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Public Service Commission

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-M-E-M-O-R-A-N-D-U-M-

DATE: March 5, 2009

TO: Office of Commission Clerk (Cole)

FROM: Division of Economic Regulation (Slemkewicz, Bulecza-Banks, Draper, Hewitt, Higgins, Kummer, Kyle, Lee, Lester, Livingston, Marsh, Matlock, Maurey, Ollila, Prestwood, Springer)
Office of the General Counsel (Young, Brown, Brubaker, Hartman)
Office of Strategic Analysis and Governmental Affairs (Graves, Sickel)

RE: Docket No. 080317-EI – Petition for rate increase by Tampa Electric Company.

AGENDA: 03/17/09 – Regular Agenda – Post-Hearing Decision - Participation is Limited to Commissioners and Staff

COMMISSIONERS ASSIGNED: All Commissioners

PREHEARING OFFICER: Skop

CRITICAL DATES: 04/13/09 (8-Month Effective Date)

SPECIAL INSTRUCTIONS: None

FILE NAME AND LOCATION: S:\PSC\ECR\WP\080317.RCM.DOC

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Case 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 the jurisdiction of the Commission. TECO provides electric service in all of Hillsborough County and parts of Polk, Pasco and Pinellas Counties. TECO serves 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, TECO's proposed permanent rate schedules were suspended 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, the following issues were stipulated: 1, 25, 40, 42, 43, 44, 45, 81, 82, 85, 89, 90, 92, 96, 106, 108, 111 and 113.

This recommendation addresses the requested permanent rate increase. The Commission has jurisdiction pursuant to Sections 366.06(2) and (4), and 366.071, F.S.

Discussion of Issues

TEST PERIOD

Issue 1: Is TECO's projected test period of the 12 months ending December 31, 2009 appropriate? (Stipulated)

Approved Stipulation: Yes, 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.

Issue 2: Are TECO's forecasts of Customer, KWH, and KW by Rate Class for the 2009 projected test year appropriate?

Recommendation: Yes. TECO's customer and load forecast assumptions, regression models, and projected system peak demands are appropriate for the 2009 projected test year. (Hewitt, Stallcup)

Position of the Parties

TECO: Yes. TECO's forecasts of customer growth, energy sales and peak demand are appropriate. TECO uses proven forward-looking econometric models and relies on reasonable assumptions in developing its forecasts. Tampa Electric witness Lorraine Cifuentes' direct testimony and exhibit addressing this issue was stipulated into the record and Ms. Cifuentes was excused from testifying.

OPC: No position.

OAG: Adopts the Post-Hearing Brief position of the Office of Public Counsel.

AARP: Adopts the Post-Hearing Brief position of the Office of Public Counsel.

FIPUG: No position.

FRF: No position.

Staff Analysis: The Company's load and customer forecast supporting the rate case petition was sponsored by TECO witness Lorraine L. Cifuentes. Witness Cifuentes offered direct testimony, exhibits attached to her testimony summarizing 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 to that presented by TECO witness Cifuentes.

Staff reviewed TECO's customer and load forecast assumptions, regression models, and the projected system peak demands and believes they are appropriate for use in this docket. The forecast assumptions were drawn from independent sources[1] which the Commission has relied upon in prior proceedings.[2] The regression models used to calculate the projected peak demands conform to accepted economic and statistical practices. Staff believes that the projected peak demands produced by the models appear to be a reasonable extension of historical trends.

[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..

QUALITY OF SERVICE

Issue 3: Is the quality of electric service provided by TECO adequate?

Recommendation: Yes, TECO's quality of service is adequate. (Slemkewicz)

Position of the Parties

TECO: Yes, the quality of service provided by TECO is adequate. TECO has delivered reliable generation, transmission and distribution service and quality customer service. FRF was the only party taking a contrary position on this issue, simply stating a "no" position by presenting no evidence on the issue.

OPC: No position.

OAG: Adopts the Post-Hearing Brief position of the Office of Public Counsel.

AARP: Adopts the Post-Hearing Brief position of the Office of Public Counsel.

FIPUG: No position.

FRF: No.

Staff Analysis: TECO witness Black testified that "Since the company's last base rate increase, Tampa Electric has experienced tremendous customer growth while providing cost-effective, reliable service." (TR 83) He further stated that the approximately 667,000 customers that TECO currently serves is almost 200,000 (42 percent) more than in 1992. (TR 84) 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 wide spread or systemic.

FRF is the only intervenor to take a position on this issue. FRF took the position "No" in its brief, citing the testimony that was presented at the customer service hearings. FRF urged the Commission to "find that the Company's service is no better than adequate." (FRF BR at 12-13) Based on the record, staff believes that TECO's quality of service is adequate.

RATE BASE

Issue 4: Has TECO removed all non-utility activities from rate base?

Recommendation: No. The adjustment is discussed in Issue 19. Except as discussed in Issue 19, no adjustments to rate base for non-utility activities are needed. (Marsh)

Position of the Parties

TECO: Yes. Except for the adjustment described in Issue 19 below, the company has removed all non-utility activities from rate base. None of the other parties have identified any non-utility activities that were not properly removed from rate base.

OPC: No. As described in Issue 19, the Company has not removed all non-utility activities from rate base.

OAG: Adopts the Post-Hearing Brief position of the Office of Public Counsel.

AARP: Adopts the Post-Hearing Brief position of the Office of Public Counsel.

FIPUG: No. See Issue 19.

FRF: Agree with OPC.

Staff Analysis: No party filed specific testimony for this issue. 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. (OPC BR at 3) Issue 19 specifically addresses Account 146. Accordingly, the adjustment will be discussed in that issue. Staff recommends that, except as discussed in Issue 19, no adjustments to rate base for non-utility activities are needed.

Issue 5: Is the pro forma adjustment related to the annualization of five simple cycle combustion turbine units to be placed in service in 2009 appropriate?

Recommendation: No. Staff recommends the elimination of the pro forma adjustments to annualize the May CTs (2 units) and September CTs (3 units). This decreases jurisdictional Utility Plant in Service and Accumulated Depreciation Reserve by $37,246,000 ($38,672,000 system) and $1,121,000 ($1,163,000 system), respectively for the May CTs. The elimination of the pro forma adjustment to annualize the September CTs (3 units) decreases jurisdictional Utility Plant in Service and Accumulated Depreciation Reserve by $97,193,000 ($100,915,000 system) and $2,630,000 ($2,730,000 system), respectively. The total of both adjustments decrease jurisdictional Utility Plant in Service and Accumulated Depreciation Reserve by $134,439,000 ($139,587,000 system) and $3,750,000 ($3,894,000 system), respectively. The impacts to Net Operating Income of staff's proposed adjustments are discussed in Issue 71. (Prestwood)

Position of the Parties

TECO: Yes. TECO appropriately included $36,125,000 and $94,562,000 in rate base and reduced NOI by $2,352,000 and $4,864,000, for the May and September units, respectively. The units will serve peak customer demand periods and improved system reliability. Should the Commission conclude that the three September CTs should not be annualized in 2009, TECO recommends a subsequent year increase of $27,700,000 (jurisdictional) effective January 1, 2010.

OPC: No. Annualizations of plant additions should not be allowed. Two turbines are to be added in May 2009 and three in September 2009. When plant additions are revenue-producing or growth-related assets and no adjustment for increased customers or demand has been made, the revenue requirement is overstated. The Company's request to annualize the five simple cycle turbines should be denied. A reduction of $130,687,000 to rate base reflecting the actual in-service dates is warranted.

OAG: Adopts the Post-Hearing Brief position of the Office of Public Counsel.

AARP: Adopts the Post-Hearing Brief position of the Office of Public Counsel.

FIPUG: No. It is inappropriate to annualize the cost of the 5 CTs. If the Commission allows this annualization without an adjustment to recognize increased growth in sales, the company's revenue requirements will be overstated. Further, the CTs are not needed to meet reliability requirements. Rate base should be reduced to remove the CTs from the test year.

FRF: No. TECO's proposed annualization is not appropriate because it would, at best, cause customers to pay an entire year's revenue requirement for assets that are only used and useful for part of the test year, and 3 of the CTs may not be in service during 2009 at all.

Staff Analysis:

PARTIES' ARGUMENTS

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 2 simple cycle combustion turbines (CTs) in 2009, each with a nominal capacity of 60 megawatts (MW). (TR 822) According to witness Hornick, 2 of the CTs will go in service in May 2009 and three of the CTs will go in service in September 2009. (TR 824)

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. (TR 1440-1441) 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. (TR 1441)

The Company's pro forma adjustment to annualize the May CTs (2 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 (3 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 5 CT units. (EXH 13, pp. 1143-1144) The effects on Net Operating Income of the Company's pro forma adjustments to annualize these CTs are discussed in Issue 71.

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. (TR 2010) 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. (TR 2011) The projected test year methodology uses forecasted data for a 12-month period and matches average rate base investment to average expenses and revenues. (TR 2011) Per 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. (TR 2011) 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. (TR 2012)

Witness Larkin noted that the Commission moved away from using historical test years with pro forma adjustments early in 1981 and began using projected test years. (TR 2010) 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 noted by the Commission 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]

ANALYSIS

The staff acknowledges 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 base their rate increase requests using historical data.

TECO's budgeted calendar year 2009 was requested by the Company in this case to be used as its projected test year. (TR 1421) 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. (TR 1421) 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 3 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. (EXH 13, pp. 184-190) Company witness Hornick stated that these peaking units, as the description suggests, will serve the demand of customers at peak periods of time. (TR 845) During his deposition, witness Hornick agreed that customer demand is what creates the sales of electricity. (EXH 13, pp. 2564-2662) During the hearings, Company witness Black testified that not all of the 5 CTs may be needed in 2009. (TR 106) Witness Black indicated that some of the later CTs might be pushed out. (TR 107) After the hearings, the Company affirmed that all 5 CTs will be placed in service during 2009. (LF EXH 112, p. 1)

CONCLUSION

Staff accepts OPC's position that the Company's pro forma adjustments to annualize the 5 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, financing, etc. Staff rejects the Company's position for the same reasons.

[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.

The Company's pro forma adjustments for the 5 simple cycle combustion turbine units should be eliminated from the test year results. Staff recommends the elimination of the pro forma adjustment to annualize the May CTs (2 units) decreases jurisdictional Utility Plant in Service and Accumulated Depreciation Reserve by $37,246,000 ($38,672,000 system) and $1,121,000 ($1,163,000 system), respectively. Staff further recommends the elimination of the pro forma adjustment to annualize the September CTs (3 units) which decreases jurisdictional Utility Plant in Service and Accumulated Depreciation Reserve by $97,193,000 ($100,915,000 system) and $2,630,000 ($2,730,000 system), respectively. (EXH 13, pp. 58604-58613)

Staff recommends that TECO's pro forma adjustments for all 5 CTs be eliminated. Staff's recommendation for the total of both adjustments is a decrease in jurisdictional Utility Plant in Service and Accumulated Depreciation Reserve of $134,439,000 ($139,587,000 system) and $3,750,000 ($3,894,000 system), respectively. The impacts to Net Operating Income of staff's proposed adjustments are discussed in Issue 71.

In the event TECO places in service these 5 combustion turbine 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. If TECO believes its ROE will drop below the floor of its authorized ROE in 2010 because of the costs associated with these combustion turbines, it has the option of petitioning the Commission in a limited scope proceeding to increase rates for the increased costs relating to these 5 combustion turbines.

Issue 6: Should an adjustment be made for the credit from CSX for the Big Bend Rail Project?

Recommendation: No. The refunds or credits to be received from CSX during the first five years of service of the rail facilities should 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 refunds or credits should be recorded as a reduction to the capital project and the related asset accounts to correct for an under projection of costs for the rail project. The Company should record the Big Bend Rail Facilities construction project without any consideration given to the refunds or credits to be received from CSX. No other adjustments for the freight discounts or credits are necessary in this case. (Prestwood)

Position of the Parties

TECO: No. TECO has properly accounted for the Big Bend Rail Project. The credit is specifically associated with the construction costs. The Commission should approved TECO's proposal to use the reimbursement to first offset capital costs associated with the facilities in excess of those granted in base rates in this proceeding with any remainder being credited to customers through the Fuel and Purchase Power Cost Recovery Clause.

OPC: Yes. The CSX credit should be used a CIAC or contributed capital to offset the capital cost of the Big Bend Rail facility.

OAG: Adopts the Post-Hearing Brief position of the Office of Public Counsel.

AARP: Adopts the Post-Hearing Brief position of the Office of Public Counsel.

FIPUG: Yes. All contributions from CSX made to offset the capital cost of the rail facility should be immediately and directly credited to ratepayers to reduce an allowed increase, not to shareholders, to offset revenue requirements.

FRF: Yes. Agree with OPC.

Staff Analysis:

PARTIES ARGUMENTS

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. (TR 826) 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 it must first be recommended by the Capital Leadership Team (CLT). (EXH 110) 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. (EXH 110) 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.

(EXH 110)

Company witness Wehle confirmed the CLT position on rebuttal by maintaining that TECO proposes that it 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 being credited to customers through the fuel and purchase power cost recovery clause. (TR 938-939) 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). (MFR Schedule B-2; TR 826) 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. (TR 1599) Concerning 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.

(TR 1600-1601)

The Company included $45,205,000 ($46,937,000 system) in its original forecast for the construction cost associated with the Big Bend Rail Facilities. (MFR Schedule B-2) The same original Big Bend rail facilities' construction cost was discussed by Company witness Hornick. (TR 826) 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. (EXH 110) During his deposition, Company witness Hornick provided an updated estimate of a $64,000,000 system cost for the rail project. (EXH 13, pp. 268-309) The Company did not use the $64,000,000 because the Company's proposal is to use the ultimate final cost of the project. The final cost project will be offset by the credit to cover the amount that exceeds the $46,000,000 that the Company included in its original rate case filing. The Company did not present any evidence or reasoning as to 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." (TR 938-939)

ANALYSIS

No other parties presented testimony on this issue. There is no evidence in the record supporting the application of the refund from CSX against the costs that exceeded the original projection. Staff believes that the entire refund should 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, the 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.

CONCLUSION

No adjustments for the CSX refunds or credits are necessary in this case. Staff recommends that all of the CSX refunds or credits TECO receives during the first five years of service of the rail facilities 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 should 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, the Company should 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 should be recorded in the fuel accounts according to the USOA.

Issue 7: Is the pro forma adjustment related to the annualization of the Big Bend Rail Project to be placed into service in December 2009 appropriate?

Recommendation: No. The Company's pro forma adjustments to annualize the Big Bend Rail Project as if it was 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, financing, etc. The Company's pro forma adjustments to annualize the Big Bend Rail Project should be eliminated from the 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.

The jurisdictional adjustments to Utility Plant in Service and Accumulated Depreciation are decreases of $45,206,000 ($46,937,000 system) and $452,000 ($469,000 system) respectively for the test year. The impacts to Net Operating Income of staff's proposed adjustments are discussed in Issue 72. (Prestwood)

Position of the Parties

TECO: Yes. TECO appropriately included $44,754,000 in rate base and reduced NOI by $1,195,000. Consistent with Order PSC-04-0999-FOF-EI, TECO contracted for bimodal transportation for solid fuels to optimize costs. The rail facilities will be completed in December 2009 for testing and deliveries will begin in January 2010. Should the Commission conclude that the rail facilities should not be annualized in 2009, TECO recommends a subsequent year increase of $7,619,000 (jurisdictional) effective January 1, 2010.

OPC: No. By annualizing the rail facility for the entire 2009 test year when it will have been in service for a month or less, would ignore lower fuel cost benefit and the productive benefit of the facility to the Company when it is fully in service, and shift any benefit to the shareholder. At least a $44,754,000 reduction to rate base reflecting the actual in-service date of December 2009 is warranted.

OAG: Adopts the Post-Hearing Brief position of the Office of Public Counsel.

AARP: Adopts the Post-Hearing Brief position of the Office of Public Counsel.

FIPUG: No. This project is not anticipated to come into service until December 2009. It appears that its purpose is to attempt to reduce fuel costs. However, annualization for all of 2009, when the facility will be in service for only a month, violates the well known principle of matching costs to benefits. A reduction should be made to reflect the actual in service date of the facility.

FRF: No. TECO's proposed annualization is not appropriate because it would require the Company's captive customers to pay an entire year's worth of costs for an asset that will only be in service for one month of the Company's requested 2009 test year.

Staff Analysis:

PARTIES' ARGUMENTS

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. The Company expects to spend a total of $45,000,000, with $15,900,000 and $29,127,000 being invested in 2008 and 2009, respectively. (TR 826) Company witness Chronister testified that the pro forma adjustment includes an impact on operating expenses as well as an impact on net plant-in-service to bring the Company's total cost profile to an amount that reflects a full year of operation for these units. (TR 1442) 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. (EXH 13, pp. 1143-1144)

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. 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. (TR 2010-2011)

Witness Larkin noted in his testimony that the Commission moved away from using historical test years with pro forma adjustments early in 1981 and began using projected test years. (TR 2010) 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 noted by the Commission 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."[4]

ANALYSIS

The staff acknowledges 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 base their rate increase requests using historical data.

[4] 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.

TECO's budgeted calendar year 2009 was requested by the Company in this case to be used as its projected test year. (TR 1421) 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. (TR 1421) 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."5

Staff accepts 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. 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.

CONCLUSION

Staff recommends the elimination of the Company's pro forma adjustment for the Big Bend Rail Project. Staff recommends jurisdictional adjustments to decrease Utility Plant in Service and Accumulated Depreciation by $45,206,000 and $452,000, respectively, for the test year. The impacts to Net Operating Income of staff's proposed adjustments are discussed in Issue 72.

[5] 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

Issue 8: Should any adjustments be made to TECO's projected level of plant in service?

Recommendation: Yes. TECO's projected level of plant in service should be reduced by $35,671,000 to reflect over-projections in the amounts. Corresponding reductions should be made to accumulated depreciation and depreciation expense in the amount of $1,248,485. (Marsh)

Position of the Parties

TECO: No adjustments, other than those proposed by the company, should be made to TECO's projected level of plant in service. The adjustment proposed by OPC is flawed and should be rejected.

OPC: Yes. An analysis of the projected level with the actual levels through September 2008 shows the projection trend for plant in service is overstated. Utilizing the average percentage difference between the projection and actual data (since the over-projection will be carried forward into the 13-month average ending December 31, 2009) results in a reduction to jurisdictional plant in service of $51,969,000. Depreciation and amortization on a jurisdictional basis should be reduced by $8,187,000.

OAG: Adopts the Post-Hearing Brief position of the Office of Public Counsel.

AARP: Adopts the Post-Hearing Brief position of the Office of Public Counsel.

FIPUG: Yes. TECO's requested plant in service is overstated. The adjustments submitted by intervenors should be implemented and projected plant in service, depreciation and amortization should be reduced accordingly.

FRF: Yes. Pending the development of additional evidence, the FRF agrees with OPC that jurisdictional Plant in Service should be reduced by $51,969,000 (total Company reduction of $53,958,000). Correspondingly, jurisdictional depreciation and amortization should be reduced by $8,187,000.

Staff Analysis:

PARTIES' ARGUMENTS

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. (TR 2017) He opined that "[i]t is unlikely that the Company's projected balances almost two years into the future are without inaccuracies." (TR 2017) 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. (TR 2017-2018)

On Schedule B-3, Exhibit HL-1 (EXH 50) 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. (TR 2018) 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. (TR 2019) He pointed out that the Company's projected plant in service balance exceeded the actual in every month shown in his exhibit. (TR 2019) 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." (TR 2019-2020)

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. (TR 2020) 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. (TR 2020) 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. (TR 2020; MFR Schedule B-3, p. 8)

Witness Larkin performed a similar study for the accumulated provision for depreciation and amortization which showed a corresponding overstatement of those amounts. (TR 2020) 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. (TR 2020-2021) He also recommended a reduction in depreciation expense since any overstatement of the Accumulated Provision resulted from the overstatement of Depreciation expense. (TR 2021)

TECO witness Chronister disagreed with OPC 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. (TR 1458) 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. (TR 1459) 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 for 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. (TR 1460) 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 contends that witness Larkin should have performed that calculation using the difference amount divided by the projected balance. (TR 1461)

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. (EXH 13, pp. 2033-2034) He also noted that projects may have greater capital expenditures than expected. (EXH 13, p. 2034) He stated that TECO may see budget variances of one or two percent, either higher or lower, based on his experience. (EXH 13, p. 2035)

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. (TR 1461-1462) 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 $35,671,000 x 3.5% = $1,248,485 in depreciation expense and a corresponding accumulated reserve offset in the amount of $1,248,485. (TR 1461-1462)

FIPUG took a position in agreement with OPC, but provided no discussion. (FIPUG BR at 9) FRF agreed with OPC witness Larkin in its brief, without further discussion. (FRF BR at 15)

ANALYSIS

OPC witness Larkin's Exhibit HL-1, Schedule B-3, showed data for 2008 in which TECO's projected plant fell short of its projections 8 months out of 8. In additional data provided by TECO, the plant fell short of its internally budgeted projections 10 months out of 12. (EXH 13, pp. 2133-2135) Thus, some 20 months of data were over-projected through September 2008.

Staff does 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. (TR 1605) Since the thirteen-month average is the number used for ratemaking, staff believes the chronic short-fall in the Company's projections are relevant. Further, staff does not believe that TECO will "catch up" its plant construction in 2009.

However, staff does 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. (TR 1460) 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. (TR 1461)

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. (TR 1461-1462) Staff believes these figures should be accepted.

CONCLUSION

Based on the record evidence, staff recommends that TECO's projected level of plant in service be reduced by $35,671,000 to reflect over-projections in the amounts. Corresponding reductions should be made to accumulated depreciation and depreciation expense in the amount of $1,248,485.

Issue 9: Should TECO's requested increase in plant in service for the customer information system be approved?

Recommendation: Yes. The adjustment for CIS modification associated with rate case modifications is appropriate. (Marsh)

Position of the Parties

TECO: Yes. TECO appropriately included $2,445,000 in rate base and reduced NOI by $342,000 for total CIS modification costs of $2,792,000 to be amortized over five years. The modifications are necessary to reflect required rate changes from this proceeding, not changes made in the normal course of business, and even routine software upgrades should be capitalized and depreciated.

OPC: No. The Customer Information System modifications are changes that are routinely done when rate adjustments are approved such as the annual fuel proceeding or a normal base rate case. Moreover, the anticipated billing adjustments may not be approved by the Commission. Therefore, the supposedly extraordinary CIS upgrade of $2,445,000 should be denied and depreciation expense decreased by $558,000.

OAG: Adopts the Post-Hearing Brief position of the Office of Public Counsel.

AARP: Adopts the Post-Hearing Brief position of the Office of Public Counsel.

FIPUG: No. The Customer Information System (CIS) changes that TECO seeks to recover are routine changes done whenever rate changes are approved. Thus, the expense of this extraordinary upgrade and related depreciation expense should be denied.

FRF: No. TECO's request should be denied, reducing rate base by $2,445,000 (and correspondingly reducing depreciation expense by $558,000 for the test year).

Staff Analysis:

PARTIES' ARGUMENTS

TECO 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. (TR 1444)

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.

(TR 1463-1464)

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." (TR 1463) 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 Commission approval in April 2009 in this docket. (TR 1464)

Witness Chronister stated that the CIS modifications are not the types of changes that TECO would routinely make. He argued that the cost is due solely to changes proposed in this proceeding and is appropriately recovered as a cost of service. (TR 1463) 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. (TR 1463) Witness Chronister also stated that the project must be viewed comprehensively, and certain rate changes that the Commission may not approve does not impact the overall necessity to modify the CIS system. (TR 1463)

OPC witness Larkin argued that none of the items requested by TECO are unusual changes to a CIS system. (TR 2021) He included in his testimony documentation provided by TECO outlining the program costs, which he noted are general in nature, without any specifics. (TR 2022; EXH 121, pp. 1-3) He testified that the rate changes that necessitate the CIS upgrades may never be approved by the Commission. 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. (TR 2022)

OPC reiterated these positions in its brief. (OPC BR at 65)

FIPUG did not provide testimony on this issue. FIPUG's discussion mirrored OPC's. (FIPUG BR at 10-11)

FRF agreed with OPC witness Larkin in its brief, without further discussion. (FRF BR at 16)

ANALYSIS

Staff agrees 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 before this Commission noted by OPC. Rather, the CIS upgrade accommodates major structural changes in the rates.

Staff agrees with OPC that the rate restructuring requested by TECO may not be approved. (TR 2022) However, staff also agrees 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, as noted by witness Chronister. (TR 1463) Staff believes the modifications to the CIS system are necessary costs of doing business for TECO and should be included in the test year.

Staff notes 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. (EXH 121, pp. 1-3)

CONCLUSION

Therefore, staff recommends that the cost of the CIS upgrade associated with rate case modifications is appropriate. No adjustment is necessary.

Issue 10: Is TECO's requested level of Plant in Service in the amount of $5,483,474,000 for the 2009 projected test year appropriate?

Recommendation: No. The appropriate level of Plant in Service for the 2009 projected test year is $5,268,158,000. (Slemkewicz)

Position of the Parties

TECO: Yes. TECO has properly forecasted the amount for plant in service and it is appropriate.

OPC: No. The amount should reflect the adjustments recommended by OPC in this proceeding.

OAG: Adopts the Post-Hearing Brief position of the Office of Public Counsel.

AARP: Adopts the Post-Hearing Brief position of the Office of Public Counsel.

FIPUG: No. This amount should be adjusted to reflect the adjustments recommended by Intervenors and discussed in specific issues throughout this Brief.

FRF: No. The amount should reflect the adjustments recommended by OPC's witnesses in this case.

Staff Analysis: This is a fallout issue. Based on staff's recommendations, the appropriate 13-month average of plant in service for the 2009 projected test year is $5,268,158,000. (See Schedule 1)

Issue 11: Is TECO's requested level of accumulated depreciation in the amount of $1,934,489,000 for the 2009 projected test year appropriate?

Recommendation: No. The appropriate Accumulated Depreciation of Electric Plant in Service for the December 2009 projected test year is $1,929,038,515. (Marsh)

Position of the Parties

TECO: Yes. TECO has properly forecasted this amount for accumulated depreciation and is it [sic] not overstated as suggested by OPC.

OPC: No. The reserve is overstated by $8,500,000 total Company ($8,187,000 jurisdictional).

OAG: Adopts the Post-Hearing Brief position of the Office of Public Counsel.

AARP: Adopts the Post-Hearing Brief position of the Office of Public Counsel.

FIPUG: No. Accumulated depreciated should reflect the amounts recommended by intervenor witnesses.

FRF: No. Agree with OPC that the Company's accumulated depreciation is overstated by $8,187,000 on a jurisdictional basis.

Staff Analysis: This is a fallout issue. OPC's positions that lead to its $8,500,000 adjustment ($8,187,000 jurisdictional) are discussed in the aforementioned issues. FIPUG and FRF took positions but did not discuss the issue further. Based on staff's recommendations in Issues 5, 7, and 8, the appropriate 13-month average amount of Accumulated Depreciation of Electric Plant in Service for the projected test year is $1,929,038,515. (See Schedule 1)

Issue 12: Have all costs recovered through the Environmental Cost Recovery Clause been removed from rate base for the 2009 projected test year?

Recommendation: Yes. No adjustment to Construction Work in Progress (CWIP) is needed to remove costs recovered through the ECRC. (Marsh)

Position of the Parties

TECO: Yes. All costs recovered through the Environmental Cost Recovery Clause have been appropriately removed from rate base for the 2009 projected test year.

OPC: No position.

OAG: Adopts the Post-Hearing Brief position of the Office of Public Counsel.

AARP: Adopts the Post-Hearing Brief position of the Office of Public Counsel.

FIPUG: No position.

FRF: No. Agree with OPC.

Staff Analysis: Amounts that are recovered through the ECRC must be removed from the Company's filing to avoid double recovery. Adjustments were shown to Plant in Service (MFR Schedule B-2, p. 6) and other schedules to remove such amounts. However, TECO did not show any amounts removed from CWIP for costs recovered through the ECRC.

On MFR Schedule B-1 under CWIP, an adjustment was made to "remove CWIP eligible for AFUDC per Commission guidelines." (MFR Schedule B-1, p. 4) 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. (EXH 13, pp. 255-258). No party filed testimony on this issue.

Staff agrees with TECO that all costs removed through the ECRC have been removed. Therefore, based on the record evidences, staff recommends that no adjustment to CWIP is needed to remove costs recovered through the ECRC.

<u>Issue 13</u>: Is TECO's requested level of Construction Work in Progress in the amount of $101,071,000 for the 2009 projected test year appropriate?

<u>Recommendation</u>: Yes. TECO's requested level of Construction Work in Progress (CWIP) in the amount of $101,071,000 for the 2009 projected test year is appropriate. (Marsh)

<u>Position of the Parties</u>

TECO: Yes. TECO has properly forecasted this amount for Construction Work in Progress and it is appropriate. The analysis and proposal advanced by OPC is flawed and should be rejected.

OPC: No. Based on an analysis of the Company's projected level of Construction Work in Progress with the actual levels for the first nine months of 2008, the comparison shows that the Company's projection is 1.90% understated. The CWIP balance should be increased by $2,608,000 on a jurisdictional basis, which results in a CWIP balance of $103,679,000.

OAG: Adopts the Post-Hearing Brief position of the Office of Public Counsel.

AARP: Adopts the Post-Hearing Brief position of the Office of Public Counsel.

FIPUG: No. Agree with Public Counsel.

FRF: No. Agree with OPC.

<u>Staff Analysis</u>:

<u>PARTIES' ARGUMENTS</u>

Witness Chronister stated that a pro forma adjustment to remove CWIP from rate base was made. 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. (TR 1446) He testified that the adjustment was made to "maintain specific financial integrity levels given the capital spending plan the company faced in 1992." (TR 1446) He noted that TECO is not requesting additional CWIP in rate base in this proceeding. (TR 1446) He stated that had the additional amount of CWIP had been included in rate base, it would have resulted in an increase to the revenue requirement of $4,316,000. (TR 1446)

OPC witness Larkin stated that he performed an analysis similar to that used for Plant In Service and Accumulated Provision for Depreciation, in that he compared the actual CWIP balance for the first nine months of 2008 with the Company's projected balance. (TR 2028) He advised that the Company's projected balance was understated by 1.90 percent, requiring an adjustment to the jurisdictional CWIP balance for 2009. (TR 2028-2029) He recommended a balance of $103,679,000 which is greater then the Company's balance by $2,608,000 on a jurisdictional basis. (TR 2029)

Although OPC's proposed adjustment to CWIP is an increase to jurisdiction rate base, witness Chronister argued that "[witness] Larkin repeats his errors related to variance extrapolation, lack of ECRC removal, and incorrect calculations." (TR 1466)

ANALYSIS

Staff believes both OPC and TECO have taken positions for CWIP that are consistent with their positions in Issue 8, Plant in Service. The application of the same methodology used by witness Larkin to reduce Plant in Service results in an increase in CWIP. (TR 2028-2029) Witness Chronister disagreed with the reduction to Plant in Service recommended by OPC, so for consistency, also disagreed with OPC that the methodology should be applied to CWIP. (TR 1466)

Staff agrees in principle with OPC. However, as discussed in Issue 14, a number of land projects associated with Plant Held for Future Use (PHFU) will be delayed. Staff believes that 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 finalized. The land costs will have the same impact on rate base, whether they are included in CWIP or in PHFU. However, over and beyond the land costs included in CWIP are the costs of the plant being constructed on the land. The record is silent as to the amount of CWIP included for those projects. Staff believes that the amount of CWIP should not be adjusted upwards, in recognition of the fact that certain projects will not be completed, as discussed in Issue 14.

CONCLUSION

Thus, based on the record evidence, staff recommends that TECO's requested level of CWIP in the amount of $101,071,000 for the 2009 projected test year is appropriate.

Issue 14: Is TECO's requested level of Property Held for Future Use in the amount of $37,330,000 for the 2009 projected test year appropriate?

Recommendation: Yes. TECO's requested level of Property Held for Future Use (PHFU) in the amount of $37,330,000 for the 2009 projected test year is appropriate. (Marsh)

Position of the Parties

TECO: Yes. TECO has properly forecasted this amount for Property Held for future Use and it is appropriate. The analysis and proposal advanced by OPC is flawed and should be rejected.

OPC: No. The Company's Property Held for Future Use should be decreased by $2,328,354 on a jurisdictional basis to reflect the change the Company made to accurately reflect all plant placed in service in 2009.

OAG: Adopts the Post-Hearing Brief position of the Office of Public Counsel.

AARP: Adopts the Post-Hearing Brief position of the Office of Public Counsel.

FIPUG: No. Agree with Public Counsel.

FRF: No. Agree with OPC that PHFFU should be decreased by $2,328,354 on a jurisdictional basis.

Staff Analysis:

PARTIES' ARGUMENTS

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. (TR 1465) He stated that land acquisitions take a period of time as work in progress until the purchase is finalized. (TR 1465)

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.

(TR 2026)

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. (TR 2026) 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 the projects to go into service in 2009 totaling $25,164,775. He argued that these projects would reduce PHFU substantially. (TR 2027)

Witness Larkin noted that TECO later changed the in-service dates on major PHFU amounts 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." (TR 2028; EXH 13, pp. 415-417)

Witness Larkin 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 which the Company made. (TR 2028)

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. (OPC BR at 16; TR 2025-2028)

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. (TR 1465) 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." (TR 1465-1466)

ANALYSIS

Staff agrees with TECO that the monthly amounts between CWIP or plant in Service and PHFU would offset each other. However, staff does have a concern that additional amounts of projects that will be delayed, as discussed in Issue 13, are reflected in CWIP. Staff notes that PHFU as discussed in this issue is only the land cost. Thus, staff disagrees 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, as noted by witness Larkin, 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, staff does not believe the PHFU account needs to be adjusted. Instead, staff believes the project delays should be reflected by recognizing an over-projection of Plant in Service, as discussed in Issue 8. Additionally, as discussed in Issue 13, the CWIP should not be increased as recommended by witness Larkin.

Staff disagrees 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. (TR 1465) Staff believes the manner in which TECO is accounting for the PHFU does not overstate the rate base.

CONCLUSION

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

Issue 15: Should an adjustment be made to TECO's requested deferred dredging cost?

Recommendation: Yes. As discussed in Issue 56, working capital should be reduced by $1,346,649 (jurisdictional). (Marsh)

Position of the Parties

TECO: No. TECO has properly forecasted deferred dredging cost to be incurred by the company based on current cost estimates and no adjustment is warranted. The analysis and proposal advanced by OPC is flawed and should be rejected.

OPC: Yes. The Company has failed to provide documentation to support that dredging costs will reach $6.9 million. Historical costs have been significantly less. The Company has not supported that any dredging will occur in 2009 test year. Therefore, the deferred dredging cost balance of $2,657,000 (jurisdictional) should be removed.

OAG: Adopts the Post-Hearing Brief position of the Office of Public Counsel.

AARP: Adopts the Post-Hearing Brief position of the Office of Public Counsel.

FIPUG: Yes. Agree with Public Counsel.

FRF: Yes. Agree with OPC that the Company's deferred dredging cost balance of $2,657,000 (jurisdictional) and related dredging operating expense of $1,330,000 should be removed.

Staff Analysis: This issue is related to Issue 56. Issue 56 is the expense portion of dredging costs, while this issue is the working capital portion. Although dredging costs are a necessary cost of doing business, the full amount requested by TECO is not supported by record evidence. The Company should 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).

Issue 16: Should an adjustment be made to TECO's requested storm damage reserve, annual accrual and target level?

Recommendation: Yes. TECO's requested increases in storm damage reserve, annual accrual, and the storm damage target reserve level should be rejected. The accrual for Storm Damage Reserve should remain at its current annual level of $4 million with a $55 million target amount. Removing TECO's requested increase to the storm damage accrual results in a decrease in the Company's jurisdictional O&M expense of $16,000,000 ($16,000,000 system) and a decrease in the jurisdictional working capital of $8,000,000 ($8,000,000 system) for the test year. At this point, it would be premature to require that the storm damage accrual stop when the target level is achieved. Staff believes this issue should be readdressed if and when the target level is actually achieved. (Prestwood)

Position of the Parties

TECO: The Commission should approve TECO's proposed annual accrual and reserve target of $20 million and $120 million. Based on the filed study, current approved accrual and reserve targets are inadequate. The Company's proposed accrual and target level are appropriate based on the value of TECO's system and will serve to normalize the level of storm damage expense over time. The Commission should also approve the ability to charge future storm insurance costs against the reserve.

OPC: Yes. The requested $16 million annual accrual increase should be denied as the current $4 million accrual is sufficient. Working capital should be increased by $8 million and operating expenses reduced by $16 million to remove the effect of increasing the storm accrual. The target level should remain at the current level of $55 million. Current Commission rules and policy are sufficient to handle potential future storm costs.

OAG: Adopts the Post-Hearing Brief positions of the Office of Public Counsel.

AARP: Yes. TECO's annual storm damage accrual should remain at $4 million and not be increased to $20 million, saving $16 million of operating expense. If excess storm damages are experienced, TECO can seek recovery through a surcharge or securitization.

FIPUG: Yes. The Commission should deny the Company's request to increase its annual accrual from $4 million to $20 million and to increase the target level of the reserve from $55 million to $120 million. The Commission has a history of permitting timely recovery of prudently incurred storm expenses and this is sufficient to deal with any future storm cost.

FRF: Yes. TECO's requested 400% increase in annual accrual from $4 million to $20 million per year is unnecessary and unreasonable. TECO's accrual should remain at $4 million per year, and its target level of $55 million should remain unchanged.

Staff Analysis:

PARTIES ARGUMENTS

On March 25, 1994, the Commission authorized TECO to accrue $4 million annually for potential storm damage and required the submittal of a storm damage study.[6] Accordingly, TECO filed its study in September 1994 which the Commission approved in 1995[7] and affirmed the annual accrual of $4 million. The Commission also established a $55 million target amount for the storm damage reserve.[8] The first time the Company had to charge storm expenses against this reserve was after the 2004 storm season. (TR 1209)

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. (TR 1209) The Commission 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.[8] According to the order, after this charge, the reserve had a balance of $7.9 million.[8] In its order approving the stipulation, the Commission 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.[8]

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. (TR 1206-1207) This conclusion was based on three fundamental objectives that were considered essential by TECO as it evaluated its needs 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. (TR 1207) Witness Carlson relied heavily on the results of the ABS Consulting study. (TR 1217)

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[6] 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.
[7] 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.
[8] 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.

Company 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 include Storm Loss Analysis and Reserve Performance Analysis. (TR 1274) Witness Harris did not make a recommendation for TECO's annual level of accrual. (TR 1284)

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. (Harris TR 1274-1275) The study estimated the total expected average annual uninsured cost to TECO from all storms to be $17.8 million. (TR 1275)

The current analysis takes into account the hurricane history up to and including the 2004 storm season. (Harris TR 1279) Adding the 2004 season increased the long-term hurricane hazard in the Tampa area by about 60 percent over the prior modeled hazard. (Harris TR 1280) 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 by the Commission, offered sufficient coverage until the abnormal storm season of 2004. (TR 2140)

Both witness Carlson and witness Stewart described the current overall regulatory framework concerning the recovery of storm damage costs in Florida. (TR 2138-2139) The Commission has 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. (Harris TR 1277)

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. Section 366.8260 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. However, Section 366.8260 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 they are deemed prudent by the Commission. (Stewart TR 2141)

Witness Stewart further testified that given the passage of Section 366.8260 subsequent to this Commission's 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 the Commission to approve a reserve that meets the historically-stated threshold of covering the costs of most, if not all, storms. (TR 2142)

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. (TR 2143)

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 which struck in that year. (TR 2035) 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.

(TR 2035-2036)

ANALYSIS

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. Also, the Commission should continue with that level of storm accrual and when, and if, a storm occurs which is in excess of the reserve, the Commission should then deal with that through a surcharge on rates if necessary or securitization. (Larkin TR 2038)

CONCLUSION

Staff recommends that TECO's requested increases to its storm damage annual accrual and storm damage target reserve level be rejected because the current annual accrual of $4,000,000 is adequate. Staff recommends that the annual accrual for the storm damage reserve remain at its current annual level of $4 million with a $55 million target amount. This results in a decrease in the Company's jurisdictional O&M expense of $16,000,000 ($16,000,000 system) and a decrease in the jurisdictional working capital of $8,000,000 ($8,000,000 system) for the test year. At this point, staff believes it would be premature to require that the annual storm damage accrual be stopped when and if the target level is achieved. Staff recommends that this issue be readdressed if the target level is achieved.

Issue 17: Should an adjustment be made to prepaid pension expense in TECO's calculation of working capital?

Recommendation: No. Staff believes that TECO has submitted sufficient evidence to demonstrate that its prepaid pension expense included in working capital is reasonable. Staff recommends that no adjustment to the Company's working capital concerning prepaid pension expense is warranted. (Kyle)

Position of the Parties

TECO: No. TECO has properly forecasted prepaid pension expense and no adjustment is warranted.

OPC: Yes, any adjustment should be made in accordance with staff's recommendation.

OAG: Adopts the Post-Hearing Brief position of the Office of Public Counsel.

AARP: Adopts the Post-Hearing Brief position of the Office of Public Counsel.

FIPUG: Yes. Agree with Public Counsel.

FRF: Yes. Agree with OPC.

Staff Analysis: 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. (TR 1425-1428) No party other than the Company presented testimony dealing with prepaid pension expense.

Staff has reviewed the data provided by the Company in its MFRs, exhibits, and through discovery. Staff believes that TECO has submitted sufficient evidence to demonstrate that its prepaid pension expense included in working capital is reasonable. As a result, staff recommends that no adjustment to the Company's working capital concerning prepaid pension expense is warranted.

Issue 18: Should an adjustment be made to working capital related to Account 143 - Other Accounts Receivable?

Recommendation: Yes. Working Capital should be reduced in the amount of $10,959,000 (jurisdictional) to remove Account 143, Other Accounts Receivable. (Marsh)

Position of the Parties

TECO: No. The revenues and costs associated with Account 143 have been properly included in NOI and TECO has properly forecasted the amount in Account 143-Other Accounts Receivable in its proposed working capital balance. If working capital is adjusted, the related revenues and costs should be removed from NOI.

OPC: Yes. The Company has yet to show that all of the accounts receivable in Account 143-Other Accounts Receivable are related to utility services and the cost or revenue associated with these accounts receivable have been included in jurisdictional operating income. The remainder of Other Accounts Receivable in the amount of $10,959,000 on a jurisdictional basis should be removed.

OAG: Adopts the Post-Hearing Brief position of the Office of Public Counsel.

AARP: Adopts the Post-Hearing Brief position of the Office of Public Counsel.

FIPUG: Yes. As recommended by Public Counsel witness Larkin, $10,959,000 should be removed because the company has failed to demonstrate that the revenues and costs related to these accounts are related to utility service.

FRF: Yes. Agree with OPC that $10,959,000 should be removed on a jurisdictional basis.

Staff Analysis: 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.[9] It does not include non-utility receivables. The Commission has a long-standing policy of excluding non-utility receivables from the working capital allowance.[10]

PARTIES' ARGUMENTS

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.

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[9] 18 CFR Ch 1 143

[10] 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.

(TR 1466-1467)

He testified that TECO has properly included the revenues associated with these balances in net operating income. (TR 1467) Witness Chronister defined each of the items:

- Off-system sales—sales to other utilities in the interchange of electricity between utilities.
- Pole attachment revenues—TECO charges other companies rent to attach equipment to TECO's poles.
- Rent revenue from fiberoptic—rentals for extra space on network used for reliability.
- By-product sales/residual revenues—Sales of by-products from generation, such as fly ash, gypsum, sulfuric acid, etc.

(EXH 13, pp. 2027-2028)

Witness Chronister discussed each of the above revenue accounts that were included in the MFRs. (EXH 13, p. 2028; MFR Schedule C-5, pp. 25-26) 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. (EXH 13, pp. 2029) He summarized 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. (EXH 13, pp. 2020) Witness Chronister testified that Account 143 is only used for receivables associated with those particular 400 accounts. (EXH 13, p. 2030)

OPC witness Larkin proposed an adjustment to the Company's working capital for Account 143, Other Accounts Receivable, 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 argued 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." (TR 2029) He recommended removal of $10,959,000 on a jurisdictional basis from Other Accounts Receivable. He contended that TECO has not shown that the items included in the account are all related to utility service, so he removed the entire account. (TR 2030)

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 ratepayers and thus related receivables should not be either. (OPC BR at 21; EXH 13, p. 2029; TR 1466). OPC added that TECO excluded 63 percent of Other Electric Revenues as non-jurisdictional, as shown on MFR Schedule C-5. (OPC BR at 21; MFR Schedule C-5, p. 25)

FRF agreed with OPC witness Larkin in its brief, without further discussion. (FRF BR at 16) FIPUG also took a position, but did not discuss the issue. (FIPUG BR at 14)

ANALYSIS

Staff agrees 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. (EXH 13, p. 2029; TR 1466; MFR Schedule C-5, p. 25) 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, staff believes that TECO has not met its burden of proof that Account 143, Other Accounts Receivable, should be included in working capital. Therefore, staff agrees with OPC that the entire amount of $10,959,000, on a jurisdictional basis, should be removed.

CONCLUSION

Therefore, based on the record evidence, staff recommends that Working Capital be reduced in the amount of $10,959,000 (jurisdictional) to remove Account 143, Other Accounts Receivable.

Issue 19: Should an adjustment be made to working capital related to Account 146 - Accounts Receivable from Associated Companies?

Recommendation: Yes. Account 146 should be reduced by $390,000 (jurisdictional) for nonutility receivables included in the account. (Marsh)

Position of the Parties

TECO: Yes. However, except for $390,000 associated with non-utility intercompany receivables, the balance in Account 146-Accounts Receivable from Associated Companies in the company's proposed working capital balance is utility related (Peoples Gas System) and is properly forecasted. Non-utility intercompany receivables of $390,000 should be removed from the account.

OPC: Yes. The entire balance of Account 146-Accounts Receivable from Associated Companies of $6,309,000 is non-utility related and should be removed from working capital. The associated revenues and expenses if identified should also be excluded. The Company has not met its burden to show that these affiliated transactions are directly related to the provision of utility service or necessary for working capital that ratepayers bear.

OAG: Adopts the Post-Hearing Brief position of the Office of Public Counsel.

AARP: Adopts the Post-Hearing Brief position of the Office of Public Counsel.

FIPUG: Yes. As recommended by Public Counsel witness Larkin $6,309,000 should be excluded as the company has not shown it is directly related to the provision of utility service.

FRF: Yes. Agree with OPC that the entire balance of $6,309,000 in Account 146 should be excluded.

Staff Analysis: Under the Uniform System of Accounts (USOA), Account 146, Accounts Receivable from Associated Companies, should include amounts due from associated companies within one year.[11] TECO has included $6,309,000 in working capital for this account. (MFR Schedule B-6, p. 23)

PARTIES' ARGUMENTS

Witness Chronister stated that the balance in Account 146 includes $5,919,000 for services Tampa Electric provides to its utility affiliate, Peoples Gas System (Peoples Gas), and is directly related to the provision of utility services. (TR 1467) 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. (TR1467-1468)

[11] 18 CFR Ch. 1 146.

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. (EXH 13, p. 2031) 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. (EXH 13, p. 2032)

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. (TR 2030) He continued that the receivables are unrelated to providing service to retail electric ratepayers and should be paid by the companies receiving the services. (TR 2047-2048)

OPC argued in its brief that witness Chronister was unable to provide any direct support for the included transactions. (OPC BR at 23) 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. (EXH 13, pp. 2076-2077; OPC BR at 23) 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. (EXH 13, p. 2080; OPC BR at 23)

Moreover, 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." (OPC BR at 23)

FIPUG took a position but did not discuss the issue. (FIPUG BR at 14)

FRF agreed with OPC witness Larkin in its brief, without further discussion. (FRF BR at 16)

ANALYSIS

TECO included $390,000 (jurisdictional) in receivables from non-utility activities. (TR 1467-1468) Witness Chronister admitted that the $390,000 was inadvertently included in the total. (EXH 13, p. 2080) The Commission's policy is to remove nonutility accounts receivables from the working capital allowance.[12] Thus, working capital should be reduced by $390,000.

Rather than a specific revenue account associated with the receivables, as discussed in the previous issue, the receivables in Account 146 would have a corresponding reduction to various expense accounts, as discussed by witness Chronister. While in the previous issue 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. Staff believes this is an important distinction between the two issues.

Staff also notes that the Company included intercompany payables, Account 234 in the amount of $7,848,000 (jurisdictional), in working capital. (MFR Schedule B-17, p. 110) 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 proposes removing the receivables, there is no proposal to remove the intercompany payables. Staff believes it is important to be even-handed in making adjustments. In staff's opinion, it would be inappropriate to remove the receivables without removing the offsetting payables.

Staff believes it is appropriate to include the receivables along with the offsetting payables in this case, except for the non-utility portion noted above.

CONCLUSION

Thus, staff recommends that Account 146 be reduced by $390,000 (jurisdictional) for nonutility receivables included in the account.

[12] 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.

Issue 20: Should an adjustment be made to rate base for unfunded Other Post-retirement Employee Benefit (OPEB) liability?

Recommendation: No. TECO has properly forecasted its unfunded Other Post-retirement Employee Benefit liability and included the balance in rate base. (Kyle)

Position of the Parties

TECO: No. TECO has properly forecasted it s unfunded Other Post-retirement Employee Benefit liability and no adjustment is warranted.

OPC: Yes, any adjustment should be made in accordance with staff's recommendation.

OAG: Adopts the Post-Hearing Brief position of the Office of Public Counsel.

AARP: Adopts the Post-Hearing Brief position of the Office of Public Counsel.

FIPUG: Yes. Agree with Public Counsel.

FRF: Yes. Agree with OPC.

Staff Analysis: In MFR Schedule B-17, the Company presented an analysis of its projected working capital, including prepayments. (EXH 118) 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. (TR 1425-1428) No party other than the Company presented testimony dealing with unfunded OPEB liability.

Staff has reviewed the data provided by the Company in its MFRs, exhibits, and through discovery. Staff believes that there is sufficient record evidence to demonstrate that TECO's unfunded OPEB liability is reasonable and has been included in rate base.

CONCLUSION

Staff believes that TECO has submitted sufficient evidence to demonstrate that its unfunded OPEB liability is reasonable and has been included in rate base. Staff recommends that no adjustment to the Company's rate base concerning unfunded OPEB liability is warranted.

Issue 21: Should an adjustment be made to TECO's coal inventories?

Recommendation: No. TECO's requested coal inventory amounts for the 2009 projected test year are appropriate. (Matlock)

Position of the Parties

TECO: No. TECO has properly forecasted its coal inventories and no adjustment is warranted. OPC's proposed 10 percent reduction is speculative, arbitrary and capricious and should be rejected.

OPC: Yes. The Company's fuel stock should be reduced by 10%, ($9,492,600 jurisdictional) to reflect current reductions which may have occurred in coal, oil, and gas prices.

OAG: Adopts the Post-Hearing Brief position of the Office of Public Counsel.

AARP: Adopts the Post-Hearing Brief position of the Office of Public Counsel.

FIPUG: Yes. The company's fuel stock should be reduced by 10% to reflect current reductions in the price of coal, oil and other fuel prices that have occurred sine the rate case was filed.

FRF: Yes. The cost value of the Company's fuel stock should be reduced by 10% to reflect reductions in coal, oil, and other fuel prices that have likely occurred since the Company filed its case.

Staff Analysis: This issue addresses the appropriate amount of coal inventory, based on the number of tons in inventory, that number of tons' relation to TECO's burn rate, and per ton price estimates.

PARTIES' ARGUMENTS

TECO's proposed 2009 coal inventory is $83,819,000. (TECO BR at 34) TECO witness Wehle testified that the Company seeks to maintain coal inventories sufficient to meet its burn requirements. Witness Wehle testified that TECO considers that supplies may be disrupted by such things as adverse weather conditions and coal and transportation industry problems and that at times, TECO's generation requirements can be unexpectedly high. (TR 918-920) TECO seeks to maintain a 98-day coal supply, consistent with the order resulting from the Company's last rate case.[13] (TR 917) The inventory proposed by TECO for 2009 represents a 94-day supply. (TR 924) The 98-day supply includes a three-day test-burn supply. (TR 924) TECO will not perform any test burns until it completes the installation of selective catalytic reduction equipment at Big Bend Station. (TR 924) In the past two years, TECO has maintained an average 97-day coal supply. (TR 925) The 2004 and 2005 hurricanes and significant river lock outages in 2006 brought the average inventory amounts down by several days. (TR 925) TECO stores roughly half of its proposed coal inventory off-site and in-transit. (TR 920) The proposed off-site coal inventory stored at transfer facilities or "in-transit, to transfer facilities" does not

[13] 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

include "transfer facility-to-Tampa" transportation costs in their values. (EXH 66, p. 2852) Coal represents approximately 85 percent of TECO's fuel inventory value, and about 56 percent of TECO's generation. (TR pp. 915, 940) The parties did not challenge TECO's proposed inventory tonnage amounts in this proceeding. (TECO BR at 35)

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. Also, 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. (EXH 66, pp. 2873, 2843, 2867, 2840). Moreover, witness Wehle stated that TECO based part of its 2009 coal inventory valuation on 2009 contractual coal prices and transportation costs. (EXH 66, p. 2842)

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. (TR 2030) However, without having the information necessary to estimate the decline in fuel prices, witness Larkin proposed a 10 percent downward adjustment. (TR 2030) 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. (FRF BR at 17)

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 were lower than January 2009 spot coal prices, the comparison did not use spot coal prices from both periods. (EXH 66, p. 2864, OPC BR at 24)

OAG, AARP, and FIPUG did not brief this issue. OPC and FRF asserted positions on this issue that the dollar value of the inventory should be reduced by 10 percent.

ANALYSIS

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 "Failure to make this adjustment will likely result in overstated fuel costs being embedded in Tampa Electric's rates until the next rate case." (FRF BR at 17-18) Staff notes 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.

[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

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, staff believes that witness Wehle's calculation of the fuel inventory value which reflects a midpoint of fuel prices for 2008 is appropriate.

Staff observes, regarding the timing of TECO's fuel-price forecasts and the changes in fuel prices since March 2008, 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, staff does not believe that the reduction in fuel-charge fuel-price estimates warrants 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, staff believes that the 10 percent fuel charge reduction and the proposed 10 percent inventory reduction are coincidentally equal.

CONCLUSION

Based on the evidence and arguments presented by the parties in this proceeding, staff recommends that no adjustment is necessary for TECO's coal inventories. Staff believes that TECO's coal inventory should 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, staff believes 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.

Issue 22: Should an adjustment be made to TECO's residual oil inventories?

Recommendation: No. TECO's requested residual oil inventory amounts for the 2009 projected test year are appropriate. (Matlock)

Position of the Parties

TECO: No. TECO has properly forecasted its residual oil inventories and no adjustment is warranted. OPC's proposed 10 percent reduction is speculative, arbitrary and capricious and should be rejected.

OPC: Yes. The Company's fuel stock should be reduced by 10% ($9,492,600 jurisdictional) to reflect current reductions which may have occurred in coal, oil, and gas prices.

OAG: Adopts the Post-Hearing Brief position of the Office of Public Counsel.

AARP: Adopts the Post-Hearing Brief position of the Office of Public Counsel.

FIPUG: Yes. The company's fuel stock should be reduced by 10% to reflect current reductions in the price of coal, oil and other fuel prices that have occurred since the rate case was filed.

FRF: Yes. The cost value of the Company's fuel stock should be reduced by 10% to reflect reductions in coal, oil, and other fuel prices that have likely occurred since the Company filed its case.

Staff Analysis: This issue addresses the appropriate amount of residual oil inventory, based on the number of barrels in inventory, that number of barrels' relation to TECO's burn rate, and per barrel price estimates.

PARTIES' ARGUMENTS

TECO's proposed 2009 residual oil inventory is $780,000. (TECO BR at 34) 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 of limited gas availability and higher than expected loads. (TR 928-929) TECO's proposed inventory is 9,203 barrels. (TR 929) 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. (TR 915) None of the parties challenged TECO's proposed inventory (barrels) amounts in this proceeding. (TECO BR at 35)

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. (EXH 66, p. 2873) For oil and gas, witness Wehle observed dramatic price increases in Summer 2008 and dramatic decreases in late 2008 and early 2009. (EXH 66, pp. 2840-2842) 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. (EXH 66, p. 2842) Witness Wehle expressed TECO's belief that the low January 2009 prices were not representative of prices for all of 2009. (EXH 66, pp. 2840-2841) Witness Wehle also noted that distillate oil and residual oil are extremely volatile commodities. (EXH 55, p. 2841)

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. (TR 2030) However, without having the information necessary to estimate the decline in fuel prices, witness Larkin proposed a 10 percent downward adjustment. (TR 2030) 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 (FRF BR at 17) OPC submitted that witness Wehle had admitted that residual oil prices were currently below the prices used by TECO to price its 2009 residual oil inventory. (OPC BR at 26)

OAG, AARP, and FIPUG did not brief this issue. OPC and FRF asserted positions on this issue that the dollar value of the inventory should be reduced by 10 percent.

ANALYSIS

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."[15] In its brief, FRF agrees with OPC witness Larkin's proposed 10 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." (FRF BR at 17-18) Staff notes 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, staff believes that witness Wehle's calculation of the fuel inventory value which reflects a midpoint of fuel prices for 2008 is appropriate.

Staff observes, regarding the timing of TECO's fuel-price forecasts and the changes in fuel prices since March 2008, 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,

[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

staff does not believe that the reduction in fuel-charge fuel-price estimates warrants 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, staff believes that the 10 percent fuel charge reduction and the proposed 10 percent inventory reduction are coincidentally equal.

CONCLUSION

Therefore, based on the evidence and arguments presented by the parties in this proceeding, staff recommends that no adjustment is necessary for TECO's residual oil inventories. Staff believes that TECO's residual oil inventory should not be adjusted to reflect the decreases in fuel prices between Summer 2008 and September 2008.

Issue 23: Should an adjustment be made to TECO's distillate oil inventories?

Recommendation: No. TECO's requested distillate oil inventory amounts for the 2009 projected test year are appropriate. (Matlock)

Position of the Parties

TECO: No. TECO has properly forecasted its distillate oil inventories and no adjustment is warranted. OPC's proposed 10 percent reduction is speculative, arbitrary and capricious and should be rejected.

OPC: Yes. The Company's fuel stock should be reduced by 10% ($9,492,600 jurisdictional) to reflect current reductions which may have occurred in coal, oil, and gas prices.

OAG: Adopts the Post-Hearing Brief position of the Office of Public Counsel.

AARP: Adopts the Post-Hearing Brief position of the Office of Public Counsel.

FIPUG: Yes. The company's fuel stock should be reduced by 10% to reflect current reductions in coal, oil, and other fuel prices that have occurred since the company filed its case.

FRF: Yes. The cost value of the Company's fuel stock should be reduced by 10% to reflect reductions in coal, oil, and other fuel prices that have likely occurred since the Company filed its case.

Staff Analysis: This issue addresses the appropriate amount of distillate oil inventory, based on the number of barrels in inventory, that number of barrels' relation to TECO's burn rate, and per barrel price estimates.

PARTIES' ARGUMENTS

TECO's proposed 2009 distillate oil inventory is $9,312,000. (TECO BR at 34) 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. (TR 928) 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. (TR 929) TECO's proposed inventory is 77,068 barrels. (TR 929) 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. (TR 915) None of the parties challenged TECO's proposed inventory (barrels) amounts in this proceeding. (TECO BR at 35)

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. (EXH 66, p. 2873) For oil and gas, witness Wehle observed dramatic price increases in Summer 2008 and dramatic decreases in late 2008 and early 2009. (EXH 66, pp. 2840-2842) 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. (EXH 66, p. 2842) Witness Wehle expressed TECO's belief that the low January 2009 prices were not representative of prices for all of 2009. (EXH 66, pp. 2840-2841) Witness Wehle also noted that distillate oil and residual oil are extremely volatile commodities. (EXH 55, p. 2841)

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. (TR 2030) However, without having the information necessary to estimate the decline in fuel prices, witness Larkin proposed a 10 percent downward adjustment. (TR 2030) 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. (FRF BR at 17) 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. (OPC BR at 25)

OAG, AARP, and FIPUG did not brief this issue. OPC and FRF asserted positions on this issue that the dollar value of the inventory should be reduced by 10 percent.

ANALYSIS

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."[16] In its brief, FRF agrees with OPC witness Larkin's proposed 10 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." (FRF BR at 17-18) Staff notes 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, staff believes that witness Wehle's calculation of the fuel inventory value which reflects a midpoint of fuel prices for 2008 is appropriate.

[16] 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

Staff observes, regarding the timing of TECO's fuel-price forecasts and the changes in fuel prices since March 2008, 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, staff does not believe that the reduction in fuel-charge fuel-price estimates warrants 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, staff believes that the 10 percent fuel charge reduction and the proposed 10 percent inventory reduction are coincidentally equal.

CONCLUSION

Therefore, based on the evidence and arguments presented by the parties in this proceeding, staff recommends that no adjustment is necessary for TECO's distillate oil inventories. Staff believes that TECO's distillate oil inventory should not be adjusted to reflect the decreases in fuel prices between Summer 2008 and September 2008.

Issue 24: Should an adjustment be made to TECO's natural gas and propane inventories?

Recommendation: No. TECO's requested natural gas and propane inventory amounts for the 2009 projected test year are appropriate. (Matlock)

Position of the Parties

TECO: No. TECO has properly forecasted its natural gas and propane inventories and no adjustment is warranted. OPC's proposed 10 percent reduction is speculative, arbitrary and capricious and should be rejected.

OPC: Yes. The Company's fuel stock should be reduced by 10% ($9,492,600 jurisdictional) to reflect current reductions which may have occurred in coal, oil, and gas prices.

OAG: Adopts the Post-Hearing Brief position of the Office of Public Counsel.

AARP: Adopts the Post-Hearing Brief position of the Office of Public Counsel.

FIPUG: Yes. The company's fuel stock should be reduced by 10% to reflect current reductions which have occurred in coal, oil, and gas prices.

FRF: Yes. The cost value of the Company's fuel stock should be reduced by 10% to reflect reductions in coal, oil, and other fuel prices that have likely occurred since the Company filed its case.

Staff Analysis: This issue addresses the appropriate amount of natural gas inventory, based on the number of thousand cubic feet (Mcf) in inventory, that number of Mcfs' relation to TECO's burn rate, and per Mcf price estimates.

PARTIES' ARGUMENTS

TECO's proposed 2009 natural gas inventory is $4,495,000. (TECO BR at 34) TECO witness Wehle testified that the Company seeks to maintain gas inventories to meet generation requirements during times of uncertain supply availability. (TR 927) Witness Wehle gave examples of such times: 1) hurricane season, 2) during times of full major plant outages, and 3) extreme cold periods. (TR 927) TECO has 850,000 million Btus (MMBtus) of storage capacity and will increase its capacity to 1,250,000 MMBtus in Summer 2009. (TR 927) The inventory capacity expansion will provide TECO with about a 6-day supply. (TR 927) TECO's proposed inventory is 545,000 MMBtus. (TR 927-928) 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. TECO requests no propane gas inventory. Natural gas represents approximately 44 percent of TECO's generation. (TR 915) None of the parties challenged TECO's proposed inventory MMBtu or Mcf amounts in this proceeding. (TECO BR at 35)

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.

(EXH 66, p. 2873) 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. (EXH 66, p. 2921) For oil and gas, witness Wehle observed dramatic price increases in Summer 2008 and dramatic decreases in late 2008 and early 2009. (EXH 66, pp. 2840-2842) 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. (EXH 66, p. 2842) Witness Wehle also expressed TECO's belief that the low January 2009 prices were not representative of prices for all of 2009. (EXH 66, pp. 2840-2842)

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. (TR 2030) However, without having the information necessary to estimate the decline in fuel prices, witness Larkin proposed a 10 percent downward adjustment. (TR 2030) 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. (FRF BR at 17) OPC submitted that witness Wehle had admitted that natural gas prices were currently below the prices used by TECO to price its 2009 natural gas inventory. (OPC BR at 26)

OAG, AARP, and FIPUG did not brief this issue. OPC and FRF asserted positions on this issue that the dollar value of the inventory should be reduced by 10 percent.

ANALYSIS

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."[17] In its brief, FRF agrees with OPC witness Larkin's proposed 10 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." (FRF BR at 17-18) Staff notes 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

[17] 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

fuel inventory may be undervalued or overvalued as market fuel prices change. Therefore, staff believes that witness Wehle's calculation of the fuel inventory value which reflects a midpoint of fuel prices for 2008 is appropriate.

Staff observes, regarding the timing of TECO's fuel-price forecasts and the changes in fuel prices since March 2008, 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, staff does not believe that the reduction in fuel-charge fuel-price estimates warrants 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, staff believes that the 10 percent fuel charge reduction and the proposed 10 percent inventory reduction are coincidentally 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. (EXH 66, p. 2921) Staff notes that 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.[18] To reduce price volatility is to pay more for gas when prices are low and less for gas when prices are higher.

CONCLUSION

Therefore, based on the evidence and arguments presented by the parties in this proceeding, staff recommends that no adjustment is necessary for TECO's natural gas inventories. Staff believes that TECO's natural gas inventory should not be adjusted to reflect the decreases in fuel prices between Summer 2008 and September 2008.

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[18] 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

Issue 25: Has TECO properly reflected the net overrecoveries or net underrecoveries of fuel and conservation expenses in its calculation of working capital? (Stipulated)

Approved Stipulation: Yes, TECO has properly reflected net over- and under-recoveries of fuel and conservation expenses in its calculation of working capital.

Issue 26: Should unamortized rate case expense be included in Working Capital?

Recommendation: No. Unamortized rate case expense in the amount of $2,628,000 should be removed from working capital. (Marsh)

Position of the Parties

TECO: Yes. Except for $116,000 associated with forecasted fees for a consultant that the company ultimately never used, the balance of unamortized rate case expense should be included in Working Capital without adjustment.

OPC: No. The amount should reflect the adjustment for rate case expense recommended by OPC in this proceeding and the remaining balance should be reduced by one-half as has been the Commission's policy. This will reflect the fact that the balance will be reduced as the rate case expense is collected in rates.

OAG: Adopts the Post-Hearing Brief position of the Office of Public Counsel.

AARP: Adopts the Post-Hearing Brief position of the Office of Public Counsel.

FIPUG: No. Agree with Office of Public Counsel.

FRF: Agree with OPC.

Staff Analysis: TECO included $2,628,000 of unamortized rate case expense in working capital for 2009. (MFR Schedule B-17, p. 111) However, neither TECO nor the other parties filed testimony on this issue.

Staff notes that the Commission has 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.[19] The rationale for this position was to adopt a sharing concept whereby the cost of a rate case would be shared between the ratepayer and stockholder; i.e., include the expense in the O&M expenses, but not allow a return on the unamortized portion. This approach recognizes that both the stockholders and the ratepayers benefit from a rate proceeding. It espouses the belief that customers should not be required to pay a return on funds expended to increase their rates.

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

[19] 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.

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 the Commission reaffirmed its long-standing policy of excluding unamortized rate case expense from working capital in electric an gas rate cases.[20] 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 Commission policy.[21]

Although there was no testimony by any party on this issue, OPC discussed it in its brief, stating that, consistent with prior Commission practice, any balance of working capital should include one-half of the total amount of rate case expense allowed.[22] (OPC BR at 27) OPC references a recent Florida Public Utilities Company (FPUC) case, in which one-half of the rate case expense was allowed in working capital.[23] 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. Staff notes that inclusion of unamortized rate case expense in working capital in the FPUC case is an exception to the Commission's long-standing policy.

FPUC was initially allowed to include rate case expense in working capital in its 1993 rate proceeding.[24] At that time, the Commission found that the exclusion of the unamortized portion of rate case expense from working capital is a partial disallowance. The Commission concluded that rate case expense is a necessary cost of doing business. The order included a concurring opinion by Commissioner Lauredo, where it was stated that:

> . . . his decision was based solely on the facts and circumstances involved with this case. He emphasized this result should not be standing Commission policy and that no precedential value should be assigned to his concurrence.[25]

Staff agrees with the long-standing policy that the cost of the rate case should be shared. Although this issue was not specifically addressed by the OAG, staff believes the basic position stated in its brief is appropriate here: ". . . the amount of any company's profit must be balanced against the needs of the citizens who depend on their services." (OAG BR at 1)

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[20] 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.
[21] 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.
[22] 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.
[23] Ibid.
[24] Order No. PSC-94-0170-FOF-EI, issued February 10, 1994, in Docket No. 930400-EI, In re: Application for a rate increase for Marianna Electric Operations by Florida Public Utilities Company, p. 10.
[25] Ibid, pp. 10-11.

Staff recommends that unamortized rate case expense in the amount of $2,628,000 should be removed from working capital.

Issue 27: Is TECO's requested level of Working Capital in the amount of ($30,586,000) for the 2009 projected test year appropriate?

Recommendation: No. The appropriate level of Working Capital for the 2009 projected test year is ($130,910,649). (Slemkewicz)

Position of the Parties

TECO: Yes. TECO has properly forecasted this amount for Working Capital and it is appropriate for the 2009 projected test year.

OPC: No. The amount should reflect the adjustments recommended by OPC in this proceeding.

OAG: Adopts the Post-Hearing Brief position of the Office of Public Counsel.

AARP: Adopts the Post-Hearing Brief position of the Office of Public Counsel.

FIPUG: No. Agree with Office of Public Counsel.

FRF: No. Working Capital should reflect the adjustments recommended by the Citizens in this proceeding.

Staff Analysis: This is a fallout issue. Based on staff's recommendations, the appropriate 13-month average for working capital for the 2009 projected test year is ($130,910,649). (See Schedule 1)

Issue 28: Is TECO's requested rate base in the amount of $3,656,800,000 for the 2009 projected test year appropriate?

Recommendation: No. The appropriate amount of rate base for the 2009 projected test year is $3,346,610,836. (Slemkewicz)

Position of the Parties

TECO: No. TECO's requested rate base amount of $3,656,800,000 for the 2009 projected test year should be $3,655,950,000 based upon changes recognized by TECO described within this brief.

OPC: No. The amount should reflect the adjustments recommended by OPC in this proceeding.

OAG: Adopts the Post-Hearing Brief position of the Office of Public Counsel.

AARP: Adopts the Post-Hearing Brief position of the Office of Public Counsel.

FIPUG: No. Rate base should include the adjustments recommended by intervenors in this case.

FRF: No. The Company's rate base should reflect the adjustments recommended by the Citizens in this proceeding.

Staff Analysis: This is a fallout issue. Based on staff's recommendations, the appropriate 13-month average rate base for the 2009 projected test year is $3,346,610,836. (See Schedule 1)

COST OF CAPITAL

Issue 29: What is the appropriate amount of accumulated deferred taxes to include in the capital structure for the 2009 projected test year?

Recommendation: The appropriate amount of accumulated deferred taxes to include in the capital structure for the 2009 projected test year is $357,400,000, as shown on Schedule 2. (Livingston, Kyle)

Position of the Parties

TECO: The appropriate amount of accumulated deferred taxes to be included in the capital structure for 2009 is $302,744,000 as shown on MFR Schedule D-1a. The methodology used by the company is proper.

OPC: TECO's $1,894,000 reduction to ADITs should be denied as improper. The interpretation of decades-old law and non-binding letter rulings is improper as the test year averaging and projections methodologies comply with the IRS requirements. Any normalization inconsistency in Commission long-standing policy should have surfaced years ago. Prior to any rate setting change, the Commission should require TECO to obtain and submit a private letter ruling that indicates that the current methodology is inconsistent.

OAG: Adopts the Post-Hearing Brief position of the Office of Public Counsel.

AARP: Adopts the Post-Hearing Brief position of the Office of Public Counsel.

FIPUG: Agree with Public Counsel.

FRF: The appropriate amount of deferred taxes is $302,744,000 per the testimony of FRF witness O'Donnell.

Staff Analysis: This issue addresses the appropriate amount of accumulated deferred income taxes (ADITs) to include in TECO's capital structure for the 2009 projected test year.

PARTIES' ARGUMENTS

In its MFRs, TECO recorded a balance of jurisdictional ADITs to include in the Company's capital structure for the test year of $302,744,000. (MFR Schedule D-1a) 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. (TR 1326-1327) 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. (TR 2104) The witness, however, cites several private letter rulings (PLRs) to support his adjustment to ADIT of $1,894,321 that results from the Company's revised methodology. (TR 1376) In the instant case, a 2009 forecasted test period is used and new rates are expected to be effective in May 2009. (TR 1375-1376) Thus, based on his interpretation of the PLRs and IRC, witness Felsenthal claims 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. (TR 1376) 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. (TR 1376) Witness Felsenthal cited PLR 9202029, which states, "The 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." (TR 1382) Witness Felsenthal stated he was not surprised that, despite repetitive audits, the IRS found no errors with the Company's former ADIT calculation methodology. (TR 1385) 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. (TR 1392)

OPC argued that TECO's deferred taxes should be increased by $1,894,000, which it contends is consistent with the Commission's long-standing policy. (OPC BR at 31) OPC asserted that prior to any rate setting change, the Commission should require TECO to obtain and submit a PLR that indicates the Company's current methodology is inconsistent. (OPC BR at 28) OPC witness Schultz disagreed with TECO witness Felsenthal's reliance on PLRs in his deferred income tax calculation. (TR 2104) Witness Schultz believes PLRs are only applicable to the company requesting the ruling and should not be used as precedent. (TR 2104) If the Commission chooses to place any reliance on the PLRs, witness Schultz asserted that the facts addressed by each PLR are specific to each company. (TR 2104) He also stated that the Company has used the methodology witness Felsenthal now claims to be incorrect for years, and that the IRS found no errors in the Company's methodology. (TR 2104) He asserts 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. (TR 2107) In addition, witness Schultz disagreed with witness Felsenthal's assumption that projected costs for 2009 are partly historic and partly projected. (TR 2104) Until the Company requests a PLR of its own, witness Schultz recommends 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. (TR 2107)

Per the testimony of witness O'Donnell, FRF agrees 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. (TR 2372; FRF BR at 42)

OAG, AARP, and FIPUG agree with OPC's position on this issue.

ANALYSIS

ADITs represent the income tax component resulting from the application of the income tax rate to temporary differences at each balance sheet date. (TR 1330) Deferred tax expense reflects the period to period change in ADIT. (TR 1330) 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. (TR 1330-1331) 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. (OPC BR at 28) 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. (TR 2366) 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. (TR 1331) In the regulated environment, the process of recording deferred income taxes on temporary differences is often referred to as "normalization". (TR 1331) Recognizing zero cost deferred taxes in the capital structure (normalization) reduces the overall rate of return charged to ratepayers. (OPC BR at 28) In ratemaking, the ADIT balance is a zero cost source of capital in the cost of capital computation thereby giving the benefit of the reduced financing costs to ratepayers. (TR 1334)

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. (TR 1338) Accelerated depreciation is the major component of deferred taxes for capital intensive entities such as TECO. (TR 1334) 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 incented to incur such expenditures. (TR 1332)

Staff believes 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, staff recommends that the Company's change in methodology is appropriate.

However, in reconciling rate base and capital structure, TECO made a prorata adjustment over all sources of capital. As discussed in Issue 38, the Company should have made this prorata adjustment over investor sources of capital only. Reversing the Company's adjustment resulted in a higher balance of ADITs.

CONCLUSION

Staff recommends that the appropriate amount of accumulated deferred taxes to include in TECO's capital structure for the 2009 projected test year is $357,400,000.

Issue 30: What is the appropriate amount and cost rate of the unamortized investment tax credits to include in the capital structure for the 2009 projected test year?

Recommendation: The appropriate amount and cost rate of unamortized investment tax credits to include in the capital structure are $10,365,000 and 8.92 percent, respectively, as shown on Schedule 2. (Livingston, Kyle)

Position of the Parties

TECO: The appropriate amount and cost rate of the unamortized investment tax credits to be included in the capital structure for 2009 is $8,780,000 and 9.75 percent, respectively, as shown on MFR Schedule D-1a. The company's proposed ITC amortization adjustment is proper and should be approved.

OPC: No position.

OAG: Adopts the Post-Hearing Brief position of the Office of Public Counsel.

AARP: Adopts the Post-Hearing Brief position of the Office of Public Counsel.

FIPUG: No position.

FRF: The appropriate amount of unamortized investment tax credits is $8,780,000 per the testimony of FRF witness O'Donnell, with a cost rate of 8.27%.

Staff Analysis: This issue addresses the appropriate amount and cost rate of unamortized investment tax credits (ITCs) to include in TECO's capital structure for the 2009 projected test year.

PARTIES' ARGUMENTS

The Company proposes that the balance of ITCs to be included in its capital structure for the test year is $8,780,000, with a cost rate of 9.75 percent. (MFR Schedule D-1a) 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 (GAAP) and the requirements of the IRC. (TR 1356) The witness 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. (TR 1326-1327) 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. (TR 1344) 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. (TR 1368) 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. (TR 1368-1369) 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. (TR 1369) 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. (TR 1369) 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. (TR 1370)

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. (TR 1373) He cited private letter rulings (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. (TR 1373-1374) Witness Felsenthal is not surprised that, despite repetitive audits, the IRS found no errors with the Company's former ITC amortization methodology. (TR 1385) 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. (TR 1392)

FRF witness O'Donnell testified that the appropriate cost rate for ITCs is 8.28 percent. (TR 2372) This cost rate is a fall-out of his recommended adjustments in Issues 34 and 37. FRF did not take issue with the amount of ITCs included in TECO's capital structure. (FRF BR 43)

OPC and FIPUG took no position on the issue of unamortized ITCs. OAG and AARP adopted the position of OPC on this issue.

ANALYSIS

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. (TR 2366) The ITC lowers income tax expense permanently if certain qualifying investments are made. (TR 1339) 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. (TR 1339) The ITC is a direct reduction of income taxes payable in a given year which will not reverse or turn around, similar to a grant or rebate. (TR 1339) 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. (TR 1339) 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. (TR 1339)

For ratemaking purposes, in 1972 utilities were required to elect how they intended to share the ITC between ratepayers and shareholders. (TR 1340) 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. (TR 1340) 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". (TR 1340) The ITC was repealed as a result of the Tax Reform Act of 1986. (TR 1340) TECO's current filing reflects unamortized ITC on property, plant, and equipment the Company realized prior to the repeal of ITCs. (TR 1340) The unamortized ITC is being amortized over the lives of the property, plant, and equipment, giving rise to the ITC. (TR 1340-1341)

Staff believes 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 prorata adjustment over all sources of capital. As discussed in Issue 38, the Company should have made this prorata adjustment over investor sources of capital only. Reversing the Company's adjustment resulted in a higher balance of ITCs. None of the adjustments recommended by staff in other issues have an impact on the unamortized ITC balance. Staff recalculated the ITC cost rate based on other staff adjustments and staff's recommended return on equity, resulting in an 8.92 percent weighted average cost rate for ITCs.

CONCLUSION

Staff recommends that the appropriate amount and cost rate of unamortized ITCs to include in TECO's capital structure for the 2009 projected test year are $10,365,000 and 8.92 percent, respectively.

Issue 31: What is the appropriate amount and cost rate for short-term debt for the 2009 projected test year?

Recommendation: The appropriate amount and cost rate for short-term debt for the 2009 projected test year are $7,227,005 and 2.75 percent, respectively, as shown on Attachment 2. (Livingston, Springer)

Position of the Parties

TECO: The appropriate amount and cost rate for short-term debt for 2009 are $8,002,000 and 4.63 percent, respectively, as shown on MFR Schedule D-1a. The current LIBOR rates are highly volatile and artificially suppressed by governmental intervention. (Tr. 240, lines 19 – 23). Recent historical LIBOR average rates are superior to current gyrations in the short term debt markets. The adjustment proposed by OPC is flawed and should be rejected.

OPC: Based on the three-month LIBOR rate (2.15%) plus the financing program fee of 18 basis points (0.18%), a short-term debt cost rate of 2.33% as of November 13, 2008 is appropriate.

OAG: Adopts the Post-Hearing Brief position of the Office of Public Counsel.

AARP: Adopts the Post-Hearing Brief position of the Office of Public Counsel.

FIPUG: Agree with Public Counsel.

FRF: The appropriate amount of short-term debt is $8,002,000 per the testimony of FRF witness O'Donnell, with a cost rate of 4.63%.

Staff Analysis: This issue addresses the appropriate amount and cost rate for short-term debt to include in TECO's capital structure for the 2009 projected test year.

PARTIES' ARGUMENTS

TECO proposes a short-term debt cost rate of 4.63 percent. (TR 447-448; MFR Schedule D-1a) As TECO witness Gillette explains, the Company utilized average historical London Interbank Offered Rate (LIBOR) rates in developing its proposed short-term interest rate of 4.63 percent. (TR 447-448) For the period 2006 through 2008 the three-month LIBOR rate was 4.5 percent on average. (TR 447) This was the number on which TECO based its proposed short-term debt cost rate. (TR 447-448) The witness asserts 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. (TR 240) Witness Gillette feels 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. (TR 240) 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 witness Woolridge. (TR 240-241)

OPC witness Woolridge recommends a short-term debt cost rate of 2.33 percent. (TR 1868) 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. (TR 1868) 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. (TR 1867) The witness feels historic rates do not reflect current rates. (TR 1960)

OPC witness Larkin supports the recommendation made by OPC witness Woolridge, as shown in Exhibit 50, Schedule D. (TR 2042-2043; EXH 50, Schedule D)

Per the testimony of witness O'Donnell, FRF proposes that the appropriate amount of short-term debt is $8,002,000 with a cost rate of 4.63 percent. (TR 2372; FRF BR at 43)

OAG, AARP, and FIPUG agree with OPC's position on this issue.

ANALYSIS

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. (TR 2365)

In December of 2008, TECO renewed a LIBOR-based credit facility. (TR 438) 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. (TR 438) These fees are in addition to the three-month LIBOR rate at the time funds are borrowed. (TR 438-439) Therefore, the effective cost of this credit facility is the current three-month LIBOR rate plus 175 basis points. (TR 439) The three-month LIBOR rate recently closed at 1 percent. (TR 377, 440) 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. (TR 441)

The three-month LIBOR rate was over 5 percent one year ago. (TR 447) At this time the Company was paying approximately 5.34 percent on the credit facility that it now pays roughly 2.75 percent on. (TR 448)

If short-term debt rates increase subsequent to the test year it will not have an adverse effect on ratepayers until the Company's next rate case. (TR 497) In turn, if the Company is able to refinance its short-term debt at a lower cost rate, it 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. (TR 492)

Staff feels 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. Staff 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 $7,227,005.

CONCLUSION

Staff recommends that the appropriate amount and cost rate for short-term debt for the 2009 projected test year are $7,227,005 and 2.75 percent, respectively.

Issue 32: Should TECO's requested pro forma adjustment to equity to offset off-balance sheet purchased power obligations be approved?

Recommendation: No. The $77 million in question should be removed from the capital structure through a specific adjustment to common equity and the same amount should be removed from rate base through an adjustment to working capital. (Maurey)

Position of the Parties

TECO: Yes. The proposed adjustment, including the use of a 25 percent risk factor, is consistent with how S&P imputes debt for purchased power agreements. The pro forma adjustment of $77 million to equity to offset off-balance sheet purchased power obligations in consistent with past Commission decisions, appropriate and should be approved.

OPC: No. The Company's proposed equity infusions related to the purchase power obligations are improper. Given the recovery mechanism for PPA payments, the financial condition of the Company is not impaired by entering these contracts. Thus, 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.

OAG: Adopts the Post-Hearing Brief position of the Office of Public Counsel.

AARP: Adopts the Post-Hearing Brief position of the Office of Public Counsel.

FIPUG: No. This is an unwarranted adjustment and should be rejected. TECO bears no risk regarding PPAs as the costs of PPAs are automatically recovered through the Commission's recovery clauses. Approval of this request would simply result in a higher rate of return for TECO.

FRF: No. The Company's imputed debt adjustment for power purchase agreements is speculative, is not based on any realistic risk, and is not supported by any witness who testified to the methodology or its alleged reasonableness. The Commission should reject it and reduce the Company's revenues by $5 million per year.

Staff Analysis: TECO has included a $77 million adjustment to equity in its 2009 projected capital structure for purposes of setting rates in this proceeding. (MFR Schedule D-1a) 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. (TR 203) 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. (TR 205) Finally, witness Gillette testified that the Commission has 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 settlements.[26] (TR 204)

OPC witness Woolridge testified that, given the Commission's specific clause recovery mechanism for PPA capacity payments, the financial condition of an electric utility is not impaired by entering into these contracts. (TR 1910) 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.

(TR 1911)

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). (TR 1911; EXH 13, p. 2276) 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." (TR 1910)

The pro forma adjustment to equity proposed by TECO is not an actual equity investment in the utility. (EXH 13, p. 3) 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 on a non-equity investment. The revenue requirement impact of recognizing this pro forma adjustment to equity in the capital structure is approximately $5 million per year. (TR 275–276)

Companies with PPAs are not required by the rating agencies to make the pro forma adjustment in question. (EXH 13, p 2276) 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

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

> achievable through self-build. The principal risk borne by a utility that relies on PPAs is the recovery of the financial obligation in rates.

(EXH 80)

With this proposed adjustment, staff believes 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 the Commission has 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 the Commission has 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, staff does not believe a decision rendered through a stipulation reached between the parties in a past proceeding constitutes a binding precedent on a future Commission decision rendered through an evidentiary hearing in an unrelated proceeding. (TR 379)

Therefore, based on the record evidence and the reasons discussed above, staff recommends TECO's requested pro forma adjustment to equity 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 equity, staff recommends the same amount be removed from rate base through an adjustment to working capital.

Issue 33: What is the appropriate amount and cost rate for long-term debt for the 2009 projected test year?

Recommendation: The appropriate amount and cost rate for long-term debt are $1,308,427,206 and 6.80 percent, respectively, as shown on Schedule 2. (Springer, Livingston)

Position of the Parties

TECO: The appropriate amount and cost rate for long-term debt for 2009 are $1,397,565,000 and 6.80 percent, respectively, as shown on MFR Schedule D-1a.

OPC: As of November 26, 2008, the appropriate long-term debt cost is 6.80%.

OAG: Adopts the Post-Hearing Brief position of the Office of Public Counsel.

AARP: Adopts the Post-Hearing Brief position of the Office of Public Counsel.

FIPUG: Agree with FRF.

FRF: Based on the Company's proposed rate base, the appropriate amount of Long-Term Debt would be $1,624,563,000, and the appropriate cost rate is 6.81%. However, this amount should be reduced to reflect Witness O'Donnell's capital structure and the lower rate base supported by OPC's witnesses and discussed elsewhere herein.

Staff Analysis: OPC witness Woolridge and TECO witness Gillette agree that the appropriate cost rate for long-term debt is 6.80 percent. (TR 1868, 193) However, FIPUG agreed with FRF witness O'Donnell that the appropriate cost rate for long-term debt should be 6.81 percent. (TR 2372) Neither FRF nor FIPUG provided any documentation to support why TECO's proposed cost rate of 6.80 percent was incorrect. Staff believes that the one basis point difference between the two cost rates is immaterial in this instance. (TR 1868, 193, 2372) Consistent with OPC and the Company, the appropriate cost rate for long-term debt is 6.80 percent. (TR 1868, 193)

As discussed in Issue 34, staff recommends certain adjustments 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 in Issue 34, the appropriate amount of long-term debt should be $1,308,427,206.

Issue 34: What is the appropriate capital structure for the 2009 projected test year?

Recommendation: The appropriate capital structure for purposes of setting rates in this proceeding is based on the Company's 2009 projected capital structure with certain adjustments to more accurately reflect the level of equity investment in the utility on a going-forward basis. This capital structure reflects a projected equity ratio of approximately 54 percent as a percentage of investor-supplied capital. The appropriate capital structure for the 2009 test year is shown on Schedule 2. (Maurey)

Position of the Parties

TECO: The appropriate capital structure for 2009 is the company's proposed capital structure as shown on MFR Schedule D-1a. The adjustment proposed by OPC is flawed and should be rejected.

OPC: The appropriate common equity ratio is 48.89% that accurately reflects the Company's past financing, the capitalization of electric utility companies, and removes the improper equity infusions for the PPAs. The appropriate capitalization ratios for the weighted average cost of capital on a regulatory structure basis are as follows: long-term debt at 43.80%; short-term debt at 0.60%; customer deposits at 2.82%; common equity at 42.48%; tax credits-weighted cost at 0.33%; and deferred income taxes at 9.97%.

OAG: Adopts the Post-Hearing Brief position of the Office of Public Counsel.

AARP: Adopts the Post-Hearing Brief position of the Office of Public Counsel.

FIPUG: Agree with FRF as adjusted to account for Mr. Herndon's recommended ROE of 7.5%.

FRF: The appropriate structure for the 2009 test year is 44.43% Long-Term Debt, 44.00% Common Equity, 8.28% Deferred Income Taxes, 0.22% Short-Term Debt, 2.84% Customer Deposits, and 0.24% Tax Credits, as indicated in Mr. Kevin O'Donnell's testimony and exhibits.

Staff Analysis: 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. (MFR Schedule D-1a) Excluding the $77 million of imputed equity, the capital structure reflects an equity ratio of 55.3 percent. (TR 200) Staff's recommendation regarding whether TECO's proposed pro forma adjustment to equity should be approved is discussed in Issue 32. The equity ratio at year-end 2008 was 52.6 percent. (TR 361)

COMPANY POSITION

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. (TR 227) TECO is currently rated in the BBB/Baa range by the three major rating agencies. (TR 195) Witness Gillette testified that the Company is targeting ratings in the A range. (TR 196)

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. (TR 196) 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. (TR 197)

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. (TR 227–229) TECO is proposing a significant construction program for the period 2009–2013. (TR 197–198) Witness Gillette testified access to the capital markets is essential so TECO can adequately fund this program. (TR 227, 247)

TECO witness Abbott also testified regarding TECO's need for credit quality sufficient to ensure access to capital under all market conditions. (TR 573) 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." (TR 573–574) 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." (TR 574) 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. (TR 575) 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." (TR 576)

Witness Gillette challenges the reasonableness of the intervenors' witnesses recommendations regarding the appropriate capital structure for TECO. (TR 225) 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." (TR 229–230) 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." (TR 231)

INTERVENOR POSITIONS

OPC witness Woolridge testified that TECO's recommended capital structure is not appropriate for ratemaking purposes in this proceeding. (TR 1909) He testified that TECO's recommended capital structure is not reflective of the recent capitalization of the Company. (TR 1909) 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. (TR 1909)

Witness Woolridge testified TECO's "proposed capital structure ratios do not reflect the actual capitalization of Tampa Electric." (TR 1865–1866) He testified that TECO's average equity ratio over the past three years has been 49.0 percent. (TR 1866) Witness Woolridge testified TECO's proposed equity ratio is not reflective of the capitalization of other electric companies. (TR 1866) The average equity ratio for the companies in witness Woolridge's proxy group for the first 11 months of 2008 was 45.7 percent. (TR 1866)

Witness Woolridge also testified that the equity ratio in TECO's proposed capital structure is inflated due to questionable adjustments and uncertain equity infusions. (TR 1867, 1909) As noted above, TECO's proposed capital structure includes $77 million of imputed equity. (TR 205) Staff's recommendation regarding the proposed adjustment related to imputed equity is discussed in Issue 32. TECO Energy invested approximately $300 million of the $350 million equity infusion projected for 2008. (TR 437) The Company's proposed capital structure also reflects an additional equity infusion of $285 million in 2009. (TR 205)

For purposes of setting rates in this proceeding, witness Woolridge recommends a capital structure that reflects an equity ratio of 48.9 percent. (TR 1867) This ratio represents the average of TECO's actual equity ratios in 2007 and 2008. (TR 1866) 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 the TECO's proposed capital structure. (TR 1867)

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." (TR 2367) 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. (TR 2368) 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." (TR 2368) He concluded that, through this process, "TECO Energy can effectively create whatever capital structure it desires for Tampa Electric and its other subsidiaries." (TR 2368)

For purposes of setting rates in this proceeding, witness O'Donnell recommends a capital structure that reflects an equity ratio of 49.6 percent. (TR 233) He recommends the Commission 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." (TR 2372; EXH 78)

ANALYSIS

Witness Gillette testified the Company's proposed equity ratio is necessary to generate credit parameters commensurate with a debt rating in the A range. (TR 200) However, the processes used by the rating agencies to determine debt ratings are complex and consider both qualitative and quantitative factors. (TR 199, 568, 572) Even if TECO received the entire rate increase it has requested in this proceeding, it is neither automatic nor is there any guarantee the Company's debt rating would be upgraded. (TR 586, 608)

Witness Abbott testified that a utility's financial integrity is primarily a product of its regulatory environment. (TR 571) She acknowledged that the Commission is regarded by a number of equity analysts as having a constructive regulatory environment because of its innovative and forward-looking regulatory practices. (TR 569) Witness Abbott also testified that regulation in Florida is considered among the best in the country by Regulatory Research Associates (RRA). (TR 569)

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." (TR 629) 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." (EXH 13, p. 1773) While her opinion may well be accurate in certain jurisdictions, staff believes 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, staff believes 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.

(EXH 13, p. 9393)

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." (EXH 13, p. 9406) 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." (EXH 13, p. 9419)

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." (EXH 13, p. 9427) 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." (EXH 13, p. 9427) TECO's S&P debt rating is still BBB minus today. (TR 574)

During this period, the other major rating agencies also commented on the 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.

(EXH 13, pp. 9416–9417)

Moody's Investors Service (Moody's) also commented on the impact the financial strain 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.

(EXH 13, p. 9421)

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.

(EXH 13, p. 9423–9424)

In 2003, TECO returned $158.3 million in equity to TECO Energy. (EXH 13, p. 26) This same year, TECO paid a dividend to TECO Energy of approximately $25 million in excess of TECO's net income that year. (EXH 13, p. 26) 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. (EXH 13, pp. 20-24; EXH 13, pp. 2301–2302)

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. (EXH 13, pp. 20-24) 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. (EXH 13, pp. 20-24; MFR Schedule D-2) Due to a significant equity infusion in 2008, TECO's equity ratio was 52.6 percent at year end 2008. (TR 361)

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. (TR 205) By year end 2008, TECO had received approximately $300 million of equity from TECO Energy. (TR 437)

From 1999 through 2007, TECO Energy invested approximately $533.6 million in equity in TECO. (EXH 13, pp. 20-24) Recognizing the return of capital made in 2003, the net equity infusion in TECO was $375.3 million over this nine year period. (EXH 13, pp. 20-24) 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. (EXH 13, pp. 20-24) 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. (TR 1867) Considering the fact that TECO Energy was unable to make the full $350 million equity infusion in 2008, staff agrees to a certain extent with witness Woolridge's concern regarding the uncertainty of the projected equity level.

Staff does not agree with witness Abbott that the Commission must set an authorized return in this proceeding that will generate revenue sufficient to achieve financial metrics in a particular rating range. The Commission has 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 its 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 there is no guarantee that 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 this Commission 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. The Commission's 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. (TR 662-663, 2346) 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." (TR 676) 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. (EXH 13, pp. 49-52) The average equity ratio for this group of utilities is 46.8 percent. (EXH 13, pp. 49-52)

RECOMMENDATION

Staff recommends the capital structure shown on Schedule 2. This capital structure reflects the Company's proposed capital structure for 2009 with specific adjustments to remove the $77 million in imputed equity discussed in Issue 32 and the $50 million equity infusion TECO Energy failed to make in 2008. Staff agrees 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 53.9 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. Staff believes this level of equity is appropriate given the substantial construction program TECO is proposing for the next five years.

While the equity ratio and authorized ROE are discussed in two separate issues, staff believes equity ratio and ROE are inextricably related. Staff's recommended ROE of 10.75 percent discussed in Issue 37 is implicitly linked to the equity ratio recommended herein. If the decision is made to adopt a higher or lower equity ratio, staff's recommendation regarding ROE may decrease or increase accordingly to recognize the decrease or increase in financial risk. The recommended capital structure is supported by competent and substantial evidence in the record.

Issue 35: Dropped.

Issue 36: Dropped.

Issue 37: What is the appropriate return on common equity for the 2009 projected test year?

Recommendation: The appropriate return on common equity for the 2009 projected test year is 10.75 percent with a range of plus or minus 100 basis points. (Maurey)

Position of the Parties

TECO: The appropriate return on common equity for the 2009 projected test year is 12 percent with a range of 11 percent to 13 percent. The adjustments proposed by OPC, FIPUG, and FRF are flawed and should be rejected.

OPC: The appropriate return on common equity for the 2009 projected test year is 9.75%.

OAG: Adopts the Post-Hearing Brief position of the Office of Public Counsel.

AARP: Adopts the Post-Hearing Brief position of the Office of Public Counsel.

FIPUG: The appropriate return on equity, given financial current conditions, is 7.5%. TECO will be able to attract equity capital at this rate because TECO is a secure utility that operates in a very low risk environment due to its monopoly position, its captive customer base, and guaranteed cost recovery clauses. Further, in these economic times, undue reliance should not be placed on computer modeling; rather, common sense and sound judgment must be used to determine an appropriate ROE.

FRF: No greater than 9.75%.

Staff Analysis: Four witnesses testify in this proceeding regarding the appropriate return on common equity (ROE) for TECO. TECO witness Murry recommends an ROE of 12.00 percent. (TR 721) OPC witness Woolridge recommends an ROE of 9.75 percent. (TR 1907) FIPUG witness Herndon recommends an ROE of 7.50 percent. (TR 2157) FRF witness O'Donnell recommends an ROE of 9.75 percent. (TR 2343) TECO's currently authorized ROE of 11.75 percent was set in 1995 in Order No. PSC-95-0580-FOF-EI.[27]

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.[28] These decisions define the fair and reasonable standards for determining rate of return for regulated enterprises. Namely, 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. (TR 662–663, 2346)

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

[27] 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.

[28] 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).

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. (TR 1875) Financial models have been developed to estimate the investor-required ROE for a company. (TR 1876) 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. (TR 673, 1875, 2346–2348)

DISCOUNTED CASH FLOW MODEL

Three witnesses used the DCF model to estimate the investor-required ROE for TECO. Because TECO is a wholly-owned subsidiary of TECO Energy, Inc. (TECO Energy), its common stock is not publicly traded. (TR 657-658, 2351) 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. (TR 658, 1864, 2351)

To select his group of comparable companies, TECO witness Murry started with all electric utilities followed by Value Line Investment Survey (Value Line). (TR 674) 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. (TR 674) 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. (TR 675) 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." (TR 676)

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. (TR 702) While he reviewed dividend growth rates, his DCF analysis relied principally on forecasted earnings growth rates. (TR 700) 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. (TR 694–695)

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. (EXH 20) 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. (TR 716–718)

To select his group of comparable companies, OPC witness Woolridge started with all electric utilities followed by Value Line and AUS Utility Reports. (TR 1864) 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. (TR 1865) He further narrowed his proxy group by focusing on companies with operating revenues less than $10 billion and 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. (TR 1864-1865)

Witness Woolridge relied on dividend yields for the six month period ended November 2008 and for the month of November 2008. (TR 1881) 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. (TR 1882–1883) 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. (TR 1887)

To select his group of comparable companies, FRF witness O'Donnell also started with all electric utilities followed by Value Line. (TR 2351) 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. (TR 2351) 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. (TR 2352) 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. (TR 2350)

Witness O'Donnell relied on the dividend yield expected over the next 12 months for each company as reported by Value Line. (TR 2352) 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. (TR 2353) 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. (TR 2354–2355) 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. (TR 2358)

Both witnesses Woolridge and O'Donnell filed rebuttal testimony challenging the reasonableness of certain aspects of witness Murry's DCF analysis. (TR 1914–1924, 2374–2376) In turn, witness Murry filed rebuttal testimony challenging the reasonableness of certain aspects of their analyses. (TR 2415–2436) 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. (TR 694, 1925, 1944, 2374, 2428–2429)

Focusing first on expected growth rates, witness Woolridge used a growth rate of 4.50 percent. (TR 1887) This growth rate is the average of the projected growth rates for EPS, DPS, BVPS, and the internal growth rate. (TR 1885–1887) Witness O'Donnell used a growth rate range of 4.00 percent to 4.50 percent. (TR 2358) This growth rate range is based on the historical and forecasted growth in EPS, DPS, and BVPS. (TR 2374) In contrast, witness Murry's relevant DCF range is based on growth rates that range from 6.50 percent to 8.06

percent. (EXH 20) These growth rates are based exclusively on forecasted EPS growth rates. (EXH 20)

The Commission has traditionally recognized a reasonable adjustment for flotation costs in the determination of the investor-required ROE. (EXH 13, p. 2692) However, such adjustments have typically been on the order of 25 to 50 basis points. (EXH 13, p. 2693) 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. (TR 694)

CAPITAL ASSET PRICING MODEL

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. (TR 712) 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. (TR 712) In both analyses, he used the average beta for his proxy group. (EXH 20)

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. (TR 714) This method produced a CAPM result of 11.24 percent. (TR 714) This result included a "small size adjustment" of 92 basis points. (TR 714; EXH 20) Witness Murry testified that this adjustment is necessary to account for an empirical bias against smaller companies in the CAPM analysis. (TR 710)

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. (TR 715) This method produced a CAPM result of 12.42 percent. (TR 715) 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. (TR 715)

OPC witness Woolridge performed an ex ante version of the CAPM analysis. (TR 1903–1905) As a proxy for the risk free rate, he used a composite yield of long-term U.S. Treasury bonds. (TR 1890) He used the average beta for his proxy group. (TR 1891) 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. (TR 1903) Witness Woolridge's CAPM analysis indicated an ROE of 8.2 percent. (TR 1906)

Both witnesses filed rebuttal testimony challenging the reasonableness of certain aspects of each other's CAPM analyses. (TR 1925–1938, 2431–2432) Both witnesses used virtually the same risk free rates (4.60 percent and 4.50 percent) and betas (.81 and .82). (TR 1890–1891;

EXH 20) 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. (TR 1925-1926)

Witness Woolridge used a risk premium of 4.56 percent in his CAPM analysis. (TR 1906) Witness Murry used risk premiums of 7.10 percent and 8.50 percent in his CAPM analyses. (EXH 20) Witness Woolridge relied on ex ante or forward looking risk premiums in his analysis. (TR 1892–1893) In contrast, witness Murry relied on ex post or historical risk premiums in his CAPM analysis. (TR 712) Witness Woolridge testified there is considerable academic research documenting that risk premiums based on historical, earned returns are poor predictors of current market expectations. (TR 1893–1895)

Witness Woolridge testified that the small size adjustment proposed by witness Murry in one of his CAPM approaches is not justified. (TR 1926) Witness Murry testified that he calculated the small size adjustment consistent with the method recommended by Ibbotson Associates. (TR 710) 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. (TR 1926) In addition, witness Murry 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. (TR 1926) Due to regulation, government oversight, performance review, accounting standards, and information disclosure, witness Woolridge testified that utilities are much different than industrial companies. (TR 1927) For these reasons, witness Woolridge testified there is no evidence of a significant size premium for utility stocks. (TR 1927)

OTHER APPROACHES

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 . . . " (TR 2359) 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. (TR 2359)

Witness O'Donnell reviewed the earned returns for the companies in his proxy group for the period 2004–2007. (TR 2359) 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. (TR 2359) For the entire four year period, the average earned ROE for the group was 9.0 percent. (TR 2360)

In addition to his analysis of earned returns, witness O'Donnell also examined recently authorized returns granted by state regulatory commissions around the country. (TR 2360) 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. (TR 2361) The average authorized return for the entire group over this period was 10.35 percent. (TR 2361) 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. (TR 2362)

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. (TR 2170–2171) He testified that in these unusual economic times, the Commission should not place undue reliance on traditional ROE models to determine the ROE for TECO. (TR 2157) Witness Herndon testified that the Commission 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. (TR 2162) Based on his review of these factors, witness Herndon recommends 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. (TR 2170)

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. (TR 2436) 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." (TR 2437) Witness Murry did not address witness O'Donnell's reliance on historical, earned returns in his comparable earnings approach. (TR 2432–2437)

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. (TR 2437) 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." (TR 2437)

ANALYSIS

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. (TR 717, 2157) Based on a more pragmatic review of the testimony, staff believes the record more strongly supports an ROE for TECO within the range of 9.75 percent to 12.00 percent. (TR 721, 1856, 2343) Moreover, based on a review of returns authorized by regulatory commissions around the country during 2007 and 2008, it is more likely the relevant return for TECO is in the range of 10.00 percent to 11.00 percent. (EXH 117)

Each of the witnesses recognized that the generally accepted models used for estimating ROE are based on a number of restrictive assumptions. (TR 688–689, 1869, 2376–2378) Under normal economic circumstances, the relaxation of these assumptions for the practical application of these models is generally understood. (TR 1876, 1982) However, as each of the ROE witnesses have testified, the economy is not presently in a normal or stable state. (TR 716, 1863, 2357–2358) 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. (TR 690–691, 1876, 2172, 2413, 2444–2445)

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, staff believes witness Murry's recommended ROE overstates the current investor-required ROE for TECO. (TR 1913) Conversely, recognizing that the intervenors' witnesses recommended ROE is only marginally greater than the current cost of utility debt, staff believes returns in the single digits may understate the investor-required ROE in the current market. (TR 598, 2414, 2437)

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. (TR 2437) 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. (TR 2376–2378) Staff does 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 the Commission can rely on for making its decision in this case. (TR 1928)

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. (TR 716) However, staff believes 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. (TR 676, 720) 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. (EXH 13, p. 2771) The average ROE for this group is 10.25 percent. Staff does 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.

RECOMMENDATION

Staff recommends an authorized ROE of 10.75 percent. In arriving at this return, staff has weighed the results of the witnesses' models against the level of currently authorized returns around the country. Staff has also taken into account TECO's proposed construction program and its need to access the capital markets during this potentially challenging period. In addition, staff considered the equity ratio recommended in Issue 34. Staff believes, at an equity ratio of approximately 54 percent, an authorized ROE of 10.75 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.

Issue 38: What is the appropriate weighted average cost of capital for the 2009 projected test year?

Recommendation: The appropriate weighted average cost of capital for the projected test year is 7.87 percent. (Springer, Livingston)

Position of the Parties

TECO: The appropriate weighted average cost of capital for the 2009 projected test year is 8.82 percent.

OPC: The appropriate weighted average cost of capital on a regulatory structure, rate of return, is 7.33%.

OAG: Adopts the Post-Hearing Brief position of the Office of Public Counsel.

AARP: Adopts the Post-Hearing Brief position of the Office of Public Counsel.

FIPUG: Mr. Herndon's recommended ROE of 7.5% should be adopted and the average cost of capital adjusted accordingly.

FRF: No greater than 7.52%.

Staff Analysis: Based upon the decisions in preceding issues and the proper components, amounts, and cost rates associated with the capital structure, staff calculated a weighted average cost of capital of 7.87 percent.

As discussed in Issue 29, staff recommends the appropriate balance of accumulated deferred income taxes (ADIT) is $357,400,000. As discussed in Issue 30, staff recommends the appropriate amount and cost rate of unamortized investment tax credits (ITCs) are $10,365,000 and 8.92 percent, respectively. As discussed in Issue 31, staff recommends 2.75 percent as the appropriate cost rate for short-term debt. As discussed in Issue 32, staff made an adjustment to remove $77 million of imputed equity. As discussed in Issue 33, the appropriate weighted average cost of long-term debt is 6.80 percent. As discussed in Issue 37, staff recommends 10.75 percent as the appropriate mid-point return on common equity.

As discussed in Issue 34, staff recommends certain adjustments to TECO's proposed capital structure to more accurately reflect the level of equity investment in the utility on a going-forward basis. Finally, in reconciling rate base and capital structure, TECO made a prorata adjustment over all sources of capital. Because the balances of ADITs and ITCs are specifically identified to plant in rate base, staff recommends the prorata adjustment necessary to reconcile rate base and capital structure be made over investor sources of capital only. This treatment is consistent with past Commission practice.[29]

[29] 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.

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 7.87 percent recommended herein. Schedule 2 shows the recommended 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, staff recommends that the appropriate weighted average cost of capital for TECO for purposes of setting rates in this proceeding is 7.87 percent.

NET OPERATING INCOME

Issue 39: Is TECO's projected level of Total Operating Revenues in the amount of $865,359,000 for the 2009 projected test year appropriate?

Recommendation: Yes, TECO's projected level of Total Operating Revenues in the amount of $865,359,000 for the 2009 projected test year is appropriate. (Slemkewicz, A. Roberts)

Position of the Parties

TECO: Yes. TECO has properly forecasted this amount for Total Operating Revenues and it is appropriate for the 2009 projected test year.

OPC: No. The Total Operating Revenues should reflect the adjustments recommended by OPC in this proceeding.

OAG: Adopts the Post-Hearing Brief position of the Office of Public Counsel.

AARP: Adopts the Post-Hearing Brief position of the Office of Public Counsel.

FIPUG: No. Adjustments should be made to reflect the adjustments recommended by Intervenors in this proceeding.

FRF: No. The amount should reflect the adjustments recommended by OPC in this case.

Staff Analysis: This is a fallout issue based on the resolution of other issues. As discussed in Issues 2 and 81, there are no adjustments to TECO's forecasts of customers, kWh, kw, or revenues for the 2009 projected test year. Therefore, staff recommends that $865,359,000 is the appropriate projected level of total operating revenues for the 2009 projected test year.

Issue 40: What are the appropriate inflation factors for use in forecasting the test year budget? (Stipulated)

Approved Stipulation: 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.

Issue 41: Is TECO's requested level of O&M Expense in the amount of $370,934,000 for the 2009 projected test year appropriate?

Recommendation: No. The appropriate amount of O&M Expense for the 2009 projected test year is $342,957,065. (Slemkewicz)

Position of the Parties

TECO: Yes. This amount is below the Commission's O&M benchmark. TECO has properly forecasted this amount for O&M Expense and it is appropriate for the 2009 projected test year.

OPC: No. The O&M Expense amount should reflect the adjustments recommended by OPC in this proceeding.

OAG: Adopts the Post-Hearing Brief position of the Office of Public Counsel.

AARP: Adopts the Post-Hearing Brief position of the Office of Public Counsel.

FIPUG: No. The specific adjustments FIPUG and other intervenors have recommended should be used to reduce O&M expense.

FRF: No. The amount should reflect the adjustments recommended by OPC in this case.

Staff Analysis: This is a fallout issue. Based on staff's recommendations, the appropriate level of O&M expense for the 2009 projected test year is $342,957,065. (See Schedule 3)

Issue 42: Has TECO 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? (Stipulated)

Approved Stipulation: Yes, 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.

Issue 43: Has TECO made the appropriate test year adjustments to remove conservation revenues and expenses recoverable through the Conservation Cost Recovery Clause? (Stipulated)

Approved Stipulation: Yes, TECO has made the appropriate test year adjustments to remove conservation revenues and expenses recoverable through the Conservation Cost Recovery Clause.

Issue 44: Has TECO made the appropriate test year adjustments to remove capacity revenues and expenses recoverable through the Capacity Cost Recovery Clause? (Stipulated)

Approved Stipulation: Yes, TECO made the appropriate test year adjustments to remove capacity revenues and expenses recoverable through the Capacity Cost Recovery Clause.

Issue 45: Has TECO made the appropriate test year adjustments to remove environmental revenues and expenses recoverable through the Environmental Cost Recovery Clause? (Stipulated)

Approved Stipulation: Yes, TECO has made the appropriate test year adjustments to remove environmental revenues and expenses recoverable through the Environmental Cost Recovery Clause.

Issue 46: Should an adjustment be made to advertising expenses for the 2009 projected test year?

Recommendation: No. Staff recommends that the Company's forecast for advertising expense is reasonable and no adjustment to the test year advertising expenses is necessary. (Prestwood)

Position of the Parties

TECO: No. TECO has properly forecasted advertising expenses and no adjustment is warranted.

OPC: Yes, any adjustment should be made in accordance with staff's recommendation.

OAG: Adopts the Post-Hearing Brief position of the Office of Public Counsel.

AARP: Adopts the Post-Hearing Brief position of the Office of Public Counsel.

FIPUG: Yes. Agree with Public Counsel.

FRF: Yes.

Staff Analysis:

ANALYSIS

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. (TR1430-1431) Advertising expenses Account 913 is included in this group, but as explained by witness Chronister, 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. (TR 1603)

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.

CONCLUSION

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

Issue 47: Has TECO made the appropriate adjustments to remove lobbying expenses from the 2009 projected test year?

Recommendation: Yes. Staff recommends that no adjustment to the 2009 projected test year is necessary to remove lobbying expenses. (Prestwood)

Position of the Parties

TECO: Yes. TECO has made the appropriate adjustments to remove lobbying expenses from the 2009 projected test year.

OPC: No, any adjustment should be made to remove lobbying expenses in accordance with staff's recommendation.

OAG: Adopts the Post-Hearing Brief position of the Office of Public Counsel.

AARP: Adopts the Post-Hearing Brief position of the Office of Public Counsel.

FIPUG: No. Agree with Public Counsel.

FRF: No. The amount should reflect the adjustments recommended by OPC in this case.

Staff Analysis:

ANALYSIS

MFR Schedule C-18 Lobbying Expenses, Other Political Expenses and Civic/Charitable Contributions states, "No 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." (TR 1506)

CONCLUSION

As staff has determined that no lobbying expenses have been included in test year expenses, staff recommends that no adjustment is necessary to remove lobbying expenses from the 2009 projected test year.

Issue 48: Should an adjustment be made to TECO's requested level of Salaries and Employee Benefits for the 2009 projected test year?

Recommendation: Yes. Staff recommends that the officer's compensation for both TECO Energy, Inc. (Parent) and TECO be reduced to reflect no increase in 2009 as announced by the Company during the hearing held in Tallahassee, January 21, 2009. This adjustment decreases jurisdictional O&M expense $206,812 ($213,088 system) for all the officers of both companies.

Staff also recommends that 90 positions be removed from the test year. 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). (EXH 52, HWS-1 Schedule C-4, C-5) (Prestwood)

Position of the Parties

TECO: Yes. Based upon changes made to 2009 merit guidelines subsequent to its filing, the Company's total salaries and benefits expense should be reduced by $1,378,987. Other than this adjustment, TECO's total salaries and benefits expense reflects reasonable levels of compensation and benefits (401k and medical) based on market comparisons.

OPC: Yes. Overtime dollars have not been identified or tracked by the Company. 2009 executive pay raises of at least $437,289 should be removed. A reduction for the overstated request for new employees above 2007 historical levels warrants elimination of 90 positions totaling $3,568,109 (jurisdictional) and related employee benefits should reduced by $1,420,208 (jurisdictional). The Company's request to increase its 401(k) matching contributions despite today's economic condition is unreasonable and should be reduced by $1.991 million.

OAG: Adopts the Post-Hearing Brief position of the Office of Public Counsel.

AARP: Adopts the Post-Hearing Brief position of the Office of Public Counsel.

FIPUG: Yes. The Commission should make the adjustments recommended by Public Counsel witness Schultz. The Company's payroll should be reduced by $3,568,109; the Company's 401(k) expense should be reduced by $1.991 million; and employee benefits expense should be reduced by $1,420,208.

FRF: Yes. Agree with OPC that TECO's Salaries and Employee Benefits for the test year should be reduced by $6,979,317 on a jurisdictional basis, as follows: $3,568,109 in payroll, $1,991,000 in 401K plan expense, and $1,420,208 in employee benefits.

Staff Analysis:

PARTIES' ARGUMENTS

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. (TR 1105) The second component mentioned above, success sharing or incentive compensation, is discussed separately in Issue 52.

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. (TR 1108) 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 witness Merrill, EXH 25 demonstrates that TECO has maintained its average total compensation for benchmarked exempt and non-exempt jobs at or below the market average. (TR 1108-1109) Witness Merrill stated that the Company targets total compensation at the 50th percentile when comparing external market data to similar Company positions. (TR 1127)

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. (TR 1112) According to witness Merrill, EXH 25 shows that 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. (TR 1112-1113)

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, Inc. and Tampa Electric Company (TECO) will receive no increase in compensation in 2009. (TR 1194-1196) The officers' total compensation for both TECO Energy, Inc.'s and TECO's officers was originally provided during discovery. (EXH 13, pp. 444-454) These responses were updated in Late-Filed EXH 107 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, Inc. 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.

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. (TR 2073) 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." (TR 2074) Witness Schultz further testified 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. (TR 2074) 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." (TR 1482) 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. (TR 1482-1483)

OPC witness Shultz 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 Shultz, 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. (TR 2085)

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.

(TR 1142)

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. (TR 1314) According to witness Chronister, payroll cost assumptions are based on appropriate compensation levels given expected conditions on the job market. (TR 1415)

Company witness Haines testified that TECO focuses on multiple initiatives to cost effectively maintain and enhance customer service and reliability. (TR 983) 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. (Haines TR 984)

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 Commission 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. (TR 997-998)

Witness Haines testified that in 2007, the Company spent approximately $10.3 million on tree trimming for its distribution system. (TR 1037) The vegetation management in 2009 is projected to be $16.1 million. (EXH 24, Document No. 7) TECO contracts out its entire tree trimming activities and the work is competitively bid. (EXH 13, pp. 397-406) Witness Haines stated the Company had not quantified the 2009 dollars saved due to tree trimming. (EXH 13, pp. 2464-2563)

OPC witness Schultz testified that he had concerns with the Company's requested 151 additional employees in the test year above the 2007 levels. (TR 2073) 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. (TR 2074)

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. (TR 2075-2076) The Company did not present rebuttal testimony to witness Shultz's proposal to reduce the number of projected positions for 2009.

ANALYSIS

With the exception of staff's recommended adjustment for Issue 52, staff does not support OPC's adjustment with respect to the level of compensation of TECO employees. Staff believes that 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. (Merrill TR 1108-1109) Staff recommends that with the exception of the adjustment to officer's compensation, no futher adjustments be made for the level of TECO's Compensation.

Staff does recommend that the officer's compensation for both TECO Energy, Inc. (Parent) and TECO be reduced to reflect no increase in 2009 as announced by the Company during the hearing held in Tallahassee Wednesday, January 21, 2009. This adjustment decreases jurisdictional O&M expense $206,812 ($213,088 system) for all the officers of both companies.

Staff also supports OPC's adjustment to reduced 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 Commission 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, staff does not believe 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. Staff believes the projected increase of 151 positions for 2009 should be reduced to account for the effects of the increased vegetation management and wood pole inspections.

Staff believes that OPC witness Shultz'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. Staff recommends that OPC's recommendation to remove 90 positions from the test year should be accepted. 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). (EXH 52, Schedule C-4, C-5)

CONCLUSION

Staff recommends that the officer's compensation for both TECO Energy, Inc. (Parent) and TECO be reduced to reflect no increase in 2009 as announced by the Company during the hearing held in Tallahassee, January 21, 2009. This adjustment decreases jurisdictional O&M expense $206,812 ($213,088 system) for all the officers of both companies.

Staff recommends that 90 positions be removed from the test year. 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). (EXH 52, Schedule C-4, C-5)

In total, staff is recommending that O&M expense be reduced by $5,195,129 ($5,351,120 system).

Issue 49: Should an adjustment be made to Other Post Employment Benefits Expense for the 2009 projected test year?

Recommendation: No. The staff recommends that no adjustments be made to the Company's revenue requirement concerning Other Post Employment Benefits Expense. (Prestwood)

Position of the Parties

TECO: No. TECO has properly forecasted Other Post Employment Benefits Expense and no adjustment is warranted.

OPC: Yes, any adjustment should be made in accordance with staff's recommendation.

OAG: Adopts the Post-Hearing Brief position of the Office of Public Counsel.

AARP: Adopts the Post-Hearing Brief position of the Office of Public Counsel.

FIPUG: Yes. Agree with Public Counsel.

FRF: Yes. Agree with OPC as to the appropriate amounts of adjustments.

Staff Analysis:

PARTIES ARGUMENTS

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 the Commission's instructions, as delineated in Order No. PSC-06-1040-PAA-EI.[30] (TR 1439-1440)

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. Order No. PSC-06-1040-PAA-EI[30] provided specific instructions to TECO on the implementation of FASB 158.

Company witness Merrill testified on the design and cost of the Company's benefit plans which include Postretirement Plans. Witness Merrill stated that TECO projects medical and dental costs to be $13,110,000 for post-retirement benefits for 2009. (TR 1113) According to witness Merrill, TECO's medical cost is below average based on the Towers Perrin BENVAL Study.

[30] 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.

ANALYSIS

Staff has reviewed the data provided by the Company in its MFRs, Exhibits, and through discovery. Staff believes that TECO has presented sufficient information to demonstrate its Other Post Employment Benefits Expense is reasonable. No party other than the Company presented testimony regarding this issue.

CONCLUSION

The staff recommends that no adjustments be made to the Company's revenue requirement concerning Other Post Employment Benefits Expense.

Issue 50: Should operating expense be reduced to take into account budgeted positions that will be vacant?

Recommendation: No. Staff's recommended adjustment in Issue 48 accounts for this issue. No further adjustment is necessary. (Prestwood)

Position of the Parties

TECO: No. TECO has properly forecasted operating expense for budgeted labor and no adjustment is warranted. Headcount is not a primary metric that TECO uses to manage its business; rather, it forecasts total resources needed to cost effectively meet operation requirements. The budget system does not utilize headcount, only forecasted expenses.

OPC: Yes. A reduction of the 2009 projected test year employee level by 90 positions reduces the possibility of an excessive amount of vacant positions. The allowed employee level should be limited to the employee compliment as of year-end 2007 and as of September 30, 2008 of 2,531 plus an additional 17 positions.

OAG: Adopts the Post-Hearing Brief position of the Office of Public Counsel.

AARP: Adopts the Post-Hearing Brief position of the Office of Public Counsel.

FIPUG: Yes. The Company has overstated the number of needed employees by approximately 100 positions compared with its historical employee numbers. These positions should be deleted from the test year.

FRF: Yes. Agree with OPC.

Staff Analysis:

ANALYSIS

TECO does not budget based on the number of employees by month. (EXH 13, pp. 180-183) 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. (TR 1166) During his deposition, Company witness Chronister stated that in TECO's budgeting process, it does not use head count. What TECO does is budget for the dollars of expense associated with the resources that it expects to consume. Staff has recommended an reduction in total budgeted positions in Issue 48 that encompasses this issue. (EXH 13, pp. 2017-2233)

No other party presented testimony on this issue.

CONCLUSION

Staff has recommended an reduction in total budgeted positions in Issue 48 that encompasses this issue. The staff recommends no separate adjustment for this issue.

Issue 51: Should operating expense be reduced to take into account TECO's initiatives to improve service reliability?

Recommendation: No. Staff has already recommended adjustments to payroll in Issue 48 that compensates for this issue. (Prestwood)

Position of the Parties

TECO: No. TECO has properly adjusted operating expenses to take into account TECO's initiatives to improve service reliability. Staff's proposed adjustment improperly focuses on positions, not resources to serve customers, and should be rejected.

OPC: Yes, any adjustment should be made in accordance with staff's recommendation.

OAG: Adopts the Post-Hearing Brief position of the Office of Public Counsel.

AARP: Adopts the Post-Hearing Brief position of the Office of Public Counsel.

FIPUG: Yes. Agree with Public Counsel.

FRF: Yes. Agree with OPC.

Staff Analysis:

PARTIES ARGUMENTS

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. (TR 1314) According to witness Chronister, payroll cost assumptions are based on appropriate compensation levels given expected conditions of the job market. (TR 1415)

Company witness Haines testified that TECO focuses on multiple initiatives to cost-effectively maintain and enhance customer service and reliability. (TR 983) 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. (TR 984)

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. (TR 997-998)

Witness Haines testified that in 2007, the Company spent approximately $10.3 million on tree trimming for its distribution system. (TR 1037) The vegetation management in 2009 is projected to be $16.1 million. (EXH 24, Document No. 7) TECO contracts out its entire tree trimming activities and the work is competitively bid. (EXH 13, pp. 397-406) Witness Haines stated the Company had not quantified the 2009 dollars saved due to tree trimming. (EXH 13, pp. 2464-2563)

ANALYSIS

Staff believes the Company is to be commended for its actions to improve operational efficiency and effectiveness 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 Commission 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, staff does not believe 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. Staff has recommended that OPC's adjustment to reduced 90 positions in Issue 48 should be accepted; this will account for the effects of the increased vegetation management and wood pole inspections.

CONCLUSION

Staff believes that its recommendation in Issue 48 to accept OPC witness Shultz'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. Staff recommends no further adjustment in this issue.

Issue 52: Should operating expense be reduced to remove the cost of TECO's incentive compensation plan?

Recommendation: Yes. Staff recommends that jurisdictional operating expenses 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. (Prestwood)

Position of the Parties

TECO: No. The Company's total level of compensation, including incentive compensation, is reasonable based on market comparisons. The Company's incentive compensation is one component of overall compensation for officers, key employee and general employees. Taken as a whole, the incentive plans are appropriately designed to motivate employees to achieve customer-focused operational and financial goals. The adjustments proposed by OPC and FIPUG are flawed and should be rejected.

OPC: Yes. The Company has not shown that the pay is required or designed to attract, retain, and/or motivate employees. The goals and/or targets are not set to improve performance that benefits customers. Ratepayers are being requested to pay more than their fair share, assuming that this incentive plan is reasonable. The entire $11,574,843 ($11,233,952 on a jurisdictional basis) should be disallowed. However, under no circumstances should ratepayers bear more than 50% of the cost.

OAG: Adopts the Post-Hearing Brief position of the Office of Public Counsel.

AARP: Adopts the Post-Hearing Brief position of the Office of Public Counsel.

FIPUG: Yes. Incentive compensation that is contingent on or related to the parent and/or operating Company achieving financial goals, such as net income, benefits shareholders not ratepayers and should be removed from the test year. Specifically, 100% of officer, key employee and general employee incentive payments contingent upon TECO or TECO Energy achieving a specific net income or other financial indicator should be disallowed as should compensation related to Performance Restricted Shares and Time-Vested Restricted Shares.

FRF: Yes. Agree with OPC that TECO's incentive compensation plan is not structured to ensure that it benefits TECO's captive customers, and accordingly, the entire $11,233,952 (jurisdictional) should be removed.

Staff Analysis:

PARTIES' ARGUMENTS

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. (TR 1110)

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. (TR 1110) Witness Merrill testified that this "at risk" component of total compensation has been a win-win for team members and customers. (TR 1111)

Concerning the Success Sharing Plan or incentive compensation, OPC witness Shultz testified that the description of the plans objectives is misleading from a ratemaking perspective, in that the plan heavily favors shareholder-oriented objectives/goals. There are significant doubts as to whether this incentive pay is truly "at risk" based on the target setting. Moreover, ratepayers are being requested to pay more than their fair share of the incentive plan, even assuming that this type of incentive plan is reasonable. (TR 2076)

Witness Shultz 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 is seriously flawed, particularly from a ratemaking and ratepayer prospective. (TR 2077) Witness Shultz 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. (TR 2077-2079) 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 five years, the Company still expensed and paid 18-49 percent more than the target level of incentive compensation budgeted during the years 2004-2007. (TR 2079-2080)

Witness Shultz 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 the Commission were to conclude that some expense is justified, it 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, the cost of that plan should be shared equally. (TR 2081-2084)

FIPUG witness Pollock testified that incentive compensation that is contingent upon the parent and/or operating Company achieving certain financial goal, 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. (TR 2241) Witness Pollock cites 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. (TR 2244-2245)

Witness Pollock recommends that Stock compensation on MFR Schedule C-35, line 15 for 2009, shown as $2.6 million, should be excluded. He also recommends 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, 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 recommends 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. (TR 2246)

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 by the Commission in the Company's last rate case in 1992. (TR 1131)

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 the Commission did not agree with him and made no adjustment.[31] The Commission 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. (TR 1131-1132)

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. Shultz'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. (TR 1132-1133)

Concerning witness Pollock's 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

[31] 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.

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. (TR 1485)

ANALYSIS

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 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 by the Commission in the Company's last rate case in 1992. Staff believes that 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.

CONCLUSION

Staff believes 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, Inc. Staff recommends that jurisdictional operating expenses 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.

Issue 53: Should operating expense be reduced to take into account new generating units added that are maintained under contractual service agreements?

Recommendation: No. The impact of new generating equipment will be minimal (if any) on headcount. Staff already recommended reductions in the overall increase in headcount in Issue 48. No further adjustment is recommended for this issue. (Prestwood)

Position of the Parties

TECO: No. TECO has properly forecasted operating expenses and has taken into account new generating units that are maintained under contractual service agreements. No adjustment is warranted.

OPC: Yes. The operating expense should be reduced by the amount the Company has included in O&M expense of $792,000 for the period that the CTs will actually be in service and will be covered by the CSAs.

OAG: Adopts the Post-Hearing Brief position of the Office of Public Counsel.

AARP: Adopts the Post-Hearing Brief position of the Office of Public Counsel.

FIPUG: Yes. Agree with Public Counsel.

FRF: Yes. Agree with OPC.

Staff Analysis:

PARTIES' ARGUMENTS

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 these turbines. Under these agreements, GE is responsible for supplying maintenance services and parts necessary to perform all planned and unplanned maintenance on the covered units in order to keep them in good working condition and to maintain availability and reliability while operating in a cost-effective and safe manner. (TR 834)

Witness Hornick further explained that under CSAs, the availability of spare parts is improved and the inventory requirements for these 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. (TR 833)

In discussing TECO's planned generation capacity additions, Witness Hornick testified that projects are underway to add 5 simple cycle CTs in 2009. (TR 822) The Company intends to enter into CSAs for the 5 new CTs to be placed in service during 2009. (EXH 13, pp. 184-190) Each one of these machines has a nominal capacity of 60 megawatts, for a total of 300 megawatts. As there are 3 combustion turbines at the Big Bend station that are old and have reached the end of their useful life and are being decommissioned, so the net capacity addition considering the new CTs and the retired CTs is approximately 170 megawatts. (TR 871) Big Bend Unit 1, which is 10 MW, is the only 1 of the 3 CT retirements occurring during the test year. (TR 823; MFR Schedule F-8, p. 9) The other 2 CT retirements occur in 2008. (MFR Schedule F-8, p. 9)

ANALYSIS

The 5 new CTs will add additional capacity to the system (300 MW) and replace old CTs that have reached the end of their useful life (130 MW). The net new capacity is 170 MW out of 300 MW. Big Bend Unit 1 with 10 MW is the only 1 of the 3 CT units of the retirements that actually occurs during the test year. The other 2 retirements occur in 2008 before the beginning of the test year. The net change in capacity occurring during the 12 months of the test year, therefore, is an increase of 290 MW (300 MW – 10 MW). The new capacity will be maintained under CSAs and should have the impact of preventing further increases in number of personnel to maintain these units. These units will be added in May and September and decrease the capacity of the total system by only 10 MW.

CONCLUSION

Staff believes the impact on the number of personnel, if any, would be minimal. Additionally, staff recommended reductions in the overall increase in headcount in Issue 48. No further adjustment is recommended due to the new CTs that will be maintained under CSAs.

Issue 54: Should an adjustment be made to TECO's generation maintenance expense?

Recommendation: Yes. Staff recommends that Generation Maintenance expenses be reduced by $2,850,000 ($2,960,000 system). (Prestwood)

Position of the Parties

TECO: No. TECO has properly forecasted generation maintenance expense; it is not overstated and no adjustment is warranted. This issue must be reviewed together with Issue 69, which addresses a subset of generation maintenance expense.

OPC: Yes. The Company did not justify its requested increase above indexed historical 2007 levels. The Company's request is overstated by $8.48 million ($8.173 million on a jurisdictional basis). See Issue 69 for a discussion of the normalization of outage O&M expense which results in the same adjustment.

OAG: Adopts the Post-Hearing Brief position of the Office of Public Counsel.

AARP: Adopts the Post-Hearing Brief position of the Office of Public Counsel.

FIPUG: Yes. The Company's request should be reduced by $8,173,000 as recommended by Public Counsel witness Schultz. The Company failed to justify its request over historical levels.

FRF: Yes. See also Issue 69. The Company's generation maintenance expense should be reduced by between $7,710,000 and $8,173,000 per year on a jurisdictional basis.

Staff Analysis:

PARTIES' ARGUMENTS

OPC witness Shultz testified that specific maintenance Accounts 511, 512, and 513 were examined because these accounts showed significant increases for the test year. EXH 52, Schedule C-10, shows 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 interrogatories, witness Shultz 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. EXH 52, Schedule 10, shows the jurisdictional adjustment to generation maintenance of $8,173,000 ($8,480,000 system). (TR 2098-2099)

Company witness Hornick testified that when witness Shultz 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. (TR 854-855)

ANALYSIS

Staff does not believe that TECO has justified the increases in Generation Expense for the test year. As discussed in detail in Issue 69, staff believes that 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. Staff believes the approach presented in this issue by OPC witness Schultz, as corrected by Company witness Hornick, eliminates the problem discussed in Issue 69 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.

CONCLUSION

Staff recommends that OPC's adjustment as corrected by Company Witness Chronister be accepted. This reduces Generation Maintenance expenses be reduced by $2,850,000 ($2,960,000 system).

Issue 55: Should an adjustment be made to TECO's substation preventive maintenance expense?

Recommendation: No. Staff does not recommend an adjustment to the Company's test year preventive maintenance on substation infrastructure. (Prestwood)

Position of the Parties

TECO: No. The Company's substation preventive maintenance expense is not overstated. TECO has properly forecasted substation preventive maintenance and no adjustment is warranted.

OPC: Yes. The Company has unreasonably increased its 2009 projected test year levels almost twice the historical 2007 level and three times the last five year average. Since the Company should have been maintaining its system in a safe and reliable manner over the years, the maintenance expense should be based on indexed 2007 historical levels. This results in a reduction of $1,057,185 ($973,201 on a jurisdictional basis).

OAG: Adopts the Post-Hearing Brief position of the Office of Public Counsel.

AARP: Adopts the Post-Hearing Brief position of the Office of Public Counsel.

FIPUG: Yes. The adjustment recommended by Public Counsel witness Schultz should be made. TECO increased its test year levels to almost twice historical levels and three times the five year average. As Mr. Schultz testified, the Company should consistently maintain its system in a safe and reliable manner.

FRF: Yes. The Company's substation preventive maintenance expense should be reduced by $973,201 on a jurisdictional basis.

Staff Analysis:

PARTIES ARGUMENTS

OPC witness Shultz 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 EXH 52, Schedule C-9, the Company spent on average $761,581 for preventive maintenance over the 5 years 2003-2007. The Company increased the required annual expense to $2,256,610, almost 3 times the average spent over the last 5 years, and more than 2 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. (TR 1041-1043)

Witness Shultz further testified 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. TECO should have been spending the needed amount on maintenance to provide safe and reliable service. The Company should have to prove that it is spending what is needed to provide safe and reliable service justify increases in spending. (TR 1041-1043)

Company witness Haines testified that there are several elements of Mr. Shultz'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. Finally, 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, as shown in EXH 84. Based on the Company's experience in 2008, the costs are most likely understated. (TR 1041-1043)

ANALYSIS

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 staff believes the Company has fully refuted OPC's objections and has justified the increase.

CONCLUSION

Staff believes the Company has justified the increase in preventive maintenance on substation infrastructure. Staff does not recommend an adjustment for this issue.

Issue 56: Should an adjustment be made to TECO's request for Dredging expense?

Recommendation: Yes. Although dredging costs are a necessary cost of doing business, the full amount requested by TECO is not supported. The Company should 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). (Marsh)

Position of the Parties

TECO: No. TECO has properly forecasted Dredging expense to be incurred by the Company based on current cost estimates and no adjustment is warranted.

OPC: Yes. The Company has failed to provide documentation to support that its dredging cost will reach $6.9 million. Further, the Company has not supported that any dredging will occur in the 2009 test year. Therefore, the operating expense of $1,330,000 for dredging should be removed.

OAG: Adopts the Post-Hearing Brief position of the Office of Public Counsel.

AARP: Adopts the Post-Hearing Brief position of the Office of Public Counsel.

FIPUG: Yes. Agree with Public Counsel.

FRF: Yes. The Company's operating expenses should be reduced by $1,330,000 (jurisdictional).

Staff Analysis:

PARTIES' ARGUMENTS

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. (TR 840) He explained that there is silt and sediment accumulation at the circulating water pump inlets, which reduces unit efficiency, increases fuel costs, and causes additional maintenance expense. (TR 841)

He 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." (TR 841)

Witness Hornick stated that the overall cost the Company plans to spend is approximately $6.9 million on channel dredging in 2009. (TR 842) He advised 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. (TR 842) He stated that the total cost, including the share allocated to another party, is $9.6 million. (EXH 13, p. 2589)

He explained that 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." (TR 842) 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. (TR 842)

Witness Hornick explained that 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. He stated that 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. He noted that, 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). He clarified that only the Company's portion of dredging costs is reflected in the 2009 projections. (TR 843)

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. (TR 844)

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. (TR 1481-1482) He opined that it is therefore appropriate to amortize the impact of this expenditure over 5 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. (TR 1442-1443)

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. (TR 1480-1481)

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. (TR 2023) Witness Larkin removed from the 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. (TR 2025)

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 5-year period should have been in the year 2007 and not 2009; thus, dredging costs would not be included in 2009. (TR 2024)

FRF did not discuss its position in its brief. (FRF BR at 47)

ANALYSIS

Staff has serious concerns regarding the lack of 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. (EXH 13, p. 2659) 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. (EXH 13, pp. 2607-2608)

Witness Hornick stated in testimony that there were increased fuel costs and additional maintenance expenses associated with the build-up of silt. (TR 841) However, when questioned about the amount of savings that would resulted for fuel and maintenance expense for the pumps, he was unable to quantify it. (EXH 13, p. 2574) Upon further consideration, he made an educated guess that the savings would be less than ten percent and probably less than one percent. (EXH 13, p. 2576) He stated that the savings were not reflected in the test year. (EXH 13, p. 2577) Staff is concerned that this cost savings will not be passed through to the ratepayers.

Staff agrees 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. (OPC BR at 17) Witness Larkin's exhibits clearly show that he removed the full amount of the dredging cost. (EXH 50, Schedule C-1, p. 2 of 2)

Staff agrees with the Company that the cost of dredging is a necessary and prudent cost. Although support is woefully deficient, staff believes 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 should not be allowed, particularly in view of the fact that the potential savings resulting from efficiencies gained have not been shared with the customer.

Staff recommends using the $4,730,813 quote and splitting the cost between TECO and Mosaic in the same proportion TECO used in this filing. This 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.

CONCLUSION

Staff recommends that, although dredging costs are a necessary cost of doing business, the full amount requested by TECO is not supported. The Company should 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).

Issue 57: Should an adjustment be made to TECO's Economic Development Expense?

Recommendation: No. Staff recommends no adjustment be made for this issue. (Prestwood)

Position of the Parties

TECO: No. TECO has properly forecasted Economic Development Expense and no adjustment is warranted.

OPC: Yes, any adjustment should be made in accordance with staff's recommendation.

OAG: Adopts the Post-Hearing Brief position of the Office of Public Counsel.

AARP: Adopts the Post-Hearing Brief position of the Office of Public Counsel.

FIPUG: Yes. Agree with Public Counsel.

FRF: Yes.

Staff Analysis:

ANALYSIS

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 Commission directives, policies, and decisions from previous rate proceedings. (TR 1435) He further testified that economic development expense for the test year was developed following the rules on what was allowable by the Commission. He stated that the Commission has various rules; some Economic Development Expenses are allowed 100 percent, some are allowed 95 percent, and some are allowed zero percent. "So, with each category we projected, we flowed that through and only allowed the allowable percentage, the allowable dollars to be included in the filing." (TR 1603) No other testimony was presented on this issue. 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. Staff has analyzed the MFRs and responses to discovery as well as the supporting work papers to the adjustments. (EXH 13, pp. 1143-1144)

CONCLUSION

TECO's testimony, MFRs, and discovery responses, including work papers, support the Company's position that the appropriate test year adjustment to remove economic development expense in accordance with Commission policy and rules. Staff recommends that no further adjustments should be made to the Company's revenue requirement for this issue.

Issue 58: Should an adjustment be made to Pension Expense for the 2009 projected test year?

Recommendation: No. Staff believes that TECO has submitted sufficient evidence to demonstrate that its pension expense is reasonable. Staff recommends that no adjustment to the Company's revenue requirement concerning pension expense is warranted. (Kyle)

Position of the Parties

TECO: No. TECO has properly forecasted Pension Expense and no adjustment is warranted.

OPC: Yes, any adjustment should be made in accordance with staff's recommendation.

OAG: Adopts the Post-Hearing Brief position of the Office of Public Counsel.

AARP: Adopts the Post-Hearing Brief position of the Office of Public Counsel.

FIPUG: Yes. Agree with Public Counsel.

FRF: Yes.

Staff Analysis: 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. (TR 1117) Witness Merrill testified that the actuarial assumptions and methods used for the pension valuation are reasonable, both individually and in the aggregate. (TR 1119) No party other than the Company presented testimony dealing with this issue.

Staff has reviewed the data provided by the Company in its MFRs, exhibits and through discovery. Staff believes that TECO has submitted sufficient evidence to demonstrate that its pension expense is reasonable.

CONCLUSION

Staff believes that TECO has submitted sufficient evidence to demonstrate that its pension expense is reasonable. Staff recommends that no adjustment to the Company's revenue requirement concerning pension expense is warranted.

Issue 59: Should an adjustment be made to the accrual for property damage for the 2009 projected test year?

Recommendation: No. Staff recommended a $16,000,000, decrease to this account for the storm damage accrual in Issue 16. Staff recommends no further adjustment for this issue. (Prestwood)

Position of the Parties

TECO: No. Since T&D insurance coverage is not commercially available at reasonable prices, the Commission should approve TECO's proposed annual accrual and target of reserve $20 million and $120 million as an insurance surrogate. Based on ABS Consulting's study, the Company's proposed accrual and target levels are appropriate for most, but not all, storms based on the value of TECO's system. TECO's proposal will service to normalize the level of storm damage expense over time.

OPC: Yes, the storm damage accrual should remain at $4,000,000.

OAG: Adopts the Post-Hearing Brief positions of the Office of Public Counsel.

AARP: Yes, as testified to by AARP witness Stewart the requested storm damage accrual should be reduced by $16,000,000 and remain at $4,000,000.

FIPUG: Yes. The Company's storm damage accrual should remain at $4 million annually and the reserve target should remain unchanged.

FRF: Yes. See also Issue 16. The Company's storm damage accrual should remain at $4,000,000 per year, and the Company's reserve target level should remain unchanged.

Staff Analysis:

ANALYSIS

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 is discussed in Issue 16. No other party presented testimony on this issue.

CONCLUSION

Staff believes that TECO has justified its property damage expense other than storm damage. Storm damage is discussed in Issue 16. Staff recommends no adjustment for this issue.

Issue 60: Should an adjustment be made to the accrual for the Injuries & Damages reserve for the 2009 projected test year?

Recommendation: No. Staff recommends no adjustment for this issue. (Prestwood)

Position of the Parties

TECO: No. TECO has properly forecasted the accrual for the Injuries & Damages reserve and no adjustment is warranted.

OPC: Yes, any adjustment should be made in accordance with staff's recommendation.

OAG: Adopts the Post-Hearing Brief position of the Office of Public Counsel.

AARP: Adopts the Post-Hearing Brief position of the Office of Public Counsel.

FIPUG: Yes. Agree with Public Counsel.

FRF: Yes.

Staff Analysis:

ANALYSIS

The Company presented information on Account 925, Injuries and Damages, in its MFRs and through discovery which support its projected Injuries and Damages expense. No other party presented testimony on this issue.

CONCLUSION

Staff believes the TECO has justified its Injuries & Damages reserve expense and recommends no adjustment for this issue.

Issue 61: Should an adjustment be made to remove TECO's requested Director's & Officer's Liability Insurance expense?

Recommendation: No. Staff recommends no adjustment for this issue. Directors and Officers (D&O) insurance is a part of doing business for a public-owned company and should be allowed. The requested amount of $1,700,908 is the lowest of the five-year period, 2005 through 2009. (Prestwood)

Position of the Parties

TECO: No. Director' & Officer's Liability ("D&O") Insurance is an ordinary and necessary business expense for a public utility and benefits the ratepayers by covering defense costs and making it possible to recruit and retain talented directors and officers. TECO has properly forecasted D&O Liability Insurance expense and no adjustment is warranted.

OPC: Yes. Director's & Officer's Liability (DOL) insurance expense of $1,605,815 (jurisdictional) should be removed as it provides no ratepayer benefits and protects shareholders from the decisions of its directors and officers whom they hired. Further, ratepayers receive no recovery of proceeds from settlements or decisions and removal of this shareholder benefit is consistent with Commission practice.

OAG: Adopts the Post-Hearing Brief position of the Office of Public Counsel.

AARP: Adopts the Post-Hearing Brief position of the Office of Public Counsel.

FIPUG: Yes. The cost of this insurance should be removed from rates as recommended by Public Counsel witness Schultz. This insurance provides protection to officers and directors provides no benefit to TECO ratepayers. The entire expense, $1,605,815, should be removed.

FRF: Yes. Agree with OPC that this expense is not reasonable or prudent in that it does not provide benefit to TECO's captive customers, but rather only to TECO's shareholders. Agree with OPC that the entire amount of $1,605,815 (jurisdictional) should be removed.

Staff Analysis:

PARTIES' ARGUMENTS

OPC witness Schultz testified that DOL insurance initially protects officers and directors when decisions that they have made are challenged and/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 and/or settlements in director and officer litigation, so ratepayers should not be responsible for the cost of protecting shareholders from their own decisions. (TR 2089-2090) Witness Shultz 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 the Commission 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. (TR 2090)

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. (TR 1487-1488)

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 D&O insurance including investor-owned electric utilities. D&O insurance enables the Company to assemble an effective team of directors and officers to manage and oversee the conduct of the electric business. Furthermore, D&O 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. (TR 1489-1490)

ANALYSIS

Staff agrees 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 D&O insurance including investor-owned electric utilities. Staff also takes note of the fact that that the requested amount of $1,700,908 is the lowest of the 5-year period 2005 through 2009. Staff does not agree with OPC that the ratepayers do not benefit from DOL insurance. Without DOL insurance, it is unrealistic that the company could operate as a large public companies and being served by a large public company helps ratepayers a number of ways including easier access to capital for their provider. Staff also believes that to reach back to the year 2003 for setting rates in today's market would be inappropriate.

CONCLUSION

Staff agrees that DOL insurance has become a necessary part of conducting business for any publicly owned company and it would be difficult for companies to attract and retain competent directors and officers without it. Staff also believes that ratepayers receive benefits from being part of a large public company including among other things, access to capital. Staff therefore recommends no adjustment for this issue.

Issue 62: Should an adjustment be made to reduce meter expense (Account 586) and meter reading expense (Account 902)?

Recommendation: No. No adjustment should be made to reduce Account 586, Meter Expense and Account 902, Meter Reading Expense. (Marsh)

Position of the Parties

TECO: No. TECO has properly forecasted meter expense and meter reading expense and no adjustment is warranted. However, $497,000 of expense should be reclassified from Account 902 – Meter Reading Expense to Account 586 – Meter Expense.

OPC: No position.

OAG: Adopts the Post-Hearing Brief position of the Office of Public Counsel.

AARP: Adopts the Post-Hearing Brief position of the Office of Public Counsel.

FIPUG: No position.

FRF: Yes.

Staff Analysis: No party other than TECO filed testimony or produced record evidence on this issue.

TECO witness Haines stated that TECO initiated an automatic meter reading (AMR) project in 2003, which allows electric meters to be read remotely. (TR 1005-1006) 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. (TR 1006) 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. (EXH 13, p. 162) He stated that "the company has factored in all productivity improvements gained from this initiative into its cost projections." (TR 1006-1007) 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. (TR 1006)

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. (EXH 13, p. 163)

FRF included a position of "Yes" in its brief, indicating that an adjustment should be made to meter expense, but did not include any amount or discussion. (FRF BR at 47-48)

Staff believes 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, staff recommends that no adjustment be made to reduce Account 586, Meter Expense and Account 902, Meter Reading Expense.

Issue 63: What is the appropriate amount and amortization period for TECO's rate case expense for the 2009 projected test year?

Recommendation: Staff recommends that the appropriate amount of rate case expense be set at $1,973,000 with a four year amortization period. Staff also recommends that the amortization period be increased from 3 to 4 years which results in a revised annual amortization of $493,250. This reduces the Company's original jurisdictional projection of $1,051,000 by $557,750 ($557,750 system basis). (Prestwood)

Position of the Parties

TECO: The appropriate amount for rate case expense is $3,037,000 and it should be amortized over a three-year period beginning in 2009. This includes the removal of the forecasted consulting fees for J. M. Cannell of $116,000 since her services for rebuttal testimony were not needed. All other amounts are prudent and appropriate.

OPC: The rate case expense should be reduced to $2.032 million and amortized over five years. Since J.M. Cannell did not provide any service, $116,000 for her services should be removed. The Huron Consulting Services amount should be reduced to the contract amount of $468,000 from the requested $1.31 million. Ms. Abbott's consulting fees are excessive and should be no more than $61,000, a reduction of $164,000 from the requested $225,000.

OAG: Adopts the Post-Hearing Brief position of the Office of Public Counsel.

AARP: Adopts the Post-Hearing Brief position of the Office of Public Counsel.

FIPUG: TECO should be required to provide actual, rather than projected rate case expense so that actual expenditures are used to set rate case expense. Because there is generally a long period of time between rate cases, a longer amortization period is more in keeping with TECO's rate case history. Such amortization period should be five years. In addition, the Commission should reduce rate case expense as recommended by Public Counsel witness Schultz.

FRF: The appropriate amount of rate case expense is $1,905,000, which reflects the effects of removing the costs for J.M. Cannell and Susan Abbott, and the difference between the Huron Consulting contract amount of $468,000 and the $1.31 million requested by TECO. Especially in light of the relative infrequency of TECO's general rate cases, the appropriate amortization period is five years. The appropriate annual rate case expense is $381,000.

Staff Analysis:

PARTIES' ARGUMENTS

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. (TR 1443-1444)

OPC witness Schultz testified that the Company's total projected rate case expense is excessive and the amortization period should be 5 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. (TR 2100) 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, and that contributing to the high cost is the excessive average hourly rate that the Company agreed to pay. (TR 2100)

Witness Schultz identified 2 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. (TR 2102) 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 5 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. (TR 2101-2102)

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. (TR 2240)

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. (TR 2342)

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. (TR 1492)

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. (TR 1492) 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. (TR 1493) Witness Chronister also testified that Huron, which has the highest charge of all the consultants, shares common directors with TECO Energy, Inc. (TR 1512; MFR Schedule C-10)

TECO provided LF EXH 109, which provided the actual expenses for external witnesses to date by witness through December 31, 2008. LF EXH 109 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.

(LF EXH 109)

ANALYSIS

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

The staff is 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. (TR 556)

Staff recommends that the fee for this witness be reduced to the level estimated for the Company's cost of capital witness Murry. Staff realizes 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. Staff believes it is reasonable to compare her fee to witness Murry's. This proposal 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). (MFR Schedule C-10)

Staff notes that the Company did not take the opportunity to provide more detail on LF EXH 109. Staff does not have any breakdown between Huron and Legal services either for year to date actual or the latest projection. Staff recommends that the expenses for Huron 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. (MFR Schedule C-10)

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. Staff also recommends that the amortization period be increased from 3 to 4 years, which is consistent with several of the Commissions recent rate cases and does not conflict with Company witness Chronister's testimony that he was relatively certain it will be 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.

CONCLUSION

Staff recommends that the appropriate amount of rate case expense be set at $1,973,000 with a 4-year amortization period. Staff also recommends the annual amortization amount of $493,250. This reduces the Company's original jurisdictional projection of $1,051,000 by $557,750 ($557,750 system basis).

Issue 64: Should an adjustment be made to Bad Debt Expense for the 2009 projected test year?

Recommendation: No. Staff recommends no adjustment for bad debt expense. (Prestwood)

Position of the Parties

TECO: No. TECO has properly forecasted Bad Debt Expense based on current and forecasted economic conditions and no adjustment is warranted. The analysis and proposal advanced by OPC is flawed and should be rejected.

OPC: Yes. The $7,971,000 (44%) increase above 2007 levels for the projected test year is unjustified. A 5-year historical average reflects a reasonable estimate of the projected and normal write-offs for the future. The bad debt expense should be reduced by $2,342,000 (jurisdictional) with a corresponding adjustment in the revenue conversion factor for the bad debt factor.

OAG: Adopts the Post-Hearing Brief position of the Office of Public Counsel.

AARP: Adopts the Post-Hearing Brief position of the Office of Public Counsel.

FIPUG: Yes. The Company's bad debt expense should be reduced as recommended by Public Counsel witness Larkin. TECO's increase in bad debt of 44% is unreasonable. A five-year average should be used to project uncollectible expenses.

FRF: Yes. The Company's Bad Debt Expense should be reduced by $2,342,000 per year (jurisdictional) as recommended by OPC's witnesses.

Staff Analysis:

PARTIES' ARGUMENTS

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. (TR 2040)

Witness Larkin recommended taking a 5-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 the Commission 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. (TR 2041) As shown on EXH 50, 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. (TR 1477-1478)

ANALYSIS

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. (TR 1478-1479) According to witness Chronister, OPC's adjustment is backward looking and not indicative of what is occurring during the test year.

CONCLUSION

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

Issue 65: Should an adjustment be made to office supplies and expenses for the 2009 projected test year?

Recommendation: No. Staff recommends no adjustment for Office Supplies and Expense. (Prestwood)

Position of the Parties

TECO: No. TECO has properly forecasted office supplies and expenses and no adjustment is warranted.

OPC: Yes. The Company failed to provide documentation to support its requested 39% increase in the 2009 projected test year over the 2007 historical level of $8.067 million for office supplies. Therefore, office supplies and expense should be reduced by $2.363 million ($2.295 million on a jurisdictional basis) to $8.818 million.

OAG: Adopts the Post-Hearing Brief position of the Office of Public Counsel.

AARP: Adopts the Post-Hearing Brief position of the Office of Public Counsel.

FIPUG: Yes. The Company's request for a 39% increase for office supplies should be rejected and reduced by $2,295,000 as recommended by Public Counsel witness Schultz.

FRF: Yes. The Company's requested amount should be reduced by $2,295,000 on a jurisdictional basis.

Staff Analysis:

PARTIES' ARGUMENTS

OPC Witness Shultz 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 Shultz, 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 Shultz did say that the response to OPC Interrogatory No. 116 provided some added detail, but again the response was quite general. (TR 2103)

Witness Shultz 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 EXH 52, Schedule C-12. On a jurisdictional basis, OPC recommends that the expense be reduced by $2.295 million. Witness Shultz asserts 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. (TR 2103)

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.

ANALYSIS

Staff has reviewed the record evidence, including TECO's responses to the interrogatories from OPC and from staff on Office Supplies and Expense.

CONCLUSION

Staff believes that based on the record evidence, TECO provided support for its projected office supplies expense, therefore, staff recommends no adjustment for Office Supplies and Expense.

Issue 66: Should an adjustment be made to reduce TECO's tree trimming expense for the 2009 projected test year?

Recommendation: Yes. Staff recommends a decrease in tree trimming expenses of $1,314,000 ($1,314,000 system). (Prestwood)

Position of the Parties

TECO: No. TECO has properly forecasted tree trimming expense to reflect current fuel and contract prices and no adjustment is warranted. It is consistent with the Commission's storm hardening requirements for a three-year distribution tree trim cycle. The analysis and proposal advanced by OPC is flawed and should be rejected.

OPC: Yes. Tree trimming should be based on the $7,897 cost rate per mile for trimming 1,530 miles in 2009, resulting in a total cost of $12,084,876 for 2009. This is the number of miles that realistically will be trimmed in 2009 based upon the Company's tree trimming history. This results in is a reduction of $3,988,568 to the Company's requested amount of $16,073,444.

OAG: Adopts the Post-Hearing Brief position of the Office of Public Counsel.

AARP: Adopts the Post-Hearing Brief position of the Office of Public Counsel.

FIPUG: Yes. Tree trimming expense should be reduced by $3,988,568 as recommended by Public Counsel witness Schultz. This reduction accounts for lower fuel costs than the Company has projected and recognizes that the Company came close to a three year tree trimming cycle in 1998-2000 and should have continued at that rate.

FRF: Yes. Agree with OPC and Staff that the Company's requested amount should be reduced by $3,988,568 on a jurisdictional basis.

Staff Analysis:

PARTIES' ARGUMENTS

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 the Commission's 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. (TR 999)

OPC witness Shultz 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 Shultz, the transmission request appears reasonable, but the distribution tree trimming request of $16,073,044 is excessive. Witness Shultz 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 EXH 52, 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. (TR 2093)

Company witness Haines testified that TECO's commitment and this requirement is the result of many workshops and due diligence by this Commission to the benefits of tree trimming as it relates to storm hardening, tree trimming reduces outages and improves restoration following a major storm event. (TR 1033-1034) 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. (TR 1035)

Witness Haines testified that the number of miles trimmed each year by the Company and reported to the Commission reflects the total miles inspected and/or trimmed, which includes some miles that have no vegetation. Therefore, Mr. Shultz'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. Shultz 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. (TR 1037)

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. 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. (TR 1037-1038)

ANALYSIS

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.

TECO is increasing its vegetation management program to establish and maintain a 3-year distribution system trimming cycle in order to comply with the Commission's requirements for storm hardening. However the Company will not reach the full 3 year cycle until 2010. The Company plans to trim 1,775 miles for the 2009 test year. (29 percent of the total 6,121 circuit miles)

Staff calculates 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. (TR 1037) 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.

CONCLUSION

Staff recommends 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.

Issue 67: Should an adjustment be made to reduce TECO's pole inspection expense for the 2009 projected test year?

Recommendation: No. Staff recommends no adjustment for this issue. 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 by the Commission in Order No. PSC-06-0778-PAA-EU issued on September 18, 2006. (Prestwood)

Position of the Parties

TECO: No. TECO has properly forecasted pole inspection expense to reflect current contract rates and no adjustment is warranted. It is consistent with the Commission's storm hardening requirements. The analysis and proposal advanced by OPC is flawed and should be rejected.

OPC: Yes. The Company's request for $1,573,778 should be reduced by $236,013 to $1,337,765. This reflects an eight year inspection cycle of 40,750 per year times the indexed 2007 average cost per pole of $32.83 which represents the most recent annual rate available.

OAG: Adopts the Post-Hearing Brief position of the Office of Public Counsel.

AARP: Adopts the Post-Hearing Brief position of the Office of Public Counsel.

FIPUG: Yes. The Company's request should be reduced by $236,013 as recommended by Public Counsel witness Schultz.

FRF: Yes. The Company's requested amount should be reduced by $236,013 on a jurisdictional basis.

Staff Analysis:

PARTIES' AGRGUMENTS

OPC witness Shultz testified that as shown on EXH 52, 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 the Commission has approved a pole inspection program, the Company has an 8-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. (TR 2094-2095)

Company witness Haines testified that TECO's pole inspection plan was filed and approved by the Commission in Order No. PSC-06-0778-PAA-EU, issued on September 18, 2006, in Docket No. 060531-EU. 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. Shultz 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. Shultz. Finally, the 40,750 poles to be inspected each year include both distribution and transmission poles which have different rates.

ANALYSIS

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. (TR 1038-1039)

CONCLUSION

Staff believes that the record evidence supports 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 by the Commission in Order No. PSC-06-0778-PAA-EU, issued on September 18, 2006. Staff recommends no adjustment for this issue.

Issue 68: Should an adjustment be made to reduce TECO's transmission inspection expense for the 2009 projected test year?

Recommendation: No. Staff recommends no adjustment to reduce TECO's transmission inspection expense. (Prestwood)

Position of the Parties

TECO: No. TECO has properly forecasted transmission inspection expense to reflect current contact rates and no adjustment is warranted. It is consistent with the Commission's storm hardening requirements. The analysis and proposal advanced by OPC is flawed and should be rejected.

OPC: Yes. The Company's request for $642,773 should be reduced by $318,846 ($268,233 on a jurisdictional basis) to $323,927. This reflects indexing the 2007 expense of $302,195.

OAG: Adopts the Post-Hearing Brief position of the Office of Public Counsel.

AARP: Adopts the Post-Hearing Brief position of the Office of Public Counsel.

FIPUG: Yes. The Company's request should be reduced by $318,846 as recommended by Public Counsel witness Schultz. TECO provided no information to support doubling 1007 historic costs.

FRF: Yes. The Company's requested amount should be reduced by $268,233 on a jurisdictional basis.

Staff Analysis:

PARTIES' ARGUMENTS

OPC witness Shultz 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 EXH 52, 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 Shultz determined the recommended expense level of $323,927 by indexing the 2007 expense of $302,195. (TR 2095-2096)

Company witness Haines testified that the Company's transmission structure inspection program was filed and approved by the Commission as part of its Ten Point Storm Hardening Plan.[32]

[32] Order No. PSC-07-1020-FOF-EI[32] 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.

ANALYSIS

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 the Commission's storm hardening rules were first established, all of the identified repairs as a result of the inspections must now be made.

CONCLUSION

Staff believes 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. (TR 1040-1041) Staff, therefore, recommends no adjustment for this issue.

Issue 69: Should an adjustment be made to O&M expenses to normalize the number of outages TECO has included in the 2009 projected test year?

Recommendation: No. Staff recommends that no adjustment should be made in this issue to normalize the number of outages TECO has included in the 2009 projected test year. (Prestwood)

Position of the Parties

TECO: No. TECO has properly forecasted O&M associated with generation outages and no adjustment is warranted. The O&M expense included in the 2009 projected test year reflects a normal level of planned outage expense, forced outage expense, and routine maintenance expense and is not overstated. This issue is redundant to Issue 54. Planned maintenance is a subset of generation maintenance.

OPC: Yes, Tampa Electric has admitted that an atypical level of major outages was included in the 2009 projected test year rather than a normal major outage level. An adjustment of approximately $8,000,000 (7,710,000) should be made to normalize outages as is discussed here and in Issue 54.

OAG: Adopts the Post-Hearing Brief position of the Office of Public Counsel.

AARP: Adopts the Post-Hearing Brief position of the Office of Public Counsel.

FIPUG: Yes. TECO has overstated its planned outages in 2009(particularly at Big Bend) and O & M expense should be adjusted to reflect normal outage levels as described in the testimony of FIPUG witness Pollock. TECO's outage expenses should be reduced by $8 million.

FRF: Yes. See also Issue 54. The Company's generation maintenance expense should be reduced by between $7,710,000 and $8,173,000 per year on a jurisdictional basis.

Staff Analysis:

PARTIES' AGRUMENTS

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). (TR 829-830) Maintenance conducted during planned outages consists of large tasks that are performed infrequently and have a long duration. Typical examples are steam turbine inspections and repairs, replacement of large heat transfer surfaces in the boiler, and refurbishment of large motors and pumps. (TR 830) 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. (TR 830) 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. (TR 831)

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 (or planned) outages. He recommends that test year O&M expenses be adjusted to reflect a more normal level of scheduled outages. He further testified that TECO is projecting the highest number of scheduled outages in 2009 than in any other year since 2003. (TR 2238) TECO's projections are provided in EXH 55.

Witness Pollock testified that the planned outages at Big Bend Station are shown on page 1, while total planned outages are shown on page 2 of EXH 55. On page 1 of that EXH 55, TECO projects 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. (EXH 55, p. 2; TR 2238)

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. Further, the SCR-related outages are non-recurring. (TR 2238) 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. (TR 825)

Witness Pollock testified that TECO did not originally plan for two major Big Bend outages in 2009. EXH 56 shows the planned outages for Big Bend for the period 2007-2013. The document shows that the Company originally planned only one major outage per year at Big Bend through 2013. (TR 2239) Witness Pollock presented EXH 57, that shows the outage costs for the period 2003-2009. He cited 2008 as an example, where a 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. (TR 2239)

Witness Pollock recommends 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. (TR 2239) 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. (TR 2239-2240)

Company witness Hornick testified that Mr. Pollock's analysis does not adjust historical expenses for known escalations. Also, his simple averaging approach focuses only on planned outage expense and ignores 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 used by witness Pollock. (TR 852)

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. EXH 84, RBH-2, shows that 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. (TR 851-852)

ANALYSIS

Staff believes the record evidence demonstrates that the planned outage expense is higher in the test than in either the historical or future periods. Based on the data presented by TECO, the 2009 the planned outages are approximately 5.6 weeks higher (54 - 48.6) 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. (EXH 13, pp. 2564-2662) This indicates a decrease of $1.44 million ($1.5 million system) for the test year.

CONCLUSION

Staff believes that Issue 54, which deals with total Generation Maintenance expenses, is a more comprehensive approach to deal with this issue in this case. Staff recommends that no further adjustment be made relative to this issue, but instead that the adjustment in Issue 54 be approved.

Issue 70: Is the pro forma adjustment related to amortization of CIS costs associated with required rate case modifications appropriate?

Recommendation: Yes. The adjustment for customer information system (CIS) modification associated with rate case modifications and TECO's proposed five-year amortization period are appropriate. (Marsh)

Position of the Parties

TECO: Yes. TECO's pro forma adjustment to amortize CIS modifications is appropriate. TECO appropriately included $2,445,000 in rate base and reduced net operating income by $342,000 to amortize total CIS modification costs over five years. The CIS modifications are necessary to reflect required rate changes from this proceeding, not changes made in the normal course of business, and even routine software upgrade should be capitalized and depreciated.

OPC: No. The Customer Information System changes are changes that are routinely done when rate changes are approved such as the annual fuel proceeding or a normal base rate case. Moreover, the anticipated billing changes may not be approved by the Commission. Therefore, the supposedly extraordinary CIS upgrade should be denied and the related depreciation expense decreased by $558,000.

OAG: Adopts the Post-Hearing Brief position of the Office of Public Counsel.

AARP: Adopts the Post-Hearing Brief position of the Office of Public Counsel.

FIPUG: No. The Customer Information System (CIS) changes that TECO seeks to recover are routine changes done whenever rate changes are approved. Thus, the expense of this extraordinary upgrade and related depreciation expense should be denied.

FRF: No. The Company's proposed CIS upgrade cost of $2,445,000 should be denied and depreciation expense decreased by $558,000.

Staff Analysis: 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. Issue 9 addresses whether the costs to upgrade the CIS system are 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. Staff recommended in Issue 9 that the costs are appropriate.

TECO witness Chronister stated that the costs to upgrade the CIS system should be amortized over five years. (TR 1444)

The intervenors focused on whether to include the upgrade costs in Plant in Service, as discussed in Issue 9. All parties' arguments are discussed there. The amortization period was unrebutted.

FIPUG addressed CIS costs as part of Issue 9. (FIPUG BR at 37) FRF took a position but did not discuss the issue. (FRF BR at 49)

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

Issue 71: Is the pro forma adjustment related to the annualization of five simple cycle combustion turbine units to be placed in service in 2009 appropriate?

Recommendation: No. The Company's proposed jurisdictional O&M, Depreciation & Amortization Expense, and Taxes Other Than Income Taxes should be reduced by $212,000, $1,391,000, and $2,226,000 respectively, for the May units. The Company's proposed jurisdictional O&M, Depreciation & Amortization Expense, and Taxes Other Than Income Taxes should be decreased by $658,000, $4,034,000, and $3,227,000, respectively for the September units. (MFR Schedule C-2) The total jurisdictional O&M, Depreciation & Amortization Expense, and Taxes Other Than Income Taxes should be decreased by $870,000, $5,425,000, and $5,453,000, respectively, for all 5 combustion turbine units. (Prestwood)

Position of the Parties

TECO: Yes. Consistent with past Commission decisions, TECO appropriately included $36,125,000 and $94,562,000 in rate base and reduced NOI by $2,352,000 and $4,864,000, for the May and September units, respectively. The units are not being added to increase revenue or for customer growth, but will serve the demand of customers during peak periods and will improve system reliability.

OPC: No annualization of plant additions should be allowed. Two of the combustion turbines are to be added in May 2009 and three in September 2009, if at all. The Company's request to annualize the five simple cycle turbines should be denied and the respective O&M of $870,000, depreciation of $5,425,000 and tax expenses of $5,453,000 should be removed.

OAG: Adopts the Post-Hearing Brief position of the Office of Public Counsel.

AARP: Adopts the Post-Hearing Brief position of the Office of Public Counsel.

FIPUG: No. It is inappropriate to annualize these plant additions. If the Commission allows this annualization without an adjustment to recognize increased growth in sales, the Company's revenue requirements will be overstated. Rate base should be reduced by $130,687.000 [sic] to reflect the actual in-service date of the CTs.

FRF: No. TECO's proposed annualization is not appropriate because it would require the Company's captive customers to pay an entire year's worth of costs for assets that will be used and useful for only parts of the Company's requested 2009 test year, if at all.

Staff Analysis:

CONCLUSION

As more fully discussed in Issue 5, staff accepts 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. Staff rejects the Company's position for the same reasons.

Staff recommends 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. (MFR Schedule C-2, p. 3) Staff's 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. (MFR Schedule C-2, p. 3)

Staff recommends that TECO's pro forma adjustments for all 5 CTs 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. Staff's total recommended adjustment to Net Operating Income before the impact of income taxes is a decrease of $11,748,000. The impacts to Rate Base of staff's proposed adjustments are discussed in Issue 5.

Issue 72: Is the pro forma adjustment related to the annualization of rail facilities to be placed in service in 2009 appropriate?

Recommendation: No. Staff recommends that Depreciation & Amortization Expense and Taxes Other Than Income Taxes be decreased by $906,000 and $1,039,000, respectively, to remove the pro forma adjustments. (Prestwood)

Position of the Parties

TECO: Yes. TECO's pro forma adjustment to annualize the rail facilities is appropriate and consistent with past Commission decisions. TECO appropriately included $44,754,000 in rate base and reduced net operating income by $1,195,000. The facilities are necessary for testing beginning in 2009 and solid fuel deliveries from CSXT beginning in January 2010.

OPC: No. As discussed in Issue 7, annualizing the rail facility for the entire 2009 test year when it will have been in service for a month or less and substantially funded by contributed capital would be inappropriate. The Company's request should be denied and the respective depreciation expense of $906,000 and tax expenses of $1,039,000 should be removed.

OAG: Adopts the Post-Hearing Brief position of the Office of Public Counsel.

AARP: Adopts the Post-Hearing Brief position of the Office of Public Counsel.

FIPUG: No. Such facilities are not scheduled to come into service until December 2009. Such facilities will be in service less than a month and the Company should not collect for such facilities for the entire year. Operating expenses should be reduced by $906,000 (depreciation) and $1,039,000 (taxes other than income) to remove the annualization.

FRF: No. TECO's proposed annualization is not appropriate because it would require the Company's captive customers to pay an entire year's worth of costs for an asset that will only be in service for one month of the Company's requested 2009 test year.

Staff Analysis:

CONCLUSION

As more fully discussed in Issue 7, staff accepts 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. The impacts to Rate Base of staff's proposed adjustments are discussed in Issue 7.

Issue 73: Should any adjustments be made to the 2009 test year depreciation expense to reflect the depreciation rates approved by the Commission in Docket No. 070284-EI?

Recommendation: No. TECO has reflected the approved rates in its MFRs. No adjustments are necessary. (Marsh)

Position of the Parties

TECO: No. TECO has properly forecasted depreciation and no adjustment is warranted. The 2009 proposed level of depreciation expense reflects the Commission's approved depreciation rates from Docket No. 070284-EI.

OPC: No position.

OAG: Adopts the Post-Hearing Brief position of the Office of Public Counsel.

AARP: Adopts the Post-Hearing Brief position of the Office of Public Counsel.

FIPUG: No position.

FRF: Yes. Although the depreciation rates from Docket No. 070284-EI may not be at issue, the FRF agrees with OPC that depreciation expense should be reduced by the amounts annualized by the Company (and removed altogether for depreciation associated with the 3 September CTs), the CIS upgrade, and the overstatement of the depreciation reserve.

Staff Analysis: TECO witness Chronister testified that the depreciation expense in the filing reflects the rates approved in the Company's 2007 Depreciation Study.[33] (TR 1423) No other witnesses filed testimony or sponsored other record evidence with regard to this specific issue.

FRF stated a position in its brief, but did not discuss the issue further. (FRF BR at 49-50)

Staff reviewed the Company's filing and believes that the record evidence demonstrates that the correct depreciation rates were used. Therefore, staff recommends that TECO has reflected the approved rates in its MFRs. Therefore, no adjustments are necessary.

[33] 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.

Issue 74: What is the appropriate amount of Depreciation Expense for the 2009 projected test year?

Recommendation: The appropriate level of Depreciation and Amortization Expense for the December 2009 projected test year is $187,028,515. (Marsh)

Position of the Parties

TECO: The appropriate amount of Depreciation Expense for the 2009 projected test year is $194,608,000 as shown on MFR Schedule C-1.

OPC: The appropriate amount is subject to the resolution of other issues. Adjustments are necessary to remove depreciation expense associated with the annualization of the CTs of $5,425,000, the rail project of $906,000, the overstated reserve for depreciation of $8,187,000 and the CIS Upgrade of $558,000.

OAG: Adopts the Post-Hearing Brief position of the Office of Public Counsel.

AARP: Adopts the Post-Hearing Brief position of the Office of Public Counsel.

FIPUG: Appropriate depreciation adjustments must be made to reflect the Commission's decision on other issues. For example, adjustments should be made to remove depreciation expense associated with the annualization of the CTs (Issue 5), annualization of the rail project (Issue 6), and the CIS upgrade (Issue 9).

FRF: No position at this time with regards to the specific amount. The appropriate amount of Depreciation Expense must reflect the adjustments recommended by OPC's witnesses in this proceeding.

Staff Analysis: This is a fallout issue. Based on staff's recommended adjustments in Issues 8, 71, and 72, the projected 2009 Depreciation and Amortization Expense of $194,608,000 should be reduced by $7,579,485, to an adjusted amount of $187,028,515. (See Schedule 3)

Issue 75: Should an adjustment be made to Taxes Other Than Income Taxes for the 2009 projected test year?

Recommendation: No. This is a fall out issue. There are no separate adjustments for Taxes Other Than Income Taxes. (Prestwood)

Position of the Parties

TECO: No. TECO has properly forecasted Taxes Other Than Income Taxes and no adjustment is warranted.

OPC: Yes. The appropriate amount is subject to the resolution of other issues. Adjustments are necessary to remove taxes other than income associated with the annualization of the CTs of $5,453,000 and the rail project of $1,039,000.

OAG: Adopts the Post-Hearing Brief position of the Office of Public Counsel.

AARP: Adopts the Post-Hearing Brief position of the Office of Public Counsel.

FIPUG: Yes. Adjustments should be made to reflect the Commission's decisions on the other issues in this case.

FRF: Yes. Agree with OPC that Taxes Other Than Income Taxes must be adjusted to reflect the removal of the Company's proposed annualization of the 5 CTs and the rail facilities, and further reduced to remove all Taxes Other Than Income Taxes associated with the 3 September CTs because the Company cannot confirm that those units will be in service at all during the 2009 test year.

Staff Analysis: This is a fallout issue. No parties recommended a separate adjustment for this issue.

CONCLUSION

This is a fallout issue. No parties recommended a separate adjustment for this issue. Therefore, staff recommends that no adjustment is necessary.

Issue 76: Is it appropriate to make a parent debt adjustment as per Rule 25-14.004, Florida Administrative Code?

Recommendation: Yes. Jurisdictional income tax expense should be decreased by $9,657,000 ($9,623,000 system) to reflect the parent debt adjustment required by Rule 25-14.004, F.A.C. (Kyle)

Position of the Parties

TECO: No. TECO Energy, Inc. only raises debt for the operations of its unregulated affiliates. None of the proceeds of TECO Energy debt have been invested in Tampa Electric. All TECO Energy equity infusions into PGS have been made from internally generated funds or externally-generated equity. A parent debt adjustment is therefore inappropriate.

OPC: Yes. The Company has not met its burden to show that the debt of the parent is not invested in the equity of its subsidiary and thus a parent debt adjustment should be made per Rule 25-14.004, Florida Administrative Code. The proper adjustment should be a decrease to income tax expense of $8,140,774.

OAG: Adopts the Post-Hearing Brief position of the Office of Public Counsel.

AARP: Adopts the Post-Hearing Brief position of the Office of Public Counsel.

FIPUG: Yes. Agree with Public Counsel.

FRF: If the Commission adopts the position explained by the FRF's witness Kevin O'Donnell, then no parent debt adjustment is necessary. If the Commission does not approve Mr. O'Donnell's position, then the Commission should make a parent debt adjustment as advocated by the Public Counsel.

Staff Analysis: 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, staff requested that the Company provide the financial information necessary to make a parent debt adjustment in accordance with Rule 25-14.004, F.A.C. (EXH 13, pp. 29-30) 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

In its response, TECO reiterated its objection to application of the parent debt adjustment in this case, as expressed in the testimony of TECO witness Gillette. (EXH 13, pp. 29-30)

In direct testimony, witness Gillette stated that TECO Energy, the parent company of TECO, has $404 million of long term debt on its books. (TR 207) Witness Gillette also stated that there were circumstances by which the Company could rebut the presumption in Rule 25-14.004(3), F.A.C., that a parent debt adjustment is appropriate. (TR 207) 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 states that the debt was related to TECO Energy's investment in TPS, a former subsidiary which is no longer in existence. (TR 207)

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.

(TR 208)

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. (TR 209-210) Staff has reviewed Order No. PSC-93-0165-FOF-EI, and notes that there is no discussion of the applicability of the parent debt adjustment in the order.[34]

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. (TR 210) He asserted that the bulk of this capital was invested in TPS and other unregulated subsidiaries. (TR 210-211) He also stated that TECO Energy has not raised debt outside this time frame and has, in fact, paid the balance down to its present level. (TR 211)

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 opined 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. (TR 214-216) 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. (TR 214-215) 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. (TR 218)

In its post-hearing brief, OPC states its disagreement with TECO's rationale for not applying the parent debt adjustment. (OPC BR at 68) OPC notes 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 BR at 68) OPC notes 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. (OPC BR at 68) In its statement of position, OPC states that a parent debt adjustment should be made in the amount of $8,140,774. (OPC BR at 67) OPC does not explain how this amount was calculated.

Staff agrees 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." (TR 212) In ruling that a

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[34] 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.

parent debt adjustment was required in a case involving Indiantown Company, Inc., the Commission 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.[35]

Staff believes that 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 deductible by the parent for income tax purposes, the income tax expense of the regulated subsidiary is reduced by the tax effect. Further, staff believes that 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, staff believes that it is appropriate to use the full amount of paid in capital reflected on the books and records of the Company. Witness Gillette criticizes what he characterizes as a change in classification of retained earnings to paid in capital resulting from TECO Energy's dividend policy. (TR 214-215) 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), the Commission 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

[35] 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.

> 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.[36]

Accordingly, staff believes that the parent debt adjustment should be applied in this case, and that the elements of the computation should be based on the projected test year capital structures of TECO Energy and TECO. Staff's calculation of the system income tax expense reduction is as follows:

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).

CONCLUSION

The Company has not effectively rebutted the presumption that a parent debt adjustment should be applied pursuant to Rule 14.004, F.A.C. Further, 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.

[36] 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.

Issue 77: Should an adjustment be made to Income Tax expense for the 2009 projected test year?

Recommendation: Yes. Total Income Tax expense should be increased by $8,562,853 resulting in a total income tax expense of $57,054,853 for the 2009 projected test year. (Kyle, Springer, Slemkewicz)

Position of the Parties

TECO: No. TECO has properly forecasted Income Tax expense and no adjustment is warranted.

OPC: Yes, adjustments are appropriate to reflect the recommended interest synchronization increase of $3,388,000, the decrease of $8,140,774 for the parent debt adjustment, and the $29,522,000 increase related to OPC's other recommended adjustments. The appropriate amount is subject to the resolution of other issues.

OAG: Adopts the Post-Hearing Brief position of the Office of Public Counsel.

AARP: Adopts the Post-Hearing Brief position of the Office of Public Counsel.

FIPUG: Yes. Agree with Public Counsel.

FRF: Yes. Agree with OPC that, while the final amount is subject to the resolution of other issues, the Company's income tax expense should be adjusted by approximately $32,910,000, including an interest synchronization adjustment.

Staff Analysis: This is a fallout issue. Based on staff's recommendations, the requested total income tax expense of $48,492,000 (current, deferred, and ITC) should be increased by $8,562,853 resulting in an adjusted total of $57,054,853 for the 2009 projected test year. (See Schedule 3)

Amount Requested	$48,492,000
Staff Adjustments:	
Issue 76 – Parent Debt	(9,657,000)
Effect of Other Adjustments	16,220,178
Interest Synchronization	1,999,675
Total Staff Adjustments	8,562,853
Staff Adjusted Amount	$57,054,853

Issue 78: Is TECO's projected Net Operating Income in the amount of $182,970,000 for the 2009 projected test year appropriate?

Recommendation: No. The appropriate Net Operating Income for the 2009 projected test year is $216,455,567. (Slemkewicz)

Position of the Parties

TECO: Yes. TECO's projected Net Operating Income of $182,970,000 for the 2009 projected test year is appropriate.

OPC: No. The amount should reflect the adjustments recommended by OPC and is subject to the resolutions of other issues in this proceeding.

OAG: Adopts the Post-Hearing Brief position of the Office of Public Counsel.

AARP: Adopts the Post-Hearing Brief position of the Office of Public Counsel.

FIPUG: No. FIPUG's adjustments and those of other intervenors, discussed in the other issues, should be adopted.

FRF: No. The Company's projected Net Operating Income should be adjusted to reflect all applicable adjustments recommended by OPC's witnesses in this proceeding.

Staff Analysis: This is a fallout issue. Based on staff's recommendations, the appropriate net operating income for the 2009 projected test year is $216,455,567. (See Schedule 3)

REVENUE REQUIREMENTS

Issue 79: What is the appropriate 2009 projected test year net operating income multiplier for TECO?

Recommendation: The appropriate 2009 projected test year net operating income multiplier is 1.63490 using a bad debt rate of .349 percent. (Slemkewicz)

Position of the Parties

TECO: The appropriate net operating income multiplier for the 2009 test year is 1.63490 as shown on MFR Schedule C-44.

OPC: The appropriate net operating income multiplier is 1.633202.

OAG: Adopts the Post-Hearing Brief position of the Office of Public Counsel.

AARP: Adopts the Post-Hearing Brief position of the Office of Public Counsel.

FIPUG: The appropriate multiplier is 1.633202 as recommended by Public Counsel witness Larkin.

FRF: Agree with OPC that the appropriate test year net operating income multiplier is 1.633202.

Staff Analysis: 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. (EXH 50, Schedule C-3) Witness Larkin's resulting NOI multiplier is 1.633202. (EXH 50, Schedule A-1)

As discussed in Issue 64, staff believes that the projected bad debt expense, resulting in a bad debt rate of .349 percent, is reasonable for the 2009 projected test year, and has recommended that no adjustment is necessary. Therefore, staff recommends that 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	STAFF
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%

		TECO	OPC	STAFF
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

Issue 80: Is TECO's requested annual operating revenue increase of $228,167,000 for the 2009 projected test year appropriate?

Recommendation: No. The appropriate annual operating revenue increase for the 2009 projected test year is $76,713,931. (Slemkewicz)

Position of the Parties

TECO: No. TECO's requested annual operating revenue increase of $228,167,000 for the 2009 projected test year should be $226,558,000 based upon changes recognized by TECO described within this brief.

OPC: No. The amount should reflect the adjustments recommended by OPC and is subject to the resolutions of other issues in this proceeding.

OAG: Adopts the Post-Hearing Brief position of the Office of Public Counsel.

AARP: Adopts the Post-Hearing Brief position of the Office of Public Counsel.

FIPUG: No. FIPUG's adjustments and those of other intervenors, discussed in the prior issues, should be adopted.

FRF: No. Considering the fair, just, and reasonable rate of return on equity, capital structure, and expenses for the Company, the Commission should not allow TECO to increase its base rates by any more than $39 million, less the appropriate rate base and expense adjustments to remove the 3 September CTs from the Company's revenue requirements altogether.

Staff Analysis: This is a fallout issue. Based on staff's recommendations, the appropriate annual operating revenue increase for the 2009 projected test year is $76,713,931. The following schedule shows the calculation of the revenue requirements.

Calculation of Revenue Requirements December 31, 2009 Test Year		
	TECO	**STAFF**
Rate Base	$3,656,800,000	$3,346,610,836
Rate of Return	x 8.82%	x 7.87%
Required NOI	$322,530,000	$263,378,273
Adjusted Achieved NOI	(182,970,000)	(216,455,567)
NOI Deficiency	$139,560,000	$46,922,706
Revenue Expansion Factor	x 1.6349	x 1.6349
Total Revenue Increase	$228,167,000	$76,713,931

RATE ISSUES

Issue 81: Did TECO correctly calculate the projected revenues at existing rates? (Stipulated)

Approved Stipulation: Yes, TECO correctly calculated the projected revenues at existing rates.

Issue 82: Is TECO's proposed Jurisdictional Separation Study appropriate? (Stipulated)

Approved Stipulation: Yes, TECO utilized, with minor changes, the same jurisdictional separation methodology approved by the Commission in its 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 FPSC 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.

Issue 83: What is the appropriate retail Cost of Service methodology to be used to allocate base rate and cost recovery costs to rate classes?

Recommendation: The appropriate methodology is 12 Coincident Peak (CP) and 25 percent Average Demand (AD). (Kummer, Draper)

Position of the Parties

TECO: The appropriate methodology is 12 CP and 25 percent AD. It provides an appropriate classification and allocation of production plant to rate classes reflecting how power plants are planned and operated. The use of 25 percent AD rather than the $1/13^{th}$ (or about 8 percent) AD better reflects cost causation.

OPC: No position.

OAG: Adopts the Post-Hearing Brief position of the Office of Public Counsel.

AARP: The 12 Coincident Peak and 25 Percent Average Demand methodology proposed by TECO.

FIPUG: The Commission should continue to use the 12CP and 1/13 AD cost of service methodology that it has used for many years. This method appropriately allocates production investment and properly recognizes that load duration drives a utility's investment decision. TECO's proposed methodology fails to reflect the basic principle of cost causation and allocates substantial costs beyond the break-even point.

FRF: No position.

Staff Analysis:

Background. 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.

The only point of contention on the cost of service methodology deals with the treatment of production demand costs in the cost of service study. Witness Ashburn explains that TECO has not proposed to change the allocation of transmission demand and distribution demand costs. (TR 1639)

TECO filed two cost of service studies in this proceeding. The Commission requires an investor-owned utility 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, is allocated on an average demand, or energy basis. CP is the maximum peak demand of the class which 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 most often relied upon previously by the Commission in rate cases involving Florida's investor-owned electric utilities.

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 12CP 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.

PARTIES' ARUGMENTS

TECO in its brief explains that once the Commission determines 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 the Commission's 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. (TR 1633) Costs removed from assignment to one class via a change in cost methodology must be made up by other classes of customers. (TECO BR at 60)

TECO proposes 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. (TR 1639) 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 states 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. (TR 1640) Witness Ashburn further states 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.[37] (TR 1640) 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. (TR 1641)

AARP supports TECO's proposed cost of service methodology.

FIPUG objects to TECO's proposed cost of service methodology. FIPUG states in its brief that TECO has asked this Commission to approve a cost of service methodology which it has never used, but which, more importantly fails to appropriately assign and allocate cost. (FIPUG BR at 5) Witness Pollock states in his direct testimony that TECO's contention that higher investment or capital costs are 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 is 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. (FIPUG BR at 40)

He notes that TECO is placing undue emphasis on year-round energy, or annual average demand, rather than on peak demand. Witness Pollock believes this emphasis is misplaced because peak demand drives the need to install generation capacity. (TR 2251) He admits that the Commission has recognized that all kWh production is considered in determining what type of capacity is installed. He goes 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 offsets 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. (TR 2259)

Witness Pollock criticizes 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 states that the 12 CP and 25 percent AD is totally contrary to capital substitution. (TR 2261)

ANALYSIS

TECO notes 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. (TECO BR at 61). Staff agrees with TECO.

Witness Ashburn notes 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. (TR 1640) This investment was made not only for fuel savings but also environmental and efficiency considerations as well. (Ashburn deposition, EXH 13, p. 1910) Witness Ashburn, in his rebuttal testimony, states that the example Mr. Pollock uses to support his position (TR 2261)

[37] 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.

is mathematically correct, but it is inconsistent with equitable principles that are generally employed in average cost rate making. It is, witness Ashburn maintains, 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. (TR 1703) Staff believes 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 which benefit all of TECO's customers equally, and staff believes a greater sharing of investment costs associated with these benefits is merited.

FIPUG argues that the Commission has never embraced the 12 CP and 25 percent AD cost of service. The Commission is not bound by any prior decisions in this matter, if it deems 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, the Commission has 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. The Commission 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, the Commission approved, based on a settlement of rate design issues, the 12 CP and 1/13 AD method.[38] (TR 1915) 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 BR at 62) TECO states 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. (TECO BR at 62)

Staff notes that Progress Energy Florida (PEF) in its 2000 rate case[39] filed the MFR required study, and two additional studies: 12 CP and 25 percent AD and 12 CP and 50 percent AD. However, 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.[40] PEF again requested a 12 CP and 25 percent AD cost allocation methodology in its 2005 rate case[41] 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 by the Commission, but simply accepted as part of the stipulations. While past

[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.
[39] 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.
[40] 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.
[41] Docket No. 050078-EI, In re: Petition for a Rate Increase by Progress Energy Florida.

decisions are instructive, the Commission 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. (TR 1703)

Exhibit 30, Document No. 3, which is an attachment to Witness Ashburn's direct testimony, compares the results of the two cost of service methodologies at issue. 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. Thus, it is clear why AARP supports TECO's proposed cost of service, and FIPUG objects.

CONCLUSION

Based on the record, staff believes TECO's proposal for a 12 CP and 25 percent Average Demand allocation is reasonable and should be approved.

Issue 84: Should the investment and expenses related to the Polk Unit 1 gasifier and the environmental costs of the Big Bend Unit scrubber be classified as energy or demand?

Recommendation: The Polk Unit 1 gasifier and the Big Bend scrubber should be classified as energy. (Draper)

Position of the Parties

TECO: The Polk Unit 1 gasifier and the Big Bend scrubber should be classified as energy. It is appropriate since customers benefit from lower energy costs as a result of these investments. The gasifier performs a fuel conversion function that is completely associated with the provision of fuel and not the supply of capacity. The scrubber was previously classified to energy and this treatment remains appropriate.

OPC: No position.

OAG: Adopts the Post-Hearing Brief position of the Office of Public Counsel.

AARP: Energy. Same position advocated by Teco and Staff.

FIPUG: Investment and expenses for the Polk Unit 1 gasifier and the environmental costs of the Big Bend Unit scrubber should be classified as demand. The need for power plants is driven by the need to serve peak demand not by energy requirements or environmental issues. Thus, these items should be classified as demand.

FRF: No position.

Staff Analysis:

PARTIES' ARGUMENTS

Witness Ashburn states 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. (TR 1635) These facilities consist of the gasifier for Polk Unit 1 and the scrubber portion of the environmental equipment for Big Bend Unit 4. (TR 1635) The classification of those two facilities is at issue here.

Witness Ashburn explains that the Polk Unit 1 is an Integrated Gasified Combined Cycle plant which 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. (TR 1636) In its brief, TECO states that coal is injected into the gasifier and is converted into a synthetic gas that is used to operate the power block. (TECO BR at 64) Witness Ashburn notes 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. (TR 1636) In his deposition, witness Ashburn clarifies that the function of the power block, which is a combustion turbine, and the gasifier are different. (EXH 13, p. 1912) 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. (EXH 13, p. 1912) TECO concludes by stating that the gasifier produces fuel, and that fuel and fuel handling equipment have always been allocated and recovered on an energy basis. (TECO BR at 64-64)

Witness Ashburn states that the classification of the Big Bend Unit 4 scrubber as energy-related was approved in TECO's last approved cost of service study.[42] (TR 1636) Witness Ashburn states that this treatment remains appropriate because the main purpose of the scrubber plant investment is related to energy output. (TR 1636) In its brief, TECO states that the scrubber captures unwanted emissions from the plant and does not serve load or help maintain reliability. (TECO BR at 64) 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. (EXH 13, p. 1913) Witness Ashburn rebuts 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. (TR 1700) 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. (TR 1636) Witness Ashburn concludes by stating that customers benefit from lower energy costs as the result of these investments, not primarily because of their contribution to system peak. (TR 1636)

AARP agrees with TECO and supports an energy allocation.

FIPUG rejects TECO's proposed classification of the gasifier and scrubber, and advocates a demand allocation. (FIPUG BR at 43-44) With respect to the gasifier, FIPUG maintains that power plants are built to produce capacity to serve load and maintain reliability. (FIPUG BR at 43) The Polk Unit, including the gasifier, was constructed to meet peak demand and should be classified to demand, not energy. (FIPUG BR at 44)

With respect to the scrubber, FIPUG argues 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. (FIPUG BR at 44) Witness Pollock further argues that in addition to being directly related to production plant, pollution control investments are primarily fixed and do not vary with energy usage. (TR 2268)

ANALYSIS

This issue does not address total dollar amounts, but the classification and allocation, i.e., energy or demand, of two production plant investment costs. Staff agrees 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

[42] 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.

allocation is no longer appropriate and that the Commission 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, it is appropriate to allocate the cost of the gasifier on a energy basis as well.

CONCLUSION

The Polk Unit 1 gasifier and the Big Bend scrubber should be classified as energy.

Issue 85: Is TECO's calculation of unbilled revenues correct? (Stipulated)

Approved Stipulation: Yes, TECO's calculation of unbilled revenues is correct.

Issue 86: What is the appropriate allocation of any change in revenue requirement?

Recommendation: The appropriate allocation of any change, after recognizing any additional revenues realized in other operating revenues, should track, to the extent practical, each class' revenue deficiency as determined from the approved cost of service study (Issues 83 and 84), and move the classes to parity as practicable. 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 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. (Draper)

Position of the Parties

TECO: The appropriate allocation of any change should track, to the extent practical, each determined class' revenue deficiency using TECO's proposed 12 CP and 25 percent AD cost of service study. The appropriate allocation must recognize approved changes in consolidation of classes, treatment of current IS customers and restructuring of lighting rate schedule. Moving the classes close to 100 percent of parity and recognizing unit price change constraints provide a measure of fair recovery of costs.

OPC: No position.

OAG: Adopts the Post-Hearing Brief position of the Office of Public Counsel.

AARP: Through the 12 Coincident Peak and 25 Percent Average Demand methodology as proposed by TECO.

FIPUG: Rates for each class should be set at a level that will recover the cost of serving that class. The appropriate cost of service methodology for accomplishing this is the 12CP- 1/13 AD methodology which this Commission has historically used.

FRF: Any increase or decrease in base rate revenues should be allocated across-the-board in proportion to base rate revenues.

Staff Analysis: This issue addresses the allocation of any revenue increase granted (Issue 80) to the various customer classes, and is therefore largely dependant on the final revenue increase amount. There appears to be no dispute among the parties, other than which cost of service study to use, which is addressed in Issue 83. It has been long-standing Commission 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 (Issues 83 and 84), and move the classes as close to parity as practicable.[43] The appropriate allocation compares present revenue for each class to the class cost of service

[43] 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.

requirement and then distributes the change in revenue requirements to the 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 (Issue 88), treatment of current IS customers (Issue 87), and restructuring of lighting rate schedules (Issue 93).

Issue 87: Should the interruptible rate schedules IS-1, IS-3, IST-1, IST-3, SBI-1 and SBI-3 be eliminated? If so, how should rates for customers currently taking service on interruptible rate schedules be designed, including whether a credit approach is appropriate, and if so, how such an approach should be implemented?

Recommendation: Yes, the interruptible rate schedules IS-1, IS-3, IST-1, IST-3, SBI-1, and SBI-3 should be eliminated and existing customers on these rate schedules should 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) should be designed based on the Commission-approved cost of service with IS customers fully sharing any production demand related costs based on their 12 Coincident Peak (CP) load responsibility. The current GSLM credit has been approved by the Commission in the Energy Conservation Cost Recovery (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. (Draper, Sickel)

Position of the Parties

TECO: Yes. Interruptible rate schedules should be eliminated and existing customers should be transferred to the appropriate GSD rate schedules with cost effective credits for interruptible service provided under the appropriate GSLM-2 and GSLM-3 conservation programs. This rate case is the appropriate time for the Commission to complete this long, gradual conversion of the remaining interruptible rate schedule customers to cost effective rates and remove any remaining subsidy being provided to them by firm service customers.

OPC: No position.

OAG: Adopts the Post-Hearing Brief position of the Office of Public Counsel.

AARP: Adopts the Post-Hearing Brief position of the Office of Public Counsel.

FIPUG: No. Interruptible customers are a distinct class as their usage characteristics demonstrate. If the Commission uses a "credit" approach, the interruptible rate schedules should be designed so that interruptible customers receive a stable credit that does not change between rate cases and which properly values interruptible service. Further, the credit should not be recovered from the interruptible class. When an appropriate calculation is made, the value of the credit is $13.70/Kw.

FRF: These rate schedules should not be eliminated. No position on design of the rates.

Staff Analysis:

PARTIES' ARGUMENTS

TECO's basic position is that interruptible service should be provided as a conservation program, not a base rate discount. (TECO BR at 67) 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. (TR 1665) To support its position, Witness Ashburn states that the Commission has 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. (TR 1665) Witness Ashburn concludes 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. (TR 1666)

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 maintains that those are issues that are determined by the Commission in the conservation proceedings where the GSLM programs are reviewed each year. (TECO BR at 67)

FIPUG maintains that the Commission should not eliminate the interruptible rate schedules, which have been in place for decades. (FIPUG BR at 46) FIPUG further states that interruptible tariffs are a valuable resource to TECO, its customers, and to the state as a whole. (FIPUG BR at 46) Interruptible customers receive an inferior quality of service in comparison to firm customers, who TECO must be prepared to serve at all times. (FIPUG BR at 47) FIPUG concludes that the Commission should retain the current interruptible schedules and reset the interruptible rate to take into account the increasing value of interruptability. (FIPUG BR at 49) However, FIPUG also states in its brief that if the Commission prefers the "credit" approach to interruptible service, it 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. (FIPUG BR at 49)

ANALYSIS

History of IS rates schedules

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. (TR 1709) 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. (TR 1731)

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. The Commission allowed the existing IS-1 customers to remain on the rate for purposes of rate continuity. In the same docket the Commission approved a new IS-3 rate schedule, with 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, the Commission ordered TECO in their next rate case to file a cost of service study which allocates costs to the interruptible classes based on their load characteristics and a study which develops a coincident kw credit based on avoided costs. The Commission approved this provision as a stipulation in the cost of service and rate design issues in the rate case.[44]

In Docket No. 990037-EI, the Commission 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).[45]

Difference between IS and GSLM rate schedules

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 explains 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. (TR 1666) 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. (TR 1666) 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. Customers who take service under the GSLM rate schedules pay all charges associated with the otherwise applicable firm rate schedule.

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[44] See Order No. PSC-93-0165-FOF-EI, issued February 2, 1993.

[45] 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.

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.[46]

Impact of TECO's proposal on current IS customers

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. (TR 1751) In late-filed hearing Exhibit No. 116 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.

Elimination of IS rate schedules

Witness Ashburn states 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. (TR 1666) 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. (TR 1666).

FIPUG in its post hearing brief states that the Commission should not eliminate the interruptible rate schedules. (FIPUG BR at 46) However, FIPUG Witness Pollock performed a revised cost-of-service study which included IS customers as firm load. (TR 2270) Staff therefore believes 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. This is discussed in Issue 88.

Since the Commission 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, staff agrees with TECO that this rate case is the appropriate time to eliminate the 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.

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

Level of CCV credit under GSLM-2 and GSLM-3 rate schedules

As stated above, under the GSLM rate schedules, customers receive a credit against the otherwise applicable firm rate. FIPUG maintains that the current $10.91 CCV is understated for two reasons. First, FIPUG argues, 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 BR at 51) FIPUG did its own evaluation and concludes that the credit should be $13.70 per kw. (FIPUG BR at 51).

Witness Ashburn testified in his rebuttal testimony, the CCV for 2009 was approved by the Commission in the 2008 ECCR proceeding. (TR 1711) Witness Ashburn 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 by the Commission. (TR 1763) Witness Ashburn further states 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. (TR 1712)

Staff agrees with the company that the level of the credit is not an issue in this base rate proceeding. The CCV for 2009 has been approved in the 2008 ECCR proceeding. The Commission 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.

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

Witness Pollock explains that it would be reasonable to set these avoided generation capacity benefits based on the installed cost of the Baytown [sic] and Polk CTs that TECO is proposing to include in this base rate proceeding. (TR 2296) As discussed in Issue 5, the CTs are scheduled to be in service during the test year 2009 and are under construction at present. 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.

Fluctuation in CCV credit

FIPUG states 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. (FIPUG BR at 49) Witness Pollock suggests that if the Commission approves 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. (TR 2293)

FIPUG Witness Pollock states that the CCVs have ranged from $3.71 in 2001 to $7.78 in 2007. (TR 2292) While Witness Ashburn agrees with Witness Pollock that the CCV value is subject to change, Witness Ashburn states that the values have increased in each of the seven years Witness Pollock brackets except for one when there was a minor reduction. (TR 1711) Witness Ashburn notes that this upward trend reflects the increasing cost of generation. (TR 1171) In 2008 the Commission-approved CCV was $7.48.[47] TECO's 2009 approved CCV of $10.91 represents a 46 percent increase over the prior CCV. (TR 1713)

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. (TR 1759) Furthermore, witness Ashburn states 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. (TR 1760) Finally, witness Ashburn states 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. (TR 1762)

Witness Ashburn further notes 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. (TR 1663) 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. (TR 1663) 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.

Staff believes that witness Pollock ignores 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. (TR 2325) 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. (TR 1763) 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.

Application of CCV to load factor adjusted demand

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

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

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 states in his rebuttal testimony that the use of a load factor adjusted credit is an equitable rate design, and Progress Energy Florida has consistently used this design for establishing credits since 1995. (TR 1714) In its brief, TECO states that the CCV is an amount established per kW of demand coincident with the company's monthly system peaks. The full credit value should 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. (TECO BR at 69) Witness Ashburn explains that since the CCV is an amount 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. (TR 1715) The load factor approach utilized in the GSLM rate schedules is a proxy for estimating a customer's load coincident with the system peak. (TR 1715)

FIPUG objects 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. (TR 2300) 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. (FIPUG BR at 53)

Staff believes that there is no basis to change the application of the credit. First, witness Pollock erroneously states that TECO is proposing a load factor adjusted credit. (TR 2299) 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 what 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.

<u>Cost recovery of GSLM credits paid to interruptible customers</u>

Witness Ashburn states that since TECO proposes 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. (TR 1671) 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. (EXH 30, Document No. 4, page 1 of 1) 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 maintains that all customers, including interruptible customers, should share in the cost of providing credits to all load management conservation programs. (TECO BR at 70) Witness Ashburn explains that since 1982, the Commission has consistently recognized the value of demand response programs through the ECCR clause. Other demand response resources include various residential and commercial load management programs. (TR 1709)

Witness Pollock asserts 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. (TR 2271-2272) Witness Pollock therefore proposes to spread the amount of the interruptible credits to the firm classes. (TR 2271)

Currently, all customer classes pay for the costs associated with Commission-approved conservation programs. Staff does not believe it is appropriate to deviate from this long standing Commission 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 to other customer classes, such as residential, would increase.

CONCLUSION

The interruptible rate schedules IS-1, IS-3, IST-1, IST-3, SBI-1 and SBI-3 should be eliminated, and existing customers on these rate schedules should 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) should be designed based on the Commission-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 by the Commission in the Energy Conservation Cost Recovery docket and is not an issue in this docket. The credit will be re-established in the next energy conservation cost recovery proceeding, Docket No. 090002-EG.

Issue 88: Should the GSD, GSLD and IS rate schedules be combined under a single GSD rate schedule?

Recommendation: No. Only the GSD and GSLD rate schedules should be combined into a single GSD rate schedule, while the IS class should be a separate firm rate schedule (with the interruptible credits provided under the GSLM-2 and GSLM-3 conservation programs as discussed in Issue 87). IS base rates and cost recovery clause charges (capacity, environmental, and conservation) should be designed based on the Commission-approved cost of service methodology with IS customers fully sharing any production demand related costs based on their 12 Coincident Peak (CP) load responsibility. (Draper)

Position of the Parties

TECO: Yes. The proposed GSD rate schedule recognizes metering and service voltage differences of all general service demand customers, including those on GSLD and IS. There is no further justification for arbitrarily establishing subsets of these customers on other rate schedules. The combined rate schedule is the appropriate schedule to transfer the IS customers to when that schedule is eliminated, as discussed in Issue 87. It is reasonable and appropriate to combine the rate schedules.

OPC: No position.

OAG: Adopts the Post-Hearing Brief position of the Office of Public Counsel.

AARP: Adopts the Post-Hearing Brief position of the Office of Public Counsel.

FIPUG: No. Customer classes should be homogeneous in their usage patterns and service characteristics. The GS, GSD, GSLD and IS classes are not homogeneous in key characteristics, including size, load factor, coincidence factor and delivery voltage. Therefore, they should not be combined because to do so would put customers with very different characteristics in the same class.

FRF: No position.

Staff Analysis:

PARTIES' ARGUMENTS

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. (TECO BR at 65) Witness Ashburn states 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. (TR 1674) Witness Ashburn states 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. (TR 1647, 1673) Witness Ashburn further states that the customer charge differences becomes 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. (TR 1674) With respect to the IS class, TECO states 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. (TECO BR at 65)

FIPUG objects to the consolidation of the GS, GSD, GSLD, and IS classes. (FIPUG BR at 54) FIPUG Witness Pollock states 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. (TR 2252-2253) Staff notes that TECO is not proposing to consolidate the GS class, as stated in FIPUG's brief.

Load factor measures the degree to which fixed facilities are being utilized and is expressed as the ratio of kilowatt hours to kilowatts. 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. (TR 2253) Witness Pollock gives great importance to 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 supports 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 sub-transmission voltage, whereas virtually no electricity is provided to GSD or GSLD customers at this high voltage level. (TR 2254)

ANALYSIS

Combine GSD and GSLD rate class.

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 the Commission 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.

<u>Arguments for keeping separate IS class</u>.

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 shows that IS customers show a wide dispersion of usage characteristics, and do not form a homogeneous rate class. However, the data support 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. (EXH 86, pp. 1-3) For each class, witness Ashburn prepared three plots. The first shows 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 shows 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 diagram is 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 staff discovery, TECO developed a separate firm IS rate schedule based on the load characteristics of the IS customers. (EXH 13, p. 340) 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 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 staff believes that it is appropriate to retain a separate IS classes, including a separate interruptible standby rate class.

As discussed in Issue 87, the current IS classes are closed to new business. TECO in its brief suggests that if the Commission determines 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 BR at 66) TECO explains 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. (TECO BR at 66) FIPUG does not address whether the IS rate schedule should be opened to new business or remain closed. Staff therefore believes 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 kilowatt hours 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.

CONCLUSION

Only the GSD and GSLD rate schedules should be combined into a single GSD rate schedule, while the IS class should be a separate firm rate schedule (with the interruptible credits provided under the GSLM-2 and GSLM-3 conservation programs as discussed in Issue 87). IS base rates and cost recovery clause charges (capacity, environmental, and conservation) should be designed based on the Commission-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 should remain closed to new business.

Issue 89: Is the change in the breakpoint from 49 kW to 9,000 kWh between the GS and GSD rate schedules appropriate? (Stipulated)

Approved Stipulation: Yes, 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.

Issue 90: What is the appropriate meter level discount to be applied for billing, and to what billing charges should that discount be applied? (Stipulated)

Approved Stipulation: The appropriate meter level discount is 1 percent for customers who take energy metered at primary voltage and 2 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.

Issue 91: Should an inverted base energy rate be approved for the RS rate schedule?

Recommendation: Yes. TECO's inverted base energy rate should be approved because it sends an appropriate conservation-oriented price signal to the company's residential customers. (Stallcup)

Position of the Parties

TECO: Yes. An inverted base energy rate for the RS rate schedule at 1,000 kWh is reasonable and should be approved. The Commission recently approved inverted fuel rates for the RS rate schedule at the same breakpoint and the implementation of inverted base energy rates will provide a further conservation-oriented incentive price signal.

OPC: No position.

OAG: Adopts the Post-Hearing Brief positions of the Office of Public Counsel.

AARP: Yes. Same position as advocated by TECO.

FIPUG: No. This rate is not cost-based.

FRF: No position.

Staff Analysis: TECO proposes to convert 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. (TR 1660-1661) 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." (Ashburn TR 1662)

In the Company's 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. (TECO BR 70-72)

Two parties took a position on TECO's proposed inverted rate design. AARP stated in its brief that TECO's proposed inverted rate design should be approved, although its brief did not specify why AARP supports TECO's proposal. (AARP BR 5) FIPUG stated in its brief that the proposed inverted rate design should not be approved citing four reasons why it believes TECO's proposal is not appropriate. (FIPUG BR 56-57) These reasons will be discussed below. OPC, OAG, and FRF took no position on the issue.

In its brief, FIPUG cited four reasons why TECO's proposed inverted rate design should not be approved. (FIPUG BR 56-57) The first reason is that the actual basis for TECO's request is simply the fact that other utilities have an inverted rate design. The second reason cited in the brief is that TECO's proposal would result in rates that are not cost-based. The third reason is that TECO's inverted rate proposal is actually a "conservation rate" and may lead the Company to come back to the Commission for further rate relief. The fourth reason cited in the brief is that the eight percent increase in customer bills at 1,000 kWh that the company described to its customers (EXH 114) is not representative of a typical customer's bill.

Staff evaluated the reasons cited by FIPUG for denying TECO's proposed inverted rate design and we do not believe that they 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 the Commission's jurisdiction have an inverted rate design. (FIPUG BR 56) Staff believes that 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. Therefore, staff does not believe that this fact is relevant in this determination.

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 notes 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 contends, the resulting inverted rates are no longer cost-based. (FIPUG BR 56) Staff 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 (EXH 118, p. 55 [MFR Schedule E-15c, p. 2 of 38]) while the cost of service for the RS class is $575,347,000. (EXH 30, p. 7) 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, staff does 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 come back to the Commission for further rate relief. (FIPUG BR 56) Staff agrees with FIPUG that an inverted rate is a conservation rate and that customers will likely reduce their energy consumption. However, a conservation rate structure like TECO's proposed inverted rate design is a tool intended to help achieve the Commission's stated policy goal of energy conservation. Therefore, staff does 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 argues 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. (FIPUG BR 57) During the hearing, FIPUG introduced TECO's Open Lines bill stuffer as an exhibit. (EHX 114) The bill stuffer includes the following sentence: With 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. (TR 1786) 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. (TR 1788)

It appears to staff that while FIPUG objects to TECO's Open Line bill stuffer, this is not directly related to the inverted rate at issue. Staff agrees 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. (TECO BR 72) 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. (EXH 31, p. 5) However, staff does not believe 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 impact 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, staff believes that using 1,000 kWh for illustrative purposes is not unreasonable. Staff notes that TECO in its MFR Schedule A-2 shows residential bill impacts for various usage levels. (EXH 118) 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 staff acknowledges 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, staff believes that 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. (TR 1764-1774; 1779-1785; 1789-1798; 1811) 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 approved by the Commission for Florida Power & Light Company and Progress Energy Florida, Inc.. (Ashburn TR 1662) A concern raised during the service hearings is 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. (TR 1767-1768)

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 proposes that the rate in the second block be set $0.01 above the rate in the second block. (Ashburn TR 1662) 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. Therefore, 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. (EXH 115, p. 5) 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 notes 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 (EXH 115, p. 2)

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. (EXH 115, p. 6) TECO notes 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 (EXH 115, p. 2)

Late Filed Hearing Exhibit No 115, page 7, provides 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, staff believes that 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 No 115, page 1, the Company notes 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." Staff believes that this is an 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, staff recommends that the base energy rate inversion point be set at 1,000 kWh.

Based on the foregoing, staff recommends that TECO's proposed inverted rate design, with an inversion point at 1,000 kWh and an increase of $0.01 between the first and second rate block, be approved.

Issue 92: Should the existing RST rate schedule be eliminated and the customers currently taking service under the schedule be transferred to service under the RS or RSVP rate schedule? (Stipulated)

Approved Stipulation: Yes, 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.

Issue 93: Should TECO's proposed single lighting schedule, and associated charges, terms, and conditions be approved?

Recommendation: Yes, staff recommends that TECO's proposed single lighting schedule, and associated charges, terms, and conditions be approved, subject to adjustment based on the Commission's decisions in other issues and reflecting corrected labor costs. (P. Lee)

Position of the Parties

TECO: Yes. TECO's proposed single lighting schedule should be approved. There is no justification for providing the same lighting services under multiple schedules. TECO's proposal to increase the lighting energy rate closer to parity and to adopt the lowest of multiple rates for the same facilities is appropriate.

OPC: No position.

OAG: Adopts the Post-Hearing Brief position of the Office of Public Counsel.

AARP: Adopts the Post-Hearing Brief position of the Office of Public Counsel.

FIPUG: No position.

FRF: No position.

Staff Analysis: This issue addresses TECO's proposal to consolidate its current three lighting service rate schedules (OL-1, OL-3, and SL-20)[48] into a single (LS-1) rate schedule. TECO is the only party filing testimony or taking a position on this issue.

PARTIES' ARGUMENTS

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. (EXH 13, p. 208) 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. (Ashburn TR 1682) Under the Company's proposal, each type of lighting fixture and pole will have one rate regardless of use. TECO witness Ashburn believes such a change will improve efficiency and understanding for customers and Company personnel who market, install, and maintain the lights. (TR 1682) 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. (TR 1681-1682)

[48] The OL rate schedules provide outdoor area lighting service. The SL rate schedule provides street lighting service applicable to governmental entities and civic groups or homeowners associations requiring lighting service for public roadways. The SL rate schedule provides offerings, many of which are the same as provided under the OL schedules. (Ashburn TR 1681; EXH 13, p. 208)

- Fixtures and poles offered under one rate schedule for one purpose are often desired by customers for another purpose. (TR 1681-1682)
- Fixtures and poles originally provided under one rate schedule change use when they are acquired by a subsequent customer. (TR 1681-1682)
- Sometimes the same identical fixture and pole are provided under different rate schedules at different prices. One rate schedule will eliminate any price variation. (TR 1618, 1681-1682; EXH 13, p. 208)
- One rate schedule will provide consistency in the terms and conditions under which service is provided. (TR 1681-1682; EXH 13, p. 208)
- A consolidated rate schedule will facilitate more efficient and understandable rates and services. (TR 1650; EXH 13, p. 208)
- 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. (TR 1650; EXH 13, p. 208)

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.[49] 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. (TR 1682-1683; MFR Schedule E-13c, pp. 89-91; MFR Schedule E-14, pp. 216-218)

TECO's proposed monthly facility and maintenance charges are developed in its Lighting Incremental Cost Study, Supplemental MFR Schedule E-13D. (TR 1684) However, where multiple rates are currently offered for the same lighting facilities, TECO proposes that the lowest rate be applied, rather than the cost study developed rate. TECO also proposes 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. (TR 1683; EXH 13, p. 217) TECO explains 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. (EXH 13, pp. 217-218)

TECO also proposes to eliminate or restrict certain lighting facility offerings. Based on queries of its Customer Information System's (CIS) billing records, TECO asserts that there is little customer interest in certain offerings. TECO notes that no customers are currently taking service under the rates of the offerings it proposes to eliminate. Additionally, these offerings have been closed to new business for several years. (EXH 13, pp. 219-220, 868-872)

[49] 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.

Cost Development

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. (EXH 13, pp. 224-225, 230-231, 884-926, 1075, 1077-1079, 1080-1083, 1142) Labor and vehicle costs are developed based on average unit times for each task involved in the installation. The unit times are determined from TECO's work order management system, updated by subject matter experts to reflect current procedures, practices, and equipment changes. (EXH 13, pp. 230-231, 944-946)

TECO developed the maintenance charge for each fixture by deriving costs for each maintenance activity: lamp failure, luminaire parts failure, photocell, and relay. (EXH 118, Supplemental MFR Schedule E-13D, pp. 3-13; EXH 13, pp. 226-227) 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. (EXH 13, p. 228-229; EXH 118, Supplemental MFR Schedule E-13D, pp. 14-21) 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. (EXH 13, pp. 222-235, 242-243, 873-963, 1072-1142; EXH 118, Supplemental MFR Schedule E-13D, pp. 3-21) 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. (EXH 13, pp. 229-231, 652-853, 875-883, 948-954, 1084-1086, 1090-1113) 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[50]	72.00%
Small Tools for TEC Field Labor	2.68%
Supv & Admin Lighting Field – TEC Labor (Maintenance)	48.92%

[50] 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. (EXH 13, pp. 238-240)

Table 93-1: Loading Factors	
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%

Source: EXH 13, pp. 237-239, 874-883; EXH 118, Supplemental MFR Schedule 13-D, Lighting Incremental Cost Study, p. 75.

The A&G/Fringe loading factor,[51] according to TECO, has two components: a 49 percent fringe component and a 23 percent A&G component. (MFR Schedule E-7, pp. 10-12, 14-19; EXH 13, p. 275) The 49 percent fringe component consists of non-productive time, direct benefits, and other payroll costs. (EXH 13, p. 275) 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.

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 costs.	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%

Source: EXH 13, pp. 81, 275, 650, 971-1046

In addition to the A&G/Fringe loading factor, Table 93-1 shows that TECO uses 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

[51] The A&G/Fringe loading factor is also used in the cost support associated with Issues 94, 95, and 98.

employed in lighting activities. The last loading factor used is a material overhead consisting of stores and inventory carrying costs and stock handling costs. (EXH 13, pp. 229, 242-243, 873-883, 1072-1073)

ANALYSIS

The first part of this issue asks 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. (TR 1650, 1681-1682; EXH 13, p. 208) Based on the record evidence and the fact that no party opposes TECO's proposal, staff believes that one consolidated lighting rate schedule is appropriate.

The remaining part of the issue 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 the Commission's decisions in other issues and the customer unit cost is changed, the non-fuel energy charge may change.

TECO proposes that where multiple rates are currently offered for the same lighting facilities, the lowest facility rate be applied. TECO also proposes 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. (TR 1683; EXH 13, p. 217) Staff believes 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 proposes 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. (EXH 13, pp. 219-220, 868-872) Based on the evidence presented, staff believes that 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.

Direct Costs

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. (EXH 13, pp. 230-231, 944-946) The direct costs consist of the material, labor, and vehicle costs associated with each light fixture or pole. (EXH 13, pp. 222-235, 873-963, 1072-1142) 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. (EXH 118, Supplemental MFR Schedule E-13D, p. 74; EXH 13, pp. 230-234) After reviewing the cost study documentation and additional support TECO submitted in response to discovery, staff believes TECO's determination of direct costs is reasonable.

Indirect Costs

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

Source: EXH 118, Supplemental MFR Schedule E-13D, Street Lighting Incremental Cost Study, p. 74; EXH 13, p. 237; EXH 13 pp., 229-231, 652-853, 875-883, 948-954, 1084-1086, 1090-1113.

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. (EXH 13, pp. 239-240) Staff notes that 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. Staff believes this example illustrates the significant impact loading factors have on total costs.

The loading factor that gives staff 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. (EXH 13, p. 276) 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. (EXH 13, p. 276) Staff agrees with TECO that indirect costs are a cost of doing business. However, recognizing that indirect costs can significantly impact the cost study results, staff notes concern with the increasing A&G component; this may warrant further investigation in the future.

Staff notes that through discovery, 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 the Commission-approved cost of service study. (EXH 13, pp. 238-239) Staff also notes that Commission decisions in other issues may impact the street lighting rates and should be reflected in order to finalize the rates. Accordingly, based on the record evidence and noting that no party has taken issue with TECO's loading factors, staff believes that TECO's proposed street lighting charges, terms, and conditions are appropriate, subject to the above qualifications.

CONCLUSION

Staff recommends that TECO's proposed single lighting schedule, and associated charges, terms, and conditions be approved, subject to adjustment based on the Commission's decisions in other issues and reflecting corrected labor costs.

Issue 94: Are the two new convenience service connection options and associated connection charges appropriate?

Recommendation: Yes. The two new service reconnection options, Same Day Reconnect and Saturday Reconnect, and their associated connection charges, $65 and $300, respectively, are appropriate. The new service reconnection options should be recalculated to reflect any applicable decisions in prior issues. (Ollila)

Position of the Parties

TECO: Yes. The two new convenience service connection options and associated connection charges will allow customers to reconnect electric service sooner and are appropriate. These options will offer enhanced customer service to those willing to pay a higher cost.

OPC: No customer service fees should be increased at the current time. At a minimum, the standard fee should not be increased and the new convenience fees should be limited to the proposed convenience fees of $40 and $275, without additional charge of the standard connection fee.

OAG: Adopts the Post-Hearing Brief position of the Office of Public Counsel.

AARP: No. No customer service fees should be increased at the current time. The standard connection fee should not be increased and the proposed convenience fees, if adopted should be limited to the proposed convenience fees of $40 and $275 without being added to the standard connection fee.

FIPUG: No position.

FRF: No position.

Staff Analysis: This issue addresses TECO's proposed additional service reconnection options, Same Day Reconnect and Saturday Reconnect, and their rates. TECO witness Ashburn filed the only testimony on this issue.

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. (TR 1652) These two charges are addressed in Issue 98.

PARTIES' ARGUMENTS

Based on customer requests, TECO proposes two new "convenience" service reconnection options. (EXH 13, p. 79) 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 pm. Saturday Reconnect provides for reconnection on Saturdays between 8 am and 12 noon as long as the special request is made by 12 noon on Friday. (TR 1652)

According to TECO, it has received "a large number" of requests from customers for Same Day or Saturday reconnection. (EXH 13, p. 79). Some of those customers have "offered to pay more if such services were available in order to meet their individual needs or schedule constraints… ." (EXH 13, p. 79) TECO conducted an informal poll in March 2008 using its call center employees to determine interest in expedited reconnection. (EXH 13, p. 281) 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. (EXH 13, p. 281)

TECO used a team of subject matter experts to review the proposed service charges.[52] For each service charge, the team identified each task and the time necessary to complete the task. (EXH 13, p. 288). 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. (EXH 13, pp. 87-89)

TECO's proposed costs for service charges also include indirect costs. TECO includes 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). (EXH 13, p. 650) TECO's second loading factor, Administrative and Overhead loading factor, is 41.33 percent and accounts for Energy Delivery's supervisory and administrative overhead. (EXH 13, p. 286) 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. (EXH 13, p. 292, 1064)

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. (EXH 13, p. 86) For the same reason, TECO does not use the Administrative and Overhead loading factor for

[52] TECO's methodology also applies to the service charges addressed in Issues 95, 98, and 99.

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. (MFR Schedule E-7, p. 4)

OPC's, OAG's, and AARP's Position

Staff notes that no intervenors filed testimony on this issue. In their briefs, OPC and AARP each take a position on this issue; OAG adopts OPC's position. AARP and OPC agree that no service charges should be increased; however, if the Commission approves the two new connection fees, the fees should be limited to $40.00 for Same Day Reconnect and $275.00 for Saturday Reconnect. (AARP BR at 5; OPC BR at 72) These amounts are TECO's proposed charges less TECO's proposed charge for Normal Reconnect Subsequent Subscriber. (AARP BR at 5; OPC BR at 72)

ANALYSIS

The first part of this issue asks whether the two new service options, Same Day Reconnect and Saturday Reconnect, are appropriate. According to TECO, it is proposing these new options in response to requests from customers. (EXH 13, p. 79) Based on the evidence in the record, staff believes that offering these new options will provide customers with additional choices.

The second part of the 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.

Issue 93 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. Staff notes that 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. Staff notes that no intervenors filed testimony or presented other record evidence addressing TECO's loading factors and whether the individual components or the percentages of the factors are appropriate.

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. (EXH 13, p. 276) 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. (EXH 13, p. 276) Based on the record evidence, staff believes TECO's argument on loading factors is reasonable.

Although TECO did not update the 23 percent with the most recent A&G percentage, staff is concerned about the increasing level of A&G expense as it relates to service charges in the future. Staff notes that 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, staff believes TECO's determination of the direct and miscellaneous costs is reasonable.

Proposed Rates

Based on the record evidence, staff believes 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. Staff believes that 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, staff does 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 proposed filed cost support for Same Day Reconnect is $69.48 while its proposed rate is $65. (MFR Schedules E-7, p. 3; E-13b, p. 1) TECO explains that while it rounds 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, . . ." (EXH 13, p. 283) TECO's proposed cost for Saturday Reconnect of $303.56 was rounded down to $300 because $300 is a "more 'round' number." (EXH 13, p. 283) Staff believes TECO's rounding explanations for Same Day Reconnect and Saturday Reconnect are reasonable.

CONCLUSION

OPC and AARP argue that during the current economic climate, customer service charges should not be increased. Staff is sympathetic to the plight of customers who are struggling financially; nevertheless, staff believes that 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.

Staff recommends that the two new service reconnection options, Same Day Reconnect and Saturday Reconnect, and their associated connection charges, $65 and $300, respectively, are appropriate. The new service reconnection options should be recalculated to reflect any applicable decisions in prior issues.

Issue 95: Are TECO's proposed Reconnect after Disconnect charges at the point of metering and at a point distant from the meter appropriate?

Recommendation: Yes, 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 should be recalculated to reflect any applicable decisions in prior issues. (Ollila)

Position of the Parties

TECO: Yes. TECO's proposed Reconnect after Disconnect charges at the point of metering and at a point distant from the meter are appropriate.

OPC: No customer service fees should be increased at the current time. The reconnection fee should remain at $35. The Company should not be allowed to create two separate charges that increase the current rate by $15 (at the meter) and by $105 (at a point distant from the meter), especially when no explanation or justification has been provided.

OAG: Adopts the Post-Hearing Brief position of the Office of Public Counsel.

AARP: No customer service fees should be increased at the current time. Teco should not be allowed to create two separate charges that increase the current rate by $15 (at the meter) and by $105 (at a point distant from the meter), especially since no explanation or justification has been provided.

FIPUG: No position.

FRF: No position.

Staff Analysis: This issue addresses two new proposed reconnection charges 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. TECO witness Ashburn filed the only testimony on this issue.

PARTIES' ARGUMENTS

Whether the reconnection takes place at the meter or on the pole depends on where TECO was able to disconnect the customer. (EXH 13, p. 71) Where possible, TECO disconnects service at the meter; however, when meter access is denied, the disconnect occurs on the pole. (EXH 13, p. 71) 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). (EXH 13, p. 71).

TECO proposes 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. (EXH 13, p. 71) Both reconnection charges include the cost for the initial disconnection. (EXH 13, p. 94)

OPC's, OAG's, and AARP's Position

Staff notes that no intervenors filed testimony on this issue. OPC and AARP each take a position on this issue; OAG adopts OPC's position. OPC's position is 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 BR at 73) OPC argues in its brief 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 BR at 73) OPC asserts that increasing the current charge is "unreasonable" for "those customers already at the end of their means." (OPC BR at 73)

AARP's position is essentially the same as OPC. (AARP BR at 6) In its brief, AARP argues that TECO "has failed to provide supporting cost data" for its proposal. (AARP BR at 6) AARP "urges" the Commission to not increase reconnection charges when "so many are struggling financially." (AARP BR at 6)

ANALYSIS

Although they offered no testimony, OPC and AARP argue in their briefs that TECO did not provide cost support for its proposal. (OPC BR at 73; AARP BR at 6) Staff respectfully disagrees. 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, e.g., see EXH 13, pp. 71, 279-280, 1066-1067. 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. (EXH 13, pp. 280, 1066-1067, 1071) 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. (EXH 13, p. 71; p. 280)

TECO's cost for Reconnect after Disconnect at Meter for Cause includes \$21.05 in direct labor costs, \$23.85 in indirect cost, and \$4.54 in miscellaneous cost, for a total cost of \$49.44 (MFR Schedule E-7, p. 5) TECO rounds the \$49.44 to the nearest \$5 for a proposed charge of \$50. (MFR Schedule E-13b, p. 1) 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. (MFR Schedule E-7, p. 6) TECO rounds the \$139.90 to the nearest \$5 for a proposed charge of \$140. (MFR Schedule E-13b, p. 1)

Neither OPC or AARP provided arguments in their briefs that any component of the charge was unreasonable or unjustified. Staff believes 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 BR at 73) OPC is referring to a sentence in TECO witness Ashburn's testimony that "all existing charges have increased to reflect the increased cost of providing the services." (TR 1654) Staff believes that 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.

CONCLUSION

OPC and AARP argue that during the current economic climate, customer service charges should not be increased. Staff is sympathetic to the plight of customers who are struggling financially; nevertheless, staff believes that 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, staff believes 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, staff believes that TECO's costs for reconnection after disconnect for cause and proposed rates are reasonable.

Staff recommends 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 should be recalculated to reflect any applicable decisions in prior issues.

Issue 96: Is the proposed new meter tampering charge appropriate? (Stipulated)

Approved Stipulation: Yes, the 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.

Issue 97: Is the proposed new $5 minimum late payment charge appropriate?

Recommendation: Yes. Staff recommends that the proposed new $5 minimum late payment charge is appropriate and should be approved. (Higgins)

Position of the Parties

TECO: Yes. TECO's proposed new $5 minimum is the type of assessment the Commission has approved for other utilities in recent years and it is appropriate.

OPC: No customer service fee should be increased in these economic times. The new $5 minimum late payment charge hurts customers and unfairly charges more than they would otherwise pay for balances under $300. The Company should not be allowed to change the returned check tariff language to allow automatic increases if the law changes because it is unnecessary.

OAG: Adopts the Post-Hearing Brief position of the Office of Public Counsel.

AARP: No. The $5 minimum late payment charge, as opposed to the current 1.5% fee on unpaid balances would dramatically increase charges to customers in these difficult economic times.

FIPUG: No position.

FRF: No position.

Staff Analysis:

PARTIES' ARGUMENTS

This issue addresses TECO's proposal of a new $5.00 minimum late payment charge for all bills of $10.00 or more, and under $334.00. TECO witness Ashburn was the only witness to file testimony on this issue. 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. (EXH 118; MFR Schedule E-14, p. 9)

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 proposes 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. (EXH 13, pp. 177-179) If the bill amount is under $10.00, the late payment fee remains 1.5 percent of the balance. (EXH 13, p. 179)

TECO states 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 asserts that the Company is requesting treatment for this charge analogous to the minimum late charges approved for Florida Power & Light Company (FPL), Progress Energy Florida, Inc. (PEF), and Florida Public Utilities

Company (FPUC). (TR 1654) Witness Ashburn cites Order No. PSC-02-1753-TRF-EI, in Docket No. 021127-EI,[53] as precedent, where the Commission approved FPUC's minimum $5.00 late fee policy. (EXH 13, p. 177)

TECO witness Ashburn states 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. (EXH 13, pp. 177-178) In its brief, AARP and OPC both argue that TECO's proposed minimum late payment charge should not be approved. They contend that TECO has not supported this change with any financial data. (AARP BR at 6; OPC BR at 73) Staff notes that neither AARP or OPC filed testimony on this issue, and that OAG adopts the position of OPC.

ANALYSIS

Staff believes the proposed changes to TECO's late payment policy 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. Staff further notes that allowing this change to TECO's late payment policy is consistent with prior commission decisions. While OPC and OAG oppose the changes, neither they nor any other party submitted testimony or other evidence on this issue.

CONCLUSION

Staff recommends that the proposed new $5 minimum late payment charge is appropriate.

[53] Order No. PSC-02-1753-TRF-EI, issued December 12, 2002, in Docket No. 021127-EI, 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.

Issue 98: What are the appropriate service charges (initial connection, normal reconnect subsequent subscriber, field credit visit, return check)?

Recommendation: 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, Florida Statutes, for the Returned Check Charge. The service charges should be recalculated to reflect any applicable decisions in prior issues. (Ollila)

Position of the Parties

TECO: The appropriate service charges are listed below.

Initial Service Connection	$ 75.00
Normal Reconnect Subsequent Subscriber	$ 25.00
Same Day Reconnect	$ 65.00
Saturday Reconnect	$300.00
Reconnect after Disconnect at Meter for Cause	$ 50.00
Reconnect after Disconnect at Pole for Cause	$140.00
Field Credit Visit	$ 20.00
Tampering Charge without Investigation	$ 50.00
Return Check Fee	Per Fl. Statutes
Late Payment Charge	The Greater of 1.5% or $5.00

OPC: No customer service fee should be increased in these economic times. The existing charges should remain unchanged since Tampa Electric has not provided documentation that supports its requested increase in these charges as further discussed in Issues 94, 95, and 97.

OAG: Adopts the Post-Hearing Brief position of the Office of Public Counsel.

AARP: No customer service fees should be increased at the current time.

FIPUG: No position.

FRF: No position.

Staff Analysis: This issue addresses the service charges for the Initial Service Connection, Normal Reconnect Subsequent Subscriber, Field Credit Visit, and Returned Check. The recommendations for the other charges listed in TECO's position statement are in prior issues:

- Issue 94 addresses Same Day Reconnect and Saturday Reconnect;
- Issue 95 addresses Reconnect after Disconnect at Meter for Cause and Reconnect after Disconnect at Pole for Cause;
- Issue 96 addresses Tampering Charge without Investigation; and

- Issue 97 addresses the Late Payment Charge.

PARTIES' ARGUMENTS

Initial Service Connection

The Initial Service Connection charge "only applies to the first customer to establish service at a premise." (EXH 13, p. 72) 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." (EXH 13, p. 72)

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 $109.82. (EXH 13, p. 290) TECO's proposed charge is $75. (MFR Schedule E-13b, p. 1) TECO explains 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]." (EXH 13, p. 80; MFR Schedule E-13b, p. 1) TECO "also took into consideration 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." (EXH 13, pp. 80, 1888)

Normal Reconnect Subsequent Subscriber

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). (MFR Schedule E-14, p. 8). The current rate is $16, with a proposed increase to $25. (MFR Schedule E-13b, p. 1) According to TECO, Normal Reconnect Subsequent Subscriber provides for reconnection on the next business day. (TR 1652)

Field Credit Visit

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. (MFR Schedule E-14, p. 8) The current rate is $8, with a proposed increase to $20. (MFR Schedule E-13b, p. 1)

Returned Check Charge

This charge is applied when a check is not honored by the bank. (MFR Schedule E-14, p. 9) Currently, the tariff provides the specific charges based on Section 68.065, F.S., but does not reference the statute. (MFR Schedule E-14, p. 7) 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. (MFR Schedule E-14, p. 9) 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. (MFR Schedule E-14, p. 7). 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's, OAG's, and AARP's Position

Staff notes that no intervenors filed testimony on this issue. OPC and AARP take essentially the same position; OAG adopts OPC's position. OPC's position is that customer service charges should not be increased and that TECO has not provided support for its proposed increases as discussed in OPC's brief for Issues 94, 95, and 97. (OPC BR at 74) AARP makes the same argument about lack of cost support in its discussion of this issue in its brief. (AARP BR at 7).

OPC addresses its position on the Returned Check Charge in Issue 97, where it avers 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." (OPC BR at 73) In its discussion, OPC argues that "the Company has not shown why they [sic] should be allowed to automatically increase a return check fee if the statute is amended." (OPC BR at 74) OPC goes on to argue in its brief that 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 BR at 74)

OPC and AARP also argue that in the current economy, customers are struggling. (OPC BR at 75; AARP BR at 7) OPC argues that increasing service charges for "those customers already at the end of their means is unjustifiable." (OPC BR at 75) AARP "urges" the Commission not to increase customer service charges "which would necessarily make it more difficult than ever for many to afford service." (AARP BR at 7)

ANALYSIS

As with Issue 95 (Reconnect after Disconnect At Meter for Cause and Reconnect after Cut on Pole Disconnect for Cause), OPC and AARP argue in their briefs that TECO did not provide cost support for its proposed rates. (OPC BR at 75; AARP BR at 7). Staff notes that OPC's position states that it discussed TECO's lack of documentation in Issue 94; however, in that issue OPC only addressed reasons why the Normal Reconnect Subsequent Subscriber charge should not increase. Staff respectfully disagrees with OPC's 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, e.g., see EXH 13, pp. 72, 650, 1056-1063, 1068. 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. (EXH 13, pp. 1056-1063, 1068)

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. (MFR Schedules E-7, p. 1, E-13b, p. 1)

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. (EXH 13, p. 290) Staff believes 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. (MFR Schedule E-7, p. 2.) TECO rounds its cost of $23.79 to the nearest $5 or $25. (MFR Schedule E-13b, p. 1) Staff believes 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. (MFR Schedule E-7, p. 7) TECO rounds its cost of $20.79 to the nearest $5 or $20. (MFR Schedule E-13b, p. 1) Staff believes 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. Staff believes that with a statutory maximum, the statute controls, thus eliminating any need for a rate case. Staff believes it is reasonable to key the Returned Check Fee to the governing statute, eliminating the need to change the tariff page when and if the statutory language changes.

CONCLUSION

OPC and AARP argue that during the current economic climate, customer service charges should not be increased. Staff is sympathetic to the plight of customers struggling financially; nevertheless, staff believes that 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, staff believes that the costs and proposed rates for the Initial Service Connection, Normal Reconnect Subsequent Subscriber, and Field Credit Visit are reasonable. Staff also believes that referring to Section 68.065, F.S., for the returned check charges is appropriate.

Staff recommends 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, Florida Statutes for the Returned Check Charge. The service charges should be recalculated to reflect any applicable decisions in prior issues.

Issue 99: What is the appropriate temporary service charge?

Recommendation: The appropriate Temporary Service charge is $235. The Temporary Service charge should be recalculated to reflect any applicable decisions in prior issues. (Ollila)

Position of the Parties

TECO: The appropriate temporary service charge is $235.

OPC: No position.

OAG: Adopts the Post-Hearing Brief position of the Office of Public Counsel.

AARP: Adopts the Post-Hearing Brief position of the Office of Public Counsel.

FIPUG: No position.

FRF: No position.

Staff Analysis: This issue addresses TECO's proposal for temporary service. Temporary service includes, but is not limited to, service provided to construction sites and trailers, Christmas tree lots, pumpkin patches, firework stands, and fairs. (EXH 13, p. 78) TECO witness Ashburn filed the only testimony on this issue.

PARTIES' ARGUMENTS

TECO proposes an increase in the Temporary Charge from $115 to $235. (MFR Schedule E-13b, p. 1) For Temporary Service, the direct costs total $98.78, indirect costs total $111.95, and the miscellaneous cost is $22.64. TECO rounds the total cost of $233.36 to the nearest $5 or $235. (MFR Schedule E-7, p. 9; Schedule E-13b, p. 1)

ANALYSIS

Staff has reviewed TECO's documentation provided on Temporary Service. Based on the record evidence, staff believes that TECO's cost development is reasonable and that its proposed rate of $235 is appropriate.

CONCLUSION

Staff recommends that the appropriate Temporary Service charge is $235. The Temporary Service charge should be recalculated to reflect any applicable decisions in prior issues.

Issue 100: What are the appropriate customer charges?

Recommendation: Staff recommends that the customer charges proposed by TECO are appropriate. (Higgins)

Position of the Parties

TECO: The proposed GSD voltage level customer charges are cost-based and they appropriately recognize the voltage related cost of service differences to customers in the combined GSD rate schedule. The appropriate customer charges are listed below:

RS Standard	$10.50/bill
RSVP	$10.50/bill
GS Standard	$10.50/bill
GS Standard – Unmetered	$9.00/bill
GS Time-of-Day	$12.00/bill
TS Standard	$10.50/bill
Metered Lighting	$10.50/bill
GSD Standard Secondary	$57.00/bill
GSD Standard Primary	$130.00/bill
GSD Subtransmission	$930.00/bill
GSD Optional Secondary	$57.00/bill
GSD Optional Primary	$130.00/bill
GSD Optional Subtransmission	$930.00
GSD Time-of-Day Secondary	$57.00/bill
GSD Time-of-Day Primary	$130.00/bill
GSD Time-of-Day Subtransmission	$930.00/bill
SBF Standard Secondary	$82.00/bill
SBF Standard Primary	$155.00/bill
SBF Standard Subtransmission	$955.00/bill
SBF Time-of-Day Secondary	$82.00/bill
SBF Time-of-Day Primary	$155.00/bill
SBR Time-of-Day Subtransmission 11	$955.00/bill

OPC: No position.

OAG: Adopts the Post-Hearing Brief position of the Office of Public Counsel.

AARP: Adopts the Post-Hearing Brief position of the Office of Public Counsel.

FIPUG: No position.

FRF: The appropriate customer charges are the existing charges, adjusted proportionally to any increase or decrease in base rate revenues approved by the Commission in this proceeding.

Staff Analysis:

PARTIES' ARGUMENTS

This issue addresses TECO's proposed customer charges associated with its provision of service. Customer charges are flat fees assessed each month, regardless of the amount of energy (kilowatt hours) 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 Progress Energy Florida, Inc. (PEF) and Florida Power & Light Company (FPL). (EXH 13, p. 1886) TECO witness Ashburn states that the decision to benchmark this rate below actual cost seemed a "reasonable rise" at this point. (EXH 13, pp. 1886-1887) 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. (EXH 118; MFR Schedule E-14, Supplement A, pp. 1-4)

ANALYSIS

Staff conducted discovery on how TECO's Residential Service (RS) and General Service (GS) customer charges were determined. Cost support for these charges is contained in TECO's Cost of Service Study, filed as part of its MFRs. Witness Ashburn states 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. (EXH 13, p. 248) However, the Company's proposed rate is $10.50 for both the RS and GS rate groups. (EXH 13, p. 248)

Currently there are two different customer charges under the GSD rate schedule, and one customer charge rate level in the GSLD rate schedule. TECO proposes combining the current GSD, GSLD, and interruptible service (IS) customers into the new GSD rate schedule. (TR 1675) TECO witness Ashburn states that the proposed rates are based on the class' cost of service. (EXH 13, p. 1887) 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. (TR 1675) 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. (TR 1675) Witness Ashburn further states that the proposed customer charges appropriately recognize the cost to provide service at different voltage levels. (TR 1675)

The FRF asserts that the appropriate customer charges are the existing charges, adjusted proportionally to any increase or decrease in base rate revenues approved by the Commission in this proceeding. However, neither the FRF nor any other intervener provided testimony or other record evidence on this issue.

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 staff believes is reasonable. Customer charges for rate groups GSD, GSD Opt., GSDT, SBF, and SBFT were appropriately set at unit cost.

CONCLUSION

Staff recommends that the customer charges proposed by TECO are appropriate.

Issue 101: What are the appropriate demand charges?

Recommendation: This is a fall-out issue and will be decided at the April 7, 2009, Agenda Conference. (Draper)

Position of the Parties

TECO: Demand charges are set in combination with energy charges at levels required after all charges are considered that produce the target revenue requirements for each class. The appropriate demand charges are listed below.

GSD Standard (all delivery voltages)	8.94 $/kW
GSD Optional (all delivery voltages)	N/A
GSD Time-of-Day Billing (all delivery voltages)	3.10 $/kW
GSD Time-of-Day Peak (all delivery voltages)	5.84 $/kW
SBF Standard (all delivery voltages)	8.94 $/kW
SBF Time-of-Day Billing (all delivery voltages)	3.10 $/kW
SBT Time-of-Day peak (all delivery voltages)	5.84 $/kW

OPC: No position.

OAG: Adopts the Post-Hearing Brief position of the Office of Public Counsel.

AARP: Adopts the Post-Hearing Brief position of the Office of Public Counsel.

FIPUG: The appropriate demand charges are set out in Mr. Pollock's Exhibit No. 70 and recover demand – related costs through the demand charge.

FRF: The appropriate demand charges are the existing charges, adjusted proportionally to any increase or decrease in base rate revenues approved by the Commission in this proceeding.

Staff Analysis: This is a fall-out issue and will be decided at the April 7, 2009, Agenda Conference.

Issue 102: What are the appropriate Standby Service charges?

Recommendation: This is a fall-out issue and will be decided at the April 7, 2009 Agenda Conference. The Standby Service charges should be designed in accordance with the Commission's prescribed methodology in Order No. 17159. (Draper)

Position of the Parties

TECO:

SBF Standby Demand Charge (All)	
SBF Local Facilities Reservation plus greater of	2.60 $/kW
SBF Power Supply Reservation	1.42 $/kW-Mo
SBF Power Supply Demand	0.57 $/kW-Day
SBF Standard Time-of-Day (all delivery voltages)	1.060 ¢/kWh

OPC: No position.

OAG: Adopts the Post-Hearing Brief position of the Office of Public Counsel.

AARP: Adopts the Post-Hearing Brief position of the Office of Public Counsel.

FIPUG: No position.

FRF: The appropriate Standby Service charges are the existing charges, adjusted proportionally to any increase or decrease in base rate revenues approved by the Commission in this proceeding.

Staff Analysis: This is a fall-out issue and will be decided at the April 7, 2009 Agenda Conference. The Standby Service charges should be designed in accordance with the Commission's prescribed methodology in Order No. 17159, issued February 6, 1987, in Docket No. 850673-EU, In re: Generic Investigation of Standby Rates for Electric Utilities.

Issue 103: Is TECO's proposed change in the application of the transformer ownership discount appropriate?

Recommendation: Yes. The change provides needed clarification on when the discount applies. (Kummer)

Position of the Parties

TECO: Yes. TECO's proposed change in the application of the transformer ownership discount, by making the discount applicable to all customers who take primary service, is appropriate.

OPC: No position.

OAG: Adopts the Post-Hearing Brief position of the Office of Public Counsel.

AARP: Adopts the Post-Hearing Brief position of the Office of Public Counsel.

FIPUG: No. TECO has understated the credit as it has failed to recognize all of the costs that are avoided when a customer takes subtransmission level service.

FRF: Agree with FIPUG.

Staff Analysis: TECO has proposed to clarify when a transformer ownership credit is appropriate. (TR 1676) 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.[54] 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 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. (TR 2282) 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 states that that a Transformer Ownership Discount will apply to service voltages as proposed in the tariff. (TR 1676) 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.

[54] Cutrale Citrus Juices USA, Inc., v. Tampa Electric Company, PSC Complaint No. 694187E

FIPUG Witness Pollock states that the current Transformation Ownership Discount understates the cost of avoided transformation for IS customers. (TR 2283). However, he does not address the language redefining when a Transformation Ownership Discount is applicable. The level of the discount is discussed in Issue 104.

Staff believes 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 should therefore be approved.

Issue 104: What is the appropriate transformer ownership discount to be applied for billing?

Recommendation: Staff recommends that the appropriate transformer ownership discounts are those calculated by TECO, adjusted to reflect the Commission's decision in Issue 88. (P. Lee)

Position of the Parties

TECO: The appropriate transformer ownership discounts are listed below.

GSD Standard Primary	(0.80) $/kW
GSD Standard Subtransmission	(1.26) $/kW
GSD Optional Primary	(2.09) $MWh
GSD Optional Subtransmission	(3.28) $MWh
GSD Time-of-Day Primary	(0.80) $/kW
GSD Time of Day Subtransmission	(1.26) $/kW
SBF Supplemental Standard Primary	(0.80) $/kW
SBF Supplemental Standard Subtransmission	(1.26) $/kW
SBF Supplemental Time-of-Day Primary	(0.80) $/kW
SBF Supplemental Time-of-Day Subtransmission	(1.26) $/kW
SBF Standby Time-of-Day Primary	(0.65) $/kW
SBF Standby Time-of-Day Subtransmission	(1.29) $/kW

OPC: No position.

OAG: Adopts the Post-Hearing Brief position of the Office of Public Counsel.

AARP: Adopts the Post-Hearing Brief position of the Office of Public Counsel.

FIPUG: TECO has understated the credit as it has failed to recognize all of the costs that are avoided when a customer takes subtransmission level service. The discounts should be modified should be modified [sic] to reflect the totality of all costs avoided by these customers so that they are appropriately compensated.

FRF: Agree with FIPUG.

Staff Analysis: 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. (EXH 13, p. 1879; TR 2282) TECO witness Ashburn and FIPUG witness Pollock presented testimony addressing the appropriate discount rates.

PARTIES' ARGUMENTS

TECO witness Ashburn testified that the proposed transformer ownership discount rates are based on updated costs. (TR 1676) 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. (EXH 13, p. 209)

In the instant case, explained witness Ashburn, 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. (EXH 13, p. 209)

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[55] or maximum demand in calculating the discount rates. (EXH 13, p. 1879) TECO believes 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. (EXH 13, p. 212)

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. The witness believes this is appropriate because TECO avoids having to invest in distribution facilities and it incurs lower losses to serve subtransmission customers. (TR 2283) In his testimony, witness Pollock disagrees with TECO's use of ratcheted demand in calculating the discount rates for standby customers. (TR 2283) Witness Pollock presented his calculations for the discount. (EXH 71) In its brief, FIPUG contends 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. (FIPUG BR at 59)

TECO witness Ashburn rebutted FIPUG witness Pollock's criticism of using ratcheted demand in calculating the transformer ownership discounts. (TR 1691, 1721) 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 asserts that ratcheted demand was not used in these calculations, and therefore the transformer ownership discounts are not understated. (TR 1722) Ratcheted demand was used only for standby customers. Contrary to FIPUG witness Pollock's contentions, TECO witness Ashburn asserts that 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. (TR 1722, 1723)

ANALYSIS

FIPUG contends that TECO's proposed transformer ownership discounts are understated because 1) TECO used ratcheted demand rather than actual demand in its discount calculations for standby customers, and 2) TECO has not reflected in its calculations all facility costs avoided

[55] Ratcheted demand assumes the maximum amount of demand is used each month for the entire period. (EXH 13, pp. 214, 1879-1880)

by subtransmission customers. (TR 2283; FIPUG BR at 59) With respect to the ratcheted demand argument, staff notes that FIPUG witness Pollock submitted errata for his calculated transformer discounts that indicated agreement with TECO's calculations. (TR 2232; EXH 71; MFR Schedule E-14, p. 270) Staff therefore believes the use of ratcheted demand for standby customers is no longer at issue.

Concerning FIPUG's second contention, staff notes that witness Pollock's testimony only appears to address his concerns with the current transformer discount for IS customers. Concern about the proposed discount was addressed only in FIPUG's brief. FIPUG asserts 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. (BR at 59) 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 BR at 59)

FIPUG's arguments appear to depend on the IS class remaining as it is currently structured. TECO proposes 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, as shown in witness Pollock's Exhibit JP-17 (EXH 71), 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. Staff believes that TECO has properly recognized all of the costs avoided for customers taking service at subtransmission voltage levels.

If the Commission accepts staff's recommendation on Issue 88 to keep the interruptible class as a separate rate classification, the Transformer Ownership Discount should be adjusted as noted in TECO's response to Staff's Fifteenth Set of Interrogatories, No. 232. TECO suggests that if the IS remains a separate class, the Transformer Ownership Credit, as well as the Power Factor Adjustment and the Emergency Relay Service charges, should be adjusted by a factor of .99 to reflect rates for primary delivery service. (EXH 13, p. 340)

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

CONCLUSION

Staff recommends that the appropriate transformer ownership discounts are those calculated by TECO, adjusted to reflect the Commission's decision in Issue 88.

Issue 105: What are the appropriate emergency relay service charges?

Recommendation: Staff recommends that the appropriate emergency relay service charges are those calculated by TECO, adjusted to reflect the Commission's decision in Issue 88. (P. Lee)

Position of the Parties

TECO: The appropriate emergency relay service charges are listed below.

GS Emergency Relay Charge	0.165 ¢/kWh
GSD Standard (all delivery voltages)	0.65 $/kW
GSD Optional (all delivery voltages)	0.165 $/kWh
GSD Time-of-Day Billing (all delivery voltages)	0.65 $/kW
SBF Supplemental	0.65 $/kW
SBF Standby	0.65 $/kW

OPC: No position.

OAG: Adopts the Post-Hearing Brief position of the Office of Public Counsel.

AARP: Adopts the Post-Hearing Brief position of the Office of Public Counsel.

FIPUG: No position.

FRF: No position at this time.

Staff Analysis: 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.[56] TECO witness Ashburn is the only witness addressing or taking a position regarding the appropriate charges.

TECO proposes 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. (MFR Schedule E-14, pp. 142, 146, 176) TECO also proposes to increase the charge from 0.60¢/kW to 0.65¢/kW for customers taking service under 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. (MFR Schedule E-14, pp. 146, 179, 199, and 203)

[56] 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.

PARTIES' ARGUMENTS

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. (TR 1676; EXH 13, p. 213) TECO explains 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. (EXH 13, p. 211)

Cost Development

TECO states 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. (EXH 13, p. 211) TECO explains 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. (EXH 13, p. 216) 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. (EXH 13, p. 212)

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. (EXH 13, p. 211)

TECO states 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, asserts TECO, a straight percentage of embedded pole and conduit costs added to the equation may not result in more accuracy. TECO asserts that the level of detail required to accurately obtain the information required for the method previously used is burdensome and difficult to derive. A simplified approach, TECO believes, to calculating the trunk line percent is reasonable and should be accepted. (EXH 13, pp. 211-212)

ANALYSIS

Upon review of the record evidence, including responses to discovery, staff believes TECO's emergency relay service charges are reasonable. Staff has reviewed TECO's approach to calculating the trunk line percent and agrees that the current method is more simplified than the method previously used. Staff also believes 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.

If the Commission accepts staff's recommendation on Issue 88 to keep the interruptible class as a separate rate classification, the Transformer Ownership Discount should be adjusted as noted in TECO's response to Staff's Fifteenth Set of Interrogatories, No. 232. TECO suggests that if the IS remains a separate class, the Transformer Ownership Credit, as well as the Power Factor Adjustment and the Emergency Relay Service charges, should be adjusted by a factor of .99 to reflect rates for primary delivery service. (EXH 13, p. 340)

CONCLUSION

Staff recommends that the appropriate emergency relay service charges are those calculated by TECO, adjusted to reflect the Commission's decision in Issue 88 are appropriate.

Issue 106: What are the appropriate contributions in aid for time of use rate customers opting to make a lump sum payment for a time-of-use meter in lieu of a higher time-of-use customer charge? (Stipulated)

Approved Stipulation: The appropriate contributions in aid for time of use rate customers opting 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.

Issue 107: What are the appropriate energy charges?

Recommendation: This is a fall-out issue and will be decided at the April 7, 2009 Agenda Conference. (Draper)

Position of the Parties

TECO: The appropriate energy charges are listed below.

RS Standard First 1,000 kWh	5.079 ¢/kWh
RS Standard All Additional kWh	6.079 ¢/kWh
RSVP All Periods	5.429 ¢/kWh
GS Standard	5.429 ¢/kWh
GS Time-of-Day On-Peak	14.873 ¢/kWh
GS Time-of-Day Off-Peak	1.060 ¢/kWh
TS Standard	5.429 ¢/kWh
Lighting	2.993 ¢/kWh
GSD Standard	1.693 ¢/kWh
GSD Optional	6.515 ¢/kWh
GSD Time-of-Day On-Peak	3.243 ¢/kWh
GSD Time-of-Day Off-Peak	1.060 ¢/kWh
SBF Supplemental Energy Standard	1.693 ¢/kWh
SBF Supplemental Energy Time-of-Day, On-Peak	3.243 ¢/kWh
SBF Supplemental Energy Time-of-Day, Off-Peak	1.060 ¢/kWh

OPC: No position.

OAG: Adopts the Post-Hearing Brief position of the Office of Public Counsel.

AARP: Same numerical relationship as proposed by Teco but actual numbers based on revenues approved, so a fall-out issue as stated by Staff.

FIPUG: the appropriate non-fuel energy charges are set out in Mr. Pollock's Exhibit No. 70.

FRF: The appropriate energy charges are the existing charges, adjusted proportionally to any increase or decrease in base rate revenues approved by the Commission in this proceeding.

Staff Analysis: This is a fall-out issue and will be decided at the April 7, 2009, Agenda Conference.

Issue 108: What changes in allocation and rate design should be made to TECO's rates established in Docket Nos. 080001-EI, 080002-EG, and 080007-EI to recognize the decisions in various cost of service rate design issues in this docket? (Stipulated)

Approved Stipulation: 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.

Issue 109: What are the appropriate monthly rental factors and termination factors to be approved for the Facilities Rental Agreement, Appendix A?

Recommendation: The appropriate monthly rental factors and termination factors for the Facilities Rental Agreement are those proposed by TECO, subject to recalculation based on the Commission's decisions in prior issues. (P. Lee)

Position of the Parties

TECO: The tariff includes a Facilities Rental Agreement with monthly rental factors and annual termination factors applicable to facilities TECO may agree to lease to customers. The appropriate monthly rental factors and termination factors to be approved are listed below.

Monthly Rental Factor	1.25%
Termination Factors:	
Year 1	4.1%
Year 2	7.9%
Year 3	11.4%
Year 4	14.5%
Year 5	17.3%
Year 6	19.7%
Year 7	21.8%
Year 8	23.4%
Year 9	24.7%
Year 10	25.5%
Year 11	25.8%
Year 12	25.7%
Year 13	25.0%
Year 14	23.7%
Year 15	21.7%
Year 16	19.0%
Year 17	15.6%
Year 18	11.3%
Year 19	6.1%
Year 20	0.0%

OPC: No position.

OAG: Adopts the Post-Hearing Brief position of the Office of Public Counsel.

AARP: Adopts the Post-Hearing Brief position of the Office of Public Counsel.

FIPUG: No position.

FRF: No position.

Staff Analysis: This issue addresses TECO's proposed tariff changes to its Facilities Rental Agreement (Agreement), MFR Schedule E-14, bates-stamped page 259. TECO witness Ashburn addressed this issue in his deposition; no other party presented testimony.

PARTIES' ARGUMENTS

Witness Ashburn explains that the subject 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. (EXH 13, p. 1865) The Agreement includes a monthly rental factor and annual termination factors applicable to the long term facilities TECO may agree to lease. (EXH 13, pp. 1684-1685)

TECO proposes to increase 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 proposes termination factors to apply to the in-place value based on the year the Agreement is terminated. MFR Schedule E-14, bates-stamped pages 259, 275-276 shows the cost analysis for the rental factor and termination factors. (EXH 13, p. 1867) The major reason for the change in the monthly rental factor and the termination factors is due to TECO's proposed capital structure. (EXH 13, pp, 1867, 1999-2000) Staff notes that the new rates would apply to new Facilities Rental Agreements. (TR 1685)

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. (EXH 13, pp. 1873-1878, 1999-2000)

ANALYSIS

Staff reviewed the assumptions used in TECO's development of the applicable factors. Staff also reviewed the supporting calculations in MFR Schedule E-14. Staff believes the underlying assumptions are appropriate with the possible exception of the capital structure and cost of equity. Staff recommends that the monthly rental factor and termination factors should be recalculated using the cost of capital and capital structure approved by the Commission in previous issues.

CONCLUSION

Staff recommends that the appropriate monthly rental factors and termination factors for the Facilities Rental Agreement are those proposed by TECO, subject to recalculation based on the Commission's decisions in prior issues.

Issue 110: Is it appropriate to establish a customer specific rate schedule for county (K-12) public schools in this proceeding?

Recommendation: It is not appropriate to apply a non cost-based discount rate to schools. (Kummer)

Position of the Parties

TECO: No. It is not appropriate and it would result in subsidization by all other customers. Furthermore, TECO does not have sufficient load research data necessary to develop such a rate; however, it is likely that for county public schools, a cost-based rate would result in rates higher than current rates.

OPC: No position.

OAG: Adopts the Post-Hearing Brief position of the Office of Public Counsel.

AARP: Adopts the Post-Hearing Brief position of the Office of Public Counsel.

FIPUG: No position.

FRF: No position.

Staff Analysis: Ms. MaryEllen Elia, Superintendent of Hillsborough County Schools, addressed the Commission 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. (October 21, 2009, Service Hearing TR 34-5, TR 34, 36) Ms. Elia suggested two changes which she believed would benefit schools. The first was 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. No party to the docket presented testimony on this issue other than through cross examination of TECO witness Ashburn.

Public witness Elia maintained that schools were different kinds of customers, in that schools had no one to whom it could pass the increase. (TR 10) She noted that an increase in electric rates was especially difficult now with all of the other budget cuts schools are facing. (TR 18) Absent relief, Ms. Elia stated that Hillsborough schools would be faced with further reductions in services to students. (TR 12) 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. (TR 19-20) She also indicated that it was unlikely that the county would increase ad valorem taxes, the primary support for schools, in this economic climate. (TR 16) Ms. 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. (TR 34)

Combining all locations.

During cross examination, witness Ashburn stated that the school system was served under multiple rates currently. (TR 1815) 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 Ms. 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. (TR 1816, 1817) 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. (TR 1818)

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. (TR 1817)

Separate rate schedule.

Ms. 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 appears to move more towards a special rate which would be lower that 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 the Commission adopted the Public Utility Regulatory Policies Act standard on cost based rates in 1980.[57] Customers were no longer 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 Staff Interrogatories, witness Ashburn described at length the information that TECO would need to design an appropriate cost based rate. (TR 1813-4, EXH 13, p. 324) Among the things required is a clear definition of the class, including which schools would be eligible. (TR 1814-5). TECO serves several public school systems, as well as multiple private schools. Once the population was defined, the utility would

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

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.[58] 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 the Commission 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. (TR 1820) 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, Ms. 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.

Summary.

While staff is sympathetic with Ms Elia's position, staff does not recommend shifting costs from one group of customer to another on a non-cost basis, purely to address current economic conditions. As witness Ashburn points 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. (TR 1816-18) 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 would spiral ever higher as the number of customers paying less than cost compensatory rates increases.

Section 366.03, F.S., states: "All 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 a any respect." The Commission is granted broad authority with Chapter 366, F.S., to interpret the term "undue" discrimination. Staff suggests that 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, Staff recommends that the Commission decline to develop a special rate for school systems at this time.

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

Issue 111: What is the appropriate effective date for the rates and charges established in this proceeding? (Stipulated)

Approved Stipulation: The revised rates should become effective for meter readings taken on or after 30 days following the date of the Commission vote approving the rates and charges which, under the current schedule, would mean for meter readings taken on or after May 7, 2009.

OTHER ISSUES

Issue 112: Should TECO's request to establish a Transmission Base Rate Adjustment mechanism be approved?

Recommendation: No. TECO's proposed Transmission Base Rate Adjustment (TBRA) mechanism 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. (Marsh, Sickel)

Position of the Parties

TECO: Yes. The TBRA will facilitate a timelier means to recover costs associated with more efficient regional planning and transmission construction resulting in lower customer costs. With enhanced regulatory mandates and the nature of regional planning, transmission investment can be volatile (making a cost recovery clause appropriate) given third party impacts and FRCC's cost allocation methodology.

OPC: No. Removing transmission costs from base rates will, in effect, reduce the Company's risk to plan and properly build transmission facilities. There is also no benefit to ratepayers to remove these costs from base rates. 60% of the Company's revenues are recovered through clauses; shifting transmission costs to a clause will shift more risk to ratepayers, and add additional administrative costs unnecessarily. Therefore, the Company's request to create this new clause should be denied.

OAG: Adopts the Post-Hearing Brief position of the Office of Public Counsel.

AARP: Adopts the Post-Hearing Brief position of the Office of Public Counsel.

FIPUG: No. TECO already has four separate cost recovery clauses and there is no need to add an additional clause which will enhance TECO's ability to change rates outside of a rate case. Transmission investment does not meet any of the criteria for a recovery clause – it is not material, volatile or beyond TECO's control. Thus, an additional recovery clause is inappropriate and should not be approved.

FRF: No. Transmission-related costs are base rate-type costs that should be incorporated into, and recovered through, base rates. Particularly in light of the long time frame required to plan and construct transmission facilities, these costs should be recovered through base rates after all relevant factors are considered in a base rate proceeding.

Staff Analysis:

PARTIES' ARGUMENTS

Witness Chronister explained that TECO's proposed TBRA mechanism would allow the Company to timely recover its transmission costs for 230 kV and above transmission projects that TECO submits for FRCC review. (TR 1448) He proposed a regulatory treatment similar to the Generation Base Rate Adjustment (GBRA) clause approved by the Commission in Docket Nos. 050045-E1 and 050078-EI.[59] 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 to the Commission 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 continued 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. (TR 1448-1449) Witness Chronister noted that the TBRA would not be automatic, but would be subject to a thorough review by this Commission. (TR 1500)

TECO witness Haines advised that TECO's projected 2009 test year transmission expenditures include $68,101,000 for 230 kV transmission projects. (TR 1020)

TECO alleged that a high degree of uncertainty has developed from recently promulgated procedures to ensure transmission reliability. Witness Haines explained: "NERC reliability standards specify transmission system scenarios to be evaluated and the levels of the system performance to be attained." (TR 990) 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.

(TR 1046-1047)

In a summary statement at the hearing, Witness Haines clarified 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. (TR 1085) In direct testimony, he also described a new cost allocation methodology to be used for regional transmission expansion. (TR 1019)

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

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[59] 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.

> . . . 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.

(EXH 13, p. 2479)

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." (TR 1017) 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." (EXH 13, pp. 2499-2550) 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." (EXH 13, pp. 2551-2559) 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." (TR 1017-1018) He added that the FERC delegated authority to the FRCC to enforce compliance. (TR 1018) 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. (TR 1018-1019) He argued that allocation of the costs will be difficult to predict in the future. (TR 1048-1049) 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. (TR 1049)

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. (TR 992)

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. (TR 1016) He advised 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." (TR 1084-1085)

OPC witness Larkin stated that the FRCC cannot impose construction requirements, but 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 the FPSC. 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. (TR 2005)

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. . . ." (TR 2004) 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. (TR 2004) He concluded "[p]resumably," this is the basis for Tampa Electric's request for an automatic adjustment clause for transmission investment." (TR 2004)

Witness Larkin stated that TECO currently recovers almost 60 percent of its revenue requirements through adjustment clauses. He opined that the addition of another clause will shift additional risk to ratepayers and add additional administrative costs to the Commission staff and the OPC, due to the short timeframe for reviewing and auditing another clause. (TR 2009)

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. (TR 2005) 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. (TR 2006-2007)

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. (TR 2008)

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." (TR 2305) He argued the clauses do not provide a balanced regulatory framework, because it is single-issue ratemaking. (TR 2305) 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." (TR 2305)

Witness Pollack argued that costs subject to recovery through a clause should be "material, volatile, and beyond the utility's control." He opined 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. (TR 2305) 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. (TR 2006) 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. (TR 2306)

FIPUG argued in its brief that TECO must seek a determination of need from this Commission before it can build transmission facilities. (EXH 13, p. 2500; See Section 403.537, F.S.) 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, Florida Statutes) (FIPUG BR at 63)

FIPUG pointed out with regard to the GBRA discussed by TECO witness Chronister (TR 448) that both Docket Nos. 050045-E1 and 050078-EI[60] 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 the Commission 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. (TR 1582-1583). (FIPUG BR at 63)

FIPUG also noted a similar situation in Docket No. 050078-EI, involved PEF's 2005 rate case. FIPUG stated that Order No. PSC-05-0945-S-EI contained a stipulation that froze 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. (FIPUG BR at 63)

FRF stated its position, but did not discuss the issue in its brief. (FRF BR at 55-56)

[60] Ibid.

ANALYSIS

Staff recognizes 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.

Staff believes that 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. In the view of staff, 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.

Staff notes 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. (TR 2005) Staff believes that 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. (TR 1017)

To date, there do not appear to be any measureable impacts of the evolving transmission policies on Florida companies. Staff does not believe this Commission should 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 staff to continue to consider such costs in the context of a rate proceeding. If the Commission determines at a future date that companies are filing rate cases primarily to recoup the cost of transportation projects, the Commission can always consider implementation of a recovery mechanism at that time. Staff also notes that 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, staff agrees with FIPUG witness Pollack that the GBRA was part of a complex settlement. The Commission 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." (TECO BR at 58) However, staff notes that 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 . . ." (TR 2323) Although there is no reason why this Commission 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.

CONCLUSION

Staff recommends that TECO's proposed Transmission Base Rate Adjustment (TBRA) mechanism should be denied. 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.

Issue 113: Should TECO 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 the Commission's finings in this rate case? (Stipulated)

Approved Stipulation: Yes, TECO should 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 the Commission's findings in this rate case.

Issue 114: Should this docket be closed?

Recommendation: The docket should be closed upon the expiration of the time for filing an appeal has run. (Young)

Staff Analysis: The docket should be closed upon the expiration of the time for filing an appeal has run.

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
	Staff 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	(8,000,000)	(8,000,000)
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	(77,000,000)	(77,000,000)
				0			0		0
				0			0		0
				0			0		0
				0			0		0
				0			0		0
—	Total Staff Adjustments	(215,316,000)	5,450,485	(209,865,515)	0	0	(209,865,515)	(100,323,649)	(310,189,164)
28	Fall Out - Staff 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	(130,909,649)	3,346,610,836

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%			

Staff Adjusted	($) Amount	($) Specific Adjustments	($) Pro Rata Adjustments	($) Staff Adjusted	Ratio	Cost Rate	Weighted Cost
Common Equity	1,835,985,000	(169,461,000)	(125,782,375)	1,540,741,625	46.04%	10.75%	4.95%
Long-term Debt	1,397,565,000	17,679,000	(106,816,794)	1,308,427,206	39.10%	6.80%	2.66%
Short-term Debt	8,002,000	(185,000)	(589,995)	7,227,005	0.22%	2.75%	0.01%
Preferred Stock	0	0	0	0	0.00%	0.00%	0.00%
Customer Deposits	103,724,000	18,726,000	0	122,450,000	3.66%	6.07%	0.22%
Deferred Income Taxes	302,744,000	54,656,000	0	357,400,000	10.68%	0.00%	0.00%
Tax Credits - Zero Cost	0	0	0	0	0.00%	0.00%	0.00%
Tax Credits - Weighted Cost	8,780,000	1,585,000	0	10,365,000	0.31%	8.92%	0.03%
Total	3,656,800,000	(77,000,000)	(233,189,164)	3,346,610,836	100.00%		7.87%
Equity Ratio	56.64%			53.94%			

Interest Synchronization	($) Adjustment Amount	Cost Rate	($) Effect on Interest Exp.	Tax Rate	($) Effect on Income Tax
Dollar Amount Change					
Long-term Debt	(89,137,794)	6.80%	(6,061,370)	38.575%	2,338,173
Short-term Debt	(774,995)	4.63%	(35,882)	38.575%	13,842
Customer Deposits	18,726,000	6.07%	1,136,668	38.575%	(438,470)
					1,913,545
Cost Rate Change					
Short-term Debt	8,002,000	-1.88%	(150,438)	38.575%	58,031
Tax Credits - Weighted Cost	8,780,000	-0.83%	(72,840)	38.575%	28,098
					86,129
TOTAL					1,999,675

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
	Staff 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	(16,000,000)	0	0	6,172,000	0	(9,828,000)	9,828,000
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	1,999,675	0	1,999,675	(1,999,675)
	Total Staff Adjustments	0	0	(27,976,935)	(7,579,485)	(6,492,000)	8,562,853	0	(33,485,567)	33,485,567
78	Fall Out - Staff Adjusted NOI	865,359,000	7,614,000	342,957,065	187,028,515	55,783,000	57,054,853	(1,534,000)	648,903,433	216,455,567

SCHEDULE 4

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

Line No.		(%) As Filed	(%) Staff 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	Staff Adjusted
1.	Rate Base	$3,656,800,000	$3,346,610,836
2.	Overall Rate of Return	8.82%	7.87%
3.	Required Net Operating Income (1)x(2)	322,530,000	263,378,273
4.	Achieved Net Operating Income	182,970,000	216,455,567
5.	Net Operating Income Deficiency (3)-(4)	139,560,000	46,922,706
6.	Net Operating Income Multiplier	1.63490	1.63490
7.	Operating Revenue Increase (5)x(6)	$228,167,000	$76,713,931