost recovery clause. Furthermore, no part of the CSX refunds or credits shall be recorded as a reduction of the capital project and related asset accounts to correct for an under projection of costs for this project. In other words, TECO shall record the Big Bend Rail Facilities construction project without any consideration given to the discounts or credits to be received from CSX. All discounts and credits received from CSX related to the project shall be recorded in the fuel accounts.

Pro Forma Adjustment related to Big Bend

Witness Hornick testified that rail facilities for unloading coal at Big Bend Power Station will be constructed in 2008 and 2009, for deliveries to begin by January 1, 2010. TECO expects to spend a total of $45,000,000, with $15,900,000 and $29,127,000 being invested in 2008 and 2009, respectively. Witness Chronister testified that the pro forma adjustment includes an impact on operating expenses, as well as an impact on net plant-in-service, bringing TECO's total cost profile to an amount that reflects a full year of operation for these units. The Company's pro forma jurisdictional adjustments to Utility Plant in Service and Accumulated Depreciation are increases of $45,206,000 ($46,937,000 system) and $452,000 ($469,000 system), respectively, for the test year.

OPC witness Larkin testified that the Company is treating these facilities as if they were in-service as of January 1, 2009, and not the actual in-service date of December 2009. The projected test year is supposed to result in a matching of the Company's projected investment with its projected earnings on a month-to-month basis and annual basis. The projected test year methodology uses forecasted data for a 12-month period, and matches average rate base investment to average expenses and revenues. As discussed regarding the five CTs, under TECO's annualization proposal, the cost of the new plant would be recovered in rates without accounting for the new customer growth that would otherwise support those costs. This type of allowance will create a mismatch between the projected test year revenues and expenses and the projected investment related to assets that generated the test period revenues.

We accept OPC's argument that the Company's proposed adjustment to annualize the effects of the Big Bend Rail Project should be rejected entirely because it violates the principle of matching revenue, expenses, and rate base for the projected test year. If the cost of the rail facilities is included in the new rates, customers would be paying for the facilities months before the assets are in service.

As we explained above in granting a step increase for the five CT units, we grant TECO a step increase in rates, effective January 1, 2010, for the rail facilities for unloading coal at Big Bend Power Station. The rail facilities for unloading coal at Big Bend Power Station represent a significant expenditure for the Company if placed into service in the 2009 test period. Thus, as stated, TECO may experience a significant adverse impact on earnings in 2010, and would most likely lead to it petitioning for a limited proceeding to raise rates again, within a very short period of time after our decision in this case.

To avoid significant cost to the consumers and significant length of time to conduct a limited proceeding, we have decided to grant TECO a step increase in rates, effective January 1, 2010, for the cost of the rail facilities for unloading coal at Big Bend Power Station, provided that the rail facilities are placed into commercial service by December 31, 2009. We authorize an increase in base rates a maximum of $4.6 million for the rail facilities for unloading coal at Big Bend Power Station in a manner consistent with the cost allocation methodology we have approved in this Order, with the condition that this investment is completed and in commercial operation by December 31, 2009. The maximum amount is subject to change depending on our decisions regarding other issues. In the event that this project is not completed by December 31, 2009, TECO shall submit a revision of the revenue requirement impact for this project.

Projected Level of Plant in Service

OPC witness Larkin testified that the Company must project each component of rate base by month for the projected test year ending December 31, 2009. He opined that "[i]t is unlikely that the Company's projected balances almost two years into the future are without inaccuracies." He advised that the best method of testing the Company's projections is to compare actual results to projections to determine whether the projected amounts are overstated or understated.

Witness Larkin provided a comparison of TECO's projected plant in service balance to the actual plant in service balance based on nine months of data through September 2008. He contended that the Company over-projected its balances, indicating a trend to over-project balances that translates into projected test year balances that are too high. He pointed out that the Company's projected plant in service balance exceeded the actual in every month shown in his exhibit. Witness Larkin advised that "any inaccuracies in 2008 are carried forward into the 2009 test year because the December 31, 2008, balance becomes the first month in the 13-month future test year average, and the same projection methodology is used."

Witness Larkin made an adjustment based on the percentage difference between the actual plant in service balance and the projected plant in service balance for each of the actual months available. He applied the average percentage overstatement derived from the 13-month average plant in service balance projected by the Company on MFR Schedule B-3 for the 13-month average ending December 31, 2009. He recommended a reduction to plant in service for the projected test year 2009 of $53,958,000 on a total Company basis, with the jurisdictional adjustment of $51,969,000.

Witness Larkin performed a similar study for the accumulated provision for depreciation and amortization, which showed a corresponding overstatement of those amounts. Using the same average percentage methodology, he reduced the Accumulated Provision for Depreciation and Amortization in the amount of $8,500,000 on a total Company basis and $8,187,000 on a jurisdictional Company basis. He also recommended a reduction in depreciation expense since any overstatement of the Accumulated Provision resulted from the overstatement of Depreciation expense.

TECO witness Chronister disagreed with witness Larkin's proposal that plant in service should be reduced for over-projected balances. He argued that witness Larkin's assumption that differences between projected and actual plant in service balances for the months January through September of 2008 are relevant to the projected test year is erroneous. He pointed out that the September 2008 projected Plant In Service of $5,472,308,000 is only $625,000 higher than the actual Plant In Service of $5,471,683,000 on September 30, 2008, a difference of only one one hundredth of one percent. He testified that another major flaw in witness Larkin's proposal is that he did not recognize that a part of the Total System Plant In Service is adjusted out of jurisdictional rate base for Plant In Service that has a return provided through the Environmental Cost Recovery Clause (ECRC) and the Energy Conservation Cost Recovery Clause (ECCR). Witness Chronister contended that only jurisdictional balances that are recovered through base rates should be used in the analysis. He also noted that witness Larkin used the amount of the difference between actual and projected plant divided by the actual balance, resulting in an overstatement. Witness Chronister contended that witness Larkin should have performed that calculation using the difference amount divided by the projected balance.

Witness Chronister explained that the budget variances are caused by timing differences in certain projects, such as projects in TECO's energy supply area, some of its transmission projects, the combustion turbine projects, the peaking units, and the rail facilities. He also noted that projects may have greater capital expenditures than expected. He stated that TECO may see budget variances of one or two percent, either higher or lower, based on his experience.

Witness Chronister advised that witness Larkin's calculations of the accumulated reserve and depreciation expense for the projected test year 2009 contains the same errors as described above with respect to ECRC removal and difference percentages. He explained that OPC's proposed changes to Plant In Service balances, multiplied by the 3.5 percent composite rate of depreciation, yields the effective accumulated reserve and depreciation expense adjustments. He testified that, based on the corrections to his proposed Plant In Service adjustment discussed above, the reduction amount would be $1,248,485 in depreciation expense ($35,671,000 x 3.5%), with a corresponding accumulated reserve offset in the amount of $1,248,485.

Witness Larkin provided data for 2008 in which TECO's projected plant fell short of its projections eight months out of eight. In additional data provided by TECO, the plant fell short of its internally budgeted projections 10 months out of 12. Thus, some 20 months of data were over-projected through September 2008.

We do not agree with witness Chronister's argument that the Company will "catch up" as a basis to ignore witness Larkin's adjustment. Witness Chronister admitted that even where there were several months in which the projections were almost equal to the actual plant balances, the thirteen-month average will not be the same. Since the thirteen-month average is the number used for ratemaking, we find that the chronic short-fall in the Company's projections are relevant. Further, we do not believe that TECO will "catch up" its plant construction in 2009.

However, we do agree with TECO that a number of calculation errors were made by witness Larkin. Two areas are noted: first, witness Larkin did not adjust for amounts that were removed for the ECRC and the ECCR. Second, witness Larkin used the amount of difference divided by the actual balance, resulting in an overstatement, while he should have performed that calculation using the difference amount divided by the projected balance.

Witness Chronister provided the corrected numbers, even though he did not agree with the overall adjustment. Those figures are a $35,671,000 reduction to plant in service, a $1,248,485 reduction in depreciation expense and a corresponding accumulated reserve offset in the amount of $1,248,485. We find that these figures shall be accepted based on the record evidence, and TECO's projected level of plant in service shall be reduced by $35,671,000 to reflect over-projections in the amounts. Corresponding reductions shall be made to accumulated depreciation and depreciation expense in the amount of $1,248,485.

<u>Increase in Plant in Service for Customer Information System</u>

Witness Chronister testified that $2,792,000 should be included for modifications to update the customer information system (CIS) that are needed to implement the rate changes requested in this docket. He asserted that these costs should be amortized over five years. He testified that the jurisdictional net operating income adjustment made by the Company in its MFRs is an increase to amortization expense of $342,000, and the jurisdictional rate base adjustment is an increase of $2,445,000.

Witness Chronister argued that the CIS modifications are necessary because of the many substantial design changes in the customer rate schedules. He testified that:

> . . . the CIS and its sub-systems must be programmed in advance to ensure accurate billings upon Commission approval of the company's proposed rate design in April 2009. The modifications include, but are not limited to: inverted energy rates for residential customers, demand rate changes, new service charges, new lighting schedules, and changes to interruptible customer rate schedules.

Witness Chronister explained that, "the project needed to be properly scoped, resources secured, requirements identified and outlined, changes programmed and tested, and Customer

Service Professionals and other company team members trained." He asserted that the changes are extensive and will require an estimated 40,000 hours of resources. He noted that the modifications are dependent on our approval in April 2009 in this docket.

Witness Chronister stated that the CIS modifications are not the types of changes that TECO would routinely make. He explained that the cost is due solely to changes proposed in this proceeding and is appropriately recovered as a cost of service. He testified that it is appropriate for ratepayers to pay the cost of CIS modifications, even if not all of the requested rate changes are approved. Witness Chronister also stated that the project must be viewed comprehensively, and certain rate changes that we may not approve does not impact the overall necessity to modify the CIS system.

OPC witness Larkin argued that none of the items requested by TECO are unusual changes to a CIS system. He included in his testimony documentation provided by TECO outlining the program costs, which he noted are general in nature, without any specifics. He testified that the rate changes that necessitate the CIS upgrades may never be approved. He stated that there is neither a cost benefit analysis provided nor is there any detailed calculation of how the proposed dollars would be used. He asserted that any costs that may be incurred, would be incurred in the normal course of business in any year base rates or fuel rate changes are made and do not justify separate adjustment. Witness Larkin recommended that the Company's request for an increase in rate base of $2,445,000 depreciation expenses be decreased by $558,000.

We concur with TECO that the rate structure changes requested, in particular those for conservation, billing on demand, and the combining of three rate classes, are major changes to the rate structure. This is not a simple matter of changing a factor or a dollar figure, as would occur in the various clause proceedings noted by OPC. Rather, the CIS upgrade accommodates major structural changes in the rates.

We agree with OPC that the rate restructuring requested by TECO may not be approved. However, we also agree with TECO that if the Company waits for a decision before beginning to make the changes, it will not be possible to complete them before the rates go into effect. The modifications to the CIS system are necessary costs of doing business for TECO and should be included in the test year. It should also be noted that the costs included by TECO in its MFRs are slightly lower than the Company-approved program scope approval that TECO submitted in response to discovery.

For all of these reasons, we find that the cost of the CIS upgrade associated with rate case modifications is appropriate, and no adjustment is necessary.

<u>Requested Level of Plant in Service</u>

We find that TECO's requested level of plant in service in the amount of $5,483,474,000 for the 2009 projected test year is not appropriate. The appropriate 13-month average of Plant in Service for the 2009 projected test year is $5,268,158,000. (See Schedule 1)

Requested Level of Accumulated Depreciation

OPC's positions that lead to its $8,500,000 adjustment ($8,187,000 jurisdictional) have been discussed above. We find that TECO's requested level of accumulated depreciation in the amount of $1,934,489,000 for the 2009 projected test year is not appropriate. The appropriate Accumulated Depreciation of Electric Plant in Service for the December 2009 projected test year is $1,929,038,515. (See Schedule 1)

Costs Recovered through ECRC

Amounts that are recovered through the ECRC must be removed from the Company's filing to avoid double recovery. TECO made adjustments to Plant in Service and other schedules to remove such amounts, but it did not show any amounts removed from Construction Work in Progress (CWIP) for costs recovered through the ECRC. On MFR Schedule B-1 under CWIP, TECO included an adjustment to "remove CWIP eligible for AFUDC per our guidelines." In response to discovery, TECO explained that the adjustment was mislabeled and provided reconciliations for 2007, 2008, and 2009, showing the amounts broken down by AFUDC-eligible projects and ECRC projects. Upon review of those reconciliations, it now appears that all costs recovered through the ECRC have been removed. Therefore, we find that no adjustment to CWIP is needed to remove costs recovered through the ECRC.

Requested Level of Construction Work in Progress (CWIP)

Witness Chronister stated that TECO made a pro forma adjustment to remove CWIP from rate base. He explained that the Company's last rate proceeding included a revenue requirement calculation including $36,171,000 of CWIP normally eligible for AFUDC in rate base. He testified that the adjustment was made to "maintain specific financial integrity levels given the capital spending plan the company faced in 1992." He noted that TECO is not requesting additional CWIP in rate base in this proceeding. He stated that had the additional amount of CWIP been included in rate base, it would have resulted in an increase to the revenue requirement of $4,316,000.

OPC witness Larkin stated that he performed an analysis similar to that used for Plant In Service and Accumulated Provision for Depreciation, by comparing the actual CWIP balance for the first nine months of 2008 with the Company's projected balance. He asserted that the Company's projected balance was understated by 1.90 percent, requiring an adjustment to the jurisdictional CWIP balance for 2009. He recommended a balance of $103,679,000 which is greater then the Company's balance by $2,608,000 on a jurisdictional basis.

Both OPC and TECO have taken positions for CWIP that are consistent with their positions on Plant in Service. The application of the same methodology used by witness Larkin to reduce Plant in Service results in an increase in CWIP. TECO disagreed with the reduction to Plant in Service recommended by OPC; and, therefore, to be consistent, TECO also disagreed with OPC that the methodology should be applied to CWIP.

We agree in principle with OPC. However, as discussed below a number of land projects associated with Plant Held for Future Use (PHFU) will be delayed. This will result in a reduction to CWIP from the projected amounts. PHFU is comprised of land costs that eventually are moved to CWIP and then to Plant in Service as construction of the projects is completed. The land costs will have the same impact on rate base, whether they are included in CWIP or in PHFU. However, in addition to the land costs included in CWIP are the costs of the plant being constructed on the land are also included in CWIP. The record is silent as to the amount of CWIP included for those projects. We find that the amount of CWIP shall not be adjusted upwards, in recognition of the fact that certain projects will not be completed. Thus, based on the record evidence, we find that TECO's requested level of CWIP in the amount of $101,071,000 for the 2009 projected test year is appropriate.

Requested Level of Property Held for Future Use

TECO witness Chronister explained that the Company made its monthly projections of expenditures for land acquisition in Account 107, CWIP, so that the amounts shown in PHFU in December 2008 and 2009 represent expenditures expected to close from Account 107 to Account 105, PHFU. He stated that land acquisitions take a period of time as work in progress until the purchase is finalized.

OPC witness Larkin stated that TECO's projected additions and reductions to PHFU for 2008 and 2009 are inaccurate. He testified that:

> [f]or the year 2008, the Company utilized the ending balance at December 31, 2007 for each month of the 2008 year with exception of December 2008 when the balance was increased by $2,713,000. In the test year 2009, the Company used the December 2008 balance for property held for future use for each month of the test year except December 2009 where the balance was increased by $1,326,000. Therefore, it is obvious that the Company did not project monthly additions. . . . If it had projected monthly, the PHFU balance would not have remained the same for each month except for December of each of the years.

Witness Larkin stated that it is not possible for the PHFU to have the same balance in each month of 2008 and 2009 except for December. He showed a list provided by the Company of each property in the account for the historical year ended December 31, 2007. He provided the data showing three projects with a total cost of $1,534,611 that were acquired prior to 2007 and slated to go into service in 2008. He also provided data for projects to go into service in 2009 totaling $25,164,775. He argued that these projects would reduce PHFU substantially.

Witness Larkin noted that TECO later changed the in-service dates on major PHFU accounts and removed others from the balance. He testified that the Company's explanation was that "[t]hese adjustments do not change the total system rate base since the reduction in [PHFU] would be offset by a corresponding increase in Electric Plant In Service." Witness Larkin also questioned the Company's assertion that its projection of Plant In Service is accurate and reflects the cost of plant to be placed in service. He argued that "[b]oth statements cannot be true." He explained that, since TECO claims to have adjusted Plant In Service to reflect all plant placed in service in 2009, he decreased PHFU by $2,328,354 on a jurisdictional basis to reflect the change that the Company made.

OPC argued in its brief that if one were to transfer witness Larkin's adjustment from PHFU to plant, as witness Chronister suggested, then the Company's projected balance of plant would be overstated because the Company did not remove all of the plant placed into service in 2008-2009 for PHFU.

Witness Chronister argued that witness Larkin's proposal to decrease the investment in PHFU by $2,328,354 is incorrect because the adjustments related to PHFU would be offset by a corresponding increase in Electric Plant In Service. He explained that this is only a balance sheet transfer or reclassification and would result in no change to total system rate base since both PHFU and Electric Plant In Service are components of rate base. He stated that the proposed decrease in PHFU reflects "only the credit side of the two-sided journal entry."

We agree with TECO that the monthly amounts between CWIP or Plant in Service and PHFU would offset each other. However, we do have a concern that additional amounts for projects that will be delayed, as discussed previously, are reflected in CWIP. In fact, PHFU as discussed here, is only the land cost. Thus, we disagree with TECO that the difference is a wash. It appears to be so only with regard to the land cost portion. If projected construction is delayed, there are excess costs contained in the filing. Because the land costs have the same impact on rate base, whether included in CWIP or in PHFU, we do not believe the PHFU account needs to be adjusted. Instead, the project delays shall be reflected by recognizing an over-projection of Plant in Service, as discussed previously. Additionally, the CWIP shall not be increased as witness Larkin recommended. We also disagree with witness Larkin that the adjustments made to PHFU are inappropriate because they are made in December. As noted by witness Chronister, land acquisitions take time to complete, but are periodically transferred to PHFU. The manner in which TECO is accounting for the PHFU does not overstate the rate base.

Therefore, based on the record evidence, we find that TECO's requested level of PHFU in the amount of $37,330,000 for the 2009 projected test year is appropriate.

Deferred Dredging Cost

Although dredging costs are a necessary cost of doing business, the full amount requested by TECO is not supported by record evidence. Therefore, we find that the Company shall be allowed a total cost of $3,400,272, resulting in a reduction to expense of $650,056 (jurisdictional), and a reduction to working capital of $1,346,649 (jurisdictional).

Storm Damage Reserve

On March 25, 1994, we authorized TECO to accrue $4 million annually for potential storm damage and required the submittal of a storm damage study.[4] Accordingly, TECO filed its study in September 1994, which we approved in 1995[5], and we affirmed the annual accrual of $4 million. We also established a $55 million target amount for the storm damage reserve. The first time the Company had to charge storm expenses against this reserve was after the 2004 storm season.

During 2004, three storms hit TECO's service territory causing approximately $73.4 million of damage to its system. At that time, the Company's storm damage reserve balance was $42.3 million. We approved a stipulation which allowed the Company to charge $34.5 million of the storm damage costs to the reserve and the remaining storm costs were charged to utility plant.[6] According to our order, after this charge, the reserve had a balance of $7.9 million. In our order approving the stipulation, we noted:

> Between August 13, 2004, and September 26, 2004, Hurricanes Charley, Frances, and Jeanne struck TECO's service territory causing extensive damage to TECO's distribution and transmission systems. As a result, 631,000 customers were impacted, causing the worst outage situation in the Company's history.

Company witness Carlson testified that, based upon his experience and the results of a detailed storm study conducted by Company witness Harris of ABS Consulting, TECO's annual reserve accrual should increase from $4 million to $20 million, and the target reserve amount should increase from $55 million to $120 million. This conclusion was based on three fundamental objectives that were considered essential by TECO as it evaluated its need for a storm damage reserve: 1) achieve an effective balance of rate stability and long-term cost for customers; 2) build a reserve sufficient to cover the majority of loss events in order to mitigate the need for a surcharge to customers immediately after such an event; and, 3) design a reserve to cover the higher probability events and not the low probability high severity events. Witness Carlson relied heavily on the results of the ABS Consulting study.

Witness Harris presented the results of ABS Consulting's independent analyses of risk of uninsured losses to TECO's transmission and distribution assets and insurance retentions from hurricanes and tropical storms. These studies included a Storm Loss Analysis and a Reserve

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[4] Order No. PSC-94-0337-FOF-EI, issued March 25, 1994, in Docket No. 930987-EI, In re: Investigation into Currently Authorized Return on Equity Of TAMPA ELECTRIC COMPANY.

[5] Order No. PSC-95-0255-FOF-EI, issued February 23, 1995, in Docket No. 930987-EI, In re: Investigation into Currently Authorized Return on Equity Of TAMPA ELECTRIC COMPANY.

[6] Order No. PSC-05-0675-PAA-EI, issued June 20, 2005, in Docket No. 050225-EI, In re: Joint petition of Office of Public Counsel, Florida Industrial Power Users Group, and Tampa Electric Company for approval of stipulation and settlement as full and complete resolution of any and all matters and issues which might be addressed in connection with matters regarding effects of Hurricanes Charley, Frances, and Jeanne on Tampa Electric Company's Accumulated Provision for Property Insurance, Account No. 228.1.

Performance Analysis. Witness Harris did not make a recommendation for TECO's annual level of accrual.

The Loss Analysis is a probabilistic windstorm analysis that uses proprietary software to develop an estimate of the expected annual amount of uninsured windstorm losses to which TECO is exposed. The Reserve Performance Analysis is a dynamic financial simulation analysis that evaluates the performance of the reserve in terms of the expected balance of the reserve and the likelihood of positive reserve balances over a five-year period, given the potential uninsured losses determined from the Loss Analysis, at various annual accrual levels. The study estimated the total expected average annual uninsured cost to TECO from all storms to be $17.8 million.

The current analysis takes into account the hurricane history up to and including the 2004 storm season. Adding the 2004 season increased the long-term hurricane hazard in the Tampa area by about 60 percent over the prior modeled hazard. Witness Stewart, on behalf of the AARP, testified that both witness Harris and Carlson's recommendations and analysis were biased by the hurricane season of 2004. Witness Stewart pointed out that the annual storm damage accrual of $4 million, and the current $55 million storm damage reserve target set in 1994, offered sufficient coverage until the abnormal storm season of 2004.

Both witness Carlson and witness Stewart described the current overall regulatory framework concerning the recovery of storm damage costs in Florida. We have established a regulatory framework consisting of three major components: (1) an annual storm accrual, adjusted over time as circumstances change; (2) a storm reserve adequate to accommodate most, but not all storm years; and, (3) a provision for utilities to seek recovery of costs that go beyond the storm reserve.

Witness Stewart testified that Section 366.8260, F.S., arguably greatly reduces the necessity for a reserve and lessens the importance of the target level. That statute permits utilities to recover all reasonable and prudent expenses for storm damage. Before the Securitization legislation, utilities collected a Commission-approved storm accrual each year to help pay for storm damage. The accrual was not designed to guarantee recovery of every penny of storm damage costs. In fact, utilities might only recover storm damage expenses that caused them to earn less than a fair rate of return. Under the earlier policy, the utilities had a financial risk and were understandably interested in keeping the reserve level as high as possible. Section 366.8260, F.S., however, guarantees the recovery of all reasonable and prudent expenses for storm damage. Therefore, no matter the amount of storm damage, TECO is statutorily guaranteed recovery of its storm expenses as long as we find the expenses to be prudently increased.

Witness Stewart further testified that given the passage of Section 366.8260, F.S., subsequent to our orders addressing the level of reserve required or desired, it is not entirely clear that a reserve is essential. However, he believes it is reasonable for us to approve a reserve that meets the historically-stated threshold of covering the costs of most, if not all, storms. Witness Stewart recommended that an adequate and appropriate Storm Damage Reserve should be $55 million, and TECO should be allowed to accrue the current level of $4 million a year until it reaches $55 million, after which the accrual should cease and rates should be reduced by the appropriate amount.

OPC witness Larkin testified that while he agreed that the value of the Company's transmission and distribution system has increased since 1994, it is clear that the reserve was adequate in the year 2004 to cover the higher value of assets damaged by the storms that struck in that year. He further testified that:

> Historically, Tampa Electric's reserve has functioned exactly as the Commission thought it would and how it was designed to operate. At the end of 2008, the reserve will have reached the level of approximately $24 million. Further, the Company's estimate of possible future storm damage was based on a full cost recovery basis, not the incremental recovery basis required under Rule 25-6.0143, Florida Administrative Code. . . . in the Company's actual 2004 storm costs, more than 50 percent of the costs did not flow through the reserve and instead were accounted for in base rate recovery.

OPC witness Larkin and AARP witness Stewart recommend that the current annual level of accrual of $4 million remain the same because it has proven adequate when a storm has actually hit the TECO system. They argue that we should continue with that level of storm accrual, and when, and if, a storm occurs that is in excess of the reserve, we should then deal with that through a surcharge on rates if necessary, or through securitization.

We find that TECO's requested increases to its storm damage annual accrual and storm damage target reserve level shall be modified to an annual accrual of $8,000,000. The annual accrual for the storm damage reserve shall be modified to achieve an annual level of $8 million with a $64 million target amount after five years. This results in a decrease in the Company's jurisdictional O&M expense of $12,000,000 ($12,000,000 system) and an increase in the jurisdictional working capital of $6,000,000 ($6,000,000 system) for the test year. At this point, it would be premature to require that the annual storm damage accrual be stopped when and if the target level is achieved. This issue may be readdressed if the target level is achieved.

Our decision is based on the belief that the storm events of 2004 in TECO's service area were significant. As discussed above, the events had a significant impacted on customers, and caused the worst outage situation in the Company's history. It is important to note that all the storms were below a level 3 hurricane. TECO's service area is susceptible to hurricanes above a level 3. Also, we believe that the self-insurance framework that we operate under, which the storm reserve is an integral component, is critical to the state of Florida. Moreover, the annual accrual is very important part of the rate process and ratemaking process.

<u>Prepaid Pension Expense</u>

In MFR Schedule B-17, the Company presented an analysis of its projected working capital, including prepayments. In direct testimony, TECO witness Chronister described the

Company's process of budgeting and forecasting, and stated that, in his opinion, the budgeted balance sheet fairly and reasonably reflects the account balances expected for the test year.

We find that TECO has submitted sufficient evidence to demonstrate that its prepaid pension expense included in working capital is reasonable. No adjustment to the Company's working capital concerning prepaid pension expense is warranted.

Working Capital related to Account 143 – Other Accounts Receivable

Under the USOA, Account 143 includes utility-related receivables other than amounts due from associated companies or from customers for utility services and merchandising, jobbing and contract work.[7] It does not include non-utility receivables. We have a long-standing policy of excluding non-utility receivables from the working capital allowance.[8]

TECO witness Chronister stated that the balances included in Account 143:

> . . . reflect activities related to utility service for jurisdictional customers. They include receivables for off-system sales, pole attachment revenue, rent revenue from fiber optic, by-product sales, and residual revenues.

Witness Chronister discussed each of the above revenue accounts that were included in the MFRs. Those revenues include Account 447, Sales for Resale (Off-System Sales); Account 454, Rent from Electric Property; Account 455, Interdepartmental Rents; and Account 456, which includes Wheeling, SO2 allowance, and Other Electric Revenues. He explained that Account 143 represents receivables for three items, off-system sales, SO2 allowance sales, and the majority of the items contained in other operating revenues, except for miscellaneous service revenues, which are billed through TECO's normal electric billing cycle. Witness Chronister testified that Account 143 is only used for receivables associated with those specific 400 accounts.

OPC witness Larkin proposed an adjustment to the Company's working capital for Account 143, in its working capital requirement. He stated that, under the USOA, this account includes amounts due the Company except for amounts due from associated companies and from current customers for utility service. He contended that TECO "should be required to show that all of the amounts in Account 143, Other Accounts Receivable, are related to utility services and that the cost or revenue associated with these accounts receivable have been included in jurisdictional operating income." He recommended removal of $10,959,000 on a jurisdictional basis from Other Accounts Receivable. He argued that TECO has not shown that the items included in the account are all related to utility service, so he removed the entire account.

OPC argued in its brief that receivables related to off-systems sales make up approximately $8 million of the requested $10 million cost, but the revenues are not charged to

[7] 18 CFR Ch 1 143
[8] See, for example, Order No. PSC-92-0580-FOF-GU, p. 15, issued June 29, 1992, in Docket No. 910778-GU, In re: Petition for a rate increase by West Florida Natural Gas Company.

ratepayers and thus related receivables should not be either. OPC added that TECO excluded 63 percent of Other Electric Revenues as non-jurisdictional, as shown on MFR Schedule C-5.

We agree with OPC that large amounts of the requested receivable balances appear to be improperly included. It is particularly telling that $8 million of receivables are included for off-system sales, but all of the revenues in the associated Account 447 were removed from the filing. Several other revenue accounts that witness Chronister named as accounts associated with the Other Accounts Receivable, including Wheeling and SO2 Allowance Sales, were also excluded from the filing, or had no balance to begin with. Further, the remaining major revenue accounts associated with Account 143, some $9,561,000 of the total $15,271,000 in revenues, or 63 percent, are shown as non-jurisdictional. Of the remaining revenue accounts discussed by witness Chronister, it is not clear what portion of the receivables may be related to them, if any.

Given the major discrepancies between the revenues included in the filing and the associated receivables, we find that TECO has not met its burden of proof that Account 143, Other Accounts Receivable, should be included in working capital. Therefore, based on the record evidence, Working Capital shall be reduced in the amount of $10,959,000 (jurisdictional) to remove Account 143, Other Accounts Receivable.

Account 146 - Accounts Receivable from Associated Companies

Under the USOA, Account 146, Accounts Receivable from Associated Companies, should include amounts due from associated companies within one year.[9] TECO has included $6,309,000 in working capital for this account.

Witness Chronister stated that the balance in Account 146 includes $5,919,000 for services TECO provides to its utility affiliate, Peoples Gas System (Peoples Gas), and is directly related to the provision of utility services. He explained that TECO provides information technology support, facility management services, and payroll and accounts payable services. He noted that associated revenues and expenses are also included in test year projections, along with Peoples Gas' balance for intercompany payables. Witness Chronister testified that the remaining jurisdictional balance of $390,000 ($6,309,000 - $5,919,000) is for non-utility intercompany receivables.

Witness Chronister explained that the receivables in Account 146 do not have a direct association with a revenue account. Rather, they are primarily the result of reductions to TECO's expenses for amounts that are charged to Peoples Gas. He provided as an example, Account 920, Office Salaries, which would include salary amounts of a TECO employee working on a project that was subject to a charge out to Peoples Gas. He explained that the amount to be charged to Peoples Gas would be booked to another account, instead of Account 920. He adds that another example would be Account 921, Office Supplies and Expense.

[9] 18 CFR Ch. 1 146.

OPC witness Larkin excluded the entire balance in Account 146, Accounts Receivable from Associated Companies. He argued that TECO should be required to show that the entire amount of $6,309,000 is on the Company's books as a result of providing service to jurisdictional ratepayers. He contended that the receivables are unrelated to providing service to retail electric ratepayers and should be paid by the companies receiving the services.

In its brief, OPC argued that witness Chronister was unable to provide any direct support for the included transactions. OPC stated that witness Chronister failed to show that the revenues and the expenses of providing these services to affiliates whether non-regulated, electric or gas companies are not subsidized by the regulated electric ratepayers. OPC stated that witness Chronister admitted that the accounts included in the MFRs are netted for these affiliate transactions but those details would have to be reviewed in the budget detail. OPC noted that witness Chronister admitted that it is inappropriate to include the accounts receivable related to other TECO energy affiliate transactions, but does not distinguish why the Peoples Gas affiliated transactions are any different than any other non-utility transactions. OPC argued that "the Company has not met its burden to show that these affiliate transactions benefit ratepayers, that there is a subsidy on the part of the electric system to provide services for the gas subsidiary, or why other non-affiliate costs should be removed but not the Peoples Gas portion."

TECO included $390,000 (jurisdictional) in receivables from non-utility activities. Witness Chronister admitted that the $390,000 was inadvertently included in the total. It is our policy to remove non-utility accounts receivables from the working capital allowance.[10] Thus, working capital shall be reduced by $390,000.

Rather than a specific revenue account associated with the receivables, as discussed previously, the receivables in Account 146 would have a corresponding reduction to various expense accounts, as discussed by witness Chronister. While in regard to Account 143 there were direct reductions in the MFRs to the associated revenue accounts, there were no adjustments to the expenses shown in the MFRs related to the receivables in Account 146. This is an important distinction between the two issues.

The Company included intercompany payables, Account 234 in the amount of $7,848,000 (jurisdictional), in working capital. This amount more than offsets the intercompany receivables of $6,309,000. The net result is a decrease to working capital. This is to the ratepayers' benefit. While OPC proposed removing the receivables, there is no proposal to remove the intercompany payables. We find that it is important to be even-handed in making adjustments. Thus, it would be inappropriate to remove the receivables without removing the offsetting payables.

Therefore, we find that it is appropriate to include the receivables along with the offsetting payables in this case, except for the non-utility portion noted above. Accordingly,

[10] Order No. PSC-92-0580-FOF-GU, issued June 29, 1992, in Docket No. 910778-GU, In re: Petition for a rate increase by West Florida Natural Gas Company, p. 15.

Account 146 shall be reduced by $390,000 (jurisdictional) for non-utility receivables included in the account.

Other Post-Retirement Employee Benefit Liability

In MFR Schedule B-17, the Company presented an analysis of its projected working capital, including prepayments. TECO witness Chronister testified to the Company's process of budgeting and forecasting, and stated that, in his opinion, the budgeted balance sheet fairly and reasonably reflects the account balances expected for the test year. We have reviewed the data provided by the Company in its MFRs, exhibits, and through discovery. We find that there is sufficient record evidence to demonstrate that TECO's unfunded OPEB liability is reasonable and has been included in rate base. Thus, no adjustment to the Company's rate base concerning unfunded OPEB liability is warranted.

Coal Inventories

TECO's proposed 2009 coal inventory is $83,819,000. TECO witness Wehle testified that the Company seeks to maintain coal inventories sufficient to meet its burn requirements. TECO seeks to maintain a 98-day coal supply, consistent with the order resulting from the Company's last rate case.[11] The inventory proposed by TECO for 2009 represents a 94-day supply. The 98-day supply includes a three-day test-burn supply. TECO will not perform any test burns until it completes the installation of selective catalytic reduction equipment at Big Bend Station. In the past two years, TECO has maintained an average 97-day coal supply. Coal represents approximately 85 percent of TECO's fuel inventory value, and about 56 percent of TECO's generation. The parties did not challenge TECO's proposed inventory tonnage amounts in this proceeding.

Witness Wehle noted that, in the 2008 fuel proceedings, TECO revised its 2009 fuel charges by revising its natural gas price forecasts, from June-July 2008 to September 2008. Witness Wehle testified that TECO estimated its inventory values in this proceeding in Spring 2008 and that coal prices increased in Summer 2008 but have not retreated to the March 2008 prices. Witness Wehle stated that TECO based part of its 2009 coal inventory valuation on 2009 contractual coal prices and transportation costs.

OPC witness Larkin testified that TECO should re-price its fuel inventory to accurately reflect the current price of fuel, noting the decline in fuel prices since 2008. Without having the information necessary to estimate the decline in fuel prices, witness Larkin proposed a 10 percent downward adjustment. In support of OPC witness Larkin's proposed 10 percent reduction, FRF argued that in the 2008 fuel proceeding,.TECO reduced its proposed 2009 fuel charge increase from 22 percent to 12 percent, a change of 10 percent.

OPC argued that 60 percent to 70 percent of TECO's 2009 coal purchases are to be long-term contract purchases and that, although TECO observes that its coal-price 2009 estimates

[11] Order No. PSC-93-0165-FOF-EI, issued February 2, 1993, in Docket No. 920324-EI, In re: Application for a rate increase by Tampa Electric Company, pp. 45-46

were lower than January 2009 spot coal prices, the comparison did not use spot coal prices from both periods.

Order No. 9273 states in part: "We recognize that the companies' projections will inevitably differ from actual results, and agree that a true-up mechanism, designed to conform the projected estimates to actual figures, is necessary to realize the objective of eliminating overrecoveries and underrecoveries of fuel costs."[12] In its brief, FRF agrees with OPC witness Larkin's proposed 10 percent reduction in fuel inventory, stating that the "[f]ailure to make this adjustment will likely result in overstated fuel costs being embedded in Tampa Electric's rates until the next rate case." We note the difference in purpose between estimated fuel prices for inclusion in fuel charges and estimated fuel prices for inclusion in base rates. Although accuracy is desired in both types of estimates, fuel-charge fuel price estimates will be trued up, and base rate fuel price estimates will not. The fuel clause is established once a year based on estimated fuel prices, and the difference between estimated prices and actual prices becomes the true-up amount for subsequent fuel factors. In contrast, base rates are determined using a point estimate, or test-year estimate, to determine fuel prices supporting the inventory value. Base rate calculations are not subject to a true-up adjustment. Base rates will be in place for several years, during which time fuel inventory may be undervalued or overvalued as market fuel prices change. We find that witness Wehle's calculation of the fuel inventory value which reflects a midpoint of fuel prices for 2008 is appropriate.

Regarding the timing of TECO's fuel-price forecasts and the changes in fuel prices since March 2008, we note that as fuel prices increased in the Summer of 2008, TECO did not seek to revise its 2009 price forecasts in this proceeding as it did in the fuel docket. Therefore, we find that the reduction in fuel-charge fuel-price estimates does not warrant a similar reduction in base-rate fuel-price estimates. Based on the timing and composition of TECO's rate-case fuel-price forecast and its fuel-charge fuel-price forecasts, the 10 percent fuel charge reduction and the proposed 10 percent inventory reduction are unintentionally equal.

Based on the evidence and arguments presented by the parties in this proceeding, we find that no adjustment is necessary for TECO's coal inventories. TECO's coal inventories shall not be adjusted to reflect the decreases in fuel prices between Summer 2008 and September 2008. Although not all of TECO's 2009 coal purchase prices were secured by contractual arrangements in March 2008, we find that TECO's price estimates of 2009 non-contract coal purchase prices are representative of the year's market prices and that over all, TECO's coal prices are reasonable.

Residual Oil Inventories

TECO's proposed 2009 residual oil inventory is $780,000. TECO witness Wehle testified that the Company seeks to maintain residual oil inventories to meet small generation requirements, and possible requirements during unexpected coal-fired unit outages, during times

[12] Order No. 9273, issued March 7, 1980, in Docket No. 94680-CI, In re: General Investigation of Fuel Cost Recovery Clause. Consideration of staff's proposed projected fuel and purchased power cost recovery clause with an incentive factor, p. 7

of limited gas availability and higher than expected loads. TECO's proposed inventory is 9,203 barrels. The 2009 residual oil price represented by TECO's $780,000 request is $85.75 per barrel. Residual oil represents less than one percent of TECO's generation. None of the parties challenged TECO's proposed inventory amounts in this proceeding.

Witness Wehle noted that in the 2008 fuel proceedings, TECO revised its 2009 fuel charges by revising its natural gas price forecasts, from June-July 2008 to September 2008. For oil and gas, witness Wehle observed dramatic price increases in Summer 2008 and dramatic price decreases in late 2008 and early 2009. Witness Wehle expressed TECO's unwillingness to revise its 2009 oil and gas price forecasts in this docket because in early 2009, although prices have declined, TECO's proposed prices in this proceeding are roughly at the mid-point of the March 2008 and January 2009 prices. Moreover, these prices reasonably represent the prices anticipated for the December 2008 to December 2009 period. Witness Wehle expressed TECO's belief that the low January 2009 prices were not representative of prices for all of 2009. Witness Wehle also noted that distillate oil and residual oil are extremely volatile commodities.

OPC witness Larkin testified that TECO should re-price its fuel inventory to accurately reflect the current price of fuel, noting the decline in fuel prices since 2008. Without having the information necessary to estimate the decline in fuel prices, witness Larkin proposed a 10 percent downward adjustment. In support of OPC witness Larkin's proposed 10 percent reduction, FRF noted that in the 2008 fuel proceeding, TECO reduced its proposed 2009 fuel charge increase from 22 percent to 12 percent, a change of 10 percent. OPC stated that witness Wehle had admitted that residual oil prices were currently below the prices used by TECO to price its 2009 residual oil inventory.

Order No. 9273 states in part: "We recognize that the companies' projections will inevitably differ from actual results, and agree that a true-up mechanism, designed to conform the projected estimates to actual figures, is necessary to realize the objective of eliminating overrecoveries and underrecoveries of fuel costs."[13] In its brief, FRF agrees with OPC witness Larkin's proposed ten percent reduction in fuel inventory, stating "Failure to make this adjustment will likely result in overstated fuel costs being embedded in Tampa Electric's rates until the next rate case." We note the difference in purpose between estimated fuel prices for inclusion in fuel charges and estimated fuel prices for inclusion in base rates. Although accuracy is desired in both types of estimates, fuel-charge fuel price estimates will be trued up, and base rate fuel price estimates will not be. The fuel clause is established once a year based on estimated fuel prices, and the difference between estimated prices and actual prices becomes the true-up amount for subsequent fuel factors. In contrast, base rates are determined using a point estimate, or test-year estimate, to determine fuel prices supporting the inventory value. Base rate calculations are not subject to a true-up adjustment. Base rates will be in place for several years, during which time fuel inventory may be undervalued or overvalued as market fuel prices change. Therefore, we find that witness Wehle's calculation of the fuel inventory value which reflects a midpoint of fuel prices for 2008 is appropriate.

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[13] Order No. 9273, issued March 7, 1980, in Docket No. 94680-CI, In re: General Investigation of Fuel Cost Recovery Clause. Consideration of staff's proposed projected fuel and purchased power cost recovery clause with an incentive factor, p. 7

Regarding the timing of TECO's fuel-price forecasts and the changes in fuel prices since March 2008, we note that as fuel prices increased in the Summer of 2008, TECO did not seek to revise its 2009 price forecasts in this proceeding as it did in the fuel docket. Therefore, we find that the reduction in fuel-charge fuel-price estimates does not warrant a similar reduction in base-rate fuel-price estimates. Based on the timing and composition of TECO's rate-case fuel-price forecast and its fuel-charge fuel-price forecasts, we find that the 10 percent fuel charge reduction and the proposed 10 percent inventory reduction are unintentionally equal.

Based on the evidence and arguments presented by the parties in this proceeding, we find that no adjustment is necessary for TECO's residual oil inventories. TECO's residual oil inventory shall not be adjusted to reflect the decreases in fuel prices between Summer 2008 and September 2008.

Distillate Oil Inventories

TECO's proposed 2009 distillate oil inventory is $9,312,000. TECO witness Wehle testified that the Company seeks to maintain distillate oil inventories to meet small generation requirements, and for boiler ignition of coal-fired units. In addition, TECO has possible distillate oil generation requirements during unexpected coal-fired unit outages, and during times of limited gas availability and higher than expected loads. TECO's proposed inventory is 77,068 barrels. The 2009 distillate oil price represented by TECO's $9,312,000 request is $120.83 per barrel. Distillate oil represents less than one percent of TECO's generation.

Witness Wehle noted that in the 2008 fuel proceedings, TECO revised its 2009 fuel charges by revising its natural gas price forecasts, from June-July 2008 to September 2008. For oil and gas, witness Wehle observed dramatic price increases in Summer 2008 and dramatic decreases in late 2008 and early 2009. Witness Wehle expressed TECO's unwillingness to revise its 2009 oil and gas price forecasts in this docket because in early 2009, although prices have declined, TECO's proposed prices in this proceeding are roughly at the mid-point of the March 2008 and January 2009 prices. Moreover, these prices reasonably represent the prices anticipated for the December 2008 to December 2009 period. Witness Wehle expressed TECO's belief that the low January 2009 prices were not representative of prices for all of 2009. Witness Wehle also noted that distillate oil and residual oil are extremely volatile commodities.

OPC witness Larkin testified that TECO should re-price its fuel inventory to accurately reflect the current price of fuel, noting the decline in fuel prices since 2008. Without having the information necessary to estimate the decline in fuel prices, witness Larkin proposed a 10 percent downward adjustment. In support of OPC witness Larkin's proposed 10 percent reduction, FRF noted that in the 2008 fuel proceeding, TECO reduced its proposed 2009 fuel charge increase from 22 percent to 12 percent, a change of 10 percent. OPC submitted that witness Wehle had admitted that distillate oil prices were currently below the prices used by TECO to price its 2009 distillate oil inventory.

Order No. 9273 states in part: "We recognize that the companies' projections will inevitably differ from actual results, and agree that a true-up mechanism, designed to conform the projected estimates to actual figures, is necessary to realize the objective of eliminating overrecoveries and underrecoveries of fuel costs."[14] In its brief, FRF agrees with OPC witness Larkin's proposed 10 percent reduction in fuel inventory, stating that the "[f]ailure to make this adjustment will likely result in overstated fuel costs being embedded in Tampa Electric's rates until the next rate case." We note the difference in purpose between estimated fuel prices for inclusion in fuel charges and estimated fuel prices for inclusion in base rates. Although accuracy is desired in both types of estimates, fuel-charge fuel price estimates will be trued up, and base rate fuel price estimates will not be. The fuel clause is established once a year based on estimated fuel prices, and the difference between estimated prices and actual prices becomes the true-up amount for subsequent fuel factors. In contrast, base rates are determined using a point estimate, or test-year estimate, to determine fuel prices supporting the inventory value. Base rate calculations are not subject to a true-up adjustment. Base rates will be in place for several years, during which time fuel inventory may be undervalued or overvalued as market fuel prices change. Therefore, we find that witness Wehle's calculation of the fuel inventory value which reflects a midpoint of fuel prices for 2008 is appropriate.

Regarding the timing of TECO's fuel-price forecasts and the changes in fuel prices since March 2008, we note that as fuel prices increased in the Summer of 2008, TECO did not seek to revise its 2009 price forecasts in this proceeding as it did in the fuel docket. We find that the reduction in fuel-charge fuel-price estimates does not warrant a similar reduction in base-rate fuel-price estimates. Based on the timing and composition of TECO's rate-case fuel-price forecast and its fuel-charge fuel-price forecasts, we find that the 10 percent fuel charge reduction and the proposed 10 percent inventory reduction are unintentionally equal.

Based on the evidence and arguments presented by the parties in this proceeding, we find that no adjustment is necessary for TECO's distillate oil inventories. TECO's distillate oil inventory shall not be adjusted to reflect the decreases in fuel prices between Summer 2008 and September 2008.

Natural Gas and Propane Inventories

TECO's proposed 2009 natural gas inventory is $4,495,000. TECO witness Wehle testified that the Company seeks to maintain gas inventories to meet generation requirements during times of uncertain supply availability. Witness Wehle gave examples of such times: (1) hurricane season, (2) during times of full major plant outages, and (3) extreme cold periods. TECO has 850,000 million Btus (MMBtus) of storage capacity and will increase its capacity to 1,250,000 MMBtus in Summer 2009. The inventory capacity expansion will provide TECO with about a 6-day supply. TECO's proposed inventory is 545,000 MMBtus. Utilities, other users of natural gas, and suppliers measure gas in two types of units, MMBtus and Mcfs. TECO presents its requested 545,000 MMBtu gas inventory as 529,898 Mcf in MFR B-18. The 2009 prices represented by TECO's $4,495,000 request are $8.25 per MMBtu and $8.48 per Mcf.

[14] Order No. 9273, issued March 7, 1980, in Docket No. 94680-CI, In re: General Investigation of Fuel Cost Recovery Clause. Consideration of staff's proposed projected fuel and purchased power cost recovery clause with an incentive factor, p. 7.

TECO requests no propane gas inventory. Natural gas represents approximately 44 percent of TECO's generation.

Witness Wehle noted that in the 2008 fuel proceedings, TECO revised its 2009 fuel charges by revising its natural gas price forecasts, from June-July 2008 to September 2008. When TECO made its 2009 natural gas price forecast in March 2008, the New York Mercantile Exchange (NYMEX) 2009 annual average natural gas price was $10.00 per MMBtu and TECO's forecast was $8.12. For oil and gas, witness Wehle observed dramatic price increases in Summer 2008 and dramatic decreases in late 2008 and early 2009. Witness Wehle expressed TECO's unwillingness to revise its 2009 oil and gas price forecasts in this docket because in early 2009, although prices have declined, TECO's proposed prices in this proceeding are roughly at the mid-point of the March 2008 and January 2009 prices, and that they reasonably represent the prices anticipated for the December 2008 to December 2009 period. Witness Wehle also expressed TECO's belief that the low January 2009 prices were not representative of prices for all of 2009.

OPC witness Larkin testified that TECO should re-price its fuel inventory to accurately reflect the current price of fuel, noting the decline in fuel prices since 2008. Without having the information necessary to estimate the decline in fuel prices, witness Larkin proposed a 10 percent downward adjustment. In support of OPC witness Larkin's proposed 10 percent reduction, FRF noted that in the 2008 fuel proceeding, TECO reduced its proposed 2009 fuel charge increase from 22 percent to 12 percent, a change of 10 percent. OPC contended that witness Wehle had admitted that natural gas prices were currently below the prices used by TECO to price its 2009 natural gas inventory.

Order No. 9273 states in part: "[w]e recognize that the companies' projections will inevitably differ from actual results, and agree that a true-up mechanism, designed to conform the projected estimates to actual figures, is necessary to realize the objective of eliminating overrecoveries and underrecoveries of fuel costs."[15] In its brief, FRF agrees with OPC witness Larkin's proposed ten percent reduction in fuel inventory, stating "[f]ailure to make this adjustment will likely result in overstated fuel costs being embedded in Tampa Electric's rates until the next rate case." We note the difference in purpose between estimated fuel prices for inclusion in fuel charges and estimated fuel prices for inclusion in base rates. Although accuracy is desired in both types of estimates, fuel-charge fuel price estimates will be trued up, and base rate fuel price estimates will not. The fuel clause is established once a year based on estimated fuel prices, and the difference between estimated prices and actual prices becomes the true-up amount for subsequent fuel factors. In contrast, base rates are determined using a point estimate, or test-year estimate, to determine fuel prices supporting the inventory value. Base rate calculations are not subject to a true-up adjustment. Base rates will be in place for several years, during which time fuel inventory may be undervalued or overvalued as market fuel prices change. We find that witness Wehle's calculation of the fuel inventory value which reflects a midpoint of fuel prices for 2008 is appropriate.

[15] Order No. 9273, issued March 7, 1980, in Docket No. 94680-CI, In re: General Investigation of Fuel Cost Recovery Clause. Consideration of staff's proposed projected fuel and purchased power cost recovery clause with an incentive factor, p. 7

Regarding the timing of TECO's fuel-price forecasts and the changes in fuel prices since March 2008, we note that as fuel prices increased in the Summer of 2008, TECO did not seek to revise its 2009 price forecasts in this proceeding as it did in the fuel docket. Therefore, we find that the reduction in fuel-charge fuel-price estimates does not warrant a similar reduction in base-rate fuel-price estimates. Based on the timing and composition of TECO's rate-case fuel-price forecast and its fuel-charge fuel-price forecasts, we find that the ten percent fuel charge reduction and the proposed ten percent inventory reduction are equal.

As mentioned above, when TECO made its 2009 natural gas price forecast in March 2008, the NYMEX 2009 annual average natural gas price was $10.00 per MMBtu and TECO's forecast was $8.12. The exchange price exceeded TECO's forecast. Witness Wehle testified in the 2007 fuel docket, regarding TECO's natural gas hedging activities, that TECO's policy is to reduce price volatility. TECO contended that the plan has been consistently applied to benefit customers by limiting exposure to the volatile nature of the natural gas price swings in the marketplace.[16] To reduce price volatility is to pay more for gas when prices are low and less for gas when prices are higher.

Based on the evidence and arguments presented by the parties in this proceeding, we find that no adjustment is necessary for TECO's natural gas inventories. TECO's natural gas inventory shall not be adjusted to reflect the decreases in fuel prices between Summer 2008 and September 2008.

Fuel and Conservation Expenses

The parties have stipulated that TECO has properly reflected net over- and under-recoveries of fuel and conservation expenses in its calculation of working capital.

Unamortized Rate Case Expense

TECO included $2,628,000 of unamortized rate case expense in working capital for 2009. We have a long-standing policy in electric and gas rate cases of excluding unamortized rate case expense from working capital, as demonstrated in a number of prior cases.[17] By including rate case expense in O&M expenses, but excluding a return on the unamortized portion, we have recognized that both the stockholders and the ratepayers benefit from a rate proceeding, and that customers should not be required to pay a return on funds expended to increase their rates.

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[16] Order No. PSC-08-0030-FOF-EI, issued January 8, 2008, in Docket No. 070001-EI, In re: General Investigation of Fuel Cost Recovery Clause. Consideration of staff's proposed projected fuel and purchased power cost recovery clause with an incentive factor, p. 6

[17] Order No. 14030, issued January 25, 1985, in Docket No. 840086-EI, In Re: Application of Gulf Power Company for authority to increase its rates and charges; Order No. 16313, issued July 8, 1986, in Docket No. 850811-GU, In Re: Petition of Peoples Gas System, Inc. for authority to increase its rates and charges in Hillsborough County; Order No. 23573, issued October 3, 1990, in Docket No. 891345-EI, In Re: Application of Gulf Power Company for a rate increase.

While this is the approach that has been used in electric and gas cases, water and wastewater cases have included unamortized rate case expense in working capital. The difference stems from a statutory requirement that water and wastewater rates be reduced at the end of the amortization period. (Section 367.0816, F.S.) While unamortized rate case expense is not allowed to earn a return in working capital for electric and gas companies, it is offset by the fact that rates are not reduced after the amortization period ends.

In Docket No. 910778-GU, the issue was argued fully and we reaffirmed our long-standing policy of excluding unamortized rate case expense from working capital in electric an gas rate cases.[18] Order No. PSC-92-0580-FOF-GU stated that unamortized rate case expense is excluded from working capital "in an effort to reflect a sharing of rate case expenses between the stockholders and the ratepayers since both benefit from a rate case proceeding." Additionally, in TECO's last rate case, unamortized rate case expense of $1,036,000 in 1993, and $344,000 in 1994 were removed in accordance with our policy.[19]

Although there was no testimony by any party on this issue, OPC discussed it in its brief, stating that, consistent with our prior practice, any balance of working capital should include one-half of the total amount of rate case expense allowed.[20] OPC references a recent Florida Public Utilities Company (FPUC) case, in which one-half of the rate case expense was allowed in working capital.[21] In that case, several parties filed testimony on the issue, in contrast to this case where the matter was not discussed by any of the witnesses. We note that inclusion of unamortized rate case expense in working capital in the FPUC case is an exception to our long-standing policy.

For the reasons explained above, we find that unamortized rate case expense in the amount of $2,628,000 shall be removed from working capital, consistent with our long-standing policy that the cost of the rate case should be shared.

Level of Working Capital

TECO has requested Level of Working Capital in the amount of $30,586,000 for the 2009 projected test year. Based on our review of all relevant factors, we find that the appropriate 13-month average for working capital for the 2009 projected test year is $39,909,649. (See Schedule 1)

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[18] Order No. PSC-92-0580-FOF-GU, issued June 29, 1992, in Docket No. 910778-GU, In re: Petition for a rate increase by West Florida Natural Gas Company p. 15.
[19] Order No. PSC-93-0165-FOF-EI, issued February 2, 1993, in Docket No. 920324-EI, In re: Application for a rate increase by Tampa Electric Company pp. 37-38.
[20] Order No. PSC-08-0327-FOF-EI, issued May 19, 2008, in Dockets Nos. 070300-EI and 070304-EI, In re: Review of 2007 Electric Infrastructure Storm Hardening Plan filed pursuant to Rule 25-6.0342, F.A.C., submitted by Florida Public Utilities Company, and In re: Petition for rate increase by Florida Public Utilities Company, p. 33.
[21] Ibid.

Requested Rate Base

TECO has requested Rate Base in the amount of $3,656,800,000 for the 2009 projected test year. Based on our review of all relevant factors, we find that the appropriate 13-month average rate base for the 2009 projected test year is $3,437,610,836. (See Schedule 1)

COST OF CAPITAL

Accumulated Deferred Income Taxes

In its MFRs, TECO recorded a balance of jurisdictional Accumulated Deferred Income Taxes (ADITs) to include in the Company's capital structure for the test year of $302,744,000. TECO witness Felsenthal testified that TECO determined its ADIT amount using a methodology consistent with the Company's actual 2007 income tax calculations, the projected test year cost of service, and the specific Internal Revenue Code (IRC) and Income Tax Regulations covering projected test years. The methodology used by witness Felsenthal to calculate the balance of ADIT for purposes of this case, represents a change from the Company's prior practice. The witness, however, cited several private letter rulings (PLRs) to support his adjustment to ADIT of $1,894,321 that results from the Company's revised methodology. In the instant case, TECO has proposed a 2009 forecasted test year, and new rates are expected to be effective in May 2009. Thus, based on his interpretation of the PLRs and IRC, witness Felsenthal claimed that the "future" portion of the forecast test period is the period from May 2009 through December 2009 and the "historic" portion of the future test period is January 2009 through April 2009. He asserted that the fact the Internal Revenue Service (IRS) has ruled consistently on what is meant by "historic" and "future" portions of forecast test periods in the PLRs makes it highly probable that they will rule in a similar manner in the future. Witness Felsenthal cited PLR 9202029, which states, "[t]he historical period is that portion of the test period before rates go into effect, while the portion of the test period after the effective date of the rate order is the future period." Witness Felsenthal stated he was not surprised that, despite repetitive audits, the IRS found no errors with the Company's former ADIT calculation methodology. He testified that the purpose of an IRS audit is typically to examine the information that is included in the current year's tax return, and this adjustment is not an item included on a tax return.

OPC argued that TECO's deferred taxes should be increased by $1,894,000, which it contended to be consistent with our long-standing policy. OPC asserted that prior to any rate setting change, we should require TECO to obtain and submit a PLR that indicates the Company's current methodology is not consistent with IRS policy. OPC witness Schultz disagreed with TECO witness Felsenthal's reliance on PLRs in his deferred income tax calculation. Witness Schultz believed PLRs are only applicable to the company requesting the ruling and should not be used as precedent. If we choose to place any reliance on the PLRs, witness Schultz asserted that the facts addressed by each PLR are specific to each company. He also stated that the Company has used the methodology witness Felsenthal claimed to have been incorrect for years, and the IRS found no errors in the Company's methodology. He asserted that if witness Felsenthal's position is adopted, the Company has been in violation of normalization requirements since rates were set in February of 1993. In addition, witness Schultz disagreed with witness Felsenthal's assumption that projected costs for 2009 are partly historic and partly projected. Until the Company requests a PLR of its own, witness Schultz recommended that the Company should be required to calculate the deferred tax balance on a consistent basis with the methodology employed for at least the last sixteen years.

In the testimony of witness O'Donnell, FRF agreed with the Company that the appropriate amount of deferred taxes to include in TECO's capital structure for the 2009 projected test year is $302,744,000.

ADITs represent the income tax component resulting from the application of the income tax rate to temporary differences at each balance sheet date. Deferred tax expense reflects the period to period change in ADITs. Because the financial statements reflect accrual accounting, the income tax expense calculation must reflect the liability for income taxes payable in the future as a result of transactions recorded in the current financial statements. Deferred income taxes are generated when ratepayers pay income tax expenses in rates prior to the Company actually being required to make those payments to the U.S. Treasury. Deferred income taxes are included in capital structure because these funds are used by the Company in the provision of utility electric service and should be reflected in the utility's regulated capital structure. The purpose of deferred income tax accounting is to reflect in the financial statements the tax effects (both current and deferred) of assets, liabilities, revenues, and expenses recorded on the financial statements. In the regulated environment, the process of recording deferred income taxes on temporary differences is often referred to as "normalization." Recognizing zero cost deferred taxes in the capital structure (normalization) reduces the overall rate of return charged to ratepayers. In ratemaking, the ADIT balance is a zero cost source of capital in the cost of capital computation, thereby sharing the benefit of the reduced financing costs with ratepayers.

The penalty for violating the normalization requirements is the loss of the ability to claim accelerated depreciation for income tax purposes on all assets as of the violation date and on subsequent additions. Accelerated depreciation is the major component of deferred taxes for capital intensive entities such as TECO. When Congress changed the IRC to permit the use of accelerated depreciation, it intended that, by being allowed to accelerate depreciation deductions (and thereby reduce current income tax payments), companies would lower the financing costs of their investment in capital assets and would be encouraged to incur such expenditures.

We find that TECO has reasonably relied on PLRs which, while not binding on the IRS, are indicative of the IRS's position on this issue. Therefore, we find that the Company's change in methodology is appropriate. However, in reconciling rate base and capital structure, TECO made a pro rata adjustment over all sources of capital. As discussed below, the Company should have made this pro rata adjustment over investor sources of capital only. Reversing the Company's adjustment resulted in a higher balance of ADITs.

Based on the discussion above, we find that the appropriate amount of accumulated deferred taxes to include in TECO's capital structure for the 2009 projected test year is $365,087,524.

Unamortized Investment Tax Credits

The Company proposed that the balance of Investment Tax Credits (ITCs) to be included in its capital structure for the test year is $8,780,000 with a cost rate of 9.75 percent. TECO witness Felsenthal testified that the ITC amortization for the projected 2009 test year has been calculated and presented appropriately in accordance with generally accepted accounting principals and the requirements of the IRC. Witness Felsenthal asserted that TECO determined its unamortized ITCs using a methodology consistent with the Company's actual 2007 income tax calculations, the projected test year cost of service, and the specific IRC and Income Tax Regulations covering projected test years. Witness Felsenthal stated that TECO's unamortized ITC is being amortized to tax expense over book life of the related property and that this amortization is "no more rapidly than ratably" in accordance with IRC requirements. The witness testified that in order to comply with IRC rules, ITC amortization must be based upon the estimated useful life of the asset exclusive of estimates of salvage and removal costs anticipated upon retirement of the asset. He stated that inclusion of these salvage and removal costs would share ITC with ratepayers more rapidly than the book life and would result in a normalization violation. The witness also testified it is important to compute annual ITC amortization using only the estimated useful lives included in the depreciation computation and not the combined depreciation rate. This is because if more than a ratable portion of ITC is used to reduce income tax expense, a violation of the IRC will occur and the taxpayer will be required to refund to the IRS any unamortized ITC. The witness noted that, under Section 1.46-6(g)(2) of the IRC regulations, "ratable" is to be determined by considering the time actually used in computing depreciation expense for the property giving rise to the ITC.

Witness Felsenthal testified that there would not be a potential issue with the IRC for the Company's past practice of using the depreciation rate rather than the depreciation life for a number of years in its amortization of ITC. He cited PLRs 200802025 and 200802026 to support his assertion that because this violation was through an oversight, was unintentional, and the regulator was unaware that the ITC amortization rate included an element for cost of removal when reaching past regulatory decisions regarding the utility, the Company will not be held accountable for a normalization violation. Witness Felsenthal is not surprised that, despite repetitive audits, the IRS found no errors with the Company's former ITC amortization methodology. He testified that the purpose of an IRS audit is typically to examine the information that's included in the current year's tax return, and this adjustment is not an item included on a tax return.

FRF witness O'Donnell testified that the appropriate cost rate for ITCs is 8.28 percent. FRF did not take issue with the amount of ITCs included in TECO's capital structure.

ITCs are included in capital structure because these funds are used by the Company in the provision of utility electric service, and should be reflected in the utility's regulated capital structure. The ITC lowers income tax expense permanently if certain qualifying investments are made. The intent of the ITC is to reduce the net cost of acquiring depreciable property, thereby providing taxpayers an incentive to invest in qualifying assets. The ITC is a direct reduction of income taxes payable in a given year that will not reverse or turn around, similar to a grant or rebate. The ITC provides an incentive to make capital investments by granting a tax credit (a direct dollar for dollar offset to current taxes payable) based on a percentage applied to investment in tangible property, which includes most generation, transmission, and distribution assets. To make sure that its objectives are met for investments in qualifying utility property, the IRC prescribes methods of sharing the benefit between the ratepayer and the shareholders.

For ratemaking purposes, in 1972 utilities were required to elect how they intended to share the ITC between ratepayers and shareholders. Most utilities, including TECO, elected to share the ITC by including the annual amortization to income tax expense as an above the line reduction which reduced income tax expense. The unamortized amounts were not used to reduce rate base, benefiting shareholders who were entitled to earn on property, plant, and equipment financed partially by the ITC "grant" or "rebate." The ITC was repealed as a result of the Tax Reform Act of 1986. TECO's current filing reflects unamortized ITC on property, plant, and equipment the Company realized prior to the repeal of ITCs. The unamortized ITC is being amortized over the lives of the property, plant, and equipment, giving rise to the ITC.

We find that TECO's methodology for calculating ITCs is appropriate and is in accordance with IRS requirements. However, in reconciling rate base and capital structure TECO made a pro rata adjustment over all sources of capital. The Company should have made this pro rata adjustment over investor sources of capital only. Reversing the Company's adjustment resulted in a higher balance of ITCs. None of the other adjustments have an impact on the unamortized ITC balance. We recalculated the ITC cost rate based on the other adjustments and return on equity, which resulted in an 9.19 percent weighted average cost rate for ITCs.

Based on the above, we find that the appropriate amount and cost rate of unamortized ITCs to include in TECO's capital structure for the 2009 projected test year are $10,587,947 and 9.19 percent, respectively.

Cost Rate for Short-Term Debt

Short-term debt is debt that matures in less than one year and represents liabilities on the Company's books that must be repaid prior to any common stockholders or preferred stockholders receiving a return on their investment. TECO proposed a short-term debt cost rate of 4.63 percent. As TECO witness Gillette explained, the Company utilized average historical London Interbank Offered Rate (LIBOR) rates in developing its proposed short-term interest rate of 4.63 percent. For the period 2006 through 2008 the three-month LIBOR rate was 4.5 percent on average. This was the number on which TECO based its proposed short-term debt cost rate. The witness asserted that OPC witness Woolridge's use of the November 13, 2008 LIBOR rate of 2.15 percent is not appropriate due to witness Gillette's assertion that this is near the absolute lowest LIBOR rate seen in the last 4 years. Witness Gillette felt that current LIBOR rates have been driven down by the billions of dollars of liquidity the Federal Reserve, Treasury Department, and U.S. Government have flooded into the market to entice banks to lend to each other. Witness Gillette testified that due to the volatility in LIBOR rates evidenced by a significant spike in September of 2008 to 4.75 percent, it is prudent to use a historical average

LIBOR rate as proposed by the Company, rather than a rate at a particular point in time as recommended by OPC.

OPC witness Woolridge recommended a short-term debt cost rate of 2.33 percent. This is based on the three-month LIBOR rate as of November 15, 2008, 2.15 percent, plus a financing program fee of 18 basis points. Witness Woolridge disagrees with the Company's use of historic LIBOR rates from 1991-2008 in its calculation of the appropriate short-term debt cost rate. The witness asserted that historic rates do not reflect current rates.

In December of 2008, TECO renewed a LIBOR-based credit facility. This credit facility includes a fixed commitment fee of 125 basis points as well as a fee for use of the facility of 50 basis points. The fees are in addition to the three-month LIBOR rate at the time funds are borrowed. Therefore, the effective cost of this credit facility is the current three-month LIBOR rate plus 175 basis points. The three-month LIBOR rate recently closed at one percent. Accordingly, if the Company were to draw on its credit facility, its rate would be 2.75 percent, which is the 1 percent three-month LIBOR rate plus 175 basis points. The three-month LIBOR rate was over five percent one year ago. At that time the Company was paying approximately 5.34 percent on the credit facility upon which it now pays roughly 2.75 percent.

If short-term debt rates increase subsequent to the test year the increase will not have an adverse effect on ratepayers until the Company's next rate case. In turn, if the Company is able to refinance its short-term debt at a lower cost rate, the decrease will initially benefit the Company's shareholders, and could potentially benefit ratepayers if the Company comes in for a rate case during the time when its cost of debt is low.

We find that a cost rate of 2.75 percent is appropriate for short-term debt. This cost rate is based on the three-month LIBOR rate at the close of the record plus 175 basis points to account for financing fees. We recalculated the amount of short-term debt to include in the Company's capital structure based on other staff adjustments, resulting in an amount of $7,430,567. Thus, the appropriate amount and cost rate for short-term debt for the 2009 projected test year are $7,430,567 and 2.75 percent, respectively.

Pro Forma Adjustment to Equity

TECO included a $77 million adjustment to equity in its 2009 projected capital structure for purposes of setting rates in this proceeding. TECO witness Gillette testified that, since the rating agencies consider portions of long-term fixed payments associated with purchased power agreements (PPAs) as debt and analyze company credit profiles with an adjustment to its credit parameters, the Company's proposed capital structure reflects an adjustment for this imputation of additional debt. By recognizing a pro forma adjustment of $77 million of additional equity, he testified the Company will have the same common equity ratio before and after the rating agencies' imputation of debt to account for PPAs. Witness Gillette stated that we have recognized the effect of off-balance sheet obligations like PPAs on a company's capital structure and weighted average cost of capital in both Florida Power & Light Company's (FPL) and Progress Energy Florida, Inc.'s (PEF) recent rate settlements.[22]

OPC witness Woolridge testified that, given our specific clause recovery mechanism for PPA capacity payments, the financial condition of an electric utility is not impaired by entering into these contracts. He based this opinion on the following passage from a recent Moody's Investors Service (Moody's) report:

> If a utility enters into a PPA for the purpose of providing an assured supply and there is reasonable assurance that regulators will allow the costs to be recovered in regulated rates, Moody's may view the PPA as being most akin to an operating cost. In this circumstance, there most likely will be no imputed adjustment to the obligations of the utility.

In addition, witness Woolridge testified that the proposed adjustment is not consistent with GAAP accounting and will not show up in the financial statements the Company files with the Securities and Exchange Commission (SEC). For these reasons, witness Woolridge believes providing incremental revenues through a higher equity ratio and overall rate of return "are unnecessary and would result in an unwarranted revenue benefit to the utility."

The pro forma adjustment to equity proposed by TECO is not an actual equity investment in the utility. If this adjustment is approved for purposes of setting rates in this proceeding, the Company would essentially be allowed to earn a risk-adjusted equity return without having actually made the equity investment. The revenue requirement impact of recognizing this pro forma adjustment to equity in the capital structure is approximately $5 million per year.

Companies with PPAs are not required by the rating agencies to make the pro forma adjustment in question. As the following passage explains, the Standard & Poors' (S&P) practice with respect to PPAs described in witness Gillette's testimony is strictly for the rating agency's own analytical purposes:

> We adjust utilities' financial metrics, incorporating PPA fixed obligations, so that we can compare companies that finance and build generation capacity and those that purchase capacity to satisfy customer needs. The analytical goal of our financial adjustments for PPAs is to reflect fixed obligations in a way that depicts the credit exposure that is added by PPAs. That said, PPAs also benefit utilities that enter into contracts with suppliers because PPAs will typically shift various risks to the suppliers, such as construction risk and most of the operating risk. PPAs can also provide utilities with asset diversity that might not have been achievable through self-build. The principal risk borne by a utility that relies on PPAs is the recovery of the financial obligation in rates.

[22] Order No. PSC-05-0902-S-EI, issued September 14, 2005, in Docket No. 050045-EI, In re: Petition for rate increase by Florida Power & Light Company.; and Order No. PSC-95-0945-S-EI, issued September 28, 2005, in Docket No. 050078-EI, In re: Petition for rate increase by Progress Energy Florida, Inc.

With this proposed adjustment, we find that the Company is attempting to take a portion of S&P's consolidated credit assessment methodology and use it for a purpose it was never intended.

Finally, while it is true that we have some familiarity with the issue of the rating agencies' evaluation of the effect of off-balance sheet obligations like PPAs on a company's financial flexibility, the Company's position that we have recognized such an adjustment for purposes of setting rates is overstated. The capital structure and resulting rate of return authorized in FPL's 2005 settlement do not include an imputed equity adjustment. While the capital structure and resulting rate of return authorized in PEF's 2005 settlement do include an imputed equity adjustment, we do not believe that a decision rendered through a stipulation reached between the parties in a past proceeding constitutes a binding precedent on our future decisions rendered through an evidentiary hearing in an unrelated proceeding.

Therefore, based on the record evidence and the reasons discussed above, we find that TECO's requested pro forma adjustment to equity shall be denied for purposes of setting rates in this proceeding. In addition to removing the $77 million from the capital structure through a specific adjustment to reduce common equity, a pro rata adjustment shall be made to increase all sources of investor-supplied capital.

Cost Rate for Long-Term Debt

OPC witness Woolridge and TECO witness Gillette agree that the appropriate cost rate for long-term debt is 6.80 percent. However, FIPUG agreed with FRF witness O'Donnell that the appropriate cost rate for long-term debt should be 6.81 percent. Neither FRF nor FIPUG provided any documentation to support why TECO's proposed cost rate of 6.80 percent was incorrect. We find that the one basis point difference between the two cost rates is immaterial in this instance. As OPC and the Company have proposed, we find that the appropriate cost rate for long-term debt is 6.80 percent.

Certain adjustments shall be made to TECO's proposed capital structure. Schedule 2 shows the components, amounts, cost rates and weighted average cost of capital associated with the projected test year. Per the adjustments made below, the appropriate amount of long-term debt shall be $1,344,280,696.

Appropriate Capital Structure

The projected 2009 capital structure TECO proposed for purposes of setting rates in this proceeding reflects an equity ratio as a percentage of investor supplied capital of 56.6 percent. Excluding the $77 million of imputed equity, the capital structure reflects an equity ratio of 55.3 percent. The equity ratio at year-end 2008 was 52.6 percent.

TECO witness Gillette testified that TECO needs to have strong investment grade ratings in order to ensure that it will have access to the debt capital markets as needed to fund its construction program. TECO is currently rated in the BBB/Baa range by the three major rating agencies. Witness Gillette testified that the Company is targeting ratings in the A range.

Witness Gillette testified that having ratings in the A range will provide a ratings "safety net" in the event of a catastrophe such as a hurricane. Since ratings in the A range are above the BBB range, there would be sufficient cushion if an unanticipated event occurs for the ratings to slip before becoming non-investment grade. In addition, witness Gillette testified that the cost rate and access to the capital markets are better for companies with an A rating compared to companies with ratings in the BBB range. TECO is proposing a significant construction program for the period 2009–2013. Witness Gillette testified access to the capital markets is essential so TECO can adequately fund this program.

TECO witness Abbott also testified regarding TECO's need for credit quality sufficient to ensure access to capital under all market conditions. Witness Abbott testified that "regulation must support the financial integrity of the company to a degree that provides the basis for a strong investment grade rating." She further stated "such a rating will not only benefit investors, but will provide capital to the company at more attractive rates, and continued access to the markets that will enable the company to pursue its capital investments for the benefit of its customers." For TECO to achieve a better rating to carry it through its construction program, during which financial stress may degrade its metrics, witness Abbott testified the Company should have stronger financial metrics than it presently has. She concluded by stating "with a heavy capital program and persistent need to access the capital markets, Tampa Electric requires healthier financial metrics to ensure capital market access on a sustainable basis."

Witness Gillette challenged the reasonableness of the intervenors' witnesses recommendations regarding the appropriate capital structure for TECO. Witness Gillette testified that OPC witness Woolridge and FRF witness O'Donnell both failed to "provide any evidence to suggest that a rating lower than single A would provide adequate financial integrity and appropriate and consistent access to the capital markets." Moreover, witness Gillette testified that "if the Commission were to accept the capital structure recommendations of the intervenors' witnesses in this case, I am very concerned that the rating agencies could downgrade Tampa Electric."

OPC witness Woolridge testified that TECO's recommended capital structure is not appropriate for ratemaking purposes in this proceeding. He testified that TECO's recommended capital structure is not reflective of the recent capitalization of the Company. Witness Woolridge also testified that, due to a number of inappropriate adjustments that result in an inflated equity ratio, the Company's proposed capital structure is "equity rich" and has a much higher equity ratio than that employed by other electric companies. Witness Woolridge testified TECO's "proposed capital structure ratios do not reflect the actual capitalization of Tampa Electric." He testified that TECO's average equity ratio over the past three years has been 49.0 percent. Witness Woolridge testified TECO's proposed equity ratio is not reflective of the capitalization of other electric companies. The average equity ratio for the companies in witness Woolridge's proxy group for the first 11 months of 2008 was 45.7 percent. Witness Woolridge also testified that the equity ratio in TECO's proposed capital structure is inflated due to questionable adjustments and uncertain equity infusions. As noted above, TECO's proposed capital structure includes $77 million of imputed equity. TECO Energy invested approximately $300 million of the $350 million equity infusion projected for 2008. The Company's proposed capital structure also reflects an additional equity infusion of $285 million in 2009.

For purposes of setting rates in this proceeding, witness Woolridge recommended a capital structure that reflects an equity ratio of 48.9 percent. This ratio represents the average of TECO's actual equity ratios in 2007 and 2008. Witness Woolridge testified that his recommended capital structure more accurately reflects how the Company has been financed in the past, more closely reflects the capitalization of other electric companies, and does not include any of the questionable adjustments and uncertain equity infusions present in TECO's proposed capital structure.

FRF witness O'Donnell testified that "allowing Tampa Electric's rates to be set using this capital structure would cause customers to over-pay for Tampa Electric's true cost of capital by forcing captive customers to pay for a hypothetical, non-existent capital structure that does not, in my opinion, accurately reflect the way the Company finances its rate base investment." He further stated that, due to the parent/subsidiary relationship between TECO Energy and TECO, there are no market forces that influence TECO's capital structure. Witness O'Donnell testified that "TECO Energy can issue long-term debt on its balance sheet and then invest the funds into Tampa Electric and call it common equity." He concluded that, through this process, "TECO Energy can effectively create whatever capital structure it desires for Tampa Electric and its other subsidiaries."

For purposes of setting rates in this proceeding, witness O'Donnell recommended a capital structure that reflects an equity ratio of 49.6 percent. He recommended that we adjust the Company's projected capital structure "to account for a proportionate amount of long-term debt in the parent company capital structure that should be accounted for as long-term debt and not common equity in the Tampa Electric capital structure."

Witness Gillette argued that the Company's proposed equity ratio is necessary to generate credit parameters commensurate with a debt rating in the A range. However, the processes used by the rating agencies to determine debt ratings are complex and consider both qualitative and quantitative factors. Even if TECO received the entire rate increase it has requested in this proceeding, it is neither automatic nor guaranteed that the Company's debt rating would be upgraded. Witness Abbott testified that a utility's financial integrity is primarily a product of its regulatory environment. She noted that we are regarded by a number of equity analysts as having a constructive regulatory environment because of our innovative and forward-looking regulatory practices. Witness Abbott also testified that regulation in Florida is considered among the best in the country by Regulatory Research Associates (RRA).

When asked for specifics regarding her testimony, witness Abbott stated she is supporting "anything that would generate cash flow to levels that would allow the company to have financial metrics that will qualify them for a single A rating." When asked about the effect a non-regulated subsidiary has on a utility's financial integrity, witness Abbott responded the effect "is secondary and results from management's practices regarding dividend and cash infusion policies." While her opinion may well be accurate in certain jurisdictions, we find that witness Abbott's views with respect to TECO's credit rating are not supported by the record in this proceeding. Contrary to witness Abbott's testimony, the comments expressed by the rating agencies in the following passages make it abundantly clear the financial strain from TECO Energy's non-regulated investments and its policies regarding dividends and cash infusions have had more of an impact on TECO's debt rating than the Florida regulatory environment.

In October 2000, Standard & Poors' (S&P) downgraded TECO's debt rating from AA to A and changed the Company's outlook to negative. In announcing its decision, S&P explained:

> TECO Energy's aggressive higher-risk nonregulated activities include independent power projects, which have become increasingly integral to the company's core business strategy. The growth of nonregulated activities could further impact the business risk profile requiring even higher credit protection measures. Additionally, the company's debt-financed share repurchase program has adversely affected credit protection measures, resulting in higher debt to total capital levels.
>
> The ratings of TECO Energy reflect Standard & Poor's consolidated rating methodology, resulting in the same corporate credit rating (risk of default) for TECO Energy and Tampa Electric. No regulatory or structural insulation is accorded Tampa Electric, given the absence of proscriptive authority by the regulators in the state of Florida.

In April 2002, S&P announced the downgrade of TECO Energy's and TECO's debt rating to A minus from A and reaffirmed the Company's outlook as negative. In explaining this action, S&P stated "the rating action reflects Standard & Poor's assessment of TECO's business strategy and the quality of the cash flow stream generated weighed against the level of risk being undertaken." S&P downgraded TECO Energy's and TECO's credit ratings again in September 2002 from A minus to BBB.

In May 2003, S&P downgraded its debt rating for TECO Energy and TECO to BBB minus from BBB. In explaining this action, S&P stated "the downgrade of TECO and its subsidiaries reflects the company's continued exposure to power plant projects that are being severely impacted by a weak power price environment, ongoing asset sale execution risk, and the paramount importance of continuing to execute planned strategic initiatives to arrest the company's weakened credit quality."

In July 2004, S&P downgraded TECO Energy's debt rating to BB. At the same time, S&P left TECO's debt rating at BBB minus. S&P explained that the downgrade of TECO Energy to a non-investment grade rating was "due to a combination of lower expected financial performance at TECO Energy and less support accorded to TECO Energy from its Tampa Electric utility subsidiary." In affirming TECO's rating at BBB minus, S&P posited "its view that the utility's credit profile is unlikely to suffer further deterioration from the parent's activities." TECO's S&P debt rating is still BBB minus today.

During this period, the other major rating agencies also commented on TECO's relative debt rating and the impact the non-regulated activities of TECO Energy exerted on its utility subsidiary's financial integrity. In an April 2003 report, Fitch Ratings (Fitch) stated:

> The downgrades and Negative Outlook for Tampa Electric reflect Fitch's policy that restricts the rating differential between a parent and its utility subsidiary. The regulated utility continues to provide an offset to the risks associated with the independent power business. Tampa Electric, which contributed 66% of consolidated EBITDA for the TECO group in 2002, has financial metrics which would be consistent with the 'A' category, despite significant investment in new plant over the last several years to meet customer and sales growth. The recent issuance of $250 million of senior unsecured notes at Tampa Electric and the recent return of capital to the parent is expected to have a moderately negative impact on financial measures, although the ratings will continue to be constrained by that of the parent.

Moody's Investors Service (Moody's) also commented on the impact the financial strain of non-regulated investments at the TECO Energy level placed on the financial position of TECO. In October 2003, Moody's stated:

> The negative outlook reflects Moody's concerns regarding the high level of debt at parent company TECO Energy (Ba1 senior unsecured, negative outlook), financial pressures at the unregulated subsidiaries of TECO, and the perceived likelihood that upstreamed dividends from Tampa Electric will be increasingly relied upon to service parent company obligations which begin to mature in 2007.
>
> The negative outlook considers Moody's view that the regulated utility is not completely insulated from the ongoing financial pressures facing the parent and other subsidiaries of the parent. Tampa Electric has in recent years delayed certain aspects of its capital expenditure program and returned some previously contributed capital to TECO, which has affected the utility's own financial flexibility during a period of significant capital spending needs.

In February 2004, Moody's elaborated on its view that TECO's credit rating was negatively impacted by the financial difficulties at the parent level when it stated:

> The downgrade of Tampa Electric's rating reflects Moody's view that the regulated utility continues to be negatively affected by the weakened financial condition of the parent company. Although TECO has recently articulated a back to basics strategy focusing on its core Florida utility operations, Moody's believes that TECO's management will continue to be preoccupied with exiting the Union and Gila plant investments, and resolving issues surrounding its other merchant plant investments through 2004, and perhaps into 2005 as well. Moody's believes there may be greater pressure on Tampa Electric for dividends to the parent for a

number of years, which may be accomplished by deferring certain expenses or capital expenditures.

In 2003, TECO returned $158.3 million in equity to TECO Energy. This same year, TECO paid a dividend to TECO Energy of approximately $25 million in excess of TECO's net income that year. This movement of funds between TECO and TECO Energy contributed to TECO's equity ratio falling from 55.6 percent in 2002 to 49.4 percent in 2003.

For the period 1998 through 2002, TECO's equity ratio varied from a high of 60.6 percent to a low of 55.6 percent and averaged 57.3 percent over the period. For the period 2003 through 2007, TECO's equity ratio varied from a high of 49.3 percent to a low of 47.5 percent and averaged 48.2 percent over the period. Due to a significant equity infusion in 2008, TECO's equity ratio was 52.6 percent at year end 2008.

To achieve an equity ratio of 55.3 percent in its 2009 projected capital structure, TECO assumed it would receive equity infusions from TECO Energy of $350 million in 2008 and $285 million in 2009. By year end 2008, TECO had received approximately $300 million of equity from TECO Energy.

From 1999 through 2007, TECO Energy invested approximately $533.6 million in equity in TECO. Recognizing the return of capital made in 2003, the net equity infusion in TECO was $375.3 million over this nine year period. The equity infusion projected for 2008 and 2009 of $635 million is approximately $100 million more than the amount TECO Energy invested in the utility over the preceding nine years combined. When the $158.3 million return of capital is recognized, the projected equity infusion over this two year period is approximately $260 million more than the actual equity investment made in the utility over the preceding nine years. The magnitude of these projected equity infusions over this relatively short period compared to the actual amount of equity invested in the utility over the past decade caused witness Woolridge to question whether this equity investment will actually take place. Considering the fact that TECO Energy was unable to make the full $350 million equity infusion in 2008, we agree to a certain extent with witness Woolridge's concern regarding the uncertainty of the projected equity level.

We do not agree with TECO witness Abbott that we must set an authorized return in this proceeding that will generate revenue sufficient to achieve financial metrics in a particular rating range. We have a long history of constructive regulatory decisions that provide for the timely recovery of prudently incurred expenses and capital investments to support the financial integrity of the companies under our jurisdiction. If a company believes a particular debt rating is optimal, it is the parent company's responsibility to make equity infusions in the utility consistently over time sufficient to achieve financial metrics in that rating range, not just during the test year.

In addition to the fact that there is no guarantee TECO's rating would be upgraded to the A range even if it received the full rate increase it requested in this proceeding, it is unrealistic to expect the rating agencies to upgrade TECO until the financial metrics at the consolidated level also improve. It is important to keep in mind that the level of equity recognized for purposes of setting rates should be in line with the risk associated with the provision of regulated operations. There is no mandate from S&P or any of the other rating agencies that we or any other regulatory commission allow an inflated equity ratio at the utility level to compensate for the parent company's use of higher debt leverage to fund other, non-regulated businesses. Our statutory responsibility is to set a rate of return for this Company commensurate with returns on investments in other companies of comparable risk, sufficient to maintain the financial integrity of the company, and sufficient to maintain its ability to attract capital under reasonable terms. This responsibility does not extend to setting a rate of return to generate cash flow sufficient to improve the debt rating of the parent company.

Finally, TECO witness Murry identified a group of companies that he testified "provide a representative sample of the financial and cost of capital information for a financially healthy electric utility such as Tampa Electric." The regulated utilities associated with the companies in witness Murry's proxy group have equity ratios that range from a high of 59.8 percent to a low of 32.6 percent. The average equity ratio for this group of utilities is 46.8 percent.

We find that the capital structure shown on Schedule 2 is appropriate. This capital structure reflects the Company's proposed capital structure for 2009 with specific adjustments to remove the $77 million in imputed equity and the $50 million equity infusion TECO Energy failed to make in 2008. We agree with OPC that it is uncertain TECO Energy will be able to make up this incremental $50 million and make the full $285 million projected for 2009. This capital structure reflects an equity ratio of approximately 54 percent. While this level of equity is within the range of equity ratios of the utilities in witness Murry's proxy group, it is well above the average equity ratio for the group. In addition, while this level of equity is below the equity ratio requested by TECO, it is well above the average equity ratio the Company has used over the past five years. We find that this level of equity is supported by competent and substantial evidence in the record and it is appropriate given the substantial construction program TECO is proposing for the next five years.

Appropriate Return on Common Equity

Four witnesses testified in this proceeding regarding the appropriate return on common equity (ROE) for TECO. TECO witness Murry recommended an ROE of 12.00 percent. OPC witness Woolridge recommended an ROE of 9.75 percent. FIPUG witness Herndon recommended an ROE of 7.50 percent. FRF witness O'Donnell recommended an ROE of 9.75 percent. TECO's currently authorized ROE of 11.75 percent was set in 1995 in Order No. PSC-95-0580-FOF-EI.[23]

The statutory principles for determining the appropriate rate of return for a regulated utility are set forth by the U.S. Supreme Court in its Hope and Bluefield decisions.[24] These decisions define the fair and reasonable standards for determining rate of return for regulated

[23] Order No. PSC-95-0580-FOF-EI, issued May 10, 1995, in Docket No. 950379-EI, In re: Investigation into earnings for 1995 and 1996 of Tampa Electric Company.

[24] Federal Power Commission v. Hope Natural Gas Company, 320 U.S. 591 (1944); and Bluefield Water Works & Improvement Company v. Public Service Commission of West Virginia, 262 U.S. 679 (1923).

enterprises. Specifically, these decisions hold that the authorized return for a public utility should be commensurate with returns on investments in other companies of comparable risk, sufficient to maintain the financial integrity of the company, and sufficient to maintain its ability to attract capital under reasonable terms. While the logic of the legal and economic concepts of a fair rate of return are fairly straight forward, the actual implementation of these concepts is more controversial. Unlike the cost rate on debt that is fixed and known due to its contractual terms, the cost of equity is a forward-looking concept and must be estimated. Financial models have been developed to estimate the investor-required ROE for a company. Market-based approaches such as the Discounted Cash Flow (DCF) model, Capital Asset Pricing Model (CAPM), and ex ante Risk Premium (RP) model are generally recognized as being consistent with the market-based standards of a fair return enunciated in the Hope and Bluefield decisions.

Three witnesses used the DCF model to estimate the investor-required ROE for TECO. Because TECO is a wholly-owned subsidiary of TECO Energy, its common stock is not publicly traded. To apply the DCF model, each witness had to select a group of companies with publicly traded stock to serve as a proxy for TECO.

To select his group of comparable companies, TECO witness Murry started with all electric utilities followed by Value Line Investment Survey (Value Line). From this initial sample, he removed all companies that were actively involved in a merger, had reduced or eliminated its dividend in the past five years, or were forecasted to have zero or negative earnings growth. He further narrowed his proxy group by focusing on companies with market capitalization greater than \$2 billion and less than \$8 billion and excluded any companies that derived less than 60 percent of its operating income from regulated electric operations. Based on this selection criteria, witness Murry identified a group of eight companies that he testified "provide a representative sample of the financial and cost of capital information for a financially healthy electric utility such as Tampa Electric."

Witness Murry relied on stock prices and dividends for a recent two week period prior to the filing of his direct testimony in August 2008 and the high and low stock prices for the preceding 52-week period. While he reviewed dividend growth rates, his DCF analysis relied principally on forecasted earnings growth rates. In lieu of making a specific adjustment for flotation costs, witness Murry recognized the high end of the results of his DCF analysis to compensate for the price impact flotation costs and market pressure from a stock issuance have on the price of that common stock. The various iterations of witness Murry's DCF analysis produced indicated returns ranging from a low of 9.14 percent to a high 13.27 percent for his proxy group. Due to the recent turmoil in the debt and equity markets, he testified the relevant DCF results from his analysis range from 11.12 percent to 13.27 percent.

To select his group of comparable companies, OPC witness Woolridge started with all electric utilities followed by Value Line and AUS Utility Reports. From this initial sample, he removed all companies that did not have an investment grade bond rating from Moody's and S&P and a three year history of paying dividends. He further narrowed his proxy group by focusing on companies with operating revenues less than \$10 billion that generate at least 75 percent of its operating income from regulated electric operations. Based on this selection criteria, witness Woolridge identified a group of 13 comparable companies for use in his analysis. Witness Woolridge relied on dividend yields for the six month period ended November 2008 and for the month of November 2008. He relied on Value Line's historical and projected growth rate estimates for earnings per share (EPS), dividends per share (DPS), and book value per share (BVPS). In addition, he used the average EPS growth rate forecasts from Bloomberg and Zacks and the expected growth rate as measured by the earnings retention method. Witness Woolridge's DCF analysis did not include an adjustment for flotation costs. The indicated return from witness Woolridge's DCF analysis is 9.8 percent.

To select his group of comparable companies, FRF witness O'Donnell also started with all electric utilities followed by Value Line. As a further screen, he only included companies that have an S&P Quality Rating of B and an S&P Stock Rating of B. From this sample, he excluded all companies that either paid no dividend, had recently reinstated its dividend, had recently purchased another company, or was the subject of takeover discussions. Based on this screening criteria, witness O'Donnell identified a group of 24 comparable companies for use in his determination of the appropriate ROE for TECO. Witness O'Donnell relied on the dividend yield expected over the next 12 months for each company as reported by Value Line. He developed the dividend yield range for the comparable group by averaging each company's dividend yield over the 13-week and 4-week periods as well as the most recent dividend yield reported by Value Line. Witness O'Donnell relied on the earnings retention method; the 5-year and 10-year historical compound annual rates of change for EPS, DPS, and BVPS; the Value Line forecasted compound annual rates of change for EPS, DPS, and BVPS; and a compilation of forecasted EPS growth rates reported by Charles Schwab & Co. Witness O'Donnell's DCF analysis did not include an adjustment for flotation costs. Witness O'Donnell's DCF analysis resulted in a range of returns of 8.9 percent to 9.9 percent.

Both witnesses Woolridge and O'Donnell challenged the reasonableness of certain aspects of witness Murry's DCF analysis. In turn, witness Murry challenged the reasonableness of certain aspects of their analyses. All three witnesses used very similar DCF models, similar estimates of dividend yields, and relatively similar proxy groups. The primary reasons for the difference in the witnesses' indicated DCF returns is their respective estimates of the growth rate to include in the DCF model and witness Murry's decision to rely on the high end of his indicated DCF results to account for flotation costs.

Focusing first on expected growth rates, witness Woolridge used a growth rate of 4.50 percent. This growth rate is the average of the projected growth rates for EPS, DPS, BVPS, and the internal growth rate. Witness O'Donnell used a growth rate range of 4.00 percent to 4.50 percent. This growth rate range is based on the historical and forecasted growth in EPS, DPS, and BVPS. In contrast, witness Murry's relevant DCF range is based on growth rates that range from 6.50 percent to 8.06 percent. These growth rates are based exclusively on forecasted EPS growth rates.

We have traditionally recognized a reasonable adjustment for flotation costs in the determination of the investor-required ROE. However, such adjustments have typically been on the order of 25 to 50 basis points. While not making a specific adjustment for flotation costs, by going to the high end of his DCF results, witness Murry has effectively incorporated an adjustment to his recommended DCF result far in excess of 25 to 50 basis points.

Two witnesses relied on the CAPM approach to estimate the investor-required ROE for TECO. For the reasons discussed earlier, the witnesses used their respective proxy groups for certain inputs to their CAPM analyses. TECO witness Murry performed two different, but complimentary, approaches to estimate a CAPM ROE for TECO. The first method compared the historical risk premium between common stocks and government bonds. The second method examined the historical risk premium of common stocks over Aaa-rated corporate bonds. In both analyses, he used the average beta for his proxy group. In witness Murry's first CAPM method, he relied on Ibbotson Associates data to compare the risk premium between the historical, earned returns on common stocks and the earned returns on 20-year Treasury bonds. This method produced a CAPM result of 11.24 percent. This result included a "small size adjustment" of 92 basis points. Witness Murry testified that this adjustment is necessary to account for an empirical bias against smaller companies in the CAPM analysis. In his second CAPM approach, witness Murry relied on Ibbotson Associates data to compare the risk premium between the historical, earned returns on common stocks and the earned returns on long-term Aaa-rated corporate bonds. This method produced a CAPM result of 12.42 percent. Witness Murry testified that this CAPM method does not require a separate recognition of the size bias because it embodies the historical relationship between common equity and debt. OPC witness Woolridge performed an ex ante version of the CAPM analysis. As a proxy for the risk free rate, he used a composite yield of long-term U.S. Treasury bonds. He used the average beta for his proxy group. He determined an expected risk premium based on the results of various studies of historical risk premium, ex ante risk premium studies, and equity risk premium surveys. Witness Woolridge's CAPM analysis indicated an ROE of 8.2 percent.

Both witness Woolridge and witness Murry challenged the reasonableness of certain aspects of each other's CAPM analyses. Both witnesses used virtually the same risk free rates (4.60 percent and 4.50 percent) and betas (.81 and .82). The primary reasons for the difference in their indicated CAPM results is the size of the market risk premium assumed in their respective analyses, and witness Murry's decision to include a small size adjustment to the results of one of his CAPM methods. Witness Woolridge used a risk premium of 4.56 percent in his CAPM analysis. Witness Murry used risk premiums of 7.10 percent and 8.50 percent in his CAPM analyses. Witness Woolridge relied on ex ante or forward looking risk premiums in his analysis. In contrast, witness Murry relied on ex post or historical risk premiums in his CAPM analysis. Witness Woolridge testified there is considerable academic research documenting that risk premiums based on historical, earned returns are poor predictors of current market expectations. Witness Woolridge testified that the small size adjustment proposed by witness Murry in one of his CAPM approaches is not justified. Witness Murry testified that he calculated the small size adjustment consistent with the method recommended by Ibbotson Associates. However, witness Woolridge countered that the errors in using historical, earned returns to measure forward-looking risk premiums also apply to this type of analysis. In addition, witness Woolridge noted that the explicit size premium in the Ibbotson study is for companies with betas much greater than the betas for electric utilities. As such, he believes these size adjustments are not associated with electric utilities. Due to regulation, government oversight, performance review, accounting standards, and information disclosure, witness

Woolridge testified that utilities are much different than industrial companies. For these reasons, witness Woolridge testified there is no evidence of a significant size premium for utility stocks.

Two witnesses relied on approaches other than the DCF and CAPM methods to estimate the investor-required ROE for TECO. FRF witness O'Donnell testified he used the comparable earnings method in his analysis "to assess the reasonableness of my DCF results and to provide an independent methodological estimate of the return that investors would consider reasonable for Tampa Electric . . ." The comparable earnings approach assumes historical, earned returns on common equity of comparable companies provide investors with insight to assess an investment's current required return.

Witness O'Donnell reviewed the earned returns for the companies in his proxy group for the period 2004–2007. Over this period, his analysis showed the average earned ROE for the group of comparable companies ranged from a low of 8.3 percent in 2004 to a high of 9.7 percent in 2006. For the entire four year period, the average earned ROE for the group was 9.0 percent.

In addition to his analysis of earned returns, witness O'Donnell also examined recently authorized returns granted by state regulatory commissions around the country. For the period June 2007 through July 2008, the authorized returns granted by state regulatory commissions for utilities operating in fully regulated states ranged from a low of 9.10 percent to a high of 11.25 percent. The average authorized return for the entire group over this period was 10.35 percent. Based on this analysis, witness O'Donnell testified that the indicated range of returns using the comparable earnings approach is 9.50 percent to 10.50 percent.

FIPUG witness Herndon did not rely on any of the generally accepted models to determine his recommended ROE for purposes of setting rates in this proceeding. He testified that in these unusual economic times, we should not place undue reliance on traditional ROE models to determine the ROE for TECO. Witness Herndon testified that we should rely on financial issues such as issues of risk, investor expectations, the current economic environment, and TECO's position as a monopoly provider of an essential service in a relatively low risk regulatory environment, to determine the appropriate ROE, rather than a strict adherence to the results of models. Based on his review of these factors, witness Herndon recommended a fair ROE for TECO in the range of 7.00 percent to 8.00 percent, with the midpoint of 7.50 percent used for purposes of setting rates in this proceeding.

In rebuttal, witness Murry testified that since the authorized returns contained in witness O'Donnell's comparable earnings approach represent decisions reached during the period June 2007 through July 2008, these decisions are based on information from several months prior to this period. Given the recent disruption in the credit markets, witness Murry testified "these decisions cannot represent current market conditions, and they are not relevant to this proceeding." Witness Murry did not address witness O'Donnell's reliance on historical, earned returns in his comparable earnings approach.

Witness Murry testified that because witness Herndon's recommended ROE is less than the current cost of utility debt, it fails to meet the economic standard of the Hope and Bluefield decisions that an allowed return should be equal to returns on alternative investments of comparable risk. He further stated that "this non-market recommended allowed return is so low relative to the costs of competitive, alternative investments in current markets that is has no value in this proceeding."

Based on a literal reading of the testimony in this proceeding, the record supports an authorized ROE within the range of 7.50 percent to 13.27 percent. Based on a more pragmatic review of the testimony, we find that the record more strongly supports an ROE for TECO within the range of 9.75 percent to 12.00 percent.

Each of the witnesses recognized that the generally accepted models used for estimating ROE are based on a number of restrictive assumptions. Under normal economic circumstances, the relaxation of these assumptions for the practical application of these models is generally understood. However, as each of the ROE witnesses have testified, the economy is not presently in a normal or stable state. This realization does not mean the models no longer have value, rather, it is particularly important at this point in time to exercise informed judgment in the application of the models.

Due to the reliance on historical, earned returns to estimate the current risk premium and the decision to include a questionable small-size adjustment in his CAPM analysis combined with the decision to recognize the high end of his DCF results, we find that witness Murry's recommended ROE overstates the current investor-required ROE for TECO. Conversely, recognizing that the intervenors' witnesses recommended ROE is only marginally greater than the current cost of utility debt, we believe returns in the single digits may understate the investor-required ROE in the current market.

Witness Murry testified that recent returns authorized by other regulatory commissions over the most recent two-year period are not relevant to this proceeding because these returns do not account for investor expectations following the recent disruption in the credit markets. However, this position is drawn into question by the fact witness Murry's recommended ROE is significantly influenced by the historical, earned returns over the period 1926–2007. We do not agree that authorized returns over the most recent two-year period are not relevant to this proceeding, but a return based on historical, earned returns over the past 81 years does convey information on current investor expectations that we can rely on for making its decision in this case.

There is little doubt the recent disruption in the credit markets has exerted some degree of upward pressure on the current expectations of the market risk premium.) However, this incremental increase in required return, whatever the appropriate amount may be, should be applied to a contemporary estimate of the current investor-required return, not an authorized return set in the mid-1990's. Witness Murry identified a group of companies he testified are comparable in risk to TECO. Excluding the companies that operate in Massachusetts under revenue sharing plans, these utilities have authorized ROEs ranging from a low of 9.40 percent to a high of 11.00 percent. The average ROE for this group is 10.25 percent. We do not believe the investor-required return for TECO is 175 basis points greater than the average authorized return for the group of companies witness Murry has identified as comparable in risk to TECO.

We thus authorize an ROE of 11.25 percent with a range of plus or minus 100 basis points. In arriving at this return, we have weighed the results of the witnesses' models against the level of currently authorized returns around the country. We have also taken into account TECO's proposed construction program and its need to access the capital markets during this potentially challenging period. At an equity ratio of approximately 54 percent, an authorized ROE of 11.25 percent is supported by competent, substantial evidence in the record and satisfies the standards set forth in the Hope and Bluefield decisions of the U.S. Supreme Court regarding a fair and reasonable return for the provision of regulated service.

Weighted Average Cost of Capital

Based upon the preceding decisions and the proper components, amounts, and cost rates associated with the capital structure, we have calculated a weighted average cost of capital of 8.11 percent.

As discussed above, the appropriate balance of accumulated deferred income taxes (ADIT) is $365,087,524. The appropriate amount and cost rate of unamortized investment tax credits (ITCs) are $10,587,947 and 9.19 percent, respectively. 2.75 percent is the appropriate cost rate for short-term debt. The appropriate weighted average cost of long-term debt is 6.80 percent, and 11.25 percent is the appropriate mid-point return on common equity.

Certain adjustments to TECO's proposed capital structure are needed to more accurately reflect the level of equity investment in the utility on a going-forward basis. We made an adjustment to remove $77 million of imputed equity. In addition, we made an adjustment to recognize that $50 million of the 2008 equity infusion included in the projected capital structure was not made. Finally, in reconciling rate base and capital structure, TECO made a pro rata adjustment over all sources of capital. Because the balances of ADITs and ITCs are specifically identified with plant in rate base, the pro rata adjustment necessary to reconcile rate base and capital structure shall be made over investor sources of capital only. This treatment is consistent with our past practice.[25]

The net effect of these adjustments is a decrease in the overall cost of capital from the 8.82 percent return requested by TECO to a return of 8.11 percent recommended herein. Schedule 2 shows the approved test year capital structure. Based upon the proper components, amounts, and cost rates associated with the capital structure for the test year ended December 31, 2009, we find that the appropriate weighted average cost of capital for TECO for purposes of setting rates in this proceeding is 8.11 percent.

[25] Order No. PSC-02-0787-FOF-EI, issued June 10, 2002, in Docket No. 010949-EI, In re: Request for rate increase by Gulf Power Company.

NET OPERATING INCOME

Total Operating Revenues

Because there are no adjustments to TECO's forecasts of customers, kWh, kw, or revenues for the 2009 projected test year, $865,359,000 is the appropriate projected level of total operating revenues for the 2009 projected test year.

Inflation Factors for Use in Forecasting the Test Year Budgets

The following stipulation was reached amongst the parties and our staff. Having reviewed TECO's inflation escalation factor for its forecasts and compared it with Florida's National Economic Estimating Conference (10/2008) CPI forecasts, we find that TECO's 2.06% inflation factor is reasonable.

Level of O&M Expense

TECO has requested level of O&M Expense in the amount of $370,934,000 for the 2009 projected test year. However, we find that the appropriate level of O&M expense for the 2009 projected test year is $346,957,065. (See Schedule 3)

Fuel and Purchase Power Revenues and Expenses

We find that TECO has made the appropriate test year adjustments to remove fuel and purchased power revenues and expenses recoverable through the Fuel and Purchased Power Cost Recovery Clause.

Conservation Revenues and Expenses

We find that TECO has made the appropriate test year adjustments to remove conservation revenues and expenses recoverable through the Conservation Cost Recovery Clause.

Capacity Revenues and Expenses

We find that TECO has made the appropriate test year adjustments to remove capacity revenues and expenses recoverable through the Capacity Cost Recovery Clause.

Environmental Revenues and Expenses

We find that TECO has made the appropriate test year adjustments to remove environmental revenues and expenses recoverable through the Environmental Cost Recovery Clause.

Advertising Expenses

MFR Schedule C-14 provides advertising expenses by subaccounts for the test year and the most recent historical year for each type of advertising that is included in TECO's cost of service. Also, MFR Schedule C-37 provides a benchmark variance comparison of the test year expenses compared to the base year 1991 from the last rate case adjusted for inflation and customer growth.

Although the Company's total O&M expense is below the benchmark, there are specific categories of 2009 expense that exceed the benchmark. Witness Chronister testified that Sales Expense (FERC Accounts 911 to 916) in 2009 totaled $2,459,000 compared to the benchmark amount of $641,000 due to a change in the classification of expenses. Advertising expenses Account 913 is included in this group, but as witness Chronister explained, the variance was due to reclassifications involving Account 912, Demonstrating and Selling Expenses, and not Account 913. Witness Chronister testified that all advertising expenses were under the benchmark for the test year.

In addition to Account 913, TECO projected expenses for Account 909, Informational and Instructional Advertising Expenses and Account 930, General Advertising Expenses. The categories that included these accounts did not exceed the benchmark comparison. In addition to analyzing the information contained in the MFRs, staff and OPC conducted discovery concerning TECO's advertising expense. TECO's total jurisdictional advertising expense is $444,000 composed of: (1) $129,000 for Informational and Instructional Advertising Account 909, (2) $311,000 for General Advertising Expenses Account 930, and, (3) $4,000 for Advertising Expenses Account 913.

Based on our review, including an evaluation of O&M benchmark calculations, we find that the Company's forecast for advertising expense is reasonable and no adjustment to the test year advertising expenses is necessary.

Lobbying Expenses

MFR Schedule C-18 Lobbying Expenses, Other Political Expenses and Civic/Charitable Contributions states, "[n]o lobbying expenses, other political expenses, or civic/charitable contributions are included in determining Net Operating Income. All are accounted for below the line." Company witness Chronister testified, ". . . every dollar of lobbying is below the line. It's not included in the ratemaking process, so ratepayers don't pay a penny for that." Because we have determined that no lobbying expenses have been included in test year expenses, we find that no adjustment is necessary to remove lobbying expenses from the 2009 projected test year.

Salaries and Employee Benefits

Company witness Merrill testified that there are three primary objectives in TECO's compensation and benefits program. First, the Company strives to offer a compensation and benefits program that will attract, retain, and competitively reward its team members based on national and local comparative markets. Second, TECO's compensation program reflects a success sharing philosophy, linking total compensation to the attainment of Company, business, unit, and individual goals. Third, the Company strives to keep its total compensation and benefit program expenses at a competitive level by targeting the market median for total compensation. The second component mentioned above, success sharing or incentive compensation, will be discussed separately.

Witness Merrill testified that TECO's total compensation levels are comparable to those of its competitors for team members performing similar jobs and with similar skill sets. TECO performs a detailed annual benchmarking analysis of its pay rates to those of its competitors to determine "position to market." Benchmark jobs are defined as jobs that are pure matches to the market and are common from company to company. The most recent market analysis completed in 2007 included market survey data from national third-party survey sources, including Towers Perrin, Hewitt, Mercer, and Watson Wyatt. According to the testimony of witness Merrill, TECO has maintained its average total compensation for benchmarked exempt and non-exempt jobs at or below the market average. Witness Merrill stated that the Company targets total compensation at the 50th percentile when comparing external market data to similar Company positions.

TECO evaluates its benefits using the Towers Perrin BENVAL Study, a nationally recognized and accepted actuarial tool that compares the value of benefit plans. The study methodology first analyzes the value of each benefit plan and then converts the plan values to a series of relative value indices by applying a standard set of actuarial methods and assumptions. This method of comparison neutralizes the effects of differences in team member demographics, geographic differences, and related influences. Towers Perrin's Employee Benefit Information Center analyzes the competitiveness of participating companies' benefit programs and produces the BENVAL Study. According to witness Merrill, TECO's BENVAL Index for the total benefit program is rated 91.5, which means that the Company's total benefit program is slightly below the national average, yet it is comparable and competitive.

Concerning officer compensation, Witness Merrill testified that since filing the rate case, the Company looked at the market to see what other companies in the US were doing to deal with the economic conditions. The Company decided that its officers for both TECO Energy and TECO will receive no increase in compensation in 2009. The officers' total compensation for both TECO Energy and TECO officers was originally provided during discovery. These responses were updated to reflect no increases in compensation for the officers in 2009. These changes require an adjustment to decrease jurisdictional O&M expenses by $129,655 ($133,589 system) for the TECO Energy officers' compensation allocated to TECO. Also, an adjustment is required to decrease jurisdictional O&M expenses by $77,157 ($79,498 system) for the TECO officers' compensation. The total adjustment is a decrease in jurisdictional O&M expense of $206,812 ($213,088 system) for all the officers of both companies. With the exception of our adjustment to the Incentive Compensation Plan, we do not support OPC's adjustment with respect to the level of compensation of TECO employees. TECO has otherwise presented sufficient information to demonstrate that the level of its salaries and employee benefits are reasonable. The Company conducts considerable market analysis that it uses to target its total compensation at the 50th percentile when its pay rates are compared to external market data for similar Company positions. The Company's market analysis also shows that its benefit program is slightly below the national average. TECO has maintained its average total compensation for benchmarked exempt and non-exempt jobs at or below the market average.

OPC witness Schultz testified that he had three concerns with the Company's requested payroll: (1) the overtime dollars included in the filing have not been identified or tracked by the Company; (2) the Company has requested 151 additional employees above the 2007 levels; and, (3) the Company's requested incentive compensation plan is problematic. According to witness Schultz, "the problem with the Company's proposed overtime dollars is that we have no idea what amount is included in the test year. The response to OPC Interrogatory No. 35 states that the Company's budget system does not have a detailed breakout of overtime and other pay for 2008 and 2009." Witness Schultz argued that not having a detailed breakout of overtime raises serious concerns as to how the Company can measure performance when an important component of payroll is not tracked and/or monitored. Although witness Schultz raised concerns about the Company's overtime payroll dollars, he did not propose a specific adjustment to the Company's test year payroll expense for this item.

Company witness Chronister testified "that overtime dollars are most certainly tracked by the Company in its actual accounting records. Tampa Electric's general ledger, along with its internal control systems, contains time data and payroll transactions with a well-documented audit trail. The same level of detail is not generated for budget purposes because it is not necessary to perform a simulated time entry process." Further, witness Chronister stated that overtime is properly estimated and included in projected expense based on the expertise and experience of the departments creating their budgets. The Company can and does measure performance by comparing both actual overtime and total payroll to budgeted amounts.

OPC witness Schultz testified that there are concerns with the Company's employee benefits relating to the 401(k) matching increase that took effect in April of 2007. According to witness Schultz, the problem with the Company's increase in the 401(k) matching is that the economy has forced a lot of changes on individuals and companies alike, yet TECO seems to be ignoring these changes.

Company witness Merrill testified:

> In April 2007, Tampa Electric did change the Company fixed match from 30 cents to 50 cents to be more comparable to other utilities. Based on Towers Perrin's 2007 Energy Services BENVAL study, the employer contribution aspect of TECO Energy's 401 (k) plan ranked fourth from the bottom and significantly below the industry average. The study also illustrates that the majority of companies in the "Energy Services" category have a defined benefit plan along with a defined contribution plan. Among companies providing both a defined benefit plan and a defined contribution plan, TECO Energy is still next to last among "Energy Services" companies.

Company witness Chronister testified that in preparing the 2009 budget, each department quantified its projects and activities into specific resource requirements in its respective budgets. According to witness Chronister, payroll cost assumptions are based on appropriate compensation levels given expected conditions on the job market.

Company witness Haines testified that TECO focuses on multiple initiatives to cost effectively maintain and enhance customer service and reliability. The two largest reliability programs the Company employs are vegetation management and wood pole inspections. These two initiatives provide the largest benefit for preventing outages before they occur. Witness Haines testified that during the 2009 test year, TECO will be increasing maintenance and tree trimming expenditures above current levels and will complete full implementation of inspection and maintenance programs in order to comply with our requirements. The expected result will be improved reliability and service to customers on both a day-to-day basis and following a major storm event. According to witness Haines, in 2007 the Company spent approximately $10.3 million on tree trimming for its distribution system. The vegetation management in 2009 is projected to be $16.1 million. TECO contracts out its entire tree trimming activities and the work is competitively bid. Witness Haines stated the Company had not quantified the 2009 dollars saved due to tree trimming.

OPC witness Schultz testified that he had concerns with the Company's requested 151 additional employees in the test year above the 2007 levels. He stated the Company has decreased its employee complement in 11 of the last 15 years (since 1992). Only in 2006 and 2007 did TECO have consecutive increases in its employees. According to witness Schultz, the Company's request should be reduced by 90 positions to a complement of 2,548. This is 17 positions more than year end 2007 and the September 30, 2008, level, and 61 positions more than the average for the historical test year 2007. The Company did not present rebuttal testimony to witness Schultz's proposal to reduce the number of projected positions for 2009.

We support OPC's proposal to reduce 90 positions from the Company's payroll. During the 2009 test year, TECO will be increasing maintenance and tree trimming expenditures above current levels and will complete full implementation of inspection and maintenance programs in order to comply with our requirements. The expected result will be improved reliability and service to customers on both a day-to-day basis and following a major storm event. However, while it is clear that the Company has projected the cost of these multiple initiatives for 2009, we find that the cost benefits of fewer outages and less restoration time have been incorporated into the total O&M expense projections for the 2009 test year. Therefore, the projected increase of 151 positions for 2009 shall be reduced to account for the effects of the increased vegetation management and wood pole inspections.

We find that OPC witness Schultz's proposed reduction of 90 positions is a reasonable method to account for the benefits that should be received from the Company's various initiatives to improve operational efficiency and effectiveness in a cost effective manner. The reduction of 90 positions reduces jurisdictional O&M expense by $3,568,109 ($3,676,382 system) and reduces Benefits expense by $1,420,208 ($1,461,650 system).

In total, we find that O&M expense shall be reduced by $5,195,129 ($5,351,120 system).

Other Post-Employment Benefits Expense

Company witness Chronister testified that the Company properly reflected in its 2009 revenue requirement calculation, the impact of accounting pronouncements that were issued since the Company's last rate case, including Financial Accounting Statement (FAS) No. 158, Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans. Witness Chronister further testified that the accounting treatments reflect our instructions, as delineated in Order No. PSC-06-1040-PAA-EI.[26] FAS 158, issued on September 29, 2006, amends FAS 87, FAS 88, FAS 106, and FAS 132R by requiring employers to recognize the funded status of a benefit plan in its statement of financial position. Previously, this information was only required to be disclosed in the footnotes.

Company witness Merrill testified on the design and cost of the Company's benefit plans that include Postretirement Plans. Witness Merrill stated that TECO projects medical and dental costs to be $13,110,000 for post-retirement benefits for 2009. According to witness Merrill, TECO's medical cost is below average based on the Towers Perrin BENVAL Study.

We have reviewed the data provided by the Company in its MFRs, Exhibits, and through discovery. We find that TECO has presented sufficient information to demonstrate that its Other Post Employment Benefits Expense is reasonable.

Budgeted Positions that will be Vacant

TECO does not budget based on the number of employees by month. Company witness Merrill testified that the Company does not track the number of vacancies. As indicated by witness Merrill, the number of vacancies is not a metric that is used to run the business. During his deposition, Company witness Chronister stated that TECO's budgeting process does not incorporate a head count. TECO's budget reflects the dollars of expense associated with the resources that it expects to consume. Regarding Salaries and Employee Benefits, we approved a reduction in total budgeted positions. No separate adjustment is needed for budgeted positions that will be vacant.

Initiatives to Improve Service Reliability

Company witness Chronister testified that in preparing the 2009 budget, each department quantified its projects and activities into specific resource requirements in its respective budgets. According to witness Chronister, payroll cost assumptions are based on appropriate compensation levels given expected conditions of the job market. Company witness Haines testified that TECO focuses on multiple initiatives to cost-effectively maintain and enhance

[26] Order No. PSC-06-1040-PAA0EI, issued December 16, 2006 in Docket No. 360733-EI, In re: Petition for authority to use deferral accounting for creation of a regulatory asset or regulatory liability to record charges or credits that would have otherwise been recorded in equity pursuant to balance sheet treatment required by Statement of Financial Accounting Standards (SFAS) No. 158, by Tampa Electric Company.

customer service and reliability. The two largest reliability programs the Company employs are vegetation management and wood pole inspections. These two initiatives provide the largest benefit for preventing outages before they occur. Witness Haines testified that during the 2009 test year, TECO will be increasing maintenance and tree trimming expenditures above current levels and will complete full implementation of inspection and maintenance programs in order to comply with FPSC requirements. The expected result will be improved reliability and service to customers on both a day-to-day basis and following a major storm event. Witness Haines testified that in 2007, the Company spent approximately $10.3 million on tree trimming for its distribution system. The vegetation management in 2009 is projected to be $16.1 million. TECO contracts out its entire tree trimming activities and the work is competitively bid. Witness Haines stated the Company had not quantified the 2009 dollars saved due to tree trimming.

We commend the Company for its actions to improve operational efficiency in a cost-effective manner. During the 2009 test year, TECO will be increasing maintenance and tree trimming expenditures above current levels and will complete full implementation of inspection and maintenance programs in order to comply with our requirements. The expected result will be improved reliability and service to customers on both a day-to-day basis and following a major storm event. However, while it is clear that the Company has projected the cost of these multiple initiatives for 2009, the cost benefits of fewer outages and less restoration time have not been incorporated into the total O&M expense projections for the 2009 test year. Therefore, OPC's proposed adjustment to reduce 90 positions under Salaries and Employment Benefits shall be made; this will account for the effects of the increased vegetation management and wood pole inspections.

Accepting OPC witness Schultz's proposed reduction of 90 positions is a reasonable method to account for the benefits that should be received from the Company's various initiatives to improve operational efficiency and effectiveness in a cost effective manner. No further adjustments are needed.

Incentive Compensation Plan

Company witness Merrill explained there are two components to TECO's annual pay program. The first component is a merit award determined by a team member's performance level and salary position relative to market. The second component is a variable incentive pay program known as "Success Sharing" that provides an annual one-time payment based on the achievements of the team member and company against pre-established goals. According to witness Merrill, the objective of the Success Sharing plan is to attract, retain and motivate high performing goal-oriented team members. Payments are tied directly to corporate performance goals that enhance operational efficiencies and financial stability of the organization, which in turn, reduces the ultimate cost to customers. Witness Merrill testified that this "at risk" component of total compensation has been a win-win for team members and customers.

Concerning the Success Sharing Plan or incentive compensation, OPC witness Schultz testified that the description of the plans' objectives is misleading from a ratemaking perspective, in that the plan heavily favors shareholder-oriented objectives/goals. Witness Schultz expressed doubt that this incentive pay is truly "at risk" based on the target setting. Moreover, according to witness Schultz, ratepayers are being asked to pay more than their fair share of the incentive plan, even assuming that this type of incentive plan is reasonable.

Witness Schultz testified that a review of the goals and achievements of goals for the period of 2003-2007 raised a number of concerns. According to witness Schultz, the goals set by the Company and the determination of eligibility payments under the plan are seriously flawed, particularly from a ratemaking and ratepayer prospective. Witness Schultz cited what he believed to be several examples of the Company setting targets and goals so that the employees are not required to improve performance in order to receive incentive pay, which he found in his review of the plan. According to witness Schultz, the Company also failed to achieve its target for five of the seven Success Sharing goals in 2003. In 2004, two of seven goals were not achieved. In 2005, five of seven goals were not achieved. In 2006, and 2007, two of seven goals were not achieved. Despite the fact that goals were not achieved in each of the 5 years, the Company still expensed and paid 18-49 percent more than the target level of incentive compensation budgeted during the years 2004-2007.

Witness Schultz recommends that the entire $11,574,843 ($11,233,952 on a jurisdictional basis) should be disallowed, because the Company's goals are not sufficiently established to require improvements that will provide either a cost benefit or safer and more reliable service to customers. If we were to conclude that some expense is justified, we should first limit the amount to the same expense percentage used for base payroll and overtime, and then limit the amount expensed to ratepayers to no more than 50 percent of the amount presumed to be justified. Because shareholders and ratepayers would conceptually benefit from a true incentive plan, witness Schultz argued, the cost of that plan should be shared equally.

FIPUG witness Pollock testified that incentive compensation that is contingent upon the parent and/or operating Company achieving certain financial goals, such as net income, cash flow, or other (stand-alone or comparative) measures, is beneficial to shareholders but not of direct benefit to ratepayers. For this reason, incentives to achieve financial goals are appropriately borne by shareholders, not ratepayers. Witness Pollock mentioned Texas and Wyoming as jurisdictions that have considered treating the portions of incentive plans that deal with financial measures differently from those that deal with operational measures. Witness Pollock recommended that Stock Compensation on MFR Schedule C-35, line 15 for 2009, shown as $2.6 million, should be excluded. He also recommended the disallowance of 100 percent of officer and key employee cash payments, because those payments are contingent upon TECO Energy achieving a specific level of net income. Additionally, he argued that a portion (50 percent) of the general employee-based incentive pay also should be excluded from allowable operating expenses, because it is based upon financial goals of both TECO and TECO Energy, the parent. Based upon the 2007 incentive compensation payout of $12.9 million, the additional disallowance would be $6.45 million. In total, he recommended a reduction of $9.05 million in the allowance of incentive compensation, on the basis that such compensation is for the benefit of shareholders rather than ratepayers.

Company witness Merrill described how the Company uses market data and benchmarking results to measure the competitiveness of its compensation. For each Company position, it matches essential job functions to those found in external market surveys. These same surveys show that incentive compensation programs like TECO's are commonly used by similarly-situated companies. Based on the World At Work 2008/2009 Annual Salary Budget Survey, over 80 percent of the 2,375 companies surveyed use an incentive pay program. TECO's Success Sharing plan has been in place since 1990, and its appropriateness was approved in the Company's last rate case in 1992. Witness Merrill stated that in Gulf Power Company's ("Gulf") most recent base rate proceeding (Docket No. 010949-EI), Mr. Schultz made similar arguments about its incentive compensation plan as he does about TECO's, but we did not agree with him and made no adjustment.[27] We noted that Gulf offers a plan consisting of base salary and incentive compensation, and that only receiving a base salary would mean Gulf employees would be compensated below employees at other companies.

Witness Merrill further testified on rebuttal that TECO would need to consider restructuring its total compensation package if any incentive compensation expenses were excluded. The Company would need to consider raising base salaries while decreasing or eliminating the "at-risk" incentive compensation component. It is inappropriate to single out the incentive component of an employee's total compensation for scrutiny just because it is called "incentive" compensation. TECO's total compensation package, including the portion that is contingent on achieving incentive goals, is set near the median level of benchmarked compensation, which is the relevant level of cost that should be considered for ratemaking purposes. Accepting Mr. Schultz's recommendation to disallow incentive compensation would adversely affect the Company's ability to compete in attracting and retaining a high quality and skilled workforce.

Concerning witness Pollock's proposed disallowance, witness Chronister testified that the amount to be adjusted would be based on total projected compensation of $11.6 million, not the $12.9 million used by witness Pollock. He further testified that only $7 million of the $11.6 million is in 2009 operating expense, and only a portion is attributable to TECO Energy's financial results. Since the payout for officers is contingent upon the parent Company's financial results, up to 100 percent could be disallowed according to witness Pollock's approach. However, it is not a trigger for a key employee payout, as only 15 percent of their incentive compensation is tied to TECO Energy results. Following Mr. Pollock's logic, only five percent (5 percent x 100 percent for officers) and three percent (20 percent x 15 percent for key employees) of total projected incentive compensation expense, or $560,000, would be subject to disallowance. According to witness Chronister, while the Company believes no disallowance is appropriate, he certainly disagrees with the $6.45 million Mr. Pollock recommends.

There are two components to TECO's annual pay program. One is a base salary based on the employee position and the other is a variable incentive pay program. TECO bases its total compensation on market data and benchmarking results to measure the competitiveness of its compensation. TECO's total compensation package, including the portion that is contingent on

[27] Order No. PSC-02-0787-FOF-EI, issued June 10, 2002, in Docket No. 010949-EI, <u>In re: Request for rate increase by Gulf Power Company.</u>

achieving incentive goals, is set near the median level of benchmarked compensation. The market data survey used by the Company shows that over 80 percent of the 2,375 companies surveyed use an incentive pay program. TECO's Success Sharing plan has been in place since 1990 and its appropriateness was approved in the Company's last rate case in 1992. Lowering or eliminating the incentive compensation would mean TECO employees would be compensated below employees at other companies, which would adversely affect the Company's ability to compete in attracting and retaining a high quality and skilled workforce. We therefore decline to do so.

We also find, however, that the incentive compensation should be directly tied to the results of TECO and not to the diversified interest of its parent Company TECO Energy. Therefore, jurisdictional operating expenses shall be reduced by $540,000 ($560,000 system) for that portion of incentive compensation pay tied directly to TECO Energy's results as recalculated by witness Chronister.

Contractual Service Agreements

Company witness Hornick testified that the combustion turbines (CTs) used by TECO at Polk and Bayside Power Stations are General Electric ("GE") 7F frames, which have a high level of performance and low emissions. The availability of parts and technical support services for these machines is very limited. Therefore, TECO entered into contractual services agreements ("CSAs") with GE to perform ongoing maintenance of the turbines. Under these agreements, GE is responsible for supplying maintenance services and parts necessary to perform all planned and unplanned maintenance on the units. Witness Hornick further explained that under CSAs, the availability of spare parts is improved and the inventory requirements for the parts are reduced. The risks of cost increases due to reduced maintenance interval requirements, replacement parts, and fallout from inspection are borne by GE. Unplanned maintenance expense and the management of maintenance services including subcontracting qualified craft labor and providing technical support are also GE's responsibility. Maintenance costs are levelized and escalation rates are pre-negotiated. He also pointed out that it is a common practice for CT operators to enter into CSAs with the original equipment supplier.

In discussing TECO's planned generation capacity additions, Witness Hornick testified that projects are underway to add 5 simple cycle CTs in 2009. The Company intends to enter into CSAs for the five new CTs to be placed in service during 2009. Each one of these machines has a nominal capacity of 60 megawatts, for a total of 300 megawatts. As there are three combustion turbines at the Big Bend station that are old and have reached the end of their useful life and are being decommissioned, the net capacity addition considering the new CTs and the retired CTs is approximately 170 megawatts. Big Bend Unit 1, which is ten MW, is the only one of the three CT retirements occurring during the test year. The other 2 CT retirements occur in 2008.

We find that the impact on the number of personnel, if any, would be minimal. Additionally, we approved reductions in the overall increase in headcount. No further adjustment is necessary due to the new CTs that will be maintained under CSAs.

<u>Generation Maintenance Expenses</u>

OPC witness Schultz testified that specific maintenance Accounts 511, 512, and 513 were examined because these accounts showed significant increases for the test year. He testified that the indexed average expense for accounts 511, 512, and 513, for the time period 2003-2007, was $59,291,000. Based on information provided to him from responses to discovery, witness Schultz then added $6,880,000 to account for additional maintenance projects that were included in 2009 over and above 2007. Adding the $6,880,000 to the indexed average cost of $59,291,000, he arrived at $60,671,000. The 2009 test year amounts presented by TECO for these accounts is $69,151,000, which is $8,480,000 higher. Schedule 10 shows the jurisdictional adjustment to generation maintenance of $8,173,000 ($8,480,000 system).

Company witness Hornick testified that when witness Schultz compared historical data with the Company's 2009 projected expenses, Account 511 was abnormally high due to the entire $6,900,000 Big Bend channel dredging expense. Since channel dredging typically occurs every 5 years, the Company subsequently made a pro forma adjustment to remove $5,500,000 of the $6,900,000 to reach an annual amount of $1,400,000. Therefore, the effective 2009 total generation maintenance expense (the total of Accounts 511, 512, and 513) is $63,631,000, not $69,151,000. Once this correction is made, witness Schultz's allowable expenses of $60,671,000 should be compared to the adjusted expense total of $63,631,000. Witness Schultz's own methodology (which the Company disagrees with) would only result in a recommended disallowance of $2,960,000.

We find that TECO has not justified the increases in Generation Expense for the test year. As discussed in detail below under <u>Number of Outages</u>, test year Generation Maintenance expenses are higher than both historical and projected future cost due to the number of planned outages. However, planned outages are just one component of Generation Maintenance Expense. The approach presented in this issue by OPC witness Schultz, as corrected by Company witness Hornick, eliminates the problem of singling out and reducing one category of maintenance expense, planned outages, without evaluating overall maintenance impacts. OPC's approach addresses a broad category of Generation Maintenance Expense for the Company rather than just planned outages. OPC's adjustment reduces generation Expense to a justified level for the test year.

We approve OPC's adjustment as corrected by Company Witness Chronister. Therefore, Generation Maintenance Expenses shall be reduced by $2,850,000 ($2,960,000 system).

<u>Substation Preventive Maintenance Expense</u>

OPC witness Schultz testified that based on information supplied in response to discovery, the Company is asking for a significant increase in preventive maintenance on substation infrastructure due to aging. The problem is, as shown on Schedule C-9, the Company spent on average $761,581 for preventive maintenance over the five years 2003-2007. The Company increased the required annual expense to $2,256,610, almost three times the average spent over the last five years, and more than two times the amount expensed in 2007. Despite the suggested urgent need, the Company planned to spend approximately 69 percent of the 2009 requested amount in the interim year 2008.

Witness Schultz proposed that the Company's maintenance request should be reduced to $1,199,425, a jurisdictional reduction of $973,201 ($1,057,185 system). The recommended spending for 2009 is based on an indexed 2007 expense of $1,118,958. OPC contended that TECO should have been spending the needed amount on maintenance to provide safe and reliable service, and that the Company should have to prove that it is spending what is needed to provide safe and reliable service justify increases in spending.

Company witness Haines testified that there are several elements of Mr. Schultz's testimony related to substation maintenance that are misleading. First, the 2007 costs he references are not representative of all activities that are needed in 2009. For example, in 2008, there were 23 fewer circuit breakers that needed to be maintained than in 2009. The additional cost of maintenance on these circuit breakers is $28,000. There were also changes made for classifying oil test costs from corrective maintenance to preventative maintenance late in 2007 that creates an additional $17,000 needed in 2009. The contractor costs for North American Electric Reliability Corporation ("NERC") required relay testing have increased, resulting in additional costs of $80,000 in 2009. TECO plans to test all of its relays. The yearly additional cost is $429,000. Finally, for 2008 and 2009, the substation condition based preventative maintenance included annual substation inspection costs, but the 2003 through 2007 historical costs did not. For comparison purposes, 2009 condition-based preventative substation maintenance should be $1,979,010. Based on the Company's experience in 2008, the costs are most likely understated.

The Company is asking for a significant increase in preventive maintenance on substation infrastructure due to aging. The Company has provided a detailed explanation of that increase and we find that the Company has fully refuted OPC's objections and has justified the increase in preventive maintenance on substation infrastructure. Thus, there is no need for an adjustment.

Dredging Expense

Witness Hornick testified that shipping channels used to deliver fuel to Big Bend Station accumulate sediment, which impedes the vessels' ability to navigate when fully loaded. He explained that silt and sediment accumulation at the circulating water pump inlets reduces unit efficiency, increases fuel costs, and causes additional maintenance expense. Witness Hornick stated that TECO's experience has shown that dredging is needed about every five years. He noted that the dock area and channels were dredged in 1992, 1997 and 2002. He advised that without dredging in 2009, vessels will need to be "light loaded" to reduce their required draft to navigate the channel, resulting in transportation inefficiencies and increased fuel costs in the form of financial penalties for waterborne fuel transportation. He stated that TECO "has a contractual obligation with United Maritime Group to maintain the Big Bend channels to accommodate vessels to a draft of 33 feet."

Witness Hornick stated that the Company plans to spend approximately $6.9 million on channel dredging in 2009. He explained that the Company's estimate consists of $5.5 million for the shipping channel dredging, $1 million for the inlet canal dredging, $200,000 for the terminal dock area dredging, and $200,000 for required aids to navigation maintenance. The total cost, including the share allocated to another party, is $9.6 million.

According to witness Hornick, costs are higher than in prior years because the spoil disposal areas "are currently about 80 percent full and there is not enough capacity to store the volume of dredge material that will be removed in 2009." He noted that TECO included costs for either expanding an existing disposal area or paying for off-site spoil disposal. He stated that the estimate from the dredging contractor to perform the work has increased significantly since 2002. The Company estimated the quantity of material to be dredged in the shipping and inlet channels based upon preliminary hydrographic surveys and past dredging experience, and then obtained estimates for this work from a local dredge/marine contractor. The Company compiled estimates for other costs that accompany dredging, including dike integrity testing, surveys, and other costs based upon the Company's last dredging project. Since there are currently two users of the channel, many of the costs are expected to be shared between TECO and the Mosaic Company (Mosaic). Witness Hornick stated that only the Company's portion of dredging costs is reflected in the 2009 projections.

Witness Chronister testified that, although there is historical variation in the timing and amount of cost, dredging is a necessary cost that typically occurs every five years. He opined that it is therefore appropriate to amortize the impact of this expenditure over five years. He advised that the jurisdictional net operating adjustment is a reduction of $3,267,000 to affect the amortization, and the jurisdictional rate base adjustment is an increase of $2,657,000 to working capital.

Witness Larkin testified that the Company's 2002 total dredging cost was $2,346,105, with $1,288,169 allocated to TECO and the remainder of $1,057,936 allocated to Mosaic. He stated that the 1997 total dredging cost was $1,329,989, with $228,400 allocated to Mosaic, leaving dredging costs expensed by TECO of $1,101,589. He argued that, based on this information, at most, only half the requested dredging cost should have been included in the current case. Witness Larkin removed from rate base the Company's deferred dredging cost balance of $2,657,000 (jurisdictional) and removed from operating expenses the remaining amount of $1,330,000. Witness Larkin stated that the historical information indicates that the Company has never incurred dredging costs which approach $6.9 million. He testified that since dredging was done in 1997 and 2002, the next five-year period should have been in the year 2007 and not 2009; thus, dredging costs would not be included in 2009.

Witness Chronister pointed out errors in OPC witness Larkin's testimony. First, the 50/50 sharing of the cost with another user of the shipping channel does not recognize that TECO only included its portion of the costs in the filing. Second, the $1,330,000 of dredging expense is the amortized portion of the cost, so that witness Larkin then amortizes it again, resulting in a 25-year amortization.

Witness Hornick stated that it is not a hard and fast rule that the Big Bend channels need to be dredged every five years, but that has been the Company's experience. He explained that in 2007 the Company determined that since it was not incurring "light loading" penalties from its waterborne carrier, it could wait for a year or two before incurring dredging expense.)

We have serious concerns regarding the lack of evidentiary support by TECO for its dredging costs. The only document provided was a one-page estimate that was two years old. That document showed a total cost of $4,730,813, not the $9.6 million cost stated by witness Hornick. Although TECO claims that there will be additional costs due to the need for additional spoils disposal, witness Hornick said the estimate was based on the Company's own understanding of dredging costs, but there was no estimate in hand.

Witness Hornick stated in testimony that there were increased fuel costs and additional maintenance expenses associated with the build-up of silt. However, when questioned about the amount of savings that would result for fuel and maintenance expense for the pumps, he was unable to quantify it. Upon further consideration, he made an educated guess that the savings would be less than ten percent and probably less than one percent. He stated that the savings were not reflected in the test year. We are concerned that this cost savings will not be passed through to the ratepayers.

We agree with TECO that there were some discrepancies in OPC witness Larkin's testimony involving the amortization costs. However, as pointed out by OPC in its brief, this was not the basis for witness Larkin's calculation, but was rather a historical check. Witness Larkin's exhibits clearly show that he removed the full amount of the dredging cost. We also agree with the Company that the cost of dredging is a necessary and prudent cost. Although support is deficient, the quote provided by Misener Marine can serve as a reasonable estimate. Any additional costs associated with the provision of an additional or improved spoils disposal area are unquantified and shall not be allowed, particularly in view of the fact that the potential savings resulting from efficiencies gained have not been shared with the customer.

Using the $4,730,813 quote and splitting the cost between TECO and Mosaic in the same proportion TECO used in this filing gives TECO a share of $3,400,272. Amortized over 5 years, the amount of expense is $680,054, for a reduction of $650,056. The remaining amount to be included in working capital is $1,309,351, for a reduction of $1,346,649. TECO's share of $3,400,272 is an increase of $1,054,166 over the 2002 amount of $2,346,106, or 45 percent.

Although dredging costs are a necessary cost of doing business, the full amount requested by TECO is not supported. The Company shall be allowed a total cost of $3,400,272, resulting in a reduction to expense of $650,056 (jurisdictional), and a reduction to working capital of $1,346,649 (jurisdictional).

Economic Development Expense

Recovery of Economic Development Expenses is governed by Rule 25-6.0426, F.A.C. Company witness Chronister presented the "Commission adjustments" to the Company's net operating income and rate base. Witness Chronister testified that the "Commission adjustments" reflect our directives, policies, and decisions from previous rate proceedings. He further testified that economic development expense for the test year was developed following the rules on what was allowable. He stated that we have various rules; some Economic Development Expenses are allowed 100 percent, some are allowed 95 percent, and some are allowed zero percent: "[s]o, with each category we projected, we flowed that through and only allowed the allowable percentage, the allowable dollars to be included in the filing." The elimination of a portion of economic development expenses is shown in the Company's MFR Schedules C-2 and C-3, and was the subject of various discovery requests. We have analyzed the MFRs and responses to discovery as well as the supporting work papers to the adjustments.

TECO's testimony, MFRs, and discovery responses, including work papers, support the Company's test year adjustment to remove economic development expense in accordance with our policies and rules. Therefore, no further adjustments shall be made to the Company's revenue requirement.

Pension Expense

TECO witness Merrill testified that pension plan expense for the test year is $7,379,000 based on an actuarial study by the Company's actuarial consultant, Towers Perrin. Witness Merrill testified that the actuarial assumptions and methods used for the pension valuation are reasonable, both individually and in the aggregate. We have reviewed the data provided by the Company in its MFRs, exhibits and through discovery. We find that TECO has submitted sufficient evidence to demonstrate that its pension expense is reasonable. Therefore, no adjustment to the Company's revenue requirement concerning pension expense is warranted.

Accrual for Property Damage

The Company presented information in its MFRs and discovery on property damage other than storm damage, in Account 924. The Company's storm damage accrual was discussed previously. We find that TECO has justified its property damage expense other than storm damage. Therefore, no adjustment is needed.

Accrual for the Injuries & Damages Reserve

The Company presented information on Account 925, Injuries and Damages, in its MFRs and through discovery that support its projected Injuries and Damages expense. We find that TECO has justified its Injuries & Damages reserve expense and therefore no adjustment is necessary.

Director's & Officer's Liability (DOL) Insurance Expense

OPC witness Schultz testified that DOL insurance initially protects officers and directors when decisions that they have made are challenged or determined to be bad business decisions. The extra factor with DOL insurance is that the primary plaintiffs are shareholders. In effect, the

DOL insurance provides shareholders protection against their own decisions. Ratepayers do not receive any of the proceeds from decisions or settlements in director and officer litigation, so ratepayers should not be responsible for the cost of protecting shareholders from their own decisions. Witness Schultz testified that the entire jurisdictional amount of $1,650,815 (system $1,700,908) of test year DOL insurance should be removed. He further testified that if we can identify a benefit that ratepayers receive, then he would recommend that the Company's request be limited to the 2003 jurisdictional expense of $635,428 ($654,392 system), reducing the 2009 rate year request by $1,046,516.

Company witness Chronister testified that he did not agree with witness Schultz that the increase in DOL insurance began to increase after 2002 as a result of the claims against officers and directors. According to witness Chronister, DOL insurance premiums fluctuate as a result of the same market forces that impact property, liability, workers' compensation, and other insurance policies. The primary drivers for the significant change in market conditions included the very negative claim experience of DOL insurance underwriters resulting from the dot-com stock market bubble, the negative influence of the 9/11 terrorist event, increasing and significant claim activity related to Enron, and a general increase in attention to corporate governance, including Sarbanes-Oxley legislation. Witness Chronister stated that, since 2007, TECO's premiums have stabilized to a point that represents the current "market" pricing level for DOL insurance.

Witness Chronister further testified that DOL insurance is clearly a necessary part of conducting business for any large corporation, and it would be impossible to attract and retain competent directors and officers without it. Corporate surveys indicate that virtually all public entities maintain DOL insurance including investor-owned electric utilities. DOL insurance enables the Company to assemble an effective team of directors and officers to manage and oversee the conduct of the electric business. Furthermore, DOL insurance provides a significant source of balance sheet protection from losses due to lawsuits, thereby safeguarding the utility from financial stress and preserving capital for uses that ensure the efficient delivery of electric service to ratepayers. Witness Chronister noted that the requested amount of $1,700,908 is the lowest of the 5-year period 2005 through 2009, including 2006 when the expense peaked at $2,115,321.

We find that DOL insurance is a part of doing business for a publicly-owned Company. It is necessary to attract and retain competent directors and officers. Corporate surveys indicate that virtually all public entities maintain DOL insurance, including investor-owned electric utilities. In fact, the requested amount of $1,700,908 is the lowest of the 5-year period 2005 through 2009. We do not agree with OPC that the ratepayers do not benefit from DOL insurance. It is not realistic to expect a large public company to operate effectively without DOL insurance. We also believe that it would be appropriate to reach back to the year 2003 to set rates in today's insurance market. Therefore, no adjustment is needed.

Meter Expense and Meter Reading Expense

TECO witness Haines stated that TECO initiated an automatic meter reading (AMR) project in 2003, which allows electric meters to be read remotely. He advised that the new technology increases operational efficiencies and aids in safety for meter readers. He testified that once an area has the new meters installed, the cost to read a meter drops from 45 cents per read to 15 cents per read, with time to read meters reduced by approximately 58 percent. He added that estimated bills are also greatly reduced. He testified that TECO expects the number of meter readers to fall from 87 at the end of 2003 to 63 by the end of 2009, with a cost reduction for meter readers and associated vehicles from $5.18 per customer in 2003 to a projected cost of $3.86 per customer in 2009. He stated that "the company has factored in all productivity improvements gained from this initiative into its cost projections." He noted that the Company plans to convert 55,000 residential meters to AMR meters each year at an estimated cost of 3 million dollars per year. According to witness Chronister, even though Account 902, Meter Reading Expense - Customer Accounts, has remained relatively level, it reflects a reduction of $205,000 due to the expected elimination of five meter readers in 2009.

We find that the record evidence indicates that the amounts included in Accounts 586 and 902 are appropriate as TECO has provided sufficient support for its projected meter reading expense. Therefore, no adjustment shall be made to reduce Account 586, Meter Expense and Account 902, Meter Reading Expense.

Amortization Period for TECO's Rate Case Expense

Company witness Chronister testified that the Company estimates rate case expense to be $3,153,000 and is proposing to amortize the expense over a 3-year period beginning in 2009. The Company did not include rate case expense in its budget for 2008 and 2009, so an adjustment is necessary to include the estimated expense in the test year. The Company-proposed jurisdictional O&M adjustment is an increase of $1,051,000. The Company-proposed jurisdictional rate base adjustment to working capital is an increase of $2,628,000.

OPC witness Schultz testified that the Company's total projected rate case expense is excessive and the amortization period should be five years. He noted that the Company is not a small company with limited human resources that would require significant assistance in assembling a rate filing. However, TECO projected contracted services other than legal of $2.123 million for this proceeding. Discussing Huron Consulting Services, L.L.C.'s (Huron) services, witness Schultz testified that in this case, it appears that the Company has an extra layer of review inserted, adding extra costs above and beyond what may really be necessary. He noted that the revised contract for Huron Consulting Services, L.L.C. provided for only $468,000. According to witness Schultz, the excessive average hourly rate that the Company agreed to pay contributes to the high cost of consulting services.

Witness Schultz identified two components of the Company's rate case expense that he believed to be excessive. First, he recommended that J.M. Cannell's cost of $116,000 should be removed since TECO has not entered into a contract for Ms. Cannell's services, and there is no justification for including these costs. Second, he recommended that $1.31 million for Huron be reduced to the contracted amount of $468,000. Concerning the amortization period, witness Schultz commented that the Company has not filed for a rate increase for years and even his recommendation of a five-year amortization period is short given TECO's history of long time periods between rate cases. He testified that if TECO were allowed to amortize the cost over a 3-year period, and were fortunate enough to stay out half as long as it did since its last filing, it would continue to recover rate case expense when no expense is being incurred.

FIPUG witness Pollock recommended that upon completion of the proceeding, and as part of the compliance filing, TECO should be required to provide actual rate case expenditures, with the actual expenditures being used to set the level of rate case expense to be recovered from customers. Second, he recommended that the amortization period for rate case expenses should be at least five years rather than the three years TECO requests. Witness Pollack noted that TECO's last rate case was in 1992 and that a longer amortization period is much more in line with TECO's rate case history.

FRF witness O'Donnell testified that Company witness Abbott's testimony provides no value to TECO's customers and accordingly, TECO should not be allowed to recover any of the $290,000 in proposed fees and costs for her testimony. He also recommended that the $116,000 in rate case expenses for the services of J.M. Cannell be denied, as Ms. Cannell offers no testimony at all in this proceeding.

Company witness Chronister testified that the Company is staffed to handle ongoing, day-to-day responsibilities, and the additional workload of the rate filings requires supplementing the existing team. He added that TECO's contract with Huron includes numerous tasks to be performed, including MFR review, tax analysis and support, testimony preparation, review of pro forma adjustments and revenue requirement components, and responding to discovery requests. In order to manage the consultant's time and scope of work, the Company divided the tasks into groups. The first grouping of tasks was for services estimated to cost $468,000. Since then, additional tasks have been authorized, and the Company's estimate of $1.31 million for Huron's services for the remainder of this proceeding remains appropriate.

Witness Chronister testified that TECO erroneously included rate case expenses for Ms. Cannell's services because it was not until intervenor testimony was filed that it became clear her services were not needed. He further testified that while it is difficult to predict when TECO will file its next base rate case, he was relatively certain it will be sooner than five years. Witness Chronister also testified that Huron, which has the highest charge of all the consultants, shares common directors with TECO Energy, Inc.

TECO provided a late-filed exhibit which detailed the actual expenses for external witnesses to date by witness through December 31, 2008. It also contained the following narrative:

> Although the Company has not closed its books for January 2009, expenses were incurred in January related to the rate case hearing. As a result of this and additional

> expenses to be incurred through the date of the Commission's decision, the total rate case expenses are expected to be reasonably close to the amount included in the Company's 2009 test year. The attached expenses do not include non-witness consulting and legal services, which total $1,122,881.18 through December 31, 2008. Total rate case expenses incurred through 2008 are $2,317,758.71.

We are concerned with the level of charges incurred and projected by the Company for this rate case. The testimony of witness Abbott was both extremely expensive when compared to the other cost of capital witness Murry, and somewhat redundant to the testimony of Company witness Gillette. The purpose of witness Abbott's testimony was to describe how rating agencies rate companies, the importance of regulation to ratings, and the basis of TECO' s current and targeted ratings. She analyzed TECO's current creditworthiness, its ratings, the reasons the Company is rated as it is, and the likely implications of its current rate request to its future ratings.

The fee for witness Abbott shall be reduced to the level estimated for the Company's cost of capital witness Murry. We realize that witness Abbott was not a cost of capital witness, but the testimony was in support of cost of capital and the Company's financial integrity. Thus, it is reasonable to compare her fee to witness Murry's. This reduces rate case expense for this witness from $290,000 to $68,000, for a decrease in rate case expense of $222,000 (system $222,000).

The Company did not take the opportunity to provide more detail in the late-filed exhibit. We do not have any breakdown between Huron and Legal services either for year to date actual or the latest projection. Therefore, we find that the expenses for Huron shall be limited to the $468,000 recommended by OPC witness Schultz. This will reduce the charges from Huron from $1,310,000 to $468,000, or by $842,000.

The original rate case estimate includes $116,000 for Ms. Cannell's services, which were not used, and shall be eliminated as agreed to by the Company.

The 3 recommended reductions of $116,000 for Ms. Cannell, $222,000 for witness Abbott, and $842,000 for Huron produce a total reduction of $1,180,000. The Company's original estimate of $3,153,000, reduced by $1,180,000, produces the revised estimate of total rate case expense of $1,973,000. Also, the amortization period shall be increased from 3 to 4 years, which is consistent with several of our recent rate cases and does not conflict with Company witness Chronister's testimony that he was relatively certain that TECO will request another rate increase sooner than 5 years. Increasing the amortization period from 3 to 4 years results in a revised annual amortization of $493,250. This reduces the Company's original projection of $1,051,000 by $557,750.

<u>Bad Debt Expense</u>

OPC witness Larkin testified that the Company based its bad debt expense on Accounts 440 through 446, Retail Billed Sales and Account 451, Miscellaneous Service Revenues, in the years 2004 through 2007 as sales subject to bad debt. However, for the years 2008 and 2009, the Company also included as sales subject to bad debt write-off Account 447, Sales for Resale, Account 456, Unbilled Revenue, and Accounts 407.3 and 407.4, Deferred Clause Revenues.

Witness Larkin recommended taking a five-year average (2003 through 2007) of the Company's Bad Debt Factor and applying that to the Company's projected gross revenues from sales of electricity (Accounts 440-446 and 451), yielding a more consistent and representative level of uncollectible expense for the test year. He also testified that we should not use the effects of economic downturns in determining bad debt in setting rates. This would protect TECO from the effects of the economy and pass it onto ratepayers. Witness Larkin testified that historical data will reflect ongoing bad debt expense and not be influenced by the effects of economic downturns. As shown on Schedule C-3, witness Larkin proposed decreasing jurisdictional bad debt expense by $2,342,000 ($2,409,000 system), using a bad debt rate of .246 percent.

Company witness Chronister testified that the revenues used by the Company to calculate uncollectible expense did not include Account 447, Sales for Resale, Account 456, Unbilled Revenues, and Accounts 407.3 and 407.4, Deferred Clause Revenues. Witness Chronister testified that the Company properly used Accounts 440 through 446, Retail Revenues Billed and Account 451, Miscellaneous Service to calculate uncollectible expenses. According to witness Chronister, witness Larkin is pointing out a discrepancy that only exists on MFR Schedule C-11, and that MFR Schedule C-11 does not impact the projection of bad debt expense contained in the 2009 test year. According to witness Chronister, the discrepancy on MFR Schedule C-11 would change the factor by less than one one-hundredth of one percent and would cause the revenue requirement to increase by $7,000.

The present economic downturn is not a theoretical concept. According to witness Chronister, the actual bad debt write-offs are increasing rapidly despite the Company's numerous efforts to manage the increase. Witness Chronister testified that bad debt expense first peaked in 2007 and then peaked again in 2008, and is expected to be at its highest level ever in 2009. According to witness Chronister, OPC's adjustment is backward looking and not indicative of what is occurring during the test year.

Certainly the current economic downturn is real and is not expected to rebound soon enough to positively affect the Company's test year. The Company is likely to experience an increase in bad debt expense in 2009 over 2007 and 2008. We find that the record evidence demonstrates that TECO has appropriately accounted for its bad debt expense; therefore, no adjustment for bad debt expense needs to be made.

<u>Office Supplies and Expenses</u>

OPC Witness Schultz testified that TECO's response to OPC Interrogatory No. 65 did not provide an analysis or any documentation to support the increased cost for Account 921, Office Supplies and Expense. According to witness Schultz, it simply stated that the projected test year amount was based primarily on historical spending adjusted for contractual agreements, additions for new activities, and removal of activities no longer applicable. The response went on to say that the primary drivers for the increase were increased training, higher information technology costs, building maintenance and miscellaneous expenses. Witness Schultz did say that the response to OPC Interrogatory No. 116 provided some added detail, but again the response was quite general.

Witness Schultz recommended that the Company's request of $11.181 million be reduced by $2.363 million to $8.818 million. The calculation of this adjustment is shown on Schedule C-12. On a jurisdictional basis, OPC recommended that the expense be reduced by $2.295 million. Witness Schultz asserted that an adjustment is required because the Company failed to provide sufficient justification for the increase of 39 percent over the 2007 test year expense of 8.067 million.

Witness Chronister testified that the Company provided a detailed breakdown of the $3.1 million increase in this expense in interrogatory No. 116. Along with other details, the Company explained how there was a $216,000 increase in expense for security associated with its facilities, a $979,000 increase in information technology costs, a $461,000 increase in building maintenance expenses, and a $530,000 increase in training and development costs. Witness Chronister further testified that it is inappropriate for witness Schultz to pick and choose certain expenses that may be higher than in a selected previous year and call for their reduction, while ignoring many other expenses that are lower than previous years.

Based on the record evidence, TECO provided support for its projected office supplies expense. Therefore, no adjustment for Office Supplies and Expense is necessary.

Tree Trimming Expense

Company witness Haines testified that TECO is increasing its vegetation management program to establish and maintain a three-year distribution system trimming cycle in order to comply with our requirements for storm hardening. TECO began ramping up its vegetation management program at the end of 2005, with an emphasis on critical trimming needed in areas identified by the Company's reliability-based methodology. The Company continues its progress toward a three-year tree trim cycle plan and anticipates reaching its goal by 2010.

OPC witness Schultz testified that the Company is asking for $16,073,444 for distribution tree trimming and $1,797,319 for transmission vegetative management. According to witness Schultz, the transmission request appears reasonable, but the distribution tree trimming request of $16,073,044 is excessive. Witness Schultz based his calculation of tree trimming costs on 1,530 trim miles at the same $7,897 rate that the Company paid in 2007. This provides for an increase in miles and takes into consideration the fact that the escalating fuel costs are now back to 2005 levels. He stated, as shown on Schedule C-6, the Company should be allowed $12,084,876 for tree trimming. That reduces the Company's request for distribution tree trimming of $16,073,444 by $3,988,568.

Company witness Haines testified that tree trimming reduces outages and improves restoration following a major storm event. He also stated that contractor rates have increased at a greater rate than the Consumer Price Index (CPI) due to increased demand for these resources and increased fuel costs. The Company based its 2009 projected expenditures on known contract rates along with other reasonable cost estimates. Witness Haines testified that the number of miles trimmed each year by the Company and reported to us reflects the total miles inspected and/or trimmed, which includes some miles that have no vegetation. Therefore, Mr. Schultz's suggestion that the actual miles requiring trimming and associated costs should be adjusted is inaccurate and inconsistent with how the Company reports miles trimmed. The $7,897 cost per mile figure that Mr. Schultz references is a total cost which includes both circuit miles with and without trees. To translate that cost to only those circuit miles with trees would result in a significantly higher cost per mile.

OPC's recommendation was based on the incorrect number of total trim miles which would have allowed the Company only 1,530 miles of tree trimming during the test year.

Witness Haines testified that in 2007, the Company spent approximately $10.3 million and trimmed roughly 22 percent of its distribution system. Applying a 4 percent contractor increase each year, the Company would need $11.2 million to trim 22 percent. According to witness Haines, given recent experience with costs, it is very reasonable to expect that $16 million will be required to trim approximately 33 percent of the distribution system by 2010. In 2009, the Company plans to ramp up the additional tree trim resources needed to trim 29 percent of the distribution system.

We calculate the trim rate per mile for 2009 to be $8,315 per mile. This is based on the year 2007 when 22 percent of the 6,121 circuit miles were trimmed. The 22 percent of 6,121 total trim miles is 1,347 trim miles for 2007. The amount spent in 2007 of $10.3 million indexed to 2009 is $11.2 million. Dividing the $11.2 million of 2007 cost indexed to 2009 by the 2007 trim mile of 1,347 produces the $8,315 per mile for 2009. Applying this rate to the 2009 trim miles of 1,775 (29 percent of 6,121 circuit miles) produces an estimate for the 2009 test year of $14,759,000.

Thus, we approve a test year tree trimming amount of $14,759,000 ($14,759,000 system). Comparing this to the Company's projection of $16,073,000 indicates that the Company's projection is overstated by $1,314,000.

<u>Pole Inspection Expense</u>

OPC witness Schultz testified that, as shown on Schedule C-7, the Company's request for $1,573,778 should be reduced by $236,013 to $1,337,765. Historically, the Company has not attempted to inspect a high number of poles in any one year. Now that we have approved a pole inspection program, the Company has an eight-year inspection cycle. The 8-year inspection cycle requires an inspection of 40,750 poles per year. Indexing the 2007 average cost per pole of $30.63 results in a 2009 average cost per pole of $32.83. The $32.83 multiplied by the annual inspection requirement of 40,750 poles equals a cost of $1,337,765.

Company witness Haines testified that TECO's pole inspection plan was filed and approved in Order No. PSC-06-0778-PAA-EU, issued on September 18, 2006, in Docket No. 060531-EU, In Re: Review of all electric utility wooden pole inspection programs. The proposed budget for the 2009 pole inspection program is appropriate and necessary to meet the order requirements. The $30.63 average cost per pole inspection in 2007 used by Mr. Schultz does not include the comprehensive pole loading analysis the Company is required to do for all joint use poles, which was included in the Company's 2009 pole inspection budget. The contractor used by the Company to perform this work has escalated its rates at a greater rate than the index referenced by Mr. Schultz. Finally, the 40,750 poles to be inspected each year include both distribution and transmission poles that have different rates.

Thus far in 2008, the Company has experienced a rate of $33.03 per distribution pole inspection. Once a 4 percent contractor price increase is factored in, the projected 2009 cost per distribution pole inspection will increase to $34.35. When this is applied to the 37,500 distribution poles to be inspected annually (one-eighth of the system), the proposed budget is $1,288,170. When the budgeted $147,844 for transmission pole inspections and $95,892 for comprehensive loading analysis are included, the total 2009 budget is reasonable.

We find that the record evidence demonstrates that TECO's proposed budget for the 2009 pole inspection program is appropriate and necessary to meet the requirements of the pole inspection plan that was approved in Order No. PSC-06-0778-PAA-EU. Thus, no adjustment is needed.

Transmission Inspection Expense

OPC witness Schultz testified that the Company's request for $642,773 is more than twice the 5-year average of $277,760 expended for transmission inspections. He testified that TECO provided no documentation that supports doubling of the costs from 2007 historic costs to the projected 2009 test year. According to witness Schultz, as shown on Schedule C-8, the Company's request for $642,773 should be reduced by $318,846 ($268,233 on a jurisdictional basis) to $323,927. Witness Schultz determined the recommended expense level of $323,927 by indexing the 2007 expense of $302,195.

Company witness Haines testified that the Company's transmission structure inspection program was filed and approved as part of its Ten Point Storm Hardening Plan.[28]

The Company's 2009 budget includes $29,000 for lattice tower inspections, something that has not been performed recently but is now required for the foreseeable future given the aging infrastructure. While the transmission structure inspections have been occurring since our storm hardening rules were first established, all of the identified repairs as a result of the inspections must now be made.

[28] Order No. PSC-07-1020-FOF-EI issued December 28, 2007, in Docket No. 070297-EI, In Re: Review of 2007 Electric Infrastructure Storm Harding Plan filed pursuant to Rule 25-6.0342, F.A.C., submitted by Tampa Electric Company.

We find that the record evidence indicates that TECO's 2009 budget is reasonable when the amount recommended by OPC of $333,927 is increased to take into consideration $29,000 for lattice tower inspections and $300,000 for expected repairs as a result of the inspections. Therefore, no adjustment is necessary.

Number of Outages

Company witness Hornick testified that planned outages, as the name suggests, are defined as those outage periods that are anticipated and planned for well in advance of the actual outage period (typically at least one year in advance). Maintenance conducted during planned outages consists of large tasks that are performed infrequently. Typical examples are steam turbine inspections and repairs, replacement of large heat transfer surfaces in the boiler, and refurbishment of large motors and pumps. The 2009 planned unit maintenance durations are shown for each unit in MFR Schedule F-8, page 10 of 21. There are 13 generating units with planned maintenance outages scheduled in 2009. A total of 54 planned outage weeks are scheduled across the 13 units. Witness Hornick testified that the planned outage schedule varies from year to year based on the maintenance requirements of each generating unit and the need for adequate generating capacity in service to meet demand throughout the year. According to witness Hornick, the planned maintenance forecasted for 2009 is typical of the past and expected future planned outage requirements.

FIPUG witness Pollock testified that as a part of his review of TECO's projected O&M expenses, he determined that these expenses are overstated because they reflect an abnormal number of scheduled outages. He asserted that TECO is projecting the highest number of scheduled outages in 2009 than in any other year since 2003. He recommended that test year O&M expenses be adjusted to reflect a more normal level of scheduled outages. TECO projected the duration of planned Big Bend outages to increase from 22.5 weeks in 2008 to 32 weeks in 2009, a more than 30 percent increase. Overall plant outages scheduled would increase from 43 weeks in 2008 to 54 weeks in 2009.

Witness Pollock characterized the test year outages as nonrecurring. He noted that the last time two major Big Bend outages occurred in the same year was in 2006 when Units 1 and 3 were both down for major inspection outage. He pointed out that in 2009, there are three proposed outages. Two of the three scheduled outages are to install selective catalytic refiners (SCR), at Units 1 and 2. He also testified that TECO has scheduled a maintenance overhaul of most of the operating equipment and boiler of Unit 4. Company witness Hornick pointed out that the Company's settlement with the Environmental Protection Agency and the Florida Department of Environmental Protection required that these alterations (SCRs) be in place by 2010.

Witness Pollock testified that TECO did not originally plan for two major Big Bend outages in 2009. The Company originally planned only one major outage per year at Big Bend through 2013. Witness Pollock presented testimony that showed the outage costs for the period 2003-2009. He cited 2008 as an example, where 43 outage weeks resulted in $13.7 million of

O&M expenses. He then compared this to 54 outage weeks at a projected cost of $20.2 million for the test year. He testified that the projected increase can be attributed to the high number of outage weeks at Big Bend and that the test year should be representative of normal circumstances.

Witness Pollock recommended that Test Year O&M expenses be adjusted to reflect normal maintenance outage levels in terms of costs. Specifically, TECO's outage-related expenses over the period 2003 - 2009 averaged $12.2 million per year. Thus, witness Pollock recommends that TECO should be allowed $12.2 million for planned outages during the test year and TECO's proposed expense should be reduced by $8 million.

Company witness Hornick testified that witness Pollock's analysis does not adjust historical expenses for known escalations. Also, his simple averaging approach focused only on planned outage expense and ignored forced outage and routine (non-outage) maintenance expense. It is not appropriate to single out and reduce one category of maintenance expense without evaluating overall maintenance impacts. Witness Hornick pointed out that the planned outage weeks for 2008 was 48.5, and not 43 weeks as used by witness Pollock.

Witness Hornick stated that it is true that since 2007, TECO has been installing SCRs on all four Big Bend units. This work will be complete in April 2010. The number of outage weeks per year will range from 45 to 54 weeks, and will average 48.4 weeks. According to witness Hornick, it is true that the planned outage duration for 2009 is greater than that for 2008, 2010, and 2011, but it is not unreasonable.

We find that the record evidence demonstrates that the planned outage expense is higher in the test year than in either the historical or future periods. Based on the data presented by TECO, the 2009 planned outages are approximately 5.6 weeks higher in the test year than the average of 2008 – 2011. The average dollar amount per week for outage expense for this same period is $333,000. This indicates a decrease of $1.44 million ($1.5 million system) for the test year. This adjustment was made under Generation Maintenance Expense. Thus, no further adjustment shall be made relative to this issue.

<u>Amortization of CIS Costs Associated with Required Rate Case Modifications</u>

CIS costs are those associated with modifications to update the customer information system that are needed to implement the rate changes requested in this docket. We previously approved the costs to upgrade the CIS system as appropriate. Once the amount to be included in Plant in Service is determined, if any, it is necessary to determine the amortization period over which to recover the costs.

TECO witness Chronister stated that the costs to upgrade the CIS system should be amortized over five years. The intervenors focused on whether to include the upgrade costs in Plant in Service. The amortization period was unrebutted.

We find that the record evidence supports TECO's proposed five-year amortization period. Accordingly, the adjustment for CIS modifications associated with rate case modifications are appropriate and shall be approved.

Annualization of Five Simple Cycle Combustion Turbine Units

As more fully discussed under Pro Forma Adjustments, we concur with OPC's position that the Company's pro forma adjustments to annualize the five simple CTs as if they were in service on January 1, 2009, violates the principle of matching revenue, expenses, and rate base for a projected test year. We reject the Company's position for the same reasons.

We find that O&M, Depreciation & Amortization Expense, and Taxes Other Than Income Taxes should be decreased by $212,000, $1,391,000, and $2,226,000, respectively, for the May units. Our jurisdictional adjustments to O&M, Depreciation & Amortization Expense, and Taxes Other Than Income Taxes are decreases of $658,000 $4,034,000, and $3,227,000, respectively, for the September units.

As discussed above, TECO's pro forma adjustments for all 5 CTs shall be eliminated. The total jurisdictional adjustments for O&M, Depreciation & Amortization Expense, and Taxes Other Than Income Taxes are decreases of $870,000 $5,425,000, and $5,453,000, respectively, for all 5 combustion turbine units. The total approved adjustment to Net Operating Income before the impact of income taxes is a decrease of $11,748,000. The impacts to Rate Base of these adjustments are also discussed under Pro Forma Adjustments.

Annualization of Rail Facilities

As more fully discussed under Pro Forma Adjustment Related to Big Bend, we concur with OPC's position that the Company's proposed adjustment to annualize the effects of the Big Bend Rail Project should be rejected entirely because it violates the principle of matching revenue, expenses, and rate base for the projected test year. The jurisdictional adjustments to Depreciation & Amortization Expense, and Taxes Other Than Income Taxes are decreases of $906,000 and $1,039,000, respectively. However, as noted above, we approve a step increase for the Big Bend Rail Project.

Test Year Depreciation Expense

TECO witness Chronister testified that the depreciation expense in the filing reflects the rates approved in the Company's 2007 Depreciation Study.[29] We have reviewed the Company's filing and find that the record evidence demonstrates that the correct depreciation rates were used. Therefore, no adjustments are necessary.

[29] Order No. PSC-08-0014-PAA-EI, issued January 4, 2008, in Docket No. 070284-EI, In Re: Petition for approval of 2007 depreciation study and annual dismantlement accrual amounts by Tampa Electric Company.

Depreciation Expense

Based on our previous adjustments under Projected Level of Plant in Service, Annualization of Five Simple Cycle Combustion Turbine Units, and Annualization of Rail Facilities, the projected 2009 Depreciation and Amortization Expense of $194,608,000 shall be reduced by $7,579,485, to an adjusted amount of $187,028,515. (See Schedule 3)

Taxes Other Than Income Taxes

We find that TECO has properly forecasted Taxes Other Than Income Taxes and no adjustment is warranted.

Parent Debt Adjustment

Rule 25-14.004, F.A.C., states that "the income tax expense of a regulated company shall be adjusted to reflect the income tax expense of the parent debt that may be invested in the equity of the subsidiary where a parent-subsidiary relationship exists and the parties to the relationship join in the filing of a consolidated income tax return." Further, Rule 25-14.004(3), F.A.C., states that "it shall be a rebuttable presumption that a parent's investment in any subsidiary or in its own operations shall be considered to have been made in the same ratios as exist in the parent's overall capital structure." Rule 25-14.004(4), F.A.C., provides that:

> The adjustment shall be made by multiplying the debt ratio of the parent by the debt cost of the parent. This product shall be multiplied by the statutory tax rate applicable to the consolidated entity. This result shall be multiplied by the equity dollars of the subsidiary, excluding its retained earnings. The resulting dollar amount shall be used to adjust the income tax expense of the utility.

In MFR Schedule C-24, TECO provided some of the information required to calculate the parent debt adjustment, but did not include an adjustment to income tax expense to reflect the parent debt in the calculation of its requested revenue requirement. In Interrogatory No. 11, the Company was asked to provide the financial information necessary to make a parent debt adjustment in accordance with Rule 25-14.004, F.A.C. The Company provided the following information:

Debt Ratio of the parent	19.01%
Debt Cost Rate of the parent	6.90%
Consolidated Statutory Tax Rate	38.575%
Subsidiary Equity	$1,901,759,000

In its response, the Company also provided an alternative set of data, which it labeled "Company Position," as follows:

Debt Ratio of the parent	0.00%
Debt Cost Rate of the parent	6.90%
Consolidated Statutory Tax Rate	38.575%
Subsidiary Equity	\$0 - \$72,957,000

TECO reiterated its objection to application of the parent debt adjustment in this case, as expressed in the testimony of TECO witness Gillette.

In direct testimony, witness Gillette stated that TECO Energy, the parent company of TECO, has \$404 million of long term debt on its books. Witness Gillette also stated that there were circumstances where the Company could rebut the presumption in Rule 25-14.004(3), F.A.C., that a parent debt adjustment is appropriate. According to witness Gillette, "TECO Energy did not raise debt to invest in Tampa Electric, nor did it invest the proceeds of the debt it did raise as equity in Tampa Electric." Witness Gillette stated that the debt was related to TECO Energy's investment in TPS, a former subsidiary which is no longer in existence.

Witness Gillette provided the following expanded rationale for not applying the parent debt adjustment:

> 1) as stated above, the debt that exists at the parent was raised for TECO Energy's merchant power plant investments at TPS and was not used to invest in Tampa Electric, 2) imputing parent debt would result in an inappropriate imputed capital structure given how TECO Energy raises capital on behalf of its regulated and unregulated companies, 3) imputing debt for the cumulative equity infused to Tampa Electric over time ignores that the vast majority of the equity that exists at Tampa Electric was invested by TECO Energy in Tampa Electric during times when either no parent debt existed or at a time when parent debt was actually being repaid, and 4) TECO Energy's internal subsidiary 100 percent net income dividend policy results in an overstatement of the paid in capital equity amounts that have required the investment of parent capital as used in the parent company debt rule calculation.

Witness Gillette stated that at the time of the Company's last rate case, TECO Energy had approximately \$100,000,000 of debt related to its Employee Stock Option Trust, and that this debt was not imputed to TECO in the rate case. We have reviewed Order No. PSC-93-0165-FOF-EI, and note that there is no discussion of the applicability of the parent debt adjustment in the order.[30]

Witness Gillette stated that between 1998 and 2003, TECO Energy raised approximately \$3.4 billion dollars of external capital, including approximately \$2.1 billion in debt. He asserted that the bulk of this capital was invested in TPS and other unregulated subsidiaries. He also

[30] See Order No. PSC-93-0165-FOF-EI, issued February 2, 1993, in Docket No. 920324-EI, In re: Application for a rate increase by Tampa Electric Company.

stated that TECO Energy has not raised debt outside this time frame and has, in fact, paid the balance down to its present level.

In addition to his argument that the parent debt adjustment is inappropriate because none of the debt proceeds were invested in TECO, witness Gillette also stated that the $1,901,759,000 of projected subsidiary equity is overstated because TECO Energy's policy requires subsidiaries to pay dividends equal to all of their net income to the parent. Most of these dividends are paid out to TECO Energy shareholders, and some are reinvested in the subsidiaries. He expressed the opinion that the accounting treatment of these transactions results in amounts that should properly be classified as retained earnings of TECO, but are instead classified as paid in capital on the financial statements. Rule 25-4.004(4), F.A.C., states that the subsidiary equity used in calculating the parent debt adjustment does not include retained earnings. Witness Gillette maintained that the appropriate subsidiary equity to be used in a parent debt calculation in this case would be approximately $72 million, rather than the approximately $1.9 billion reflected in the financial statements.

In its post-hearing brief, OPC disagreed with TECO's rationale for not applying the parent debt adjustment. OPC noted that the assets of TPS are no longer on the consolidated books of TECO Energy, and that the remaining debt must be repaid from corporate funds of TECO Energy, which could include funds generated by TECO. OPC noted that TECO Energy receives the tax benefit of the interest paid on the debt, but cannot specifically link the tax benefit to a subsidiary which no longer exists. In its statement of position, OPC stated that a parent debt adjustment should be made in the amount of $8,140,774. OPC does not explain how this amount was calculated.

We concur with OPC that the Company has not effectively rebutted the presumption that the parent debt adjustment should be applied in this case. In his testimony, witness Gillette admitted that "tracing funds is a complicated and difficult exercise." In ruling that a parent debt adjustment was required in a case involving Indiantown Company, Inc., we stated:

> Based on our analysis, the rule requires that a parent debt adjustment be made in this proceeding. Further, the rule does not allow for specific identification of debt from the parent to the subsidiary utility. Since the utility is included in the consolidated income tax returns of the parent, we believe that it would be very difficult to prove specific identification to only the utility. Rule 25-14.004(3), Florida Administrative Code, states that it shall be a rebuttable presumption that a parent's investment in any subsidiary or in its own operations shall be considered to have been made in the same ratios as exist in the parent's overall capital structure.[31]

Rule 25-14.004, F.A.C., is based on the premise that debt at the parent level supports a portion of the parent's equity investment in the utility. Since the interest expense on such debt is

[31] See Order No. PSC-00-2054-PAA-WS, issued October 27, 2000, in Docket No. 990939-WS, In re: Application for rate increase in Martin County by Indiantown Company, Inc.

deductible by the parent for income tax purposes, the income tax expense of the regulated subsidiary is reduced by the tax effect. Furthermore, the Company has not demonstrated that the interest on the debt on its books can be attributed to any source other than the general funds of the parent.

With respect to the subsidiary equity amount to be used in the calculation of the parent debt adjustment, we find that it is appropriate to use the full amount of paid in capital reflected on the books and records of the Company. Witness Gillette criticized what he characterizes as a change in classification of retained earnings to paid in capital resulting from TECO Energy's dividend policy. However, he does not contend that the current books and records are not presented in accordance with generally accepted accounting principles (GAAP). In a case involving United Telephone of Florida (UTI), we required the use of UTI's current capital structure in the computation of a parent debt adjustment, stating:

> However, we must determine the capital structure to be used for that adjustment. United, although opposed to the parent debt adjustment, proposed that if such an adjustment was to be made it should utilize the parent's 1983 capital structure which preceded the significant increase in debt at the parent level to finance the acquisition and expansion of US Sprint. OPC contends that the Commission should not apply the parent company debt adjustment proposed by United based on UTI's debt level in 1984, because such a procedure would implicitly assume that it is possible to trace dollars. However, if the Commission chooses a procedure to trace funds, then a double leverage capital adjustment utilizing UTI's 1983 consolidated capital structure and cost rates to determine UTF's cost of common equity should be used.
>
> We believe that the current UTI capital structure should be used for determining the parent debt adjustment. It would not be appropriate to use UTF's 1983 capital structure for ratemaking purposes in 1993; similarly, it would make no sense to use UTI's 1983 capital structure for making a parent debt adjustment for ratemaking purposes in 1993. Additionally, we will not use the double leverage adjustment suggested by OPC. The double leverage formula inherently traces funds to their capital source, but we consider funds to be fungible. Also, we believe that a double leverage adjustment for UTF may result in an ROE that understates the Company's required return on capital. Accordingly, we shall apply the parent debt adjustment as set forth in Rule 25-14.004.[32]

Accordingly, the parent debt adjustment shall be applied in this case, and the elements of the computation shall be based on the projected test year capital structures of TECO Energy and TECO. Our calculation of the system income tax expense reduction is as follows:

[32] See Order No. PSC-92-0708-FOF-TL, issued July 24, 1992, in Docket No. 910980-TL, In re: Application for a rate increase by United Telephone Company of Florida.

Debt Ratio of parent		.1901	
Debt Cost Rate of parent	X	.069	
	=	.0131169	
Consolidated Tax Rate	X	.38575	
	=	.005059844	
Subsidiary Equity	X	$1,901,759	(in 000s)
Parent Debt Adjustment	=	$9,623	(in 000s)

In MFR Schedule C-4, p. 5, TECO calculated a jurisdictional separation factor for income taxes of 1.003612. Applying this factor to the adjustment calculated above results in a jurisdictional adjustment of $9,657,000 (9,623,000 x 1.003612).

In conclusion, the Company has not effectively rebutted the presumption that a parent debt adjustment should be applied pursuant to Rule 25-14.004, F.A.C. The appropriate subsidiary equity amount to be used in the calculation is the projected test year equity of $1,901,759,000. Accordingly, the appropriate jurisdictional adjustment is a reduction of income tax expense in the amount of $9,657,000.

Income Tax Expense

Based on our adjustments, the requested total income tax expense of $48,492,000 (current, deferred, and ITC) shall be increased by $6,004,887 resulting in an adjusted total of $54,496,887 for the 2009 projected test year. (See Schedule 3)

Amount Requested	$48,492,000
Commission Adjustments:	
Issue 76 – Parent Debt	(9,657,000)
Effect of Other Adjustments	14,677,178
Interest Synchronization	984,709
Total Adjustments	6,004,887
Adjusted Amount	$54,496,887

Projected Net Operating Income

Based on our adjustments, the appropriate net operating income for the 2009 projected test year is $215,013,533. (See Schedule 3)

REVENUE REQUIREMENTS

Net Operating Income Multiplier

In calculating the net operating income (NOI) multiplier, the only component at issue is the bad debt rate. In its calculation, TECO used its 2009 projected bad debt rate of .349 percent, resulting in an NOI multiplier of 1.63490. OPC witness Larkin used a 5-year average (2003 – 2007) of write-offs and gross revenues to calculate an average bad debt rate of .2464 percent. Witness Larkin's resulting NOI multiplier is 1.633202.

As discussed previously, the projected bad debt expense, resulting in a bad debt rate of .349 percent, is reasonable for the 2009 projected test year, and no adjustment is necessary. Therefore, the appropriate NOI multiplier is 1.63490 using a bad debt rate of .349 percent. The calculation of the NOI multiplier is shown below.

		TECO	OPC	COMMISSION
1.	Revenue Requirement	100.000%	100.0000%	100.000%
2.	Gross Receipts Tax Rate	0.000%	0.0000%	0.000%
3.	Regulatory Assessment Fee	0.072%	0.0720%	0.072%
4.	Bad Debt Rate	0.349%	0.2464%	0.349%
5.	Net Before Income Taxes (1) - (2) - (3) - (4)	99.579%	99.6816%	99.579%
6.	Income Taxes (5) x 38.575%	38.413%	38.4522%	38.413%
7.	Revenue Expansion Factor (5) - (6)	61.166%	61.2294%	61.166%
8.	Net Operating Income Multiplier (100%/line 7)	1.63490	1.633202	1.63490

Annual Operating Revenue Increase

Based on our decisions in this case, the appropriate annual operating revenue increase for the 2009 projected test year is $104,268,536. The following schedule shows the calculation of the revenue requirements.

Calculation of Revenue Requirements December 31, 2009 Test Year		
	TECO	**COMMISSION**
Rate Base Rate of Return	$3,656,800,000 x 8.82%	$3,437,610,836 x 8.11%
Required NOI Adjusted Achieved NOI	$322,530,000 (182,970,000)	$278,790,239 (215,013,533)
NOI Deficiency Revenue Expansion Factor	$139,560,000 x 1.6349	$63,776,706 x 1.6349
Total Revenue Increase	$228,167,000	**$104,268,536**

RATE ISSUES

Calculate The Projected Revenues At Existing Rates

TECO has correctly calculated the projected revenues at existing rates.

Jurisdictional Separation Study

TECO utilized, with minor changes, the same jurisdictional separation methodology we approved in TECO's last base rate proceeding, producing separation factors utilized in the MFRs. Changes made to that methodology relate to transmission and were made to comply with FERC and Commission orders and practices. The results of TECO's jurisdictional separation study show that retail represents the vast majority of the electric service provided by TECO and that retail is responsible for 96.3 percent of production plant, 82.3 percent of transmission plant, and 100 percent of distribution plant.

Retail Cost of Service Methodology

The purpose of a cost of service study is to form a cost basis for establishing revenue requirements for each rate class. To accomplish this, a cost of service study performs three activities. First, it functionalizes costs into production, transmission, distribution, customer and administrative/general categories. Second, these functionalized costs are separated into classifications based on the utility service being provided. There are three principal classifications of costs: (1) demand costs, which are costs that vary with the kilowatt (kW) demand imposed by the customer; (2) energy costs, which are costs that vary with the energy or kilowatt-hours (kWh) used; and (3) customer costs, which are costs that are directly related to the number of customers served. Finally, the costs are allocated among the rate classes, with the goal that the share of cost responsibility borne by each class approximates the costs imposed on the utility by that class.

TECO in its brief explained that once we determine the overall revenue requirement for a utility, the responsibility for paying the revenue requirement must be allocated among the various customer classes. Cost of service studies are our primary tool in assigning revenue requirements to customer classes to help ensure that the prices customers pay for electric service bear a reasonable relationship to the costs of providing that service. Costs removed from assignment to one class via a change in cost methodology must be made up by other classes of customers.

TECO proposed to modify the cost of service study used for rate design from the 12 CP and 1/13 AD method to the 12 CP and 25 percent AD method to better reflect cost causation.

The only point of contention on the cost of service methodology dealt with the treatment of production demand costs in the cost of service study. Witness Ashburn explained that TECO has not proposed to change the allocation of transmission demand and distribution demand costs.

TECO filed two cost of service studies in this proceeding. We require an investor-owned utility (IOU) to file, at a minimum, a cost of service study consistent with the methodology approved in the utility's last rate case. As required by the MFRs, TECO filed a cost of service study allocating production demand cost on a 12 CP and 1/13 Average Demand (AD), or energy method, which was the approved methodology in TECO's last rate case. Under the 12 CP and 1/13 AD method, approximately 92 percent, or 12/13, of the production demand classified costs are allocated on a 12 CP basis, and approximately eight percent, or 1/13, are allocated on an average demand, or energy basis. CP is the maximum peak demand of the class that occurs at the time of the system peak. The term "12 CP" refers to the average of each rate class's 12 monthly CP demands in the projected test year. Average demand or energy is simply the relative kWh usage by class. This has been the method we have most often relied upon in previous rate cases involving Florida's IOUs.

TECO also filed a second cost of service study, which represents the study TECO is requesting approval of, and which differs from the MFR-required study in the treatment of production demand costs. TECO's proposed cost of service study increases the proportion of production demand costs that are allocated on energy from eight percent to 25 percent. The remaining 75 percent of demand costs are allocated on a 12 CP demand basis. This methodology is called the 12 CP and 25 percent AD method.

TECO's proposed cost of service study does not change total dollars collected by TECO when compared to the 12 CP and 1/13 study, but it does change the allocation of the approved total revenue requirement among the customer classes. A greater energy allocation shifts costs away from residential customers to larger commercial and non-firm customers, who have a greater energy responsibility relative to their peak load responsibility.

Witness Ashburn testified that the proposed methodology provides a more appropriate allocation of production plant within the cost of service study when considering how power plants are planned and operated. Witness Ashburn stated that the Company has installed a significant amount of base and intermediate-load generation, which was more expensive to install than peaking generation, but less expensive to operate over time. Witness Ashburn further stated that the percentage in prior Commission-approved studies for TECO have ranged from 8 percent (under the 12 CP and 1/13 AD methodology) to over 70 percent derived from the Equivalent Peaker method approved in Docket No. 850246-EI, TECO's 1985 rate case.[33] Investment in more expensive generating units and associated equipment to provide more efficient fuel conversion for generation of electricity drives the need to use a greater energy allocation, i.e., 25 percent, with the production demand cost allocator.

FIPUG objected to TECO's proposed cost of service methodology. FIPUG stated in its brief that TECO has asked us to approve a cost of service methodology which it has never used, but which, more importantly fails to appropriately assign and allocate cost. Witness Pollock stated in his testimony that TECO's contention that higher investment or capital costs are

[33] Order No. 15451, issued December 13, 1985, in Docket No. 850050-EI, In re: Petition of Tampa Electric Company for authority to increase its rates and charges.

incurred to save energy costs, or the notion that a utility is said to "substitute" capital investment for fuel savings, is referred to as the theory of "capital substitution." Witness Pollock's main criticism of TECO's proposal was that it allocates costs beyond the economic breakpoint between base load and peaking capacity, and thus crosses the line between cost causation and cost shifting.

He noted that TECO is placing undue emphasis on year-round energy, or annual average demand, rather than on peak demand. Witness Pollock believed this emphasis is misplaced because peak demand drives the need to install generation capacity. He admitted that we have recognized that all kWh production is considered in determining what type of capacity is installed. He went on to explain that if new capacity is expected to run only a limited number of hours, total costs are minimized by the choice of a peaker because the lower capital costs offset the higher fuel costs. On the other hand, if the unit is expected to run a sufficient number of hours, then the intermediate or base load will be more economical because the lower fuel costs offset the higher capital costs.

Witness Pollock criticized the use of a higher percentage for average demand because it allocates more costs to higher load factor customers beyond the "break point," or the benefits they receive from the lower fuel costs of the units. He stated that the 12 CP and 25 percent AD are totally contrary to capital substitution.

TECO noted in its brief that the selection of the appropriate cost allocation method is a matter of judgment upon which reasonable people can disagree, and it comes down to a judgment decision which affects how much of the revenue requirement should be allocated to each class. We agree with TECO on this point.

Witness Ashburn noted that TECO has installed a significant amount of base and intermediate generation, which was more expensive to install but less expensive to operate over time. This investment was made not only for fuel savings but also for environmental and efficiency considerations. Witness Ashburn, in his rebuttal testimony, stated that the example Mr. Pollock used to support his position is mathematically correct, but it is inconsistent with equitable principles that are generally employed in average cost rate making. It is, witness Ashburn maintained, closer to a marginal cost pricing concept in that it assumes usage beyond the break-even point does not benefit from the higher investment costs. Under the average cost pricing, which has traditionally been used to set utility rates, both the first and last kWh benefit equally from the lower operating costs of the base and intermediate plant. Witness Pollock's argument that no benefits accrue beyond the break even point results in the benefits to high load factor customers to be understated. TECO must consider not only the pure capital substitution argument offered by FIPUG but also the societal emphasis on environmental quality and efficiency. While fuel costs and investment costs can be easily quantifiable, the environmental and efficiency benefits are, to some extent, societal benefits that benefit all of TECO's customers equally, and a greater sharing of investment costs associated with these benefits is merited.

FIPUG argued that we have never embraced the 12 CP and 25 percent AD cost of service. We are not bound by any prior decisions in this matter, if we believe that circumstances warrant a change in cost methodology. While the 12 CP and 1/13 AD method has been relied upon frequently in the past, we have also deviated in the past from that method.

In TECO's 1985 rate case, Docket No. 850050-EI, five cost of service studies were introduced into evidence. We approved what is referred to as the "Equivalent Peaker Cost Method." That method allocated 70 percent of production plant to energy and the remaining 30 percent on demand. Witness Ashburn explained in his deposition that TECO was not a supporter of the Equivalent Peaker methodology, and in TECO's next rate case in 1992, Docket No. 920324-EI, we approved, based on a settlement of rate design issues, the 12 CP and 1/13 AD method.[34] TECO believes that that Equivalent Peaker method allocated too much plant to energy (70 percent) and the 12 CP and 1/13 AD allocates too little (8 percent). TECO stated that it is its and AARP's view that the 25 percent is just right and that it is the fairest balancing of the energy allocation for all parties.

In its 2000 rate case,[35] Progress Energy Florida, Inc. (PEF) filed the MFR required study, and two additional studies: 12 CP and 25 percent AD and 12 CP and 50 percent AD. That rate case was settled among all the parties and the stipulation provided that the 12 CP and 1/13 AD methodology would continue to be used during the term of the stipulation.[36] PEF again requested a 12 CP and 25 percent AD cost allocation methodology in its 2005 rate case,[37] which was also settled by stipulation using the 12 CP and 1/13 AD cost methodology. In both cases, the cost of service methodology was never formally reviewed or approved, but simply accepted as part of the stipulations. While past decisions are instructive, we demonstrated in 1985 that history does not preclude even a radical new approach to cost allocation. What TECO has offered here is a step towards a greater allocation of costs on energy.

In an attachment to Witness Ashburn's direct testimony, the results of the two cost of service methodologies at issue are compared. Specifically, the exhibit shows the allocated class revenue requirement resulting from each of the two cost of service studies. Under TECO's proposed 12 CP and 25 percent AD cost of service study, the revenue requirement for the residential customers decreases by 1.2 percent, or \$6.9 million, when compared to the 12 CP and 1/13 AD method. A lower revenue requirements means lower base rates. Small commercial customers would also see a decrease (0.9 percent) in their revenue requirement. The GSD rate class, which includes larger commercial customers and the interruptible customers, would see a 1.8 percent, or \$6.7 million, increase in the class revenue requirement. Finally, lighting customers would see an increase in the revenue requirement.

[34] Order No. PSC-93-0165-FOF-EI, issued February 2, 1993, in Docket No. 920324-EI, In re: Application for a rate increase by Tampa Electric Company.
[35] Docket No. 000824-EI, In re: Review of Florida Power Corporation's earnings, including effects of proposed acquisition of Florida Power Corporation by Carolina Power & Light.
[36] Order No. PSC-02-0655-AS-EI, issued May 14, 2002, in Docket No. 000824-EI, In re: Review of Florida Power Corporation's earnings, including effects of proposed acquisition of Florida Power Corporation by Carolina Power & Light.
[37] Docket No. 050078-EI, In re: Petition for a Rate Increase by Progress Energy Florida.

Based on the record, we find that TECO's proposal for a 12 CP and 25 percent Average Demand Allocation is reasonable and therefore it shall be approved.

Investment and Expenses related to the Polk Unit 1 Gasifier

Witness Ashburn stated in his direct testimony that all of the Company's production plant facilities are classified as demand-related; however, there are portions of two production facilities that TECO classified as energy. These facilities consist of the gasifier for Polk Unit 1 and the scrubber portion of the environmental equipment for Big Bend Unit 4. The classification of those two facilities is at issue here.

Witness Ashburn explained that the Polk Unit 1 is an Integrated Gasified Combined Cycle plant that has two main sections, the power block, which produces the power, and the gasifier, which converts solid coal fuel into gas used in the power block. In its brief, TECO stated that coal is injected into the gasifier and is converted into a synthetic gas that is used to operate the power block. Witness Ashburn noted in his testimony that the gasifier performs a fuel conversion function that is completely associated with the provision of fuel to the unit and not the supply of capacity. In his deposition, witness Ashburn explained that the function of the power block, which is a combustion turbine, and the gasifier are different. The gasifier is associated with fuel input into the plant and simply serves as a conversion of one fuel to another, whereas the power block provides reliable energy to the system. TECO stated that the gasifier produces fuel, and that fuel and fuel handling equipment have always been allocated and recovered on an energy basis.

Witness Ashburn stated that the classification of the Big Bend Unit 4 scrubber as energy-related was approved in TECO's last approved cost of service study.[38] He argued that this treatment remains appropriate because the main purpose of the scrubber plant investment is related to energy output. In its brief, TECO stated that the scrubber captures unwanted emissions from the plant and does not serve load or help maintain reliability. Witness Ashburn further explained during his deposition that the scrubber that was originally built for Big Bend 4 was integrated into Big Bend 3. Therefore both coal units are using the scrubber, which is being recovered through base rates. Witness Ashburn testified that, while the scrubber is physically connected to the power plant, there is no engineering requirement that the scrubber must operate for the unit to operate. Witness Ashburn further testified that since the last rate case, additional scrubber investments for Big Bend 1 and 2 made by the Company have been recovered through the Environmental Cost Recovery Clause (ECRC), where they have been allocated on an energy basis. Witness Ashburn concluded by stating that customers benefit from lower energy costs as the result of these investments, not primarily because of their contribution to system peak.

FIPUG rejected TECO's proposed classification of the gasifier and scrubber, and advocated a demand allocation. With respect to the gasifier, FIPUG maintained that power plants are built to produce capacity to serve load and maintain reliability. The Polk Unit,

[38] Order No. PSC-93-0165-FOF-EI, issued February 2, 1993, in Docket No. 920324-EI, In re: Application for a rate increase by Tampa Electric Company.

including the gasifier, was constructed to meet peak demand and should be classified to demand, not energy. With respect to the scrubber, FIPUG argued that the scrubbers were installed to comply with a settlement TECO entered into with the Environmental Protection Agency and the Florida Department of Environment Protection. Witness Pollock further argued that in addition to being directly related to production plant, pollution control investments are primarily fixed and do not vary with energy usage.

This issue does not address total dollar amounts, but the classification and allocation, i.e., energy or demand, of two production plant investment costs. We agree with TECO that the Polk Unit 1 gasifier and the Big Bend Units 3 and 4 scrubber should be classified as energy, as opposed to demand, and thus allocated to the rate classes on an energy basis. An energy allocation typically shifts cost away from the residential class to larger commercial/industrial customers, which have greater energy responsibilities than demand responsibilities. The classification of the Big Bend Unit scrubber as energy-related was approved in TECO's 1992 rate case, and continues to be appropriate. FIPUG has presented no evidence to suggest that this allocation is no longer appropriate and that we erred in the 1992 rate case. While TECO is required because of environmental obligations to operate the scrubber, the plant can operate without a scrubber. The scrubber removes unwanted emissions, allowing TECO to burn high sulfur coal which is a lower cost coal, thereby reducing fuel costs which are allocated on an energy basis. Furthermore, the scrubber for Big Bend Units 1 and 2 is being recovered through the ECRC, which allocates costs on an energy basis.

The Polk Unit 1 gasifier performs a fuel conversion function, converting solid coal into gas. Polk Unit 1 can operate without the gasifier, as the unit has a dual fuel capability and can operate using oil. Therefore, we find that it is appropriate to allocate the cost of the gasifier on a energy basis as well.

Unbilled Revenues

We find that TECO's calculation of unbilled revenues is correct.

Allocation of Any Change in Revenue Requirement

The allocation of any revenue increase granted to the various customer classes is largely dependant on the final revenue increase amount. There appears to be no dispute among the parties regarding the allocation of the revenue increase, other than which cost of service study to use. It has been our long-standing practice in rate cases that the appropriate allocation of any change in revenue requirements, after recognizing any additional revenues realized in other operating revenues, should track, to the extent practical, each class's revenue deficiency as determined from the approved cost of service study, and move the classes as close to parity as practicable.[39] The appropriate allocation compares present revenue for each class to the class cost of service requirement and then distributes the change in revenue requirements to the

[39] Order No. PSC-02-0787-FOF-EI, p. 66, issued June 10, 2002, in Docket No. 010949-EI, In re: Request for rate increase by Gulf Power Company.; and Order No. PSC-08-0327-FOF-EI, p. 63, issued May 19, 2008, in Docket No. 070304-EI, In re: Petition for rate increase by Florida Public Utilities Company.

classes. No class should receive an increase greater than 1.5 times the system average percentage increase in total, and no class should receive a decrease. The appropriate allocation must recognize approved changes in consolidation of classes, treatment of current IS customers, and restructuring of lighting rate schedules.

Interruptible Rate Schedules

TECO's basic position is that interruptible service should be provided as a conservation program, not a base rate discount. TECO proposed that the currently closed to new business interruptible rate schedules be eliminated and existing customers on those rate schedules be transferred to the GSD, GSDT (time of use), or SBF (standby) rate schedules with cost effective credits for interruptible service provided under the General Service Industrial Load Management Rider (GSLM-2) and General Service Industrial Standby and Supplemental Load Management Rider (GSLM-3) conservation program rate riders. To support its position, Witness Ashburn stated that we have allowed customers under the IS-1 and IS-3 rate schedules to continue service under these rate schedules even though they are no longer cost-effective. Witness Ashburn concluded that this proceeding provides the best opportunity to accomplish a transfer and permanently eliminate the IS-1 and IS-3 rate schedules with limited impact to the customers still served under those schedules.

With respect to all other issues raised by FIPUG, such as the level of the credits, the length of time those credits remain in effect, and which customer classes should pay for the cost of the credits, TECO maintained that those are issues that are determined in the conservation proceedings where the GSLM programs are reviewed each year.

FIPUG maintained that we should not eliminate the interruptible rate schedules, which have been in place for decades. FIPUG further stated that interruptible tariffs are a valuable resource to TECO, its customers, and to the state as a whole. Interruptible customers receive an inferior quality of service in comparison to firm customers, who TECO must be prepared to serve at all times. FIPUG concluded that we should retain the current interruptible schedules and reset the interruptible rate to take into account the increasing value of interruptability. However, FIPUG also stated in its brief that if we prefer the "credit" approach to interruptible service, we must ensure that such a rate design provides rate stability by maintaining the same credit between rate cases, is properly valued, is properly recovered, and is not reduced by a load adjustment factor.

TECO provides interruptible service to industrial customers under currently closed to new business rate schedules IS-1/IST-1/SBI-1 and IS-3/IST-3/SBI-3, collectively referred to as interruptible or IS rates schedules. Interruptible service is one of TECO's demand response resources used to reduce load while continuing to provide service to firm customers. A customer taking service under the IS rate schedules is subject to immediate and total interruption whenever any portion of such energy is needed by the utility for the requirements of its firm customers or to comply with requests for emergency power to serve the needs of firm customers of other utilities. At the hearing, witness Ashburn noted that while TECO is not required to provide notice about an interruption pursuant to the tariff, TECO has procedures in place to provide notice to interruptible customers in advance that an interruption may happen.

The IS-1 rates were closed to new business during TECO's 1985 rate case in Docket No. 850050-EI because the rates were no longer cost-effective. We allowed the existing IS-1 customers to remain on the rate for purposes of rate continuity. In the same docket we approved a new IS-3 rate schedule, which provides for a higher base energy charge than the IS-1 rate. A cost-effective analysis for non-firm load compares the credit IS customers receive, i.e., the difference between firm rates and the lower interruptible rates, to the cost of the next generating unit.

In TECO's 1992 rate case, we ordered TECO in its next rate case to file a cost of service study that allocates costs to the interruptible classes based on their load characteristics, and a study that develops a coincident kW credit based on avoided costs. We approved this provision as a stipulation in the cost of service and rate design issues in the rate case.[40]

In Docket No. 990037-EI, we approved the closure of the IS-3 rate schedules to new customers on the basis that they were no longer cost effective to the general body of ratepayers, and approved two new load management programs: General Service Industrial Load Management Rider (GSLM-2) and General Service Industrial Standby and Supplemental Load Management Rider (GSLM-3).[41]

The rationale for offering interruptible customers a lower rate is that their loads are available for interruption, and the utility avoids building new generating facilities to serve them. Under both the current IS rates and GSLM load management riders, interruptible customers receive a reduction in their bills to recognize the fact that they are receiving non-firm service. However, the way the IS and the GSLM rate schedules are calculated differs.

The IS rate schedules provide for reduced base rates (compared to firm service) based on the allocation process in a cost of service study. Witness Ashburn explained that when calculating base rates, IS customers have received a minimal allocation of production capacity cost under a 12 Coincident Peak (CP) and 1/13 average demand methodology. This minimal allocation is a result of assuming a zero 12 CP load responsibility and an average demand load responsibility for 1/13 or approximately eight percent of the production capacity costs. Any production costs not allocated to the IS class are allocated to all non-interruptible customers. Therefore, the reduction in base rates received by the IS customers is recovered from firm customers through an increase in their base rates.

The GSLM rate schedules are demand side management (DSM) programs and provide for a credit to the otherwise applicable firm rate. Any credits paid to interruptible customers on the GSLM rate schedules are recovered from all ratepayers through the ECCR charge.

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[40] See Order No. PSC-93-0165-FOF-EI, issued February 2, 1993.
[41] See Order No. PSC-99-1778-FOF-EI, issued September 10, 1999, in Docket No. 990037-EI, In re: Petition of Tampa Electric Company to close Rate Schedules IS-3 and IST-3, and approve new Rate Schedules GSLM-2 and GSLM-3.

Customers who take service under the GSLM rate schedules pay all charges associated with the otherwise applicable firm rate schedule.

The monthly interruptible demand credit contained in the GSLM rate schedule is applied each month regardless of whether an interruption occurs. The credit is the product of the Contracted Credit Value (CCV) and the monthly load factor adjusted demand. The CCV is determined in TECO's annual ECCR clause filings. The CCV for the period January through December 2009 is $10.91 per KW and has been approved in Docket No. 080002-EG.[42]

TECO currently serves 55 interruptible accounts under the IS rate schedules and all IS customers will be eligible for service under the GSLM rate schedules. Witness Ashburn pointed out that in the interruptible class there is one customer that currently has multiple accounts, and a couple of customers have one or two accounts. In late-filed hearing exhibit, TECO provided an analysis that shows that the IS rate class would see, under TECO's proposal, an 11.66 percent increase. This is in line with the increase residential customers would experience under TECO's proposal. TECO's revised MFR Schedule A-2, as filed on December 1, 2008, shows that a residential customer using a 1,000 kWhs will experience an 8 percent increase, and a residential customer using 1,500 kWhs will experience a 10 percent increase under TECO's requested increase.

Witness Ashburn stated that the primary benefit of transferring the IS customers to the GSLM interruptible conservation programs is to ensure that such load is provided under a cost-effective rate schedule so that firm customers will not be required to provide a long-term subsidy to interruptible load. Furthermore, witness Ashburn testified that under the GSLM conservation programs, the credit for interruptible service will track avoided cost and be commensurate with the benefits IS customers provide to the overall ratepayers.

In its post-hearing brief, FIPUG stated that we should not eliminate the interruptible rate schedules. However, FIPUG witness Pollock performed a revised cost-of-service study that included IS customers as firm load. We therefore believe that witness Pollock agrees with TECO's proposal that IS customers pay base rates based on their fully allocated cost of service. TECO and FIPUG do not agree on whether the IS, GSD, and GSLD customers should be consolidated under one new GSD class as proposed by TECO, or whether the IS class should be a separate IS rate as proposed by FIPUG. We will discuss this issue below.

Since we determined in 1985 that the IS-1 rates were no longer cost-effective, and in 1999 that the IS-3 rates were no longer cost-effective, we concur with TECO that this rate case is the appropriate time to eliminate the current IS rate schedules and transfer all current IS-1 and IS-3 customers to a cost-based firm IS rate schedule, with the appropriate credit provided under the GSLM load management riders.

[42] Order No. PSC-08-0783-FOF-EG, issued December 1, 2008, in Docket No. 080002-EG, In re: Energy Conservation Cost Recovery Clause.

As stated above, under the GSLM rate schedules, customers receive a credit against the otherwise applicable firm rate. FIPUG maintained that the current $10.91 CCV is understated for two reasons. First, FIPUG argued, the credit does not assign any value for plant that is avoided from 2009 though 2011, and second, the analysis should use 2009 instead of 2008 as the base year. FIPUG did its own evaluation and concluded that the credit should be $13.70 per kW.

Witness Ashburn testified in his rebuttal testimony that we approved the CCV for 2009 in the 2008 ECCR proceeding. He restated his position during the hearing, pointing out that TECO is not recommending a credit in this proceeding, as the credit has been approved in the 2008 ECCR docket. Witness Ashburn further stated that the CCV methodology used was consistent with prior determinations, and that witness Pollock's concerns about the CCV would have been more appropriately addressed in the ECCR docket, a docket in which FIPUG was an active participant.

We agree with the Company that the level of the credit is not an issue in this base rate proceeding. The CCV for 2009 was approved in the 2008 ECCR proceeding. We will determine the CCV for 2010 in the 2009 ECCR proceeding, Docket No. 090002-EG. The 2009 ECCR proceeding will provide FIPUG an opportunity to address its concerns regarding the appropriate credit level.

We reviewed Witness Pollock's calculation of the $13.70 credit. The calculation did not utilize our approved methodology in calculating the credit. The methodology is specified in Rule 25-17.008(3), F.A.C.

Witness Pollock explained that it would be reasonable to set these avoided generation capacity benefits based on the installed cost of the Baytown and Polk CTs that TECO proposed to include in this base rate proceeding. As discussed previously, the CTs are scheduled to be in service during the test year 2009 and are presently under construction. In association with the referenced rule, the meaning for the term "avoided generating unit" is explained as a proposed generating unit that can be avoided in whole or in part by a conservation program. Once construction is underway on a unit, that unit is not available to serve as an "avoided unit." The units used by witness Pollock as the basis for his calculation are not allowed by the rule.

FIPUG stated that the interruptible credit must remain stable between rate cases. Interruptible service may require substantial investment in equipment and modifications to manufacturing operations, the cost of which interruptible customers expect to recover over a period of time through lower rates. Significant changes in interruptible rates increase the risk that the expected benefits will not outweigh the costs. Witness Pollock suggested that if we approve TECO's proposal, then an interruptible customer should have the option of locking-in the current CCV for an extended period of time, such as five to ten years, at the customer's option, to provide a more stable rate design.

FIPUG witness Pollock stated that the CCVs have ranged from $3.71 in 2001 to $7.78 in 2007. While witness Ashburn agrees with witness Pollock that the CCV value is subject to change, witness Ashburn stated that the values have increased in each of the seven years witness

Pollock bracketed except for one when there was a minor reduction. Witness Ashburn noted that this upward trend reflects the increasing cost of generation. In 2008, the approved CCV was $7.48.[43] TECO's 2009 approved CCV of $10.91 represents a 46 percent increase over the prior CCV.

During cross examination by FIPUG, witness Ashburn testified that the credit is subject to being reset every year, and it may change, or may stay the same, just like base rates could change in a rate case. Furthermore, witness Ashburn stated that interruptible customers will have to predict all the elements of rates which change, including the clauses, which change every year, in the same time period the CCV may change. Finally, witness Ashburn stated that a fixed credit between rate cases may provide rate stability for the customer, but it may not be an appropriate mechanism to reimburse the interruptible customers for the value of their interruptible service.

Witness Ashburn further noted that under the GSLM rate schedules, the credit applied in the first year is locked-in for a three-year period. Therefore customers can plan for a specific credit for up to three years. In addition, at any point during the three-year period, the customer may choose to lock-in at the then current credit for a new three-year period. The three-year lock-in period under the GSLM rate schedules is comparable to the three-year notice requirement included in the IS rate schedules for interruptible customers who desire to switch to firm service.

Witness Pollock ignored the fact that customer bills are already subject to fluctuations because of annual changes in the cost recovery clauses. During cross examination by OPC, witness Pollock even admitted that currently at least 54 percent of the revenue that TECO collects is recovered through clauses. Furthermore, as witness Ashburn testified in the hearing, if interruptible customers were to receive a fixed CCV between rate cases, they would loose the opportunity to get a bigger credit if the credit goes up. The credit is based on the avoided cost of new generation, and to the extent those costs vary between rate cases, the credit should be adjusted.

Under the GSLM rate schedule, the credit is the product of the CCV and the monthly load factor adjusted demand. The load factor adjusted demand is the product of the monthly billing demand and the monthly billing load factor. Thus the $10.91 per kW CCV would be reduced in proportion to the customer's billing load factor. In other words, only a customer with a 100 percent load factor would receive the full credit amount.

Witness Ashburn stated in his rebuttal testimony that the use of a load factor adjusted credit is an equitable rate design, and PEF has consistently used this design for establishing credits since 1995. In its brief, TECO stated that the CCV is an amount established per kW of demand coincident with the Company's monthly system peaks. The full credit value shall be applied to a customer's demand coincident with system peak. The load factor approach utilized in the GSLM-2 and GSLM-3 conservation programs is a proxy for measuring a customer's load coincident with system peak. Witness Ashburn explained that since the CCV is an amount

[43] See Order No. PSC-07-0933-FOF-EG, issued November 26, 2007, in Docket No. 070002-EG, In re: Energy Conservation Cost Recovery Clause.

established per kW of demand coincident with the Company's monthly system peak, the full credit should only be applied to a customer's demand coincident with the system peak. The load factor approach utilized in the GSLM rate schedules is a proxy for estimating a customer's load coincident with the system peak.

FIPUG objected to TECO's load factor adjustment since the $10.91 per kw CCV would be reduced in proportion to the customer's billing load factor. FIPUG's concern seems to be based on the fact that if a customer's load factor is sufficiently low in a given month, TECO's proposed adjustment could effectively cause the customer to pay a firm rate for an interruptible service of lower quality.

There is no basis to change the application of the credit. First, witness Pollock erroneously stated that TECO is proposing a load factor adjusted credit. This provision is already included in the current GSLM rate schedule, and is therefore not a new proposal by the Company. Second, to determine the appropriate credit amount, TECO needs to know if the customer's demand was coincident with the system peak during an interruption event. If TECO interrupts its IS customers, there is no load during the monthly system peak. TECO's load factor adjusted credit, i.e., billing demand times load factor, provides an estimate of what the customer's load would have been during the monthly system peak. A high load factor customer is likely to be on during the monthly system peak, while a low load factor customer is not likely to be on during the system peak.

Witness Ashburn stated that since TECO proposed to treat the interruptible load as a conservation program, the GSLM credits paid to interruptible customers are costs that must be recovered from all customers through the ECCR. If all current IS accounts are transferred to the GSLM conservation programs as proposed by TECO, the projected GSLM credits to be recovered through the ECCR clause during the period May through December 2009 are $22,698,235. Therefore, under TECO's proposal, the ECCR factors for all rate classes will increase at the same time revised base rates will go into effect. TECO maintained that all customers, including interruptible customers, should share in the cost of providing credits to all load management conservation programs. Witness Ashburn explained that since 1982, we have consistently recognized the value of demand response programs through the ECCR clause. Other demand response resources include various residential and commercial load management programs.

Witness Pollock asserted that interruptible customers should not have to share in the cost recovery of the credits paid to them because they do not cause such costs to be incurred. He therefore proposed to spread the amount of the interruptible credits to the firm classes.

Currently, all customer classes pay for the costs associated with approved conservation programs. It is not appropriate to deviate from this long standing policy and exempt interruptible customers from paying any GSLM credits. To the extent interruptible customers are excluded from sharing in the cost recovery of the GSLM credits, the ECCR factor would increase to other customer classes, such as residential.

The interruptible rate schedules IS-1, IS-3, IST-1, IST-3, SBI-1 and SBI-3 shall be eliminated, and existing customers on these rate schedules shall be transferred to a new firm IS and IS standby and supplemental rate schedule, with the credit for interruptible service provided under the approved GSLM-2 and GSLM-3 conservation program rate riders. The new IS base rates and cost recovery clause charges (capacity, environmental, and conservation) shall be designed based on the approved cost of service, with IS customers fully sharing any production demand related costs based on their 12 CP load responsibility. The current GSLM credit has been approved in the ECCR docket and is not an issue in this docket. The credit will be re-established in the next ECCR proceeding, Docket No. 090002-EG.

GSD, GSLD and IS Rate Schedules

TECO's proposed rate design consolidated the IS, GSD, and GSLD customers under one GSD rate class, which includes features that appropriately consider the full range of the various characteristics of all customers who will be served under this rate class. Witness Ashburn stated that combining all demand billing customers under one rate schedule will simplify the provision of service to this important customer group and provide a better matching of the cost of providing service. Witness Ashburn stated that the present GSD and GSLD base energy and demand charges are identical, with the only difference being the customer charge and the application of a power factor clause for GSLD. Witness Ashburn further stated that the customer charge differences become moot with the proposed design of voltage level customer charges for the new GSD rate. The power factor can be accommodated in the newly combined GSD rate by simply making it applicable to customers who exceed the 1,000 kw threshold that was applied under the present rates. The risk of poor power factors affecting other customers is greater from customers with large demand requirements. With respect to the IS class, TECO stated in its brief that interruptibility is fully considered in TECO's proposed consolidation by allowing all GSD customers who agree to be served on an interruptible basis (including the transferred IS customers) to be compensated for such agreement under the Company's GSLM-2 and GLSM-3 conservation programs.

FIPUG objected to the consolidation of the GS, GSD, GSLD, and IS classes. FIPUG Witness Pollock stated that customer classes should be homogeneous according to their usage patterns and service characteristics, and that the GSD, GSLD, and IS classes exhibit significant differences in key characteristics such as size, load factor, coincidence factors, and delivery voltage. We note that TECO is not proposing to consolidate the GS class, as stated in FIPUG's brief.

The load factor measures the degree to which fixed facilities are being utilized and is expressed as the ratio of kWh to kW. The coincidence factor measures how likely it is that the customer contributes to the system peak demand, and is a good indicator of the demand-related costs incurred to serve the customer. A lower coincidence factor means that it is less costly to serve a customer. Witness Pollock placed great importance on the fact that the GSD, GSLD, and IS customers have different coincidence factors, with the IS class having the lowest coincidence factor. Witness Pollock further supported his argument by stating that the IS class is much larger than the GSD or GSLD classes and that IS customers take a preponderance of service at subtransmission voltage, whereas virtually no electricity is provided to GSD or GSLD customers at this high voltage level.

Under TECO's existing rate structure, commercial customers with maximum billing demands of 50 kW to 999 kW are required to take service under the GSD rate, while customers with maximum billing demands that exceed 999 kW take service under the GSLD rate. The base energy and demand charges were set equal for both rate schedules in Docket No. 850050-EI, TECO's 1985 rate case, and continued to remain the same in Docket No. 920324-EI, TECO's 1992 rate case. In the 1985 rate case we only kept the GSD and GSLD rate classes separate to allow for different customer charges to recover the cost of metering the two classes. The GSLD rate also includes a power factor penalty/credit provision, while the GSD class does not. These current differences in the customer charges are addressed in the proposed new GSD class through different customer charges based on the voltage level at which the customer is metered, i.e., secondary, primary, and subtransmission. The application of the power factor provision in the new GSD rate will apply only to customers over 1,000 kW in demand, as it is currently done under the GSLD rate.

Typically, all customers in a rate class exhibit a wide range of usage characteristics, with base rates being set on an average cost of service. TECO's IS customers are no different, and TECO demonstrated that IS customers show a wide dispersion of usage characteristics, and do not form a homogeneous rate class. However, the data supports leaving IS as a separate class for other reasons.

To support the consolidation of the GSD, GSLD and IS classes, witness Ashburn presented in his rebuttal testimony several scatter diagrams to show that all three classes demonstrated diversity in load characteristics. For each class, witness Ashburn prepared three plots. The first showed the average monthly load factor by customer account. This illustrates that customers have a range of load profiles in terms of their load factor. The second diagram showed the average monthly coincidence factor by customer account by month. This illustrates how many of the customers on average within each rate group are taking power during the system peak. The third set of scatter diagrams was a combination of the first two, plotting the monthly coincident factor against the monthly load factor. This confirms that the higher the average load factor, the more likely the customers are to take power on peak.

The monthly load factor comparison shows that while there are some low load factor customers, the bulk of both the GSD and GSLD customers fall into the over 40 percent load factor range. The diagram for the IS customers shows no such trend. The load factors of the IS customers are much more dispersed and do not show any trend. Similarly, the monthly coincidence factor comparison shows that a large portion of the GSD and GSLD cluster at the top of the chart, indicating a large number of customers taking service on peak. For the IS class, the pattern is much less distinct. This is reasonable since IS customers tend to design their operations to operate during off peak hours to minimize any potential interruptions.

Finally, combining the two sets of data points, one would expect to see a concentration of customers who are both high load factor and likely to take power during peak periods as shown for GSD and GSLD. The pattern, while discernable for the IS customers, is far less dramatic.

In response to discovery, TECO developed a separate firm IS rate schedule based on the load characteristics of the IS customers. The results show that while the customer unit costs used to develop the fixed monthly customer charge are higher for a separate IS rate compared to the new GSD rate, the base energy and demand charges would be lower in a separate IS rate, which indicates a lower cost of service for IS customers compared to GSD/GSLD customers. These cost differences are consistent with capturing the diversity within the class demonstrated in the scatter diagrams. Diversity of loads and usage patterns within a class tends to be lower per unit costs because customers who are cheaper to serve are averaged in with high cost customers. Combining the IS customers with the GSD and GSLD classes swamps the diversity within the smaller IS customer grouping resulting in higher costs to IS compared to a stand alone class calculation. Therefore, we find that it is appropriate to retain separate IS classes, including a separate interruptible standby rate class.

As discussed previously, the current IS classes are closed to new business. In its brief, TECO suggested that if we determine that the IS class should remain separate from the GSD, the class should remain closed to new business and should only consist of existing accounts. TECO explained that to retain the existing IS class, then open it to new business for any GSD customer seeking interruptible service, would provide new customers agreeing to be interrupted with the appropriate benefits of the credit provided under GSLM rate schedules and lower base rate charges. FIPUG did not address whether the IS rate schedule should be opened to new business or remain closed. Therefore, there is no evidence in the record to suggest opening the IS rate schedule to new business. GSD customers have the option of taking interruptible service under the GSLM conservation program.

There are two disadvantages to not combing the IS class with the GSD/GSLD classes as TECO has proposed. The first is the GSD optional rate. This option provides for a higher energy charge (compared to the regular GSD energy charge), and no demand charge, and benefits low load factor commercial customers by providing them a lower bill. Low load factor customers use relatively few kWh in relation to their maximum monthly demand. If the IS customers were combined with the GSD and GSLD rate classes, low load factor IS customers could benefit from the GSD optional rate as well. TECO has proposed no such optional rate for the IS class. Second, carving out the IS customers from the GSD class, who have a lower cost of service, will raise rates for the GSD class. Keeping IS customers together with the GSD class will lower the average GSD rate as discussed above.

Only the GSD and GSLD rate schedules shall be combined into a single GSD rate schedule, while the IS class shall be a separate firm rate schedule (with the interruptible credits provided under the GSLM-2 and GSLM-3 conservation programs). IS base rates and cost recovery clause charges (capacity, environmental, and conservation) shall be designed based on our approved cost of service methodology with IS customers fully sharing any production demand related costs based on their 12 CP load responsibility. The IS rate shall remain closed to new business.

GS and GSD Rate Schedules

We find that establishing an energy rather than a demand threshold will facilitate transition from one rate class to another and will reduce the need for the installation of demand meters on GS class customers for this purpose. Therefore, we change the breakpoint from 49 kW to 9,000 kWh between the GS and GSD rate schedule.

Meter Level Discount

We find that the appropriate meter level discount is one percent for customers who take energy metered at primary voltage and two percent for customers who take energy metered at subtransmission voltage or higher and should apply to the demand charge, energy charge, transformer ownership discount, power factor billing, emergency relay power supply charge, and any credits from optional riders.

Inverted Base Energy Rate

TECO proposed that conversion of its current RS rate schedule flat base energy rate to a two-block inverted base energy rate design with an inversion point at 1,000 kWh and a $0.01 per kWh differential between the two blocks. TECO witness Ashburn stated in his direct testimony that the Company is proposing the inverted rate design to "... provide a price signal to customers about energy use that can serve as a way to encourage energy conservation while the lower first block rate provides a billing benefit to lower use customers."

In its brief, TECO argued that its proposed inverted rate design is appropriate because: (1) it is consistent with the inverted rate designs previously approved for FPL, PEF, and FPUC; (2) it continues the movement toward inverted rate designs for the electric IOUs begun in 1977; (3) it will lower bills for customers using less than 1,539 kWh per month compared to a flat rate design; and (4) using an inversion point of 1,000 kWh per month will more effectively lower bills for low use customers compared to a rate design with an inversion point of 1,250 kWh per month.

In its brief, FIPUG cited four reasons why TECO's proposed inverted rate design should not be approved. We have evaluated the reasons cited by FIPUG for denying TECO's proposed inverted rate design and we find that that they do not represent sufficient grounds for denying the Company's proposal. The first reason cited by FIPUG was that TECO based its request on the fact that other electric utilities under our jurisdiction have an inverted rate design. TECO's request should be evaluated solely on the effect implementing an inverted rate design will have on TECO's customers and their energy consumption choices. The fact that other electric utilities have already implemented inverted rates does not enter into this evaluation.

The second reason cited by FIPUG is that the rates calculated under an inverted rate design would not be cost-based. However, as acknowledged in its own brief, FIPUG noted that

TECO calculates its inverted rates by first starting with a flat rate which is based upon the Company's cost of service study, then applying a "mathematical formula" to create the inverted rates. By adjusting the flat rates, FIPUG contended, the resulting inverted rates are no longer cost-based. We would agree with FIPUG's contention if the revenues generated by TECO's proposed inverted rates differed significantly from the revenue requirement for the RS class derived from the cost of service study; however, this is not the case. TECO's proposed inverted rates are estimated to generate $567,705,233, while the cost of service for the RS class is $575,347,000. This means that the revenues generated by the inverted rates will cover approximately 99 percent of the costs required to serve the RS class. Therefore, we do not agree with FIPUG's contention that the proposed inverted rates are not cost-based.

The third reason cited by FIPUG for denying TECO's proposed inverted rate is that the rate design is intended to be a "conservation rate" that will cause customers to reduce their consumption. This, in turn, may well lead the Company to return for further rate relief. We concur with FIPUG that an inverted rate is a conservation rate and that customers will likely reduce their energy consumption. A conservation rate structure like TECO's proposed inverted rate design is a tool intended to help achieve our stated policy goal of energy conservation. Therefore, we do not believe that the effect that a "conservation rate" has on customers' energy consumption is sufficient cause for denying TECO's proposal.

The fourth reason cited by FIPUG for denying TECO's proposed inverted rate is that the 1,000 kWh consumption level used in a bill stuffer to illustrate the impact of the Company's rate relief request is not representative of the usage for a typical residential customer. FIPUG also argued that the eight percent increase in customer bills at 1,000 kWh that would result from the Company's request for rate relief may underestimate the total impact on customer bills because it does not include fuel adjustment increases, gross receipts tax, and city utility tax or franchise fees. During the hearing, FIPUG introduced TECO's Open Lines bill stuffer as an exhibit. The bill stuffer includes the following sentence: "[w]ith FPSC approval of proposed base rates the overall increase for a Tampa Electric residential customer using one thousand kWh per month is anticipated to be approximately 8 percent." FIPUG cross-examined witness Ashburn on the bill stuffer to make the point that 8 percent is not a typical increase, if TECO's full revenue requirement gets approved.

It appears that FIPUG's objection to TECO's Open Line bill stuffer is not directly related to the inverted rate at issue. We agree with FIPUG that 1,000 kWh per month is not necessarily representative of a typical customer's usage. According to TECO, the average monthly usage for a residential customer is 1,262 kWh per month. If TECO had used an average usage of 1,262 kWh instead of 1,000 kWh to illustrate the effect of its rate relief request, the percentage increase in a customer's bill would have been 9.2 percent instead of the 8.0 percent cited by FIPUG. We do not believe, however, that the use of a 1,000 kWh usage level in the bill stuffer justifies denial of TECO's inverted rate proposal. The purpose behind illustrating how the Company's rate relief request would affect customer bills is to give customers a sense of how much they can expect their bill to change. Because the difference between an 8.0 percent change and a 9.2 percent change is not that great, using 1,000 kWh for illustrative purposes is not unreasonable.

In its MFR Schedule A-2, TECO showed residential bill impacts for various usage levels. That exhibit also shows that the 8 percent increase quoted does include Gross Receipts Tax.

FIPUG also argued that other factors, such as fuel adjustment increases, could cause a customer's bill to increase by more than the 8.0 percent cited by TECO. While we acknowledge that these other factors can impact a customer's bill, the purpose of the bill stuffer was to illustrate how the Company's request for base rate relief would affect a customer's bill. Therefore, basing the illustration on the increase in base rates alone, and not including other possible factors in the calculations, is appropriate.

There was also an extended discussion at the hearing whether the inversion point between the first and second rate blocks should be set at 1,000 kWh or at 1,250 kWh. TECO's proposed rate design sets the inversion point at 1,000 kWh, because this value is consistent with the inversion point for TECO's inverted fuel factor and is also consistent with the inversion points that we approved for FPL and PEF. A concern raised during the service hearings was whether it is appropriate to set the inversion point below the level of average residential consumption of 1,250 kWh, or whether it would be preferable to set the inversion point at 1,250 kWh.

The inversion point is the level of usage at which the rate changes from the rate in the first block to the rate in the second block. TECO proposed that the rate in the second block be set $0.01 above the rate in the second block. Because the rates in both the current flat rate design and the proposed inverted rate design are calculated to generate the same amount of revenue, the rate in the first block of the inverted rate design will be lower than the flat rate, and the rates in the second block will be higher than the flat rate. This results in customers using lower amounts of energy receiving lower bills under the inverted rate design, and customers using higher amounts of energy receiving higher bills. An inverted rate design achieves the dual policy goals of rewarding customers who use less energy while also sending stronger price signals to those who use more energy. At issue here is which inversion point, 1,000 kWh or 1,250 kWh, best achieves these goals.

Under TECO's proposed inversion point of 1,000 kWh, residential customers using less than 1,539 kWh per month will receive a lower bill with the inverted rate compared to TECO's current flat rate, while customers using more than 1,539 kWh will receive a higher bill. The reason customers using between 1,000 kWh and the 1,539 kWh receive a lower bill compared to the flat rate is that the rate charged for the first 1,000 kWh is lower than the flat rate, so it takes a while for the higher rate in the second block to let the bill "catch up" to the flat rate bill. The point at which the bill under the inverted rate "catches up" to the flat rate bill is called the "break-even point." TECO noted that using an inversion point of 1,000 kWh results in approximately two-thirds of all residential energy being consumed in the first block and approximately two-thirds of all bills being lower under the inverted design

Using an inversion point of 1,250 kWh, residential customers using less than 1,689 kWh per month will receive a lower bill with the inverted rate compared to TECO's current flat rate, while customers using more than 1,689 kWh will receive a higher bill. TECO noted that using an inversion point of 1,250 kWh results in approximately three-quarters of all residential energy being consumed in the first block and approximately three-quarters of all bills being lower under the inverted design

TECO provided a side-by-side comparison of residential customer bills using the 1,000 kWh and 1,250 kWh inversion points. According to this exhibit, the customer bills resulting from the competing rate designs do not differ significantly for all levels of usage up to 4,000 kWh per month. That is, neither rate design produces significantly lower bills for low use customers or significantly higher bills for high use customers. Therefore, neither rate design stands out as being clearly superior to the other with respect to achieving the above-mentioned rate design goals.

In TECO witness Ashburn's late-filed hearing exhibit, the Company noted that it believes that use of its proposed inversion point of 1,000 kWh is more appropriate because the 1,000 kWh inversion point "is designed to be consistent with its inverted fuel rate design. Having the same inversion point for both fuel and base energy rates is essential in sending an understandable conservation-oriented message to customers." This is a very important point. With the $0.01 differential in rates for both fuel and energy starting at the same level of usage, customers will have a clearer picture of exactly where the higher rates will begin. Therefore, of the two competing inversion points, we find that the base energy rate inversion point shall be set at 1,000 kWh. We also approve an increase of $0.01 between the first and second rate block.

Existing RST Rate Schedule

We find that the RST rate schedule should be eliminated and the approximately 40 customers taking service under RST should be transferred to their choice of the RSVP or RS rate schedule. Both of these rate schedules afford customers the opportunity to modify usage similar to RST.

Single Lighting Schedule

According to TECO, its current three street lighting schedules include many of the same fixtures or poles but at different prices and with different terms and conditions. TECO believes that three different rate schedules cause customer confusion and frustration because the reasons for the differences among the rate schedules are not clear. Under the Company's proposal, each type of lighting fixture and pole will have one rate regardless of use. TECO witness Ashburn believed such a change will improve efficiency and understanding for customers and Company personnel who market, install, and maintain the lights. TECO's reasons for proposing that all lighting service be combined under one lighting rate schedule include:

- Separate tariff agreements associated with these three rate schedules have been replaced with a single agreement for use under all three schedules.
- Fixtures and poles offered under one rate schedule for one purpose are often desired by customers for another purpose.
- Fixtures and poles originally provided under one rate schedule change use when they are acquired by a subsequent customer.

- Sometimes the same identical fixture and pole are provided under different rate schedules at different prices. One rate schedule will eliminate any price variation.
- One rate schedule will provide consistency in the terms and conditions under which service is provided.
- A consolidated rate schedule will facilitate more efficient and understandable rates and services.
- A consolidated rate schedule will recognize that some costs do not vary with providing street lighting service, such as stocking and material handling, engineering, vehicles, operation and maintenance labor, supervision labor, energy production, transmission, and distribution.

TECO's proposed street lighting rate design is comprised of three components: a facility charge, a maintenance charge, and a non-fuel energy charge. The facility charge refers to the type of light fixture or pole. The charge is similar in nature to a rental charge and is designed to recover the carrying cost of the facility.[44] The maintenance charge is designed to recover the monthly cost of maintaining each light fixture or pole, as determined from TECO's lighting incremental cost study. The energy charge applies only to the lighting fixture rates. It is determined by multiplying the kilowatt-hour usage for each fixture by the non-fuel energy and customer unit cost determined from the cost of service study.

TECO's proposed monthly facility and maintenance charges are developed in its Lighting Incremental Cost Study, Supplemental MFR Schedule E-13D. However, where multiple rates are currently offered for the same lighting facilities, TECO proposed that the lowest rate be applied, rather than the cost study developed rate. TECO also proposed to eliminate the current reduced rate for additional lights on a pole, so that all lights of the same type, whether the initial light or an additional light, are priced at the same rate. TECO explained that the elimination of a reduced rate for additional lights on a pole is proposed for two reasons: (1) experience has shown that service wiring or cable often requires upgrading to accommodate the installation of an additional service; and (2) there are no savings in labor or travel time for additional lights because they are many times installed later than the initial lights.

TECO also proposed to eliminate or restrict certain lighting facility offerings. Based on queries of its Customer Information System's (CIS) billing records, TECO asserted that there is little customer interest in certain offerings. TECO noted that no customers are currently taking service under the rates of the offerings it proposed to eliminate. Additionally, these offerings have been closed to new business for several years.

TECO's proposed monthly facility charge for each fixture or pole is determined by developing material, labor, and vehicle costs associated with installing each given fixture or pole. The total installed cost for each fixture or pole is then multiplied by a levelized fixed charge rate, resulting in an annual carrying cost that is then restated as a monthly rate. TECO identifies the materials needed for installation from its work management system. The material unit costs are identified on a system unit price from TECO's materials management system. Labor and vehicle costs are developed based on average unit times for each task involved in the installation. The

[44] Order No. PSC-95-1440-FOF-EI, p. 2, issued November 27, 1995, in Docket No. 951120-EI, In Re: Petition for Approval of Revised Lighting Tariffs by Tampa Electric Company.

unit times are determined from TECO's work order management system, updated by subject matter experts to reflect current procedures, practices, and equipment changes.

TECO developed the maintenance charge for each fixture by deriving costs for each maintenance activity: lamp failure, luminaire parts failure, photocell, and relay. The maintenance charge for each pole type is designed to capture wiring (overhead and underground) maintenance and other "aesthetic" maintenance (e.g., painting poles) costs associated with decorative poles. The cost for each maintenance activity for each fixture and pole is calculated by adding the average material cost of the fixture or pole, material handling, and labor and vehicle cost. The total activity cost is then multiplied by a frequency percent that reflects how often that activity might occur. This yields the annual maintenance cost that is restated as a monthly charge.

Labor costs for each of the various installation and maintenance lighting crews consist of direct and indirect costs. TECO determined the direct labor hourly costs by multiplying the per hour labor rate for each assigned crew position times the number of positions of that type in the crew. TECO derived indirect labor costs by multiplying loading factors times direct labor costs. The two labor costs for each position are then summed to arrive at the crew's fully loaded hourly labor cost. Table 93-1 shows the loading factors TECO used in its lighting incremental cost study.

Table 93-1: Loading Factors	
Administrative and General (A&G)/Fringe[45]	72.00%
Small Tools for TEC Field Labor	2.68%
Supv & Admin Lighting Field – TEC Labor (Maintenance)	48.92%
Supv & Admin TEC Lighting Engineering – TEC Labor (Installation)	32.10%
Supv & Admin TEC Lighting Field – TEC Labor (Installation)	32.10%
ED Material Handling	25.17%

The A&G/Fringe loading factor,[46] according to TECO, has two components: a 49 percent fringe component and a 23 percent A&G component. The 49 percent fringe component consists of non-productive time, direct benefits, and other payroll costs. The 23 percent A&G component consists of administrative salaries, office supply costs, and miscellaneous general expenses. Table 93-2 provides a description of each of the A&G/Fringe loading factor components.

[45] TECO's originally filed street lighting incremental cost study used two separate loading factors for A&G/Fringe (70 percent for A&G and 72 percent for Fringe). In the course of responding to staff discovery, TECO determined that the two factors were essentially different versions of the same loading factor. TECO concluded that the use of both factors in the labor cost calculations resulted in double-counting for certain labor loading components. As a result, TECO submitted a revised cost study on December 29, 2008, with corrected labor costs.

[46] The A&G/Fringe loading factor is also used in the cost support associated service connection options, reconnect after disconnect charges, and services charges.

Table 93-2: A&G/Fringe Loading Factor		
Category	Description	Portion
Non-Productive Time	Time not worked but paid as a benefit, such as vacation time, sick time, jury duty time, holiday time, and other paid time while not working.	13%
Direct Benefits Paid	Benefit costs such as retirement benefits, life insurance, long-term care insurance, education benefits, and savings plan benefits	22%
Other Payroll Costs	TECO's portion of FICA taxes, state and federal unemployment taxes, and the Success Sharing Plan cost.	14%
	Total Fringe Rate	49%
A&G Costs	An overhead allocation from FERC Account 920 (Administrative Salaries), Account 921 (Office Supplies and Expenses), Account 925 (Injuries and Damages), and Account 930 (Miscellaneous General Expenses).	23%
	Total A&G/Fringe Loading Factor	72%

In addition to the A&G/Fringe loading factor, Table 93-1 shows that TECO used a loading factor to account for small tools such as hammers, screwdrivers, and padlocks that are not issued for a specific job or task. TECO also applies separate loading factors to account for supervision and administrative time not contained in direct costs or other loading factors: one applies to non-engineering labor in the maintenance of lighting equipment, one applies to non-engineering labor in the installation of lighting equipment, and one applies to engineering labor employed in lighting activities. The last loading factor used is a material overhead consisting of stores and inventory carrying costs and stock handling costs.

The first part of this question is whether TECO should consolidate its three lighting rate schedules into one. According to TECO, one rate schedule will be more efficient and will provide consistency by eliminating differences in pricing and in the terms and conditions for lighting service product offerings that are identical. Based on the record evidence and the fact that no party opposes TECO's proposal, we find that one consolidated lighting rate schedule is appropriate.

The remaining part of this question addresses whether TECO's proposed street lighting charges, terms, and conditions are appropriate. TECO's proposed charges consist of a facility charge, a maintenance charge, and a non-fuel energy charge. The facility and maintenance charges for each fixture and pole are driven in part by labor costs associated with the installation or maintenance of a light fixture or pole. The non-fuel energy charge is predicated on the customer unit cost from the cost of service study. To the extent there are revisions to TECO's cost of service study as a result of our decisions in other issues and the customer unit cost is changed, the non-fuel energy charge may change.

TECO proposed that where multiple rates are currently offered for the same lighting facilities, the lowest facility rate be applied. TECO also proposed to eliminate the current reduced rate for additional lights on a pole, so that all lights of the same time are priced at the same rate. We find that TECO's proposal where multiple facility rates are currently offered is reasonable, and that TECO has demonstrated that there are often additional costs incurred with placing additional lights on a pole, making the elimination of a reduced rate for additional lights reasonable.

TECO also proposed to eliminate or restrict certain lighting facility offerings. TECO demonstrated that: (1) there is a lack of customer interest in certain offerings; (2) no customers are currently taking service under the rates of the fixtures and poles proposed for elimination; and (3) these offerings have been closed to new business for several years. Based on the evidence presented, TECO's proposed elimination or restriction of certain lighting offerings is reasonable.

TECO's proposed facility and maintenance charges for all other street lights or poles include both direct (hourly) and indirect (non-hourly) costs. Direct costs are costs directly assignable to the installation or maintenance work order. Indirect costs are costs applied by the use of loading factors.

TECO's incremental lighting cost study identifies each task necessary to install or maintain a given light fixture or pole, the crew make-up to perform the work, and the time necessary to complete the task. The direct costs consist of the material, labor, and vehicle costs associated with each light fixture or pole. TECO calculates the direct labor costs by multiplying the straight time non-loaded hourly labor rate for each employee classification required for the job by the unit times to complete each task. After reviewing the cost study documentation and additional support TECO submitted, we find that TECO's determination of direct costs is reasonable.

TECO uses loading factors to account for indirect costs. As an example of TECO's application of loading factors, Table 93-3 shows the development of direct and indirect labor costs for a Conductor Crew.

Table 93-3. Conductor Crew (CC1)

Position	Hourly Rate	Positions per Crew	Direct Labor Costs	Loading Factor	Indirect Labor Costs	Fully Loaded Costs
UG Serviceman	$25.41	2	$50.82	123.6%	$62.81	$113.63
Light Vehicle	$ 4.84	2	NA	NA	NA	9.68
Heavy Vehicle (Class A)	$11.59	1	NA	NA	NA	11.59
Heavy Vehicle (Class B)	$13.56	1	NA	NA	NA	13.56
Total Labor and Vehicle						$148.46

The loading factors used for the CC1 lighting crew are 72 percent A&G/Fringe, 2.68 percent small tools, and 48.92 percent supervision and administrative time associated with non-engineering labor in the maintenance of lighting equipment. Direct labor costs are $50.82 per hour. Loadings or indirect costs amount to $62.81 per hour, resulting in a fully-loaded labor cost of $113.63 per hour. The fully-loaded labor costs are 123.6 percent greater than the direct labor costs, and represent 76.5 percent of the total hourly labor and vehicle cost for the CC1 crew. This example illustrates the significant impact loading factors have on total costs.

The loading factor that gives us the most pause is the A&G/Fringe factor of 72 percent, that includes A&G expense of 23 percent and Fringe expense of 49 percent. The A&G portion is based on a 2003 TECO analysis, the most current data available at the time of the rate case filing. According to TECO, a post-filing analysis based on 2008 and 2009 expenses indicated that the A&G loading factor increased to 36 percent and 34 percent, respectively. We concur with TECO that indirect costs are a cost of doing business. However, recognizing that indirect costs can significantly impact the cost study results, we are concerned about the increasing A&G component; this may warrant further investigation in the future.

TECO discovered that it had double-counted the A&G/Fringe labor loading factor in its lighting cost studies. As a result, TECO submitted a revised cost study reflecting the corrected labor costs. TECO indicated that the impact of the correction would be reflected in the lighting rates when those rates are recalculated based on our approved cost of service study. Accordingly, based on the record evidence and noting that no party has taken issue with TECO's loading factors, we find that TECO's proposed street lighting charges, terms, and conditions are appropriate, subject to the above qualifications.

Therefore we approve TECO's proposed single lighting schedule, and associated charges, terms, and conditions, adjusted to reflect our decisions described in the body of this Order and corrected labor costs.

Two New Convenience Service Connection Options

Currently, there are two service connection options, but they apply to different types of connections. The first, Initial Service Connection, applies to the first customer who establishes service at a house or other premise. The current rate is $38, with a proposed increase to $75. The second option, Normal Reconnect Subsequent Subscriber, applies when service is reconnected in another subscriber's name to a house or premise. The current rate is $16, with a proposed increase to $25. According to TECO, Normal Reconnect Subsequent Subscriber provides for reconnection on the next business day.

Based on customer requests, TECO proposed two new "convenience" service reconnection options. These options would provide additional choices for customers eligible for Normal Reconnect Subsequent Subscriber. Same Day Reconnect reconnects the customer on the same day as long as the customer places his or her request before 6 p.m. Saturday Reconnect provides for reconnection on Saturdays between 8 a.m. and 12 noon as long as the special request is made by 12 noon on Friday.

According to TECO, it has received "a large number" of requests from customers for Same Day or Saturday reconnection. Some of those customers have "offered to pay more if such services were available in order to meet their individual needs or schedule constraints... ." TECO conducted an informal poll in March 2008 using its call center employees to determine interest in expedited reconnection. In one day of polling, approximately 50 business customers expressed interest in same day reconnection. In one week of polling, 41 of 1,093 residential customers expressed interest in same day reconnection. TECO determined interest in Saturday reconnection using calls received by Customer Care supervisors on weekends.

TECO used a team of subject matter experts to review the proposed service charges.[47] For each service charge, the team identified each task and the time necessary to complete the task. TECO determined the direct labor costs by multiplying the weighted per hour labor rates of the employees performing tasks by the weighted time in hours.

TECO's proposed costs for service charges also include indirect costs. TECO included two categories or factors of indirect costs. TECO calls the first category "Payroll and A&G [Administrative and General] loading factor." The Payroll and A&G loading factor is 72 percent and includes non-productive time paid (13 percent), direct benefits (22 percent), other payroll costs (14 percent), and A&G expenses (23 percent). TECO's second loading factor, Administrative and Overhead loading factor, is 41.33 percent and accounts for Energy Delivery's supervisory and administrative overhead. Together, the loading factors total 113.33 percent.

There are also miscellaneous costs included in the total cost. Miscellaneous costs include materials (e.g., a meter seal cost of $0.23) and vehicle costs. TECO determined the vehicle cost by multiplying a weighted average rate for each vehicle type in the process by a weighted time for each vehicle rate.

The total cost for Same Day Reconnect service is $69.48, which is comprised of a $30.05 direct labor cost, an indirect cost of $34.06, a vehicle cost of $5.15, and a meter seal cost of $0.23.

TECO developed the costs for Saturday Reconnect similarly to Same Day Reconnect; however, the loading factors are different because the reconnection is an overtime reconnection. Saturday Reconnect uses a single, reduced loading factor because the time worked is overtime. TECO's Payroll and A&G loading factor is reduced from 72 percent to 35.5 percent because Non-productive and A&G loadings do not apply in an overtime scenario. For the same reason, TECO does not use the Administrative and Overhead loading factor for Saturday Reconnect. The total cost for Saturday Reconnect is $303.56, which is comprised of $201.03 in direct costs, indirect costs of $71.37, a Pager Call Out Cost of $15, and a vehicle cost of $16.17.

No intervenors filed testimony on this issue. In their briefs, AARP and OPC argued that no service charges should be increased; however, if we approve the two new connection fees, the

[47] TECO's methodology also applies to the following service charges: Reconnect after Disconnect at Meter for Cause; Reconnect after Disconnect at Pole for Cause; Initial Service Connection; Normal Reconnect Subsequent Subscriber; Field Visit Credit; and Temporary Service.

fees should be limited to $40.00 for Same Day Reconnect and $275.00 for Saturday Reconnect. These amounts are TECO's proposed charges less TECO's proposed charge for Normal Reconnect Subsequent Subscriber.

The first part of this question asks whether the two new service options, Same Day Reconnect and Saturday Reconnect, are appropriate. According to TECO, it proposed these new options in response to requests from customers. Based on the evidence in the record, we find that offering these new options will provide customers with additional choices.

The second part of this issue asks whether the charges for these new options are appropriate. TECO's proposed costs consist of several components: (1) direct costs (actual hourly costs); (2) indirect costs (non-hourly labor costs); and (3) other or miscellaneous costs (e.g., vehicle costs). Once TECO developed the costs, it determined the proposed rates.

Our discussion under Single Lighting Schedule contains an analysis of the Payroll and A&G (Administrative and General) loading factor of 72 percent used in the development of the recurring lighting rates. Loading factors are significant contributors to the cost of the non-recurring service charges, and for Same Day Reconnect, are greater than the direct (labor) cost.

TECO's Payroll and A&G loading factor includes A&G expense of 23 percent. The 23 percent number is derived from TECO's 2003 data, the most current data available at the time of filing. According to TECO, a post-filing analysis based on 2008 and 2009 data indicated that the A&G loading factor increased to 36 percent and 34 percent, respectively. Based on the record evidence, we find that TECO's position on loading factors is reasonable.

Although TECO did not update the 23 percent with the most recent A&G percentage, we are concerned about the increasing level of A&G expense as it relates to service charges in the future. Loading factors, their composition, and percentage levels may warrant investigation in the future.

In response to discovery, TECO provided substantial information documenting its determination of the direct and miscellaneous costs. After reviewing the record evidence, we find that TECO's determination of the direct and miscellaneous costs is reasonable.

Based on the record evidence, we find that TECO incurs additional costs to provide same day or Saturday reconnection; these costs exceed the normal connection fee which provides for next day service. The charges for special services provided for the benefit of a single customer should reflect those additional costs. Without record evidence to decrease each charge by $25, we do not believe that $25 should be excluded in either charge. Arbitrarily reducing these charges by the Normal Reconnect Subsequent Subscriber proposed charge would understate the cost to provide the service.

TECO's filed cost support for Same Day Reconnect is $69.48 while its proposed rate is $65. TECO explained that while it rounded the proposed charge to zero or five, it made two exceptions: Same Day Reconnect and Saturday Reconnect. TECO rounded down Same Day

Reconnect to $65 because it wanted "to maintain a differential between it and the Initial Service Connection charge, which was limited to $75 ..." TECO's proposed cost for Saturday Reconnect of $303.56 was rounded down to $300 because $300 is a "more 'round' number." We find that TECO's rounding explanations for Same Day Reconnect and Saturday Reconnect are reasonable.

OPC and AARP argue that during the current economic climate, customer service charges should not be increased. We are sympathetic to the plight of customers who are struggling financially; nevertheless, TECO has adequately supported the costs underlying its proposed rates. To the extent possible, rates should be designed to collect the costs from the cost causer. Thus, based on the record evidence, we find that the two new service reconnection options, Same Day Reconnect and Saturday Reconnect, and their associated connection charges, $65 and $300, respectively, are appropriate.

<u>Reconnect after Disconnect Charges</u>

Two new reconnection charges have been proposed for customers whose service has been disconnected for cause, e.g., nonpayment. The proposed charges have different rates depending on whether the customer can be reconnected at the meter or must be reconnected at the pole. Currently, there is one reconnection charge, with a rate of $35. Whether the reconnection takes place at the meter or on the pole depends on where TECO was able to disconnect the customer. Where possible, TECO disconnects service at the meter; however, when meter access is denied, the disconnect occurs on the pole. Meter access may be denied for several reasons, including a "bad" dog, locked gate, or when it is not physically possible to disconnect at the meter (e.g., medium or large non-residential customer). TECO proposed a separate charge for reconnection on the pole because of (1) the frequency of pole disconnects and (2) the difference in labor and vehicle costs between meter and pole disconnects and reconnects. Both reconnection charges include the cost for the initial disconnection.

OPC contended that no customer service fees should be increased and that separate charges for reconnection at the pole and at the meter should not be permitted. OPC argued that TECO did not provide "any satisfactory explanation as to why different reconnect fees are necessary, let alone a justification of the cost differential for a point of [sic] meter versus point distant from the meter." OPC asserted that increasing the current charge is "unreasonable" for "those customers already at the end of their means." In its brief, AARP argued that TECO "has failed to provide supporting cost data" for its proposal. AARP "urges" us to not increase reconnection charges when "so many are struggling financially."

OPC and AARP argued in their briefs that TECO did not provide cost support for its proposal. We disagree. TECO provided general cost support in its MFR Schedule E-7, pages 5 and 6, for Reconnect after Disconnect at Meter for Cause and Reconnect after Cut on Pole Disconnect for Cause, respectively. TECO provided detailed support for its cost analysis in response to discovery. This cost support includes a description of each step required to reconnect a customer after a disconnect for cause, why different employee skill sets are needed for each reconnect, the number of minutes each step takes, actual and weighted labor rates, and vehicle rates. TECO explained in its response to discovery why a disconnect at the pole might be necessary and why a reconnect at a pole requires a higher paid employee than a reconnect at a meter.

TECO's cost for Reconnect after Disconnect at Meter for Cause includes $21.05 in direct labor costs, $23.85 in indirect costs, and $4.54 in miscellaneous costs, for a total cost of $49.44. TECO rounded the $49.44 to the nearest $5 for a proposed charge of $50. TECO's cost for Reconnect After Cut at Pole for Cause includes $53.26 of direct labor costs, $60.35 of indirect cost and $26.29 in miscellaneous cost, for a total cost of $139.90. TECO rounded the $139.90 to the nearest $5 for a proposed charge of $140. We find that there are cost differences between disconnection at the meter and at the pole.

OPC also argued that TECO "did not give any detailed explanation or breakdown that demonstrates that the costs have actually increased." OPC is referring to TECO witness Ashburn's testimony that "all existing charges have increased to reflect the increased cost of providing the services." TECO's burden is to prove that the proposed costs are reasonable, not necessarily to prove that costs have increased between the 1992 and 2008 rate cases.

OPC and AARP argued that during the current economic climate, customer service charges should not be increased. We are sympathetic to the plight of customers who are struggling financially; nevertheless, TECO has adequately supported the costs underlying its proposed rates. To the extent possible, rates should be designed to collect the costs from the cost causer.

We find that segmenting reconnection options provides a more accurate reflection of the costs incurred. Segmenting reconnection options also sends appropriate price signals to customers. For example, if a customer disconnected for nonpayment allows the TECO employee access to the meter for disconnection of service (e.g., by restraining the bad dog), the customer will pay less to reconnect service.

Based on the record evidence, we find that TECO's costs for reconnection after disconnect for cause and proposed rates are reasonable. We also find that it is appropriate to have a Reconnect after Disconnect at Meter for Cause charge and a Reconnect after Cut on Pole Disconnect for Cause charge; the appropriate rates are $50 and $140, respectively. The reconnection options shall be recalculated to reflect any applicable decisions herein.

Meter Tampering Charge

We find that TECO's proposed new meter tampering charge, designed to recover the costs of discovering and confirming tampering when the cost of investigating and estimating is greater than the damages, is appropriate.

Late Payment Charge

TECO has proposed a new $5.00 minimum late payment charge for all bills of $10.00 or more, and under $334.00. This new minimum late fee does not apply to the accounts of federal, state, and local government entities, agencies, and instrumentalities, whose late fee will be no greater than allowed for by applicable law.

Currently, TECO customers who pay their bill past the delinquency date, which is 20 days from the mailing date, are subject to a late fee of 1.5 percent of the invoice balance. TECO proposed to change its tariff to include a minimum late fee of $5.00 for all bills between $10.00 and $334.00. At bill amounts of $334.00 or greater, the late fee becomes 1.5 percent of the total bill amount. If the bill amount is under $10.00, the late payment fee remains 1.5 percent of the balance.

TECO stated that this change to its late payment policy is appropriate because it places the costs associated with past due invoice collections on cost causers, and encourages bills to be paid in a timely manner. TECO witness Ashburn asserted that the Company is requesting treatment for this charge analogous to the minimum late charges approved for FPL, PEF, and FPUC. Witness Ashburn cited Order No. PSC-02-1753-TRF-EI, in Docket No. 021127-EI,[48] as precedent, where we approved FPUC's minimum $5.00 late fee policy.

Witness Ashburn stated in response to discovery that during calendar year 2007, 1,585,890 residential service bills were assessed a late payment charge. This represents 22.5 percent of all TECO's residential bills during 2007. Under TECO's proposed late payment charge methodology, 1,199,088 of the 1,585,890 delinquent bills would have been assessed at the $5.00 minimum fee. TECO's average residential bill for calendar year 2007 was $178.42. In their briefs, AARP and OPC argued that TECO's proposed minimum late payment charge should not be approved. They contended that TECO has not supported this change with any financial data.

We find that the proposed changes to TECO's late payment policy will allow the utility to recover costs associated with processing delinquent accounts, and will provide an incentive for customers to remit payments in a timely manner, thus reducing the costs associated with collecting delinquent accounts. Moreover, TECO's proposed charge is consistent with the late payment charges of PEF and FPUC. Allowing this change to TECO's late payment policy is consistent with our prior decisions.

<u>Service Charges</u>

According to TECO, the Initial Service Connection charge only applies to the first customer to establish service at a premise. In addition to processing the request for service, the cost includes engineering for the new service, processing releases, performing inspections, setting the meter, connecting service and setting up the new account in the billing system.

TECO's original proposed cost for this service was $116.55; however, when TECO reviewed its weighting factors for overhead and underground services, it revised the cost to

[48] Order No. PSC-02-1753-TRF-EI, issued December 12, 2002, in Docket No. 021127-EI, <u>Request for approval of Eighth Revised Tariff Sheet No. 22.1 to change late fee provisions to assist in reducing late payment amounts and to reduce bad debts to historical level by Florida Public Utilities Company</u>.

$109.82. TECO's proposed charge is $75. TECO explained that the proposed charge is lower than the cost in order "to limit what would otherwise be a significant increase from the current charge [$38]." TECO also considered comparable charges currently being imposed by other Florida electric utilities (FPL, PEF, and Gulf) and determined that $75.00 is an appropriate and reasonable charge.

The Normal Reconnect Subsequent Subscriber charge applies to a customer who is requesting that service be reestablished at a premise (e.g., a homeowner or renter moves into a house or apartment where service has already existed). The current rate is $16, with a proposed increase to $25. According to TECO, Normal Reconnect Subsequent Subscriber provides for reconnection on the next business day.

The Field Credit Visit charge applies when a TECO representative visits a premise in order to disconnect service for non-payment and, instead of disconnection, the customer makes other payment arrangements. The current rate is $8, with a proposed increase to $20.

The Returned Check charge is applied when a check is not honored by the bank. Currently, the tariff provides the specific charges based on Section 68.065, F.S., but does not reference the statute. When and if the statute changes, then the tariff page must be updated. TECO's proposed tariff states, "A Returned Check Charge as allowed by Florida Statute 68.065 shall apply for each check or draft dishonored by the bank upon which it is drawn," but does not provide the current rates. Currently, if the check is $50 or less, the returned check charge is $25.00. For checks between $50.01 and $300.00, the returned check charge is $30.00. For checks over $300.00, the returned check charge is $40.00 or 5 percent of the amount of the check, whichever is greater. Because the current returned check charges match those permitted by statute, there is no change to the returned check charge, until and unless the law changes.

OPC and AARP contended that customer service charges should not be increased and that TECO has not provided support for its proposed increases.

Regarding the Returned Check Charge, OPC contended that TECO "should not be allowed to change the returned check tariff language to allow automatic increases if the law changes because it is unnecessary." In its discussion, OPC argued that "the Company has not shown why they [sic] should be allowed to automatically increase a return check fee if the statute is amended." According to OPC, changing the Returned Check Charge language would allow TECO to collect additional revenues without the scrutiny of a base rate case or a review of the cost justification for any requested increase.

OPC and AARP also argued in their briefs that TECO did not provide cost support for its proposed rates. We disagree with the contention that the proposed charges lack cost support. TECO provided general cost support in its MFR Schedule E-7, pages 1, 2 and 7, for Initial Service Connection, Normal Reconnect Subsequent Subscriber, and Field Credit Visit, respectively. TECO provided additional detailed support for its cost analyses in response to discovery. This cost support includes a description of each activity required to perform the service, the number of minutes each step takes, actual and weighted labor rates, and vehicle rates.

TECO is proposing a rate of $75 for its Initial Connection charge, which applies only to the first customer to establish service at a location. The proposed charge is higher than its current charge of $38, but lower than its developed cost. TECO's filed cost totaled $116.55; however, in response to discovery, TECO discovered an error that reduced the cost to $109.82, which is still considerably higher than the proposed charge. We find that the proposed charge of $75 is reasonable.

TECO's cost for the Normal Reconnect Subsequent Subscriber charge includes $10.17 in direct labor costs, $11.52 in indirect cost, and miscellaneous costs of $2.09, for a total cost of $23.79. TECO rounds its cost of $23.79 to the nearest $5 or $25. We find the rounding to be reasonable.

TECO's cost for the Field Credit Visit includes $8.98 in direct labor costs, $10.18 in indirect cost, and miscellaneous costs of $1.63, for a total cost of $20.79. TECO rounds its cost of $20.79 to the nearest $5 or $20. We find the rounding to be reasonable.

For the Returned Check Charge, TECO may charge what it wishes as long as it does not exceed the statutory maximum as set forth in Section 68.065, F.S. Therefore, we find that it is reasonable to key the Returned Check Fee to the governing statute, thus eliminating the need to change the tariff page when and if the statutory language changes.

OPC and AARP argued that during the current economic climate, customer service charges should not be increased. We are sympathetic to the plight of customers struggling financially; nevertheless, TECO has adequately supported the costs underlying its proposed rates. To the extent possible, rates should be designed to collect the costs from the cost causer.

Based on the record evidence, we find that the appropriate service charges are $75 for Initial Connection, $25 for Normal Reconnect Subsequent Subscriber, $20 for the Field Credit Visit, and the reference to Section 68.065, F.S., for the Returned Check Charge. The service charges shall be recalculated to reflect any applicable decisions herein.

Temporary Service Charge

Temporary service includes, but is not limited to, service provided to construction sites and trailers, Christmas tree lots, pumpkin patches, firework stands, and fairs. TECO proposed an increase in the Temporary Charge from $115 to $235. For Temporary Service, the direct costs total $98.78, indirect costs total $111.95, and the miscellaneous cost is $22.64. TECO rounded the total cost of $233.36 to the nearest $5 or $235. We have reviewed TECO's documentation provided on Temporary Service. Based on the record evidence, we find that TECO's cost development is reasonable and that its proposed rate of $235 is appropriate.

Customer Charges

Customer charges are flat fees assessed each month, regardless of the amount of energy (kWh) used. Utilities typically design and levy customer charges to recover the costs associated with meter reading, metering equipment, customer service, and bill processing. Different customer charges are levied depending on the class of customer and the types of equipment used to provision service.

For the purposes of developing its customer charges, TECO either set rates at cost, or benchmarked its rate at a price comparable to that of other IOUs. Instead of setting its residential customer charge at cost, TECO set it at a price comparable to that of PEF and FPL. TECO witness Ashburn stated that the decision to benchmark this rate below actual cost seemed a "reasonable rise" at this point. TECO's cost support indicates that the charges for rate groups RS, RST, RSVP-1, GS, GST, TS, and LS-1 are benchmarked. Customer charges for rate groups GSD, GSD Opt., GSDT, SBF, and SBFT were set at unit cost, plus $25.00 for the standby option rate classes.

Cost support for TECO's Residential Service (RS) and General Service (GS) customer charges is contained in TECO's Cost of Service Study, filed as part of its MFRs. Witness Ashburn stated that the summed unit costs for meters, services, meter reading, billing, and customer service for the RS and GS classes equals $11.71 and $12.30, respectively. However, the Company's proposed rate is $10.50 for both the RS and GS rate groups.

Currently there are two different customer charges under the GSD rate schedule, and one customer charge rate level in the GSLD rate schedule. TECO proposed combining the current GSD, GSLD, and interruptible service (IS) customers into the new GSD rate schedule. Witness Ashburn stated that the proposed rates are based on the class's cost of service. The proposed customer charges in the GSD rate schedules have been designed to recover the cost of metering, meter reading, billing, and customer service, and vary according to the voltage level at which service is taken. Customers with higher voltage requirements, as well as associated transformer equipment, require meters that are more expensive, and this cost difference is reflected in the proposed customer charges. Witness Ashburn further stated that the proposed customer charges appropriately recognize the cost to provide service at different voltage levels.

While customer charges for rate groups RS, RST, RSVP-1, GS, GST, TS, and LS-1 are set below cost, the proposed rate reflects an increase of 23 percent, which we find to be reasonable. Customer charges for rate groups GSD, GSD Opt., GSDT, SBF, and SBFT were appropriately set at unit cost. Therefore, we find that the customer charges proposed by TECO are appropriate.

Demand Charges

The appropriate demand charges are shown in Schedule 8. We set the demand charges at a level that, in combination with the remaining rate components, will result in the recovery of the total revenues allocated to each rate class. Thus, we grant our staff the authority to administratively approve the tariffs filed to implement the approved rates.

Stand-by Service Charges

The appropriate Standby Service charges are shown in Schedule 8. These rates were calculated by using the revenue requirement we approved, consistent with Order 17159, issued February 6, 1987, in Docket No. 850673-EU, In re: Generic Investigation of Standby Rates for Electric Utilities.

Transformer Ownership Discount Application

TECO has proposed to clarify when a transformer ownership credit is appropriate. The change does not reflect a change in policy, only a change in the tariff language explaining the policy. TECO's current tariff language was discussed at length in Docket 070733-EI, in which a customer sought the discount for transformers he had installed behind the primary meter.[49] While parties to Docket No. 070733-EI are still in settlement negotiations, it became clear that, at a minimum, the description of the Transformer Credit need to be clarified to avoid disagreements in the future.

As stated in FIPUG witness Pollock's testimony, the base demand and energy charges for the GSD and GSLD classes are designed to reflect the cost to serve at secondary voltage levels. This means that the utility incurs the cost to provide transformation to step down the delivery voltage to the secondary, or lowest voltage, delivery levels. The cost of this transformation is included in the base rates. Customers who take service at primary, sub-transmission, or transmission level allow the utility to avoid these additional transformation costs. The transformer ownership credit reflects the difference in the cost to serve customers taking power at a higher voltage level.

In his direct testimony, TECO witness Ashburn stated that that a Transformer Ownership Discount will apply to service voltages as proposed in the tariff. The proposed language contained in MFR E-14 (Revised Tariff Sheets) continues to show different credits for service at primary and sub-transmission, with the level of the credits adjusted based on the proposed Cost of Service Study.

FIPUG Witness Pollock stated that the current Transformation Ownership Discount understates the cost of avoided transformation for IS customers. However, he does not address the language redefining when a Transformation Ownership Discount is applicable.

We find that TECO's proposed change to clarify the application of the Transformation Ownership Discount is appropriate to avoid confusion over the ownership of transformers and billing, is supported by record evidence, and shall therefore be approved.

[49] Order No. PSC-08-0397-PAA-EI, issued June 16, 2008, in Docket No. 070733-EI, In re: Complaint No. 694187E by Cutrale Citrus USA, Inc. against Tampa Electric Company for refusing to provide transformer ownership discount for electrical service provided through Minute Maid substation.

Transformer Ownership Discount to be Applied for Billing

The transformer ownership discount is a mechanism to reflect the lower cost of providing service at a higher voltage level, i.e., primary and subtransmission voltage. TECO witness Ashburn testified that the proposed transformer ownership discount rates are based on updated costs. While the underlying theory of recognizing the embedded revenue requirements of transformers is the same as in the 1992 rate case, witness Ashburn explained that the procedures and methodologies used in developing the transformer ownership discount rates have changed. In this case, witness Ashburn explained, the transformer ownership discount rates are derived using the proposed cost of service study details and are calculated on the same basis they would be applied, i.e. $/kilowatt (kW). The methodology employed in the 1992 rate proceeding developed the discount rates using the transformer nameplate rating in kilovolt-amperes.

For the primary and subtransmission voltage levels of supplemental demand, TECO used actual class demand in calculating the transformer ownership discount rates. For standby demand, TECO used ratcheted demand[50] or maximum demand in calculating the discount rates. TECO contended that using the average class demand in kWs rather than the transformer nameplate rating in kilovolt-amperes is appropriate because kWs are the basis on which the discount is applied.

FIPUG witness Pollock explained that the transformer ownership discounts are consistent with cost-of-service principles because they prevent intra-class subsidies by providing lower rates to customers taking service at higher delivery levels. Witness Pollock believed this is appropriate because TECO avoids having to invest in distribution facilities and asserted that it incurs lower losses to serve subtransmission customers. Witness Pollock disagreed with TECO's use of ratcheted demand in calculating the discount rates for standby customers. Witness Pollock presented his calculations for the discount. In its brief, FIPUG contended that TECO's discount proposal is also inconsistent with the cost of service study because it does not reflect all costs avoided by subtransmission customers.

TECO witness Ashburn rebutted FIPUG witness Pollock's criticism of using ratcheted demand in calculating the transformer ownership discounts. Witness Ashburn asserted that the transformer ownership discount for the proposed, combined GSD class was calculated by dividing the avoided cost by the projected billing demand. The witness stated that ratcheted demand was not used in these calculations, and therefore the transformer ownership discounts are not understated. Ratcheted demand was used only for standby customers. Contrary to FIPUG witness Pollock's contentions, witness Ashburn asserted, the tariffs contain monthly reservation charges that are derived and applied on a ratcheted demand basis. The development of TECO's proposed discount for standby customers is therefore derived by dividing the avoided cost by the ratcheted demand measurement. Ratcheted demand is utilized only to calculate the discount for the standby rate schedule.

FIPUG contended that TECO's proposed transformer ownership discounts are understated because: (1) TECO used ratcheted demand rather than actual demand in its discount

[50] Ratcheted demand assumes the maximum amount of demand is used each month for the entire period.

calculations for standby customers; and (2) TECO has not reflected in its calculations all facility costs avoided by subtransmission customers. With respect to the ratcheted demand argument, we note that FIPUG witness Pollock submitted errata for his calculated transformer discounts that indicated agreement with TECO's calculations. Therefore, we find that the use of ratcheted demand for standby customers is no longer at issue.

In its brief, FIPUG asserted that TECO witness Ashburn admitted at hearing that the subtransmission load was excluded from the allocation of primary and secondary distribution plant in the cost study. Therefore, "the transformer discounts are inconsistent with the cost of service study and should be modified to reflect the totality of all costs avoided by these customers so that they are appropriately compensated."

FIPUG's arguments appear to depend on the IS class remaining as it is currently structured. TECO proposed to eliminate the IS class and combine all demand metered customers into a single GSD class. As a result, TECO did not propose a separate Transformation Ownership Discount for the IS class. Instead, the IS class would receive the same discounts as all other customers taking service under the proposed GSD rate. Since the rate would be determined at secondary voltage, the discount is comprised of both the avoided secondary distribution costs ($0.80) and the avoided primary distribution delivery costs ($0.46), for a total subtransmission discount of $1.26. We find that TECO has properly recognized all of the costs avoided for customers taking service at subtransmission voltage levels.

Because we approved keeping the interruptible class as a separate rate classification, the Transformer Ownership Discount, as well as the Power Factor Adjustment and the Emergency Relay Service charges, shall be adjusted by a factor of .99 to reflect rates for primary delivery service.

FIPUG did not provide any evidence regarding how the discounts should be modified or any calculations showing what it believed the discount rates should be. In short, FIPUG provided no evidence supporting its allegations concerning the proposed Transformer Ownership Discounts. For these reasons, we find that FIPUG's arguments are without merit.

Emergency Relay Service Charges

Emergency relay service provides a higher-than-standard level of reliability for customers who desire the ability to automatically switch the power source to a back-up trunk-line when there is a service outage.[51]

TECO proposed to decrease the current emergency relay power supply service rate for general service (GS), general service demand (GSD), and general service time-of-day (GST) optional rate customers from 0.190¢/kWh to 0.165¢/kWh of billing energy. TECO also proposed to increase the charge from 0.60¢/kW to 0.65¢/kW for customers taking service under

[51] Order No. PSC-98-0508-FOF-EI, p. 1, issued April 13, 1998, in Docket No. 980131-EI, In Re: Petition by Tampa Electric Company for approval of emergency relay power supply service option for general service customers.

the GSD rate, the GSDT optional rate, the firm standby and supplemental service (SBF) rate, and the time-of-day firm standby and supplemental service (SBFT) optional rate.

TECO witness Ashburn testified that the proposed emergency relay service charges are based on updated material and labor costs and also a change in methodology for allocating O&M costs to trunk lines. TECO explained that the underlying theory of emergency relay service charges is to recognize the portion of the cost of service embedded revenue requirements associated with back-up capacity at the substation and the O&M expense associated with both the trunk line and back-up capacity at the substation.

TECO stated that the methodology for determining the service charges has changed since the 1992 rate proceeding only with respect to the calculation of the trunk line percent. The trunk line percent determines the portion of the total distribution primary line O&M expense that is attributed to trunk or feeder lines. TECO explained that the trunk line percent used in this proceeding is calculated based on the ratio of the embedded cost of underground (UG) and overhead (OH) wire typically used for feeder or trunk lines to the embedded cost of total system cable and wire. The ratio is then applied to the O&M expense for primary lines. The resulting trunk line O&M portion of the relay service charge is divided by the kW billing for a $/kW charge for the combined GSD class. The ¢/kWh charge for GSD option customers is the result of dividing the trunk line O&M allocation by billing kWh.

In TECO's last rate proceeding, a weighted average trunk line percent was calculated using OH and UG trunk line conductor footage allocations, embedded pole and conduit costs, and embedded primary OH line and UG cable costs. The percent was then applied to the billing kW unit cost for primary line O&M expense. A $/kW O&M expense associated with trunk lines resulted.

TECO stated that while footage allocations attempt to factor in other variables on a cost basis, the embedded cost of poles and conduit used in feeder work does not compare to the embedded cost of poles and conduit used in other primary conductor work on a dollar for dollar basis. Therefore, contended TECO, a straight percentage of embedded pole and conduit costs added to the equation may not result in more accuracy. TECO asserted that the level of detail required to accurately obtain the information required for the method previously used is burdensome and difficult to derive. TECO believes a simplified approach to calculating the trunk line percent is reasonable and should be accepted.

Upon review of the record evidence, we find that TECO's emergency relay service charges are reasonable. We have reviewed TECO's approach to calculating the trunk line percent and agrees that the current method is more simplified than the method previously used. We also find that the cost of maintaining the level of detail required for the previous method may not outweigh any possible accuracy gained in the final calculations, especially given that the embedded costs of conductor types are readily available information.

Because we approved keeping the interruptible class as a separate rate classification, the Transformer Ownership Discount, as well as the Power Factor Adjustment and the Emergency

Relay Service charges, shall be adjusted by a factor of .99 to reflect rates for primary delivery service.

Time Of Use Rate Customers

We find that the appropriate contributions in aid of construction for time of use rate customers choosing to make a lump sum payment for a time-of-use meter in lieu of a higher time-of-use customer charge are $70 for the GST rate schedule and $0 for the GSDT rate schedule.

Energy Charges

Our decision herein establishes the method by which any increase in revenue requirements is allocated to the various customer classes to set new rates. This decision set certain parameters for designing new rates: (1) to the extent possible, consistent with other parameters, the revenue increase should be allocated so as to bring all rate classes as close to parity as practicable; (2) no class should receive an increase greater that 1.5 times the system average increase; and (3) no class should receive a decrease. The final class revenue requirements are shown in Schedule 7.

Several interim steps are necessary to establish final rates. First, to determine the increase by class, the present revenues must be restated to reflect the change in rate structure for the interruptible (IS) class approved herein. Because production demand costs will now be allocated to the IS class based on its actual measured 12 Coincident Peak load responsibility, demand costs to all other rate classes are reduced. However, the ECCR charge for all classes will increase to reflect the demand-side management (DSM) credits payable to IS customers, in lieu of the reduced base rate. If current revenues are not adjusted to reflect the IS rate restructuring, firm customers will see an increase in their total bills (base rates plus clauses) simply due to the restructuring, even without any change in total revenue requirements.

Second, the unadjusted revenue requirement by class is determined by subtracting the revenues at current rates (determined in step one) by class, from the revenue requirement shown in the compliance cost of service study. This unadjusted result must then be evaluated against the parameters set forth herein. If the increase to any class is greater than 1.5 times the system average increase (11.6 percent), revenue requirements will be shifted to other classes to meet that constraint. Also, since no class is granted a decrease in a general rate increase, the surplus shown for the IS class is reallocated to reduce the increase to other classes.[52] Class revenue requirements are then adjusted to recognize unbilled revenues to arrive at the final revenue requirement by rate class.

[52] We note that this apparent surplus for the IS class is likely the result of the one-time change from a discount base rate to the treatment of this rate group as a DSM program. There is no way to know if the credit built into the existing base rate was greater or less than the currently available credit used to adjust current revenues for the structure change, and that relationship determines if the class is shown as under- or over-earning in this analysis.

The final step is to translate the class revenue requirement into actual rates. The total revenue requirement for each rate class is first reduced by the customer charge revenue we approved herein. The proposed energy and demand charges are designed to provide approximately the same percentage increase in energy and demand charge revenues as the overall percentage increase in class revenues. All other rates, charges, and credits reflect our decisions herein. Final rates, charges, and credits by rate class are contained in Schedule 8.

Pursuant to our approval of the GSD, GSLD, IS rate schedules, TECO also developed rates and charges for the new firm IS and IS standby and supplemental rate schedule. The IS customer charge is based on the approved GSD customer charges for primary and subtransmission level plus the cost of interruptible equipment. IS service is only provided at primary or higher level. TECO proposed to keep the current IS-1 and IS-3 demand charge of $1.45 per kW at the same level, while increasing the non-fuel energy charge. The dollar increase in the energy charge will be offset by the per kW DSM credit interruptible customers will now receive under the GSLM-2 and GSLM-3 load management riders. Since the DSM credit is a load factor adjusted credit, increasing the energy charge in lieu of the demand charge will ensure that the base rate component of bills for all IS customers with varying load factors will remain unchanged.

Schedule 10 contains a calculation of TECO's 1,000 kWh monthly residential bill at both present and recommended rates. While the base rate component of the bill will increase by $1.45, overall bills will decrease due to projected lower fuel charges that we approved in Docket No. 090001-EI, in TECO's petition for a mid-course correction to its fuel factors.

TECO proposes that the revised fuel factors be effective May 7, 2009, coincident with the Company's base rate changes approved in this docket. Based on the fuel factors we approved in Docket No. 090001-EI, the 1,000 kWh residential bill will decrease from $128.44 to $114.06, a $14.38 decrease.[53] Schedule 10 also contains residential bill calculations at various other usage levels based on our decisions regarding base rates and fuel adjustment. TECO's energy charges are included in Schedule 8.

Allocation and Rate Design

The methodology for adjusting the affected cost recovery clause factors was stipulated. We approved the following language:

> The changes in allocation and rate design to TECO's capacity cost recovery factors established in Docket No. 080001-EI, conservation cost recovery factors established in Docket No. 080002-EI, and environmental cost recovery factors established in Docket No. 080007-EI should reflect the Commission vote in Issues 83, 87, and 88. In addition, the capacity cost recovery clause and energy conservation cost recovery clause factors should be recovered on demand basis rather than an energy basis as it is currently done.

[53] Under TECO's proposed fuel factor in Docket No. 090001-EI, the residential bill would be $116.66.

The current factors require revision for four reasons. First, we approved a change in cost of service methodology from 12 CP and 1/13 Average Demand (AD) to 12 CP and 25 percent AD to allocate production demand costs. This change in cost of service methodology applies to both base rates and cost recovery clause factors. Second, pursuant to our decisions regarding interruptible rate schedules, interruptible customers will now be responsible for their full 12 CP load share of production capacity related costs in base rates and cost recovery clause factors. Third, the DSM credits payable to interruptible customers will be recovered from all rate classes through the ECCR clause. Finally, the capacity and ECCR factors will be recovered on a demand basis from the demand rate classes rather than an energy basis as it is currently done.

Pursuant to our decisions regarding this issue, TECO revised the factors in the above dockets. We have reviewed the calculations and approve the factors by rate class as shown in Schedule 9. The factors shall become effective May 7, 2009.

Monthly Rental And Termination Factors

TECO has proposed tariff changes to its Facilities Rental Agreement (Agreement). Witness Ashburn explained that the tariff applies to distribution equipment, such as a transformer, that a customer might lease from TECO in order to take service at a higher voltage. The Agreement includes a monthly rental factor and annual termination factors applicable to the long term facilities TECO may agree to lease.

TECO proposed an increase in the monthly rental factor from 1.23 to 1.25 percent per month, plus applicable taxes. The rental factor is applied to the in-place value of the rented facilities. If the agreement is terminated earlier than 20 years, TECO also proposed termination factors to apply to the in-place value based on the year the Agreement is terminated. MFR Schedule E-14 shows the cost analysis for the rental factor and termination factors. The major reason for the change in the monthly rental factor and the termination factors is due to TECO's proposed capital structure. The new rates would apply to new Facilities Rental Agreements.

The development of the monthly rental factor and the termination factors are based on assumptions of the book and tax life of distribution equipment, property tax, insurance, and the capital structure and cost of equity. The factors reflect the cumulative present value of revenue requirements levelized over the remaining life of the distribution plant.

We have reviewed the assumptions used in TECO's development of the applicable factors and the supporting calculations in MFR Schedule E-14. We find that the underlying assumptions are appropriate with the exception of the capital structure and cost of equity. The monthly rental factor and termination factors shall be recalculated using the cost of capital and capital structure that we have approved herein.

Customer-Specific Rate Schedule

Ms. MaryEllen Elia, Superintendent of Hillsborough County Schools, addressed us both at the Service Hearing held in Tampa on October 21, 2008, and prior to the technical hearing in Tallahassee on January 20, 2009. On both occasions, she expressed concern over the impact of

TECO's rate increase on the already strained budgets of the school system. Superintendent Elia suggested two changes that she believed would benefit schools. The first was to combine all school locations as a single customer for purposes of billing. Since different school sites are billed at different rates, even though the school district is one of TECO's largest customers, it is unable to negotiate a lower rate on individual locations. Alternatively, she suggested a separate rate class for schools.

Superintendent Elia maintained that schools were different kinds of customers, in that schools had no one to whom it could pass the increase. She noted that an increase in electric rates was especially difficult now with all of the other budget cuts schools are facing. Absent relief, Superintendent Elia stated that Hillsborough schools would be faced with further reductions in services to students. In response to cross examination, she stated that the school system had taken advantage of numerous conservation programs to attempt to reduce their overall demand. She also indicated that it was unlikely that the county would increase ad valorem taxes, the primary support for schools, in this economic climate. Superintendent Elia stated that the Hillsborough system electric bill for the preceding year was $39 million, and she expected costs to go up for the current year even without a rate increase.

During cross examination, witness Ashburn stated that the school system was served under multiple rates currently. From a ratemaking perspective, rate classes are established by grouping customers with similar usage characteristics and assigning costs based on those usage characteristics. In response to Superintendent Elia's suggestion that all schools be combined for purposes of determining rates, witness Ashburn stated that combining different locations under a single rate distorts the price signals each school location receives. Combining all locations under a single large customer rate would reduce the bills to the school system, but that rate would not reflect the cost to provide such service.

Witness Ashburn noted that a single combined bill also does not provide information to individual schools on their conservation efforts. If the bills and responsibility for evaluating conservation efforts rests with the school board, it makes policing all of the different locations the board's responsibility. On a daily basis, however, the local principal is in the best position to actively monitor conservation activities and take corrective action quickly. Centralized monitoring might result in inappropriate conservation programs or cross-subsidization among school locations.

Superintendent Elia also suggested at the Tampa Service Hearing that a separate rate schedule be established for schools. At the Service Hearing, she spoke about a separate rate based on usage characteristics, however, at the Technical Hearing, she appeared to move more towards a special rate that would be lower than otherwise applicable rates.

Up until the 1980's, many utilities had multiple end-use specific rates such as irrigation rates and farm rates. These rates were effectively eliminated when we adopted the Public Utility Regulatory Policies Act standard on cost based rates in 1980.[54] Customers were no longer

[54] Order No. 10179, p. 7, issued August 3, 1981, in Dockets 780793-EU, 790571-EU, 790593-EU, 790594-EU, and 790859-EU, In re: Consideration of PURPA Standards in the following Dockets: Peak Load Pricing, Declining

classified by how they used electricity, but by the cost to the utility to provide that electricity. Customers with similar usage patterns were grouped into rate classes based primarily on contribution to peak, load factor and energy usage levels. As a point of clarification, while the non-residential rate schedules are often referred to as "commercial," the more correct terminology is General Service rates, as reflected in the titles of the rate schedules. These rates apply to all non-residential usage. Schools, churches, and local governments all take service on these General Service rates, as well as commercial entities.

During cross examination and in response to discovery, witness Ashburn described at length the information that TECO would need to design an appropriate cost based rate. Among the things required is a clear definition of the class, including which schools would be eligible. TECO serves several public school systems, as well as multiple private schools. Once the population was defined, the utility would need to collect load data specific to that subset of customers. Currently load data is collected on a statistically valid sample of existing customer classes.[55] Special time-of-use meters would have to be installed on a similar statistically valid sample of schools to determine their specific usage characteristics. Defining the usage characteristics of the eligible load is critical to estimating the impact on the rest of TECO's ratepayers. Even if we were to decide a special school rate was appropriate, there is insufficient data in this docket to design such a cost based rate.

Witness Ashburn stated that no government entity currently receives a discounted rate from TECO. He went on to state that, while the Company recognizes the various economic constraints the school faces, his responsibility was to design rates which provide the right price signal to make a decision on whether or not to purchase energy. Discount rates could result in little or no conservation since the customer would not be realizing the full cost the utility incurs to serve him. In a discussion about the level of ad valorem taxes, Superintendent Elia noted that increasing taxes would impact the parents of her students. However, allowing the school system to take service at a discount rate has the same impact. To the extent an increase is granted, costs not recovered from the school system will not be absorbed by TECO. The parents of her students and the businesses which employ them would see higher electric rates as a result of any discount afforded the school system.

While we are sympathetic with Superintendent Elia's position, we do not approve shifting costs from one group of customers to another on a non-cost basis, purely to address current economic conditions. As witness Ashburn pointed out, non-cost based rates send incorrect price signals and could result in higher usage, or the failure to invest in further conservation efforts, leading to increased cost to other customers in higher fuel costs or additional plant construction. Providing a subsidy to schools would open the door to requests for subsidies by other tax supported entities such as hospitals, police and fire departments, and local governments, all of which, it could be argued, serve a similar public purpose as schools. Rates to remaining customers might spiral ever higher as the number of customers paying less than cost compensatory rates increases.

Block Rates, Cost of Service, Load Management Decision Making (note: DN 790859-EU was the PURPA umbrella docket)

[55] Rule 25-6.0437, F.A.C., Cost of Service Load Research

Section 366.03, F.S., states: "[a]ll rates and charges made, demanded, or received by any public utility for any service rendered, or to be rendered by it, and each rule and regulation of such public utility, shall be fair and reasonable. No public utility shall make or give any undue or unreasonable preference or advantage to any person or locality, or subject the same to any undue or unreasonable prejudice or disadvantage in any respect." We are granted broad authority with Chapter 366, F.S., to interpret the term "undue" discrimination. Adopting a non-cost base rate to achieve a public good could open the door not only to other such requests, but also charges of discriminatory treatment of those customers who would bear the increased cost not paid by the cost causer. Therefore, we decline to develop a special rate for school systems at this time.

Effective Dates for Rates and Charges

We find that the revised rates shall become effective for meter readings taken on or after 30 days following the date of our vote approving the rates and charges which would mean for meter readings taken on or after May 7, 2009.

OTHER ISSUES

Transmission Base Rate Adjustment Mechanism

Witness Chronister explained that TECO's proposed Transmission Base Rate Adjustment (TBRA) mechanism would allow the Company to timely recover its transmission costs for 230 kV and above transmission projects that TECO submits for review by the Florida Reliability Coordinating Council, Inc. (FRCC). He proposed a regulatory treatment similar to the Generation Base Rate Adjustment (GBRA) clause that we approved in Docket Nos. 050045-E1 and 050078-EI.[56] He stated that the Company would be entitled to receive the annualized base revenue requirement for the first 12 months of operation, reflecting the actual costs incurred once the asset is placed in service. He explained that the TBRA would be calculated using TECO's approved ROE and capital structure. He added that TECO would use a methodology similar to that used for the Capacity Cost Recovery Clause. He testified that the Company would provide its specific construction plans, estimated construction costs and its expected in-service date once a project has been identified by the FRCC in its regional planning process. He explained that TECO would file for cost recovery in the year the transmission project is expected to be substantially complete, and use a true-up mechanism for any variances in cost. Witness Chronister noted that the TBRA would not be automatic, but would be subject to a thorough review. TECO witness Haines testified that TECO's projected 2009 test year transmission expenditures include $68,101,000 for 230 kW transmission projects.

TECO alleged that a high degree of uncertainty has developed from recently promulgated procedures to ensure transmission reliability. Witness Haines explained: "NERC reliability

[56] Order No. PSC-05-0902-S-EI, issued September 14, 2005, in Docket No. 050045-EI, In re: Petition for rate increase by Florida Power & Light Company; Order No. PSC-05-0945-S-EI, issued September 28, 2005, in Docket No. 050078-EI, In re: Petition for rate increase by Progress Energy Florida, Inc.

standards specify transmission system scenarios to be evaluated and the levels of the system performance to be attained." He stated further that:

> NERC's reliability standards dictate the planning and operating criteria for the transmission system that all utilities must meet. The criteria can and does have a direct impact on what transmission gets constructed and when it is required.

Witness Haines testified that there are significant penalties and fines associated with not being compliant with NERC reliability standards, although specific transmission projects are not ordered under the standards. He also described a new cost allocation methodology to be used for regional transmission expansion.

When asked to name or describe recently-developed specific changes to transmission planning, witness Haines explained:

> . . . prior to the new FERC standards, each utility would develop its own transmission plan internally and construct transmission facilities that existed within its own footprint. Now, with the new regional transmission planning process that is in place, each utility will do that, but in addition will submit those plans to the FRCC for the transmission planning committee at the FRCC to consolidate those plans, review and study and ensure that that is the best expansion plan for the state of Florida.

Witness Haines described an extensive planning process that begins with "consolidation of the long-term transmission plans of all transmission owners and providers in the FRCC region." Witness Haines also stated in deposition that, "We have a role as far as submitting what we believe needs to be constructed in our footprint to meet the FERC standards and requirements, and then we have a role in reviewing the consolidated plan and ensuring that it's the most efficient plan for the state." The witness described an extensive cost-sharing methodology. As part of a late-filed exhibit, he provided a nine-page document titled "FRCC principles for Sharing of Certain Transmission Expansion Costs." The document sets out guidelines for cost sharing among parties involved with developments that result in a need for expansion of transmission facilities. Remuneration is to be arranged among the affected parties, and financial assistance is part of the planning when a transmission owner must accommodate the needs of other parties.

Witness Haines stated that the Energy Policy Act of 2005 (the Act) "made compliance with reliability standards approved by FERC mandatory and enforceable, subject to civil penalties." He added that the FERC delegated authority to the FRCC to enforce compliance. He stated that the FRCC also developed a cost allocation methodology for regional transmission expansion in response to the FERC's Order 890, issued in December 2007. He explained that the methodology incorporates a settlement structure to address third party impacts. He argued that allocation of the costs will be difficult to predict in the future. He also pointed out that requests for generator interconnection and firm transmission service require the construction of new transmission facilities, and that such requests are unpredictable in nature.

Witness Haines advised that the Company's transmission and distribution expansion plans are part of a five-year construction plan and budget developed to identify the near term projects required to provide reliable service. He added that the plans are incorporated into the FRCC's planning process. Witness Haines described the FRCC's transmission planning process as a more comprehensive regional planning model than the former approach, whereby transmission planning was primarily performed and studied individually by electric utilities. He stated that TECO is "one of the members that sits on the FRCC planning committee and also the board of directors of the FRCC that reviews annual transmission plans and does have a vote in approving those plans."

OPC witness Larkin stated that the FRCC cannot impose construction requirements, but can only suggest that a particular transmission project be undertaken. He argued that the transmission facilities constructed by TECO are fully under the control of the Company and this Commission. He noted that construction expenditures over lengthy periods of time have always been difficult to project, but that is not a reason to establish an automatic adjustment clause.

Witness Larkin referred to the testimony of TECO witness Haines as a basis for his understanding that "because the FRCC is reviewing regional transmission planning documents… the Federal Energy Regulatory Commission (FERC) has required the development of a cost allocation methodology for regional transmission expansion…" Witness Larkin noted that TECO anticipates a possibility that "the FERC review may somehow impose costs on Tampa Electric over the next five years" and that it would be virtually impossible to predict the magnitude of the cost TECO would be required to bear. He concluded "[p]resumably, this is the basis for Tampa Electric's request for an automatic adjustment clause for transmission investment."

Witness Larkin stated that TECO currently recovers almost 60 percent of its revenue requirements through adjustment clauses. He argued that the addition of another clause will shift additional risk to ratepayers and add additional administrative costs to our staff and the OPC, due to the short timeframe for reviewing and auditing another clause.

Witness Larkin contrasted the proposed TBRA with currently approved clauses. He described the Fuel and Purchased Power Cost Recovery Clause as being designed to compensate for day-to-day fluctuations in the cost of fuel which cannot be anticipated in base rates. He noted that fuel varies both as to price and the amount consumed almost on a daily basis, making it impossible to anticipate the actual level or cost of fuel for any length of time. He stated that such a clause is necessary to ensure that there is a reasonable matching of fuel costs with fuel revenues. He added that the Capacity Cost Recovery Clause is similar because capacity costs related to Purchased Power are difficult to predict and control on a long-term basis and cannot be accurately anticipated in order to be included in rate base. He also described several other clauses as having the characteristics of promoting efficiency and providing programs that benefit ratepayers.

Witness Larkin stated that transmission facilities are planned several years in advance. He explained that a cost benefit analysis is performed, followed by acquisition of the right-of-way for the transmission facility, and followed by addressing environmental issues, before making a cost estimate. He asserted the process spans several years during which the costs are neither unknown, nor uncontrollable by a utility. He opined that the process affords ample time for a company to file a rate request which incorporates the projected cost of this construction and any operating expenses, if needed.

FIPUG witness Pollack described the cost-recovery clauses as "piecemeal rate riders [that] shift the risks that are normally the responsibility of utility shareholders between rate cases to ratepayers." He argued the clauses do not provide a balanced regulatory framework, because it is single-issue ratemaking. He continued that this form of ratemaking "would allow a utility to raise rates to reflect changes in certain specified costs, while ignoring potentially offsetting changes in other costs not subject to the rider." Witness Pollack argued that costs subject to recovery through a clause should be "material, volatile, and beyond the utility's control." He contended that transmission investment is none of these things, noting that "the projected $68.1 million of transmission plant additions in 2009 is less than 2 percent of TECO's rate base." He added that once a transmission facility is in service, the revenue requirement is fixed and does not vary over time. He pointed out that TECO receives additional base rate revenues from the sales of additional energy, thus helping to offset the cost of plant additions. Further, he stated that the dollar-for-dollar recovery of a clause reduces TECO's regulatory risk, which should be considered in determining TECO's authorized ROE.

FIPUG argued in its brief that TECO must seek a determination of need before it can build transmission facilities. FIPUG added that companies must also seek siting approval from the Department of Environmental Protection and the Governor and Cabinet sitting as the Siting Board for transmission lines over 230 kV. (See Sections 403.502-.539, F.S.)

FIPUG pointed out with regard to the GBRA discussed by TECO witness Chronister that both Docket Nos. 050045-E1 and 050078-EI[57] involved settlements as well as other pertinent provisions not at issue in this case. FIPUG argued that "[t]here is a large difference between a time-limited settlement and a new, on-going adjustment clause." FIPUG described Docket No. 050045-E1 as FPL's 2005 rate case, which resulted in a stipulation and settlement which we approved in Order No. PSC-05-0902-S-EI. FIPUG explained the provisions whereby:

> FPL's retail base rates and base rate structure were frozen for four years; no petition for any new surcharges to recover costs traditionally recovered in base rates was permitted; a revenue sharing plan between FPL and its customers above a threshold level was put in place as well as other terms and conditions. No such stipulations or agreements are at issue in this docket.

FIPUG also noted a similar situation in Docket No. 050078-EI, involving PEF's 2005 rate case. FIPUG stated that Order No. PSC-05-0945-S-EI contained a stipulation that froze

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[57] Ibid.

PEF's base rates for four years, included a revenue sharing plan between the company and customers, and applied the generation adjustment only to the Hines plant.

We recognize that the transmission planning process is extensive and on-going. TECO stated the process begins with long-term plans of individual parties, and TECO is a participant in the evaluation of those plans by the FRCC. This process is a matter of years rather than months. The planning process extends over a period of time that affords TECO an opportunity to utilize the standard FPSC rate case procedure, if needed.

The ratemaking process is based on maintaining an appropriate balance between revenue and costs. Since the cost of expansion may be offset or compensated by associated revenue, it is not valid to assume that some unquantified cost in the future will upset the balance and require some added revenue provision. Planning for a transmission expansion will necessarily provide sufficient time for TECO to file a rate case if the situation requires arrangements for additional revenue.

It should be noted that the FRCC does not impose a plan upon any transmission owner, but rather facilitates resolution of issues among the impacted transmission owners in a given region. TECO's depiction leads one to believe that the Company has less control over transmission investment than prior to changes made in 2005. The recent changes associated with the FRCC planning process are limited to: (1) the cost allocation to address third-party impact on transmission expansion and, (2) the assessment of penalties for utilities that are not in compliance with reliability standards. Otherwise, the planning procedure remains as it has been, a process for consolidating the long-term transmission plans of all transmission owners.

To date, there do not appear to be any measureable impacts of the evolving transmission policies on Florida companies. We decline to react to TECO's "sky is falling" approach by instituting a mechanism, which once in place, will more than likely be difficult to remove. TECO included costs of future transmission projects in its filing. Given the long-term horizon that transmission projects appear to have, it appears more prudent to continue to consider such costs in the context of a rate proceeding. If we determine at a future date that companies are filing rate cases to recoup the cost of transportation projects, we can always consider implementation of a recovery mechanism at that time. Of course, other companies would have an interest in such proceedings. There is no record evidence that TECO is in a unique position with regard to transmission expansion needed in Florida.

Although TECO proposed a mechanism similar to the GBRA already in place for FPL and Progress, we agree with FIPUG witness Pollack that the GBRA was part of a complex settlement. Acceptance of a settlement among parties is not the same as establishing a generic policy.

TECO noted in its brief that "FIPUG's own witness admitted the Texas Commission allows utilities to recover transmission costs in between base rate cases." However, FIPUG witness Pollack also clarified that the situation is different in Texas because "the utilities are completely unbundled and . . .the regulated utilities in Texas only provide delivery of service. . ."

Although there is no reason why we could not be the first to adopt a transmission cost recovery mechanism, the lack of such in other states may be an indication that there is no need.

Therefore, we do not approve TECO's proposed Transmission Base Rate Adjustment (TBRA) mechanism. The TBRA considers the cost of constructing new transmission facilities in isolation, without considering potential increases in revenues from additional sales or decreases in rate base due to retirements or depreciation that may offset the impact of construction costs. If the cost of additional transmission facilities does necessitate a rate increase, the long-term nature of transmission planning, design, and construction would afford TECO sufficient time to request a base rate increase.

Entries or Adjustments to Various Reports, Books and Records

We find that TECO shall be required to file, within 90 days after the date of the final order in this docket, a description of all entries or adjustments to its annual report, rate of return reports, and books and records which will be required as a result of our findings in this rate case.

Step Increase In Revenue Requirements

We approved an additional increase in base rates of $33.5 million, effective January 1, 2010, provided that the investments in the five Combustion Turbines and the Big Bend Rail facilities are in service by December 31, 2009. (See Schedule 6) Furthermore, we decided that such costs shall be allocated to rate classes consistent with the approved cost of service methodology.

In order to retain the relative class relationships developed in the current cost of service study, the incremental costs shall first be allocated to each rate class, consistent with the 12 CP and 25 percent AD cost methodology approved herein. Once the dollar increase per class is established, the base rate energy, or energy and demand charges, shall be increased by the percentage increase in class revenues. In addition, non-clause recoverable credits shall also be increased by a similar amount to retain the relationship between the charges and credits approved in the current cost study.

Additionally, we grant our staff the authority to approve the step increase rates administratively, once the dollar amount of the increase has been verified and our staff has confirmed that the new plant and facilities are in service by December 31, 2009.

Based on the foregoing, it is

ORDERED by the Florida Public Service Commission that Tampa Electric Company's Petition for Rate Increase is granted in part and denied in part as set forth herein. It is further

ORDERED that each of the findings made in the body of this Order are hereby approved in every respect. It is further

ORDERED that all matters contained in the attachments and schedules appended hereto are incorporated herein by reference. It is further

ORDERED that within five business days of the issuance of this Order, Tampa Electric Company shall file revised tariffs to reflect our approved final rates and charges for administrative approval by our staff. It is further

ORDERED that the approved rates and charges for Tampa Electric Company shall be effective for meter readings on or after May 7, 2009. Pursuant to the requirements of Rule 25-22.0406(8), F.A.C., customers shall be notified of the revised rates in their first bill containing the new rates. It is further

ORDERED that Tampa Electric Company shall file, within 90 days after the date of the Final Order in this docket, a description of all entries or adjustments to its annual report, earnings surveillance reports, and books and records that will be required as a result of the decision's made in this docket. It is further

ORDERED that upon expiration of the period for appeal these dockets shall be closed.

By ORDER of the Florida Public Service Commission this 30th day of April, 2009.

Ann Cole

ANN COLE
Commission Clerk

(S E A L)

KY

DISSENTS BY: CHAIRMAN CARTER
COMMISSIONER ARGENZIANO

CHAIRMAN CARTER dissents on Storm Damage Reserve.

COMMISSIONER ARGENZIANO dissents on the following: Non-Utility Activities Removed from Rate Base; Pro Forma Adjustment; Adjustment for the Credit from CSX; Pro Forma Adjustment related to Big Bend; Cost Rate for Long-Term Debt; Appropriate Capital Structure; Appropriate Return on Common Equity; Weighted Average Cost of Capital; Demand Charges; Stand-by Service Charges; Energy Charges; Step Increase In Revenue Requirements; and Close Docket, with opinion:

DISSENT

BY COMMISSIONER ARGENZIANO:

I dissent from certain decisions of the majority.

The record for this docket reflects my negative votes on issues 4-7, 33, 34, 37, and 38. I have substantive objections to the votes of the Commission on issues 5, 7, 34, and 37. The other issues reflect my negative vote due to the form of the motions, which grouped issues for vote.

Issues 5 and 7:

These two issues relate to the annualization of 5 Combustion Turbines (CTs) to be placed into service during the course of 2009 (none of which were actually in service at the time of the hearing) and the railroad facilities to be built for the Big Bend Power Station which are not contemplated to be in service until 2010.

My first objection to the inclusion of these expenses in this rate case is the gross violation of the test year "matching principle." The whole concept of a test year is to match revenues to expenses during the period when rates will be in effect. In this case, the company chose to use a projected 2009 test year, which did not include 12 full months of revenues and expenses related to the CT and Big Bend rail projects. However, the company then attempted to add "pro-forma" expenses related to those projects without any consideration of associated revenues, and worse, attempted to "annualize" those expenses so that they could be included in base rates immediately, regardless of whether the facilities are even actually placed into service. This is wrong.

My second objection is the late notice of staff's "step increase" proposal, and lack of ability to hear from all sides. The staff recommendation, released 12 days prior to the vote, contained a recommendation to deny the company's requests for the CT and rail projects. Then, at the vote, staff presented a "revision" of their recommendation, allowing the costs. Given that this item was limited to discussion between Commissioners and staff, no opportunity was given for parties or intervenors to provide comment or input on staff's "revision." The issue was framed as "should a pro forma adjustment be made," and the testimony and briefs addressed that issue, not whether a "step increase" should be allowed, at some time in the future, with some types of conditions. The lack of opportunity for the parties to this case to be heard on staff's proposal to modify the issues post-hearing, without any opportunity to object or be heard on a $33 million change from the agreed-upon issue, constitutes an abject denial of due process.

Issue 34.

Staff made very clear the 54% equity ratio ("E/R") recommended for the capital structure was based on a 10.75% return on equity ("ROE"). The recommended equity ratio was designed to enable the company to attract the low cost capital needed to finance both operations and a significant capital investment program over the next several years. I supported that goal.

However, with the higher ROE the Commission ordered in issue 37, the appropriate amount of equity in the capital structure could have been reduced without any adverse impact to the company's credit rating, resulting in a significant savings to the ratepayers. While the higher E/R may improve the company's credit rating[58] and access to capital, given the cost to ratepayers of the higher E/R - where no unambiguous measure was made of either a benefit to the company's credit rating or a pass-through benefit to the ratepayers from lower capital costs - this decision was in error.

Issue 37.

As a Public Service Commissioner, my ultimate concern is the appropriate balance between a financially healthy company and the ultimate cost of product to the ratepayers. The tension in attempting to achieve this balance is perhaps nowhere more evident than in this one issue.

The record evidence supported a return on equity investment (ROE) for the company ranging from 7.5% - 12.75 13.27%. The record further reflected that the national average of electric utility's authorized ROEs was 10.35%.

Florida is by no means an "average" state, for reasons on which I will comment shortly. Staff recommended an ROE of 10.75%, and a 200 basis point range, high to low. I have determined an ROE of 10.50% is the absolute highest which in rationally good conscience might be awarded.[59]

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[58] This is not to validate the estimations of Standard and Poor, Fitch's, or Moody's, given their triple A awards to entities issuing Credit Default Obligations.

[59] Every 25 basis points has a value of approximately $7,250,000. So, 150 basis points higher is an additional $43,500,000 per year, just in return to the company's shareholders. This is in addition, of course, to the dollars being used to repay debt.

And, if the step increase goes into effect in January, 2010, there will be an additional $700,000 ratepayers to shareholders transfer, in the name of "creditworthiness", which the record demonstrates would be met at a much lower ROE and therefore lower cost to ratepayers.

The ROE determined by my colleagues, 11.25%, is simply an extravagant grant to the utility, for the following reasons:

Bluefield Waterworks and Improvement Co. v. Public Service Commission of West Virginia et. al., 262 U.S. 679, 43 S.Ct. 675, 67 L.Ed. 1176, as hoary as it may be, gives guidance in connection with the application of the "just and reasonable" standard which the FPSC is charged with applying in rate cases before it. Bluefield gives further guidance on what matters are to be considered in connection with determinations related to rate fixing.

> "A public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public equal **to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding risks and uncertainties,...**". 262 U.S. 679, 692 (emphasis added)

Without preamble, there are no similar "business undertakings" outside regulated utilities, at this time in this or any part of the country which enjoy a 1) stranded consumer constituency for 2) an essential service whose existence is 3) protected by government with 4) a guaranteed profit, operating in an economic environment made 5) virtually risk free by legislative accommodation. The record is absent of any effort by any party – or staff – to identify any alternative "business undertakings", such as non-regulated industries providing an essential service (food, healthcare, fuel, housing, etc.) and with their corresponding returns to investors. I conclude therefore, that such a creature is pure fiction, and the measure of the entitlement by the utility to a return on its investment based on such an entity is purely as fashioned by the Commission on other guidance provided by *Bluefield*.

Inasmuch as *Bluefield* requires consideration of a utility's operational risk in establishing return on equity, it is notable that by legislative action, the following no longer exist as risk factors in the conduct of the utility business:

1. costs related to storm events, per 366.8260, in 2000;
2. renewable energy undertakings, per 366.91, in 2005;
3. nuclear costs, not applicable with regard to this petitioner, per 366.93, in 2006;
4. If passed by the 2009 Legislature, costs associated with expanded renewable portfolio standards.

Prior to the last rate case for this company, recoveries for environmental compliance costs (authorized by Section 366.8295 F.S); conservation costs (authorized by Section 366.82, F.S.); and fuel and capacity costs (authorized by Orders of the Commission) were provided to the utility.[60]

[60] Something in excess of 60% of the company's annual revenues are generated by these "clause" recoveries, which are virtually guaranteed and correspond to zero risk for the company's investors.

Each of the four numbered statutory recovery guarantees has occurred since the last rate case awarded the utility a return on equity of 11.75%. To now install a return on equity of 11.25, almost a full percentage point above the national average, is to disregard the Bluefield Court's contemplation of risk.

In fact, it is difficult to see what "risk" exists for the utility in the conduct of its operations. I believe that my colleagues have wholly failed to appreciate that, with the absence of risk, the entitled rate of return might well commence at the essentially risk free rates of Treasury bills, with the burden shifting to the utility to make a case for every point rise in the rate which it needs above Treasury bill rates averaged over the term since the last ROE award. Certainly, the legislature may well have intended that, as the legislature acted to eliminate risk to the utility, the FPSC would exercise its responsibility to provide for "just and reasonable" rates, by way of reduction in ROE, as contemplated by *Bluefield*.

Too, my colleagues further disregard the Bluefield Court's identification of the context in which the return on equity should be set:

> "A rate of return may be reasonable at one time and become too high or too low by changes affecting opportunities for investment, the money market, and business conditions generally." 262 U.S. 679, 693

The Dow Jones Industrial Average, for example, reflects a reduction in value of 34%, 1/08 – 1/09, I believe inarguably establishing the market reflected "changes" contemplated by the Court.

Apparently the meltdown of the world's financial systems, and the United States' in particular, is not an occurrence deserving notice. I believe that it is unconscionable and rationally indefensible to disregard the evaporation of trillions of dollars in wealth, to slight the 250% increase in unemployment, to ignore what has been described as the most significant economic disaster since the Great Depression, and to avoid consideration of the Court's requirement to consider "business conditions generally," in ho-hum establishing the utility's return on equity at 11.25%, or a mere 4% deviation from that which it enjoyed in 1992.

Finally, the Bluefield Court advises that the utility "... has no constitutional right to such profits as are realized or anticipated in highly profitable enterprises or speculative ventures." 262 U.S. 679, 692-693. The $50,000,000,000 of capital lost through investments made in Bernard Madoff's schemes were induced by the promise of "phenomenal" returns in the 10-12 % range, the same realm the Commission has awarded the utility.

NOTICE OF FURTHER PROCEEDINGS OR JUDICIAL REVIEW

The Florida Public Service Commission is required by Section 120.569(1), Florida Statutes, to notify parties of any administrative hearing or judicial review of Commission orders that is available under Sections 120.57 or 120.68, Florida Statutes, as well as the procedures and time limits that apply. This notice should not be construed to mean all requests for an administrative hearing or judicial review will be granted or result in the relief sought.

Any party adversely affected by the Commission's final action in this matter may request: 1) reconsideration of the decision by filing a motion for reconsideration with the Office of Commission Clerk, 2540 Shumard Oak Boulevard, Tallahassee, Florida 32399-0850, within fifteen (15) days of the issuance of this order in the form prescribed by Rule 25-22.060, Florida Administrative Code; or 2) judicial review by the Florida Supreme Court in the case of an electric, gas or telephone utility or the First District Court of Appeal in the case of a water and/or wastewater utility by filing a notice of appeal with the Office of Commission Clerk, and filing a copy of the notice of appeal and the filing fee with the appropriate court. This filing must be completed within thirty (30) days after the issuance of this order, pursuant to Rule 9.110, Florida Rules of Appellate Procedure. The notice of appeal must be in the form specified in Rule 9.900(a), Florida Rules of Appellate Procedure.

TAMPA ELECTRIC COMPANY
DOCKET NO. 080317-EI
13-MONTH AVERAGE RATE BASE
DECEMBER 2009 TEST YEAR

SCHEDULE 1

Issue No.		Plant in Service	Accumulated Depreciation	Net Plant in Service	CWIP	Plant Held for Future Use	Net Plant	Working Capital	Total Rate Base
	Adjusted per Company	5,483,474,000	(1,934,489,000)	3,548,985,000	101,071,000	37,330,000	3,687,386,000	(30,586,000)	3,656,800,000
	Commission Adjustments:								
4	Non-Utility Activities	0	0	0	0	0	0	0	0
5	Combustion Turbine Annualization	(134,439,000)	3,750,000	(130,689,000)	0	0	(130,689,000)	0	(130,689,000)
6	CSX Credit - Big Bend Rail Project	0	0	0	0	0	0	0	0
7	Big Bend Rail Project Annualization	(45,206,000)	452,000	(44,754,000)	0	0	(44,754,000)	0	(44,754,000)
8	Plant in Service Amount	(35,671,000)	1,248,485	(34,422,515)	0	0	(34,422,515)	0	(34,422,515)
9	Customer Information System	0	0	0	0	0	0	0	0
10	Total Plant in Service	0	0	0	0	0	0	0	0
11	Total Accumulated Depreciation	0	0	0	0	0	0	0	0
12	ECRC Costs	0	0	0	0	0	0	0	0
13	Total CWIP	0	0	0	0	0	0	0	0
14	Total PHFFU	0	0	0	0	0	0	0	0
15	Deferred Dredging Costs	0	0	0	0	0	0	(1,346,649)	(1,346,649)
16	Storm Damage Reserve	0	0	0	0	0	0	6,000,000	6,000,000
17	Prepaid Pension Expense	0	0	0	0	0	0	0	0
18	Other Accounts Receivable (143)	0	0	0	0	0	0	(10,959,000)	(10,959,000)
19	Accts Rec. Associated Cos. (146)	0	0	0	0	0	0	(390,000)	(390,000)
20	OPEB Liability	0	0	0	0	0	0	0	0
21	Coal Inventory	0	0	0	0	0	0	0	0
22	Residual Oil Inventory	0	0	0	0	0	0	0	0
23	Distillate Oil Inventory	0	0	0	0	0	0	0	0
24	Natural Gas & Propane Inventories	0	0	0	0	0	0	0	0
25-S	Clause Over/Under Recoveries	0	0	0	0	0	0	0	0
26	Rate Case Expense	0	0	0	0	0	0	(2,628,000)	(2,628,000)
27	Total Working Capital	0	0	0	0	0	0	0	0
32	Imputed Equity Infusion	0	0	0	0	0	0	0	0
---	Total Commission Adjustments	(215,316,000)	5,450,485	(209,865,515)	0	0	(209,865,515)	(9,323,649)	(219,189,164)
28	Commission Adjusted Rate Base	5,268,158,000	(1,929,038,515)	3,339,119,485	101,071,000	37,330,000	3,477,520,485	(39,909,649)	3,437,610,836

TAMPA ELECTRIC COMPANY
DOCKET NO. 080317-EI
13-MONTH AVERAGE CAPITAL STRUCTURE
DECEMBER 2009 TEST YEAR

SCHEDULE 2

Company As Filed	($) Amount	Ratio	Cost Rate	Weighted Cost
Common Equity	1,835,985,000	50.21%	12.00%	6.02%
Long-term Debt	1,397,565,000	38.22%	6.80%	2.60%
Short-term Debt	8,002,000	0.22%	4.63%	0.01%
Preferred Stock	0	0.00%	0.00%	0.00%
Customer Deposits	103,724,000	2.84%	6.07%	0.17%
Deferred Income Taxes	302,744,000	8.28%	0.00%	0.00%
Tax Credits - Zero Cost	0	0.00%	0.00%	0.00%
Tax Credits - Weighted Cost	8,780,000	0.24%	9.75%	0.02%
Total	3,656,800,000	100.00%		8.82%
Equity Ratio	56.64%			

Commission Adjusted	($) Amount	($) Specific Adjustments	($) Specific Adjustments	($) Pro Rata Adjustments	($) Commission Adjusted	Ratio	Cost Rate	Weighted Cost
Common Equity	1,835,985,000	(169,461,000)	36,921,713	(118,305,459)	1,585,140,254	46.11%	11.25%	5.19%
Long-term Debt	1,397,565,000	17,679,000	29,365,827	(100,329,131)	1,344,280,696	39.11%	6.80%	2.66%
Short-term Debt	8,002,000	(185,000)	168,140	(554,573)	7,430,567	0.22%	2.75%	0.01%
Preferred Stock	0	0	0	0	0	0.00%	0.00%	0.00%
Customer Deposits	103,724,000	18,726,000	2,633,848	0	125,083,848	3.64%	6.07%	0.22%
Deferred Income Taxes	302,744,000	54,656,000	7,687,524	0	365,087,524	10.62%	0.00%	0.00%
Tax Credits - Zero Cost	0	0	0	0	0	0.00%	0.00%	0.00%
Tax Credits - Weighted Cost	8,780,000	1,585,000	222,947	0	10,587,947	0.31%	9.19%	0.03%
Total	3,656,800,000	(77,000,000)	77,000,000	(219,189,164)	3,437,610,836	100.00%		8.11%
Equity Ratio	56.64%				53.97%			

Interest Synchronization	($) Adjustment Amount	Cost Rate	($) Effect on Interest Exp.	Tax Rate	($) Effect on Income Tax
Dollar Amount Change					
Long-term Debt	(53,284,304)	6.80%	(3,623,333)	38.575%	1,397,701
Short-term Debt	(571,433)	4.63%	(26,457)	38.575%	10,206
Customer Deposits	21,359,848	6.07%	1,296,543	38.575%	(500,141)
					907,765
Cost Rate Change					
Short-term Debt	8,002,000	-1.88%	(150,438)	38.575%	58,031
Tax Credits - Weighted Cost	8,780,000	-0.56%	(49,027)	38.575%	18,912
					76,944
Total Interest Synchronization					984,709

TAMPA ELECTRIC COMPANY
DOCKET NO. 080317-EI
NET OPERATING INCOME
DECEMBER 2009 TEST YEAR

SCHEDULE 3

		Operating Revenues	O&M - Fuel & Purchased Power	O&M Other	Depreciation and Amortization	Taxes Other Than Income	Total Income Taxes	(Gain)/Loss on Disposal of Plant	Total Operating Expenses	Net Operating Income
	Adjusted per Company	865,359,000	7,614,000	370,934,000	194,608,000	62,275,000	48,492,000	(1,534,000)	682,389,000	182,970,000
	Commission Adjustments:									
2	Revenue Forecast	0	0	0	0	0	0	0	0	0
8	Plant in Service Amount	0	0	0	(1,248,485)	0	481,603	0	(766,882)	766,882
39	Total Operating Revenues	0	0	0	0	0	0	0	0	0
40-S	Inflation Factors	0	0	0	0	0	0	0	0	0
41	Total O&M Expense	0	0	0	0	0	0	0	0	0
42-S	FAC Revenues and Expenses	0	0	0	0	0	0	0	0	0
43-S	ECCR Revenues and Expenses	0	0	0	0	0	0	0	0	0
44-S	CCRC Revenues and Expenses	0	0	0	0	0	0	0	0	0
45-S	ECRC Revenues and Expenses	0	0	0	0	0	0	0	0	0
46	Advertising Expenses	0	0	0	0	0	0	0	0	0
47	Lobbying Expenses	0	0	0	0	0	0	0	0	0
48	Salaries and Employee Benefits	0	0	(5,195,129)	0	0	2,004,021	0	(3,191,108)	3,191,108
49	OPEB Expenses	0	0	0	0	0	0	0	0	0
50	Vacant Positions	0	0	0	0	0	0	0	0	0
51	Service reliability Initiatives	0	0	0	0	0	0	0	0	0
52	Incentive Compensation Plan	0	0	(540,000)	0	0	208,305	0	(331,695)	331,695
53	Generating Units - CSAs	0	0	0	0	0	0	0	0	0
54	Generation Maintenance Expense	0	0	(2,850,000)	0	0	1,099,388	0	(1,750,613)	1,750,613
55	Preventive Maintenance Expense	0	0	0	0	0	0	0	0	0
56	Dredging Expense	0	0	(650,056)	0	0	250,759	0	(399,297)	399,297
57	Economic Development Expense	0	0	0	0	0	0	0	0	0
58	Pension Expense	0	0	0	0	0	0	0	0	0
59	Storm Damage Accrual	0	0	(12,000,000)	0	0	4,629,000	0	(7,371,000)	7,371,000
60	Injuries & Damages Accrual	0	0	0	0	0	0	0	0	0
61	Executives' Liability Insurance	0	0	0	0	0	0	0	0	0
62	Meter & Meter Reading Expenses	0	0	0	0	0	0	0	0	0
63	Rate Case Expense Amortization	0	0	(557,750)	0	0	215,152	0	(342,598)	342,598
64	Bad Debt Expense	0	0	0	0	0	0	0	0	0
65	Office Supplies	0	0	0	0	0	0	0	0	0
66	Tree Trimming Expense	0	0	(1,314,000)	0	0	506,876	0	(807,125)	807,125
67	Pole Inspections	0	0	0	0	0	0	0	0	0
68	Transmission Inspection Expense	0	0	0	0	0	0	0	0	0
69	Outage Normalization	0	0	0	0	0	0	0	0	0
70	CIS Expenses	0	0	0	0	0	0	0	0	0
71	Combustion Turbine Annualization	0	0	(870,000)	(5,425,000)	(5,453,000)	4,531,791	0	(7,216,209)	7,216,209
72	Big Bend Rail Project Annualization	0	0	0	(906,000)	(1,039,000)	750,284	0	(1,194,716)	1,194,716
73	Depreciation Study	0	0	0	0	0	0	0	0	0
74	Total Depreciation Expense	0	0	0	0	0	0	0	0	0
75	Taxes Other Than Income	0	0	0	0	0	0	0	0	0
76	Parent Debt Adjustment	0	0	0	0	0	(9,657,000)	0	(9,657,000)	9,657,000
77	Income Tax Expense	0	0	0	0	0	0	0	0	0
	Interest Synchronization	0	0	0	0	0	984,709	0	984,709	(984,709)
	Total Commission Adjustments	0	0	(23,976,935)	(7,579,485)	(6,492,000)	6,004,887	0	(32,043,533)	32,043,533
78	Commission Adjusted NOI	865,359,000	7,614,000	346,957,065	187,028,515	55,783,000	54,496,887	(1,534,000)	650,345,467	215,013,533

SCHEDULE 4

TAMPA ELECTRIC COMPANY
DOCKET NO. 080317-EI
DECEMBER 2009 PROJECTED TEST YEAR
NET OPERATING INCOME MULTIPLIER

Line No.		(%) As Filed	(%) Commission Adjusted
1	Revenue Requirement	100.000	100.000
2	Gross Receipts Tax	0.000	0.000
3	Regulatory Assessment Fee	(0.072)	(0.072)
4	Bad Debt Rate	(0.349)	(0.349)
5	Net Before Income Taxes	99.579	99.579
6	Income Taxes (Line 5 x 38.575%)	(38.413)	(38.413)
7	Revenue Expansion Factor	61.166	61.166
8	Net Operating Income Multiplier (100%/Line 7)	1.63490	1.63490

SCHEDULE 5

TAMPA ELECTRIC COMPANY
DOCKET NO. 080317-EI
DECEMBER 2009 PROJECTED TEST YEAR
REVENUE REQUIREMENTS CALCULATION

Line No.		As Filed	Commission Adjusted
1.	Rate Base	$3,656,800,000	$3,437,610,836
2.	Overall Rate of Return	8.82%	8.11%
3.	Required Net Operating Income (1)x(2)	322,530,000	278,790,239
4.	Achieved Net Operating Income	182,970,000	215,013,533
5.	Net Operating Income Deficiency (3)-(4)	139,560,000	63,776,706
6.	Net Operating Income Multiplier	1.63490	1.63490
7.	Operating Revenue Increase (5)x(6)	$228,167,000	$104,268,536

SCHEDULE 6

TAMPA ELECTRIC COMPANY
DOCKET NO. 080317-EI
CALCULATION OF JANUARY 1, 2010 STEP INCREASE

Step Increase Revenue Requirement	
Big Bend Rail Facility	$7,006,720
May 2009 CTs	7,924,344
September 2009 CTs	18,630,306
Total Step Increase	$33,561,370

Line No.		Big Bend Rail Facility	May CTs (2 Units)	September CTs (3 Units	Total CTs (5 Units)
1	Net Plant in Service	$44,754,000	$36,125,000	$94,563,000	$130,688,000
2	Rate Of Return	8.11%	8.11%	8.11%	8.11%
3	Required Return (2x3)	3,629,549	2,929,738	7,669,059	10,598,797
4	O&M Expenses	0	212,000	658,000	870,000
5	Depreciation	906,000	1,391,000	4,034,000	5,425,000
6	Taxes Other Than Income	1,039,000	2,226,000	3,227,000	5,453,000
7	Income Taxes (4+5+6) x (-.38575)	(750,284)	(1,477,037)	(3,054,754)	(4,531,791)
8	Income Tax Effect of Interest	(538,548)	(434,711)	(1,137,925)	(1,572,636)
	[(1) x 3.12% x (-.38575)]	------	------	------	------
9	Total NOI Requirement (3+4+5+6+7+8)	4,285,718	4,846,990	11,395,380	16,242,370
10	NOI Multiplier	1.6349	1.6349	1.6349	1.6349
11	Revenue Requirement (9x10)	$7,006,720	$7,924,344	$18,630,306	$26,554,650

	($) Amount	Ratio	Cost Rate	Weighted Cost
Common Equity	1,585,140,254	53.97%	N/A	N/A
Long Term Debt	1,344,280,696	45.77%	6.80%	3.11%
Short Term Debt	7,430,567	0.25%	2.75%	0.01%
Total	2,936,851,516	100.00%		3.12%

TAMPA ELECTRIC COMPANY
TEST PERIOD: PROJECTED CALENDAR YEAR 2009
DEVELOPMENT OF TARGET FINAL CLASS SALES REVENUES
IN $(000)

Line No.	Rate Class	(A) Cost of Service w/ Other Oper.Rev. Cr. Prod. Cap. Alloc.: 12 CP & 25% AD	(B) Additional Revenue Credits (a)	(C) Class Sales Revenue Requirement (A) - (B)	(D) Revision of Base Revenues for IS Restructuring: Present Class Revenue	(E) Change for IS Restructuring (b)	(F) Restructured Present Class Revenue (D) + (E)	(G) Present Class Revenue Deficiency / (Surplus): $ (C) - (F)	(H) % (G) / (F)	(I) Allocated Class Sales Revenue Increase: $ (d)	(J) % (I) / (F)	(K) Target Final Class Sales Revenue: Total (F) + (I)	(M) Unbilled Revenue Change (e)	(N) Billed Sales Revenue (K) - (M)
3	I. Residential (RS)	512,944	6,094	506,850	454,812	(11,914)	442,898							
5	II. General Service -													
6	Non-Demand (GS)	57,783	835	56,948	53,970	(1,366)	52,604							
8	Total: I + II	570,727	6,929	563,798	508,782	(13,280)	495,502	68,296	13.8% (c)	60,150	12.1%	555,652	(57)	555,718
11	III. General Service -													
12	Demand (GSD)	298,141	188	297,953	266,206	(8,198)	258,008	39,945	15.5%	35,181	13.6%	293,189	(54)	293,243
14						22,698								
15	IV. Interruptible					(1,134)								
16	General Service (IS)	37,374	1	37,373	21,915	21,564	43,479	(6,106)	-14.0%	-	0.0% (g)	43,479	(9)	43,488
19	V. Lighting Service (LS)													
20	A. Energy	6,147	-	6,147	4,683	(86)	4,597	1,550	33.7%	800	17.4% (g)	5,396	(2)	5,398
21	B. Facilities	29,731	-	29,731	36,265	-	36,265	(6,534)	-18.0%	1,022	2.8% (f)	37,287	-	37,287
22	Total: V.	35,878	-	35,878	40,948	(86)	40,862	(4,984)	-12.2%	1,822	4.5%	42,683	(2)	42,685
27	Total	942,120	7,117	935,003	837,851	(0)	837,851	97,152	11.6%	97,152	11.6%	935,003	(132)	935,135

Revenue Reconciliation Check

Present Operating Revenues			
Sales Revenu	$	837,851	Per Original Filing
Other Oper. Rev	$	27,508	Per Original Filing
Total Pres. Rev	$	865,359	
Plus:			
Revenue Increase	$	104,269	FPSC Decision
Equals: Final Revenues	$	969,628	

Summary of Final Revenue Development:			
Sales Revenue	$	935,135	Col. (N), L. 27
Other Oper. Revenue	$	27,508	Per Original Filing
Plus:Addtnl. Serv. Chg. Rev.	$	7,117	Col. (B), L.27
Plus:Addtnl. Unbilled Rev.	$	(132)	Col. (M), L. 27
Equals: Final Revenues	$	969,628	

Notes:

(a) Additional revenue credits from increase in service charges allocated in proportion to present service charge revenue allocation in COS

(b) Under the approved IS Rate Restructuring, class revenues must be restated to reflect a revenue neutral implementation of IS as a DSM program with demand credits recoverable through the ECCR clause. The off-setting change in base revenues reflect payments of $ 22,698,235 to interruptible customers and recovery from all rate classes on the basis of the 12 CP and 25% AD production capacity allocation method.

(c) Revenues of rate classes I. and II. have been combined for increase determination since rate charges of each class are set effectively the same.

(d) Class Revenue Increases determined by (1) assigning FPSC approved revenue changes to class V.B., Lighting Facilities, (2) limiting class V.A., Lighting Energy, to 1.5 times total average percentage increase per FPSC policy, (3) setting no change to class IV. revenues per FPSC policy, and (4) allocating remainder of revenue increase to combined classes' I & II and class III in proportion to these classes revenue deficiencies.

(e) Additional total unbilled revenue amount calculated as total base rate increase of 11.6% applied to total unbilled revenue amount valued at present rates and allocated to rate classes on basis of class MWH requirements. [11.6% x ($1,139) = ($132)]

(f) Reflects revenue effect of lighting facility and maintenance changes in accordance with Issue 93 as approved.

(g) Set per Commission Policy: No class should receive an increase greater than 1.5 times the system average percentage increase in total, and no class should receive a decrease

Schedule 7

Base rates, other charges, and credits for all rate schedules – effective May 7, 2009

Schedule 8, page one of ten

Current Rate Schedule	Type of Charge	Current Rate		Approved Rate Schedule	Approved Rate
RS	Customer Facilities Charge:			RS	
	Standard	8.50	$/Bill		10.50
	Time-of-Day	11.50	$/Bill		10.50
	Energy and Demand Charge:				
	Standard	4.342	¢/kWh		-
	First 1,000 kWh	-	¢/kWh		4.287
	All additional kWh	-	¢/kWh		5.287
	Time-of-Day On-Peak	11.460	¢/kWh		4.637
	Time-of-Day Off-Peak	0.968	¢/kWh		4.637

Current Rate Schedule	Type of Charge	Current Rate		Approved Rate Schedule	Approved Rate	
GS	Customer Facilities Charge:			GS		
	Standard	8.50	$/Bill		10.50	$/Bill
	Standard - Unmetered	7.50	$/Bill		9.00	$/Bill
	Time-of-Day	11.50	$/Bill		12.00	$/Bill
	Energy and Demand Charge:					
	Standard	4.342	¢/kWh		4.637	¢/kWh
	Time-of-Day On-Peak	11.460	¢/kWh		12.477	¢/kWh
	Time-of-Day Off-Peak	0.968	¢/kWh		1.010	¢/kWh
	Emergency Relay Charge	0.190	¢/kWh		0.145	¢/kWh

Current Rate Schedule	Type of Charge	Current Rate		Approved Rate Schedule	Approved Rate	
TS	Customer Facilities Charge:			TS		
	Standard	8.50	$/Bill		10.50	$/Bill
	Energy and Demand Charge:					
	Standard	4.342	¢/kWh		4.637	¢/kWh

Schedule 8, page two of ten

Current Rate Schedule	Type of Charge	Current Rate		Approved Rate Schedule	Approved Rate	
GSD	Customer Charge:			GSD		
	Standard Secondary	42	$/Bill		57	$/Bill
	Standard Primary	42	$/Bill		130	$/Bill
	Standard Subtransmission	42	$/Bill		930	$/Bill
	Optional Secondary	42	$/Bill		57	$/Bill
	Optional Primary	42	$/Bill		130	$/Bill
	Optional Subtransmission	42	$/Bill		930	$/Bill
	Time-of-Day Secondary	49	$/Bill		57	$/Bill
	Time-of-Day Primary	49	$/Bill		130	$/Bill
	Time-of-Day Subtransmission	49	$/Bill		930	$/Bill
	Energy Charge:					
	Standard	1.370	¢/kWh		1.515	¢/kWh
	Optional	5.210	¢/kWh		5.564	¢/kWh
	Time-of-Day On-Peak	2.198	¢/kWh		2.751	¢/kWh
	Time-of-Day Off-Peak	1.008	¢/kWh		1.010	¢/kWh
	Demand Charge:					
	Standard (all delivery voltages)	7.25	$/kW		8.06	$/kW
	Optional (all delivery voltages)	-	$/kW		-	$/kW
	Time-of-Day Billing (all delivery voltages)	2.36	$/kW		2.72	$/kW
	Time-of-Day Peak (all delivery voltages)	5.08	$/kW		5.34	$/kW
	Transformer Ownership Discount:					
	Standard Primary	(0.36)	$/kW		(0.70)	$/kW
	Standard Subtransmission	(0.59)	$/kW		(1.10)	$/kW
	Optional Primary	(0.36)	$/kW		(1.85)	$/MWh
	Optional Subtransmission	(0.59)	$/kW		(2.87)	$/MWh
	Time-of-Day Primary	(0.36)	$/kW		(0.70)	$/kW
	Time-of-Day Subtransmission	(0.59)	$/kW		(1.10)	$/kW
	Emergency Relay Power Supply Charge:					
	Standard (all delivery voltages)	0.60	$/kW		0.57	$/kW
	Optional (all delivery voltages)	0.60	$/kW		1.45	$/MWh
	Time-of-Day Billing (all delivery voltages)	0.60	$/kW		0.57	$/kW
	Meter Level Discount:					
	Standard Primary	(1.0)	%		(1.0)	%
	Standard Subtransmission	(2.0)	%		(2.0)	%
	Optional Primary	(1.0)	%		(1.0)	%
	Optional Subtransmission	(2.0)	%		(2.0)	%

Schedule 8, page three of ten

Current Rate Schedule	Type of Charge	Current Rate		Approved Rate Schedule	Approved Rate	
GSLD	Customer Charge:			GSD		
	Standard Secondary	255	$/Bill		57	$/Bill
	Standard Primary	255	$/Bill		130	$/Bill
	Standard Subtransmission	255	$/Bill		930	$/Bill
	Time-of-Day Secondary	255	$/Bill		57	$/Bill
	Time-of-Day Primary	255	$/Bill		130	$/Bill
	Time-of-Day Subtransmission	255	$/Bill		930	$/Bill
	Energy Charge:					
	Standard (All delivery voltages)	1.370	¢/kWh		1.515	¢/kWh
	Time-of-Day On-Peak (All delivery voltages)	2.198	¢/kWh		2.751	¢/kWh
	Time-of-Day Off-Peak (All delivery voltages)	1.008	¢/kWh		1.010	¢/kWh
	Demand Charge:					
	Standard (All delivery voltages)	7.25	$/kW		8.06	$/kW
	Time-of-Day Billing (All delivery voltages)	2.36	$/kW		2.72	$/kW
	Time-of-Day Peak (All delivery voltages)	5.08	$/kW		5.34	$/kW
	Power Factor Charge:					
	Standard (All Delivery voltages)	0.002	$/kVARh		0.002	$/kVARh
	Time-of-Day (All Delivery voltages)	0.002	$/kVARh		0.002	$/kVARh
	Power Factor Credit:					
	Standard (All Delivery voltages)	(0.001)	$/kVARh		(0.001)	$/kVARh
	Time-of-Day (All Delivery voltages)	(0.001)	$/kVARh		(0.001)	$/kVARh
	Emergency Relay Power Supply Charge:					
	Standard (All Delivery voltages)	0.60	$/kW		0.57	$/kW
	Time-of-Day (All Delivery voltages)	0.60	$/kW		0.57	$/kW
	Transformer Ownership Discount:					
	Standard Primary	(0.36)	$/kW		(0.70)	$/kW
	Standard Subtransmission	(0.59)	$/kW		(1.10)	$/kW
	Time-of-Day Primary	(0.36)	$/kW		(0.70)	$/kW
	Time-of-Day Subtransmission	(0.59)	$/kW		(1.10)	$/kW
	Meter Level Discount:					
	Standard Primary	(1.0)	%		(1.0)	%
	Standard Subtransmission	(2.0)	%		(2.0)	%
	Time-of-Day Primary	(1.0)	%		(1.0)	%
	Time-of-Day Subtransmission	(2.0)	%		(2.0)	%

Schedule 8, page four of ten

Current Rate Schedule	Type of Charge	Current Rate		Approved Rate Schedule	Approved Rate	
SBF	Customer Charge:			SBF		
	Standard Secondary	280	$/Bill		82	$/Bill
	Standard Primary	280	$/Bill		155	$/Bill
	Standard Subtransmission	280	$/Bill		955	$/Bill
	Time-of-Day Secondary	280	$/Bill		82	$/Bill
	Time-of-Day Primary	280	$/Bill		155	$/Bill
	Time-of-Day Subtransmission	280	$/Bill		955	$/Bill
	Supplemental Demand Charge:					
	Standard (All delivery voltages)	7.25	$/kW		8.06	$/kW
	Time-of-Day Billing (All delivery voltages)	2.36	$/kW		2.72	$/kW
	Time-of-Day Peak (All delivery voltages)	5.08	$/kW		5.34	$/kW
	Supplemental Energy Charge:					
	Standard (All delivery voltages)	1.370	¢/kWh		1.515	¢/kWh
	Time-of-Day On-Peak (All delivery voltages)	2.198	¢/kWh		2.751	¢/kWh
	Time-of-Day Off-Peak (All delivery voltages)	1.008	¢/kWh		1.010	¢/kWh
	Standby Demand Charge (All):					
	Local Facilities Reservation	2.66	$/kW		2.23	$/kW
	Plus the greater of					
	Power Supply Reservation, or	0.87	$/kW-Mo		1.20	$/kW-Mo
	Power Supply Demand	0.34	$/kW-Day		0.48	$/kW-Day
	Standby Energy Charge:					
	Time-of-Day (All delivery voltages)	0.984	¢/kWh		1.010	¢/kWh
	Transformer Ownership Discount:					
	Supplemental					
	Standard Primary	(0.36)	$/kW		(0.70)	$/kW
	Standard Subtransmission	(0.59)	$/kW		(1.10)	$/kW
	Time-of-Day Primary	(0.36)	$/kW		(0.70)	$/kW
	Time-of-Day Subtransmission	(0.59)	$/kW		(1.10)	$/kW
	Standby					
	Time-of-Day Primary	(0.32)	$/kW		(0.58)	$/kW
	Time-of-Day Subtransmission	(0.52)	$/kW		(1.11)	$/kW
	Emergency Relay Power Supply Charge (all):					
	Supplemental	0.60	$/kW		0.57	$/kW
	Standby	0.60	$/kW		0.57	$/kW
	Power Factor Charge (all):	0.002	$/kVARh		0.002	$/kVARh
	Power Factor Credit (all):	(0.001)	$/kVARh		(0.001)	$/kVARh
	Meter Level Discount:					
	Supplemental					
	Standard Primary	(1.0)	%		(1.0)	%
	Standard Subtransmission	(2.0)	%		(2.0)	%
	Time-of-Day Primary	(1.0)	%		(1.0)	%
	Time-of-Day Subtransmission	(2.0)	%		(2.0)	%
	Standby					
	Time-of-Day Primary	(1.0)	%		(1.0)	%
	Time-of-Day Subtransmission	(2.0)	%		(2.0)	%

Schedule 8, page five of ten

Current Rate Schedule	Type of Charge	Current Rate		Approved Rate Schedule	Approved Rate	
IS-1	Customer Charge:			IS		
	Standard Primary	1,000	$/Bill		622	$/Bill
	Standard Subtransmission	1,000	$/Bill		2,372	$/Bill
	Time-of-Day Primary	1,000	$/Bill		622	$/Bill
	Time-of-Day Subtransmission	1,000	$/Bill		2,372	$/Bill
	Energy Charge:					
	Standard Primary	1.078	¢/kWh		2.504	¢/kWh
	Standard Subtransmission	1.078	¢/kWh		2.504	¢/kWh
	Time-of-Day On-peak - Primary	1.078	¢/kWh		2.504	¢/kWh
	Time-of-Day On-peak -Subtransmission	1.078	¢/kWh		2.504	¢/kWh
	Time-of-Day Off-peak - Primary	1.078	¢/kWh		2.504	¢/kWh
	Time-of-Day Off-peak -Subtransmission	1.078	¢/kWh		2.504	¢/kWh
	Demand Charge:					
	Standard (all delivery voltages)	1.45	$/kW		1.45	$/kW
	Time-of-Day Billing - (All delivery voltages)	1.45	$/kW		1.45	$/kW
	Time-of-Day Peak - (All delivery voltages)	-	$/kW		-	$/kW
	Emergency Relay Power Supply Charge (all):	0.60	$/kW		0.56	$/kW
	Power Factor Charge (all):	0.002	$/kVARh		0.002	$/kVARh
	Power Factor Credit (all):	(0.001)	$/kVARh		(0.001)	$/kVARh
	Transformer Ownership Discount:					
	Standard Primary	-	$/kW		-	$/kW
	Standard Subtransmission	(0.23)	$/kW		(0.40)	$/kW
	Time-of-Day Primary	-	$/kW		-	$/kW
	Time-of-Day Subtransmission	(0.23)	$/kW		(0.40)	$/kW
	Meter Level Discount:					
	Standard Primary	0.0	%		0.0	%
	Standard Subtransmission	(1.0)	%		(1.0)	%
	Time-of-Day Primary	0.0	%		0.0	%
	Time-of-Day Subtransmission	(1.0)	%		(1.0)	%

Schedule 8, page six of ten

Current Rate Schedule	Type of Charge	Current Rate		Approved Rate Schedule	Approved Rate	
IS-3	Customer Charge:			IS		
	Standard Primary	1,000	$/Bill		622	$/Bill
	Standard Subtransmission	1,000	$/Bill		2,372	$/Bill
	Time-of-Day Primary	1,000	$/Bill		622	$/Bill
	Time-of-Day Subtransmission	1,000	$/Bill		2,372	$/Bill
	Energy Charge:					
	Standard Primary	1.327	¢/kWh		2.504	¢/kWh
	Standard Subtransmission	1.327	¢/kWh		2.504	¢/kWh
	Time-of-Day On-peak - Primary	1.327	¢/kWh		2.504	¢/kWh
	Time-of-Day On-peak - Subtransmission	1.327	¢/kWh		2.504	¢/kWh
	Time-of-Day Off-peak - Primary	1.327	¢/kWh		2.504	¢/kWh
	Time-of-Day Off-peak - Subtransmission	1.327	¢/kWh		2.504	¢/kWh
	Demand Charge:					
	Standard (all delivery voltages)	1.45	$/kW		1.45	$/kW
	Emergency Relay Power Supply Charge (all):	0.60	$/kW		0.56	$/kW
	Power Factor Charge (all):	0.002	$/kVARh		0.002	$/kVARh
	Power Factor Credit (all):	(0.001)	$/kVARh		(0.001)	$/kVARh
	Transformer Ownership Discount:					
	Standard Primary	-	$/kW		-	$/kW
	Standard Subtransmission	(0.23)	$/kW		(0.40)	$/kW
	Time-of-Day Primary	-	$/kW		-	$/kW
	Time-of-Day Subtransmission	(0.23)	$/kW		(0.40)	$/kW
	Meter Level Discount:					
	Standard Primary	0.0	%		0.0	%
	Standard Subtransmission	(1.0)	%		(1.0)	%
	Time-of-Day Primary	0.0	%		0.0	%
	Time-of-Day Subtransmission	(1.0)	%		(1.0)	%

Schedule 8, page seven of ten

Current Rate Schedule	Type of Charge	Current Rate		Approved Rate Schedule	Approved Rate	
SBI-1	Customer Charge:			SBI		
	Standard Primary	1,025	$/Bill		647	$/Bill
	Standard Subtransmission	1,025	$/Bill		2,397	$/Bill
	Time-of-Day Primary	1,025	$/Bill		647	$/Bill
	Time-of-Day Subtransmission	1,025	$/Bill		2,397	$/Bill
	Supplemental Demand Charge:					
	Standard (all delivery voltages)	1.45	$/kW		1.45	$/kW
	Time-of-Day Billing - (All delivery voltages)	-	$/kW		1.45	$/kW
	Time-of-Day Peak - (All delivery voltages)	-	$/kW		-	$/kW
	Supplemental Energy Charge:					
	Standard (all delivery voltages)	1.078	¢/kWh		2.504	¢/kWh
	Time-of-Day On-Peak - (All delivery voltages)	1.078	¢/kWh		2.504	¢/kWh
	Time-of-Day Off-Peak - (All delivery voltages)	1.078	¢/kWh		2.504	¢/kWh
	Standby Demand Charge (all delivery voltages):					
	Local Facilities Reservation	0.95	$/kW		1.43	$/kW
	Plus the greater of					
	Power Supply Reservation, or	0.09	$/kW-Mo		1.19	$/kW-Mo
	Power Supply Demand	0.03	$/kW-Day		0.48	$/kW-Day
	Standby Energy Charge:					
	Time-of-Day (All)	0.961	¢/kWh		1.000	¢/kWh
	Transformer Ownership Discount:					
	Supplemental					
	Standard Primary	-	$/kW		-	$/kW
	Standard Subtransmission	(0.23)	$/kW		(0.40)	$/kW
	Time-of-Day Primary	-	$/kW		-	$/kW
	Time-of-Day Subtransmission	(0.23)	$/kW		(0.40)	$/kW
	Standby					
	Time-of-Day Primary	-	$/kW		-	$/kW
	Time-of-Day Subtransmission	(0.21)	$/kW		(0.33)	$/kW
	Emergency Relay Power Supply Charge (all):					
	Supplemental	0.60	$/kW		0.56	$/kW
	Standby	0.60	$/kW		0.56	$/kW
	Power Factor Charge:	0.002	$/kVARh		0.002	$/kVARh
	Power Factor Credit:	(0.001)	$/kVARh		(0.001)	$/kVARh
	Meter Level Discount:					
	Supplemental					
	Standard Primary	0.0	%		0.0	%
	Standard Subtransmission	(1.0)	%		(1.0)	%
	Time-of-Day Primary	0.0	%		0.0	%
	Time-of-Day Subtransmission	(1.0)	%		(1.0)	%
	Standby					
	Time-of-Day Primary	0.0	%		0.0	%
	Time-of-Day Subtransmission	(1.0)	%		(1.0)	%

Schedule 8, page eight of ten

Current Rate Schedule	Type of Charge	Current Rate		Approved Rate Schedule	Approved Rate	
SBI-3	Customer Charge:			SBI		
	Standard Primary	1,025	$/Bill		647	$/Bill
	Standard Subtransmission	1,025	$/Bill		2,397	$/Bill
	Time-of-Day Primary	1,025	$/Bill		647	$/Bill
	Time-of-Day Subtransmission	1,025	$/Bill		2,397	$/Bill
	Supplemental Demand Charge:					
	Standard (all delivery voltages)	1.45	$/kW		1.45	$/kW
	Time-of-Day Billing - (All delivery voltages)	-	$/kW		1.45	$/kW
	Time-of-Day Peak - (All delivery voltages)	-	$/kW		-	$/kW
	Supplemental Energy Charge:					
	Standard (all delivery voltages)	1.327	¢/kWh		2.504	¢/kWh
	Time-of-Day On-Peak - (All delivery voltages)	1.327	¢/kWh		2.504	¢/kWh
	Time-of-Day Off-Peak - (All delivery voltages)	1.327	¢/kWh		2.504	¢/kWh
	Standby Demand Charge (all delivery voltages):					
	Local Facilities Reservation	0.95	$/kW		1.43	$/kW
	Plus the greater of					
	Power Supply Reservation, or	0.09	$/kW-Mo		1.19	$/kW-Mo
	Power Supply Demand	0.03	$/kW-Day		0.48	$/kW-Day
	Standby Energy Charge:					
	Time-of-Day (All)	0.961	¢/kWh		1.000	¢/kWh
	Transformer Ownership Discount:					
	Supplemental					
	Standard Primary	-	$/kW		-	$/kW
	Standard Subtransmission	(0.23)	$/kW		(0.40)	$/kW
	Time-of-Day Primary	-	$/kW		-	$/kW
	Time-of-Day Subtransmission	(0.23)	$/kW		(0.40)	$/kW
	Standby					
	Time-of-Day Primary	-	$/kW		-	$/kW
	Time-of-Day Subtransmission	(0.21)	$/kW		(0.33)	$/kW
	Emergency Relay Power Supply Charge (all):					
	Supplemental	0.60	$/kW		0.56	$/kW
	Standby	0.60	$/kW		0.56	$/kW
	Power Factor Charge:	0.002	$/kVARh		0.002	$/kVARh
	Power Factor Credit:	(0.001)	$/kVARh		(0.001)	$/kVARh
	Meter Level Discount:					
	Supplemental					
	Standard Primary	0.0	%		0.0	%
	Standard Subtransmission	(1.0)	%		(1.0)	%
	Time-of-Day Primary	0.0	%		0.0	%
	Time-of-Day Subtransmission	(1.0)	%		(1.0)	%
	Standby					
	Time-of-Day Primary	0.0	%		0.0	%
	Time-of-Day Subtransmission	(1.0)	%		(1.0)	%

Schedule 8, page nine of ten

Rates for LS-1 lighting rate schedule

Description	Charge per Unit	
LIGHTING FIXTURES	**Fixture**	**Maintenance**
COBRA 50 WATT HPS	2.85	2.24
PT 50 WATT HPS	3.59	2.24
COBRA_NEMA 70 WATT HPS	2.89	1.90
COACH PT 70 WATT HPS	4.25	1.90
COBRA_NEMA 100 WATT HPS	3.28	2.10
COBRA 150 WATT HPS	3.77	1.82
COBRA 250 WATT HPS	4.40	2.35
FLOOD 250 WATT HPS	4.85	2.35
COBRA 400 WATT HPS	4.59	2.70
FLOOD 400 WATT HPS	5.15	2.71
MONGOOSE 400 WATT HPS	5.87	2.73
YBOR ARCHWAY 80 x 10 WATT	15.26	16.44
CLASSIC PT 100 WATT HPS	10.70	1.71
CONTEMPORARY PT 100 WATT HPS	7.48	1.93
COLONIAL PT 100 WATT HPS	10.61	1.71
SALEM _STND_ PT 100 WATT HPS	8.15	1.71
SHOEBOX 100 WATT HPS	7.23	1.71
SHOEBOX 250 WATT HPS	7.84	2.87
SHOEBOX 400 WATT HPS	8.59	2.20
FLAT DECOR 400 WATT HPS	eliminated	eliminated
SHOEBOX 175 WATT MH	7.18	3.34
SHOEBOX 400 WATT MH	9.04	3.58
SHOEBOX 1000 WATT MH	14.89	7.37
FLOOD 400 WATT MH	7.55	3.63
FLOOD 1000 WATT MH	9.48	7.37
CUBE DECORATIVE 400 WATT MH	eliminated	eliminated
GENERAL PT 175 WATT MH	9.83	3.37
SALEM PT 175 WATT MH	8.47	3.38
COBRA 400 WATT MH	5.44	3.62

Schedule 8, page ten of ten

LIGHTING POLES	Pole	Maintenance
WOOD 30 FT OH	2.36	0.15
WOOD 30 FT INACCESSIBLE OH	5.44	0.15
WOOD POLE 35 FT OH	2.66	0.15
CONC STD DB 35 FT OH	4.82	0.15
EXISTING POLE UG	4.47	0.31
CONC STD DB 35 FT UG FOR 70 _100 WATT	10.23	0.31
CONC STD DB 35 FT UG FOR 150 WATT	13.88	0.31
CONC STD DB 35 FT UG FOR 250_400 WATT	20.98	0.31
ALUM DB 28 FT UG FOR 70_100 WATT	10.64	0.31
ALUM AB 27 FT UG FOR 150 WATT	25.15	0.31
ALUM AB 27 FT UG FOR 250_400 WATT	25.15	0.31
ALUM AB 37 FT UG	36.17	0.31
FIBER PT DB 16 FT UG	6.43	1.17
ALUM PT 10 FT UG	7.07	1.17
ALUM PT HERITAGE UG	17.72	0.99
ALUM PT CAPITOL UG	24.10	0.99
CONC PT WATERFORD UG	19.10	0.13
ALUM PT ALUMINUM UG	15.36	0.99
ALUM PT ARLINGTON UG	eliminated	eliminated
ALUM PT CHARLESTON UG	18.44	0.99
ALUM PT RIVIERA UG	18.56	0.99
COMP PT FRANKLIN DB 16 FT	21.58	0.99
FIBER PT WINSTON UG	12.38	0.99
CONC PT VICTORIAN UG	22.19	0.13
STEEL AB 30 FT UG	35.39	1.52
ALUM AB 30 FT UG	eliminated	eliminated
CONC TALL WATERFORD 35 FT UG	26.01	0.13
CONC STD DB 16 FT UG	14.47	0.13
CONC STD DB 25 OR 30 FT UG	19.44	0.13
CONC STD DB 35 FT UG	21.28	0.31
CONC STD DB 45 FT UG	25.01	0.13
CONC ROUND 23 FT UG	18.43	0.13
WOOD UP TO 45 FT OH	5.99	0.28
CONC UP TO 45 FT OH	9.03	0.28
CHARLESTON HD	20.96	0.99
CHARLESTON BANNER	23.93	0.99
MISCELLANEOUS EQUIPMENT	**Bracket/Timer**	**Maintenance**
DUAL PT BRACKET	3.85	0.05
TIMER DEVICE	6.81	1.29

BASE ENERGY CHARGE (¢/KWH)	2.385	¢/kWh
CUSTOMER CHARGE (only for metered street lights)	10.50	$/Bill

Schedule 9

TAMPA ELECTRIC COMPANY

Cost Recovery Factors for the period May through December 2009

Rate Class	Environmental Cost Recovery Factor	Capacity Cost Recovery Factor		Energy Conservation Cost Recovery Factor	
	(c/kwh)	(c/kwh)	($/kw)	(c/kwh)	($/kw)
RS	0.223	0.541		0.221	
GS, TS	0.223	0.518		0.214	
GSD, SBF					
Secondary	0.223		1.73		0.73
Primary	0.221		1.72		0.73
Transmission	0.219		1.70		0.72
GSD-Optional					
Secondary	0.223	0.411		0.174	
Primary	0.221	0.407		0.172	
Transmission	0.219	0.403		0.171	
IS					
Primary	0.220		1.41		0.61
Transmission	0.218		1.39		0.61
LS 1	0.222	0.158		0.084	

Schedule 10

TAMPA ELECTRIC COMPANY
Docket No. 080317-EI
Monthly 1,000 Kilowatt-Hour Residential Electric Bill

	Current	Approved effective May 7, 2009*	Increase/ Decrease
Customer Charge	$8.50	$10.50	$2.00
Energy Charge	$43.42	$42.87	($0.55)
Fuel and Purchased Power	$64.16	$47.99	($16.17)
Energy Conservation Cost Recovery	$1.06	$2.21	$1.15
Environmental Cost Recovery	$2.29	$2.23	($0.06)
Capacity Cost Recovery	$5.80	$5.41	($0.39)
Gross Receipts Taxes	$3.21	$2.85	($0.36)
Total Monthly Bill	**$128.44**	**$114.06**	**($14.38)**

Tampa Electric Company
Total Residential Bill Comparisons by kWh Usage

Usage	Current	Approved effective May 7, 2009*	Difference From Current $	Difference From Current %
1,000 kWh	$128.44	$114.06	-$14.38	-11.2%
1,250 kWh	$160.93	$145.02	-$15.91	-9.9%
1,500 kWh	$193.44	$175.97	-$17.47	-9.0%
2,000 kWh	$258.42	$237.87	-$20.55	-8.0%
2,500 kWh	$323.42	$299.77	-$23.65	-7.3%
3,000 kWh	$388.40	$361.67	-$26.73	-6.9%