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February 17, 2009

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Ms. Ann Cole, Director
Office of Commission Clerk
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, FL 32399-0850

Re: Petition for Rate Increase by Tampa Electric Company
FPSC Docket No. 080317-EI

Dear Ms. Cole:

Enclosed for filing in the above docket are the original and twenty (20) copies of Tampa Electric Company's Brief and Post-Hearing Statement of Issues and Positions.

Also enclosed is a CD containing the above document generated on a Windows 98 operating system and using Word 2000 as the word processing software.

Please acknowledge receipt and filing of the above by stamping the duplicate copy of this letter and returning same to this writer.

Thank you for your assistance in connection with this matter.

Sincerely,

Lee L. Willis

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Enclosures

cc: All Parties of Record (w/enc.)

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BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 080317-EI

IN RE: TAMPA ELECTRIC COMPANY'S
PETITION FOR AN INCREASE IN BASE RATES
AND MISCELLANEOUS SERVICE CHARGES

TECO
TAMPA ELECTRIC

BRIEF AND POST-HEARING
STATEMENT OF ISSUES AND POSITIONS

FILED: FEBRUARY 17, 2009

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TAMPA ELECTRIC COMPANY'S
BRIEF AND POST-HEARING
STATEMENT OF ISSUES AND POSITIONS

Tampa Electric Company ("Tampa Electric" or "the company"), pursuant to the Commission's Order Establishing Procedure[1] issued August 26, 2008, as modified by the Prehearing Order[2] issued January 16, 2009, submits this its Brief and Post-Hearing Statement of Issues and Positions:

BRIEF

SUMMARY OF TAMPA ELECTRIC'S POSITION

The Exhaustive Nature of this Proceeding

This case has involved perhaps one of the most extensive vetting of facts in the history of Florida Public Service Commission rate proceedings. On August 11, 2008, Tampa Electric filed extensive testimony and exhibits of 14 witnesses, along with supporting Minimum Filing Requirements ("MFRs"). Subsequently, the Commission's Staff conducted a lengthy and thorough audit of Tampa Electric's books and records. Furthermore, the Commission's Staff, Office of Public Counsel ("OPC"), the Office of the Attorney General ("OAG"), the Florida Industrial Power Users Group ("FIPUG"), the Florida Retail Federation ("FRF"), and AARP have aggressively reviewed the filing through extensive and protracted discovery.

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[1] Order No. PSC-08-0557-PHO-EI
[2] Order No. PSC-09-0033-PHO-EI

This discovery process included some 460 interrogatories and 276 requests for production of documents, along with nine depositions. During the course of this proceeding, Tampa Electric produced in excess of 650,000 pages of documents. The company's preparation of its filing and defense of its case, including extensive discovery responses, demanded the concentrated efforts of several hundred Tampa Electric employees for over a year.

The exhaustive record developed in this case demonstrates that Tampa Electric has a compelling need for significant rate relief if it is to continue providing its customers with safe, reliable and reasonably priced electric service. While the various parties to this proceeding have suggested adjustments to Tampa Electric's $228.2 million rate request, it is clear that a substantial base rate increase is essential, given the challenges Tampa Electric faces, including the substantial capital investments the company must make.

Rate Relief Requested

Tampa Electric is requesting approval by the Commission of an increase of $228.2 million in the company's retail base rates and miscellaneous service charges effective on and after May 7, 2009, based on a 2009 projected test year. This increase is designed to cover Tampa Electric's cost of service and afford the company an opportunity to earn a compensatory return on its investment, including a fair return on equity of 12.0 percent with a range of 11.0 to 13.0 percent.

Reasons for this Filing

Tampa Electric filed this case after an extensive and careful analysis that unquestionably shows that the company critically needs a significant base rate increase in order to continue to providing reliable service to its customers. Over the last 16 years since the company's last rate case, Tampa Electric continually and successfully sought ways to avoid seeking a base rate increase. The company has now simply exhausted all reasonable alternatives without affecting service quality and without failing to comply with this Commission mandates with respect to, among other things, generating reserve margins, service quality standards and storm hardening activities.

Since the company's last rate case, Tampa Electric's customer base has grown 42 percent and through year-end 2009, the company will have invested $1.7 billon dollars in additional generating facilities, including the company's commitment to a significant environmental plan. The company will also have added $1.5 billion in additional transmission and distribution ("T&D") facilities.

Tampa Electric's O&M Cost Control Achievements

Since its last rate case, Tampa Electric has succeeded in maintaining its total operating and maintenance ("O&M") expenses below the Commission's O&M benchmark, which tracks inflation and customer growth and serves as a tool with which to analyze the reasonableness of the company's spending levels. This is clear evidence of the company's strong focus on controlling O&M expenses.

Despite these efforts, Tampa Electric is now at a point in time where further efficiency and cost reductions cannot be achieved while maintaining adequate service. At year-end 2008, Tampa Electric achieved a return on equity of 8.68 percent, well below the bottom of its allowed range. Without rate relief, Tampa Electric projects that its return on equity will drop to 4.38 percent in 2009. (Tr. 423, lines 18 – 25). These results are seriously below what any party has contended is a fair and reasonable return on equity for Tampa Electric and it is obvious that a substantial rate increase is necessary.

Return on Equity

One of the central issues in this case is the appropriate authorized return on common equity. A range of recommendations has been presented for the Commission's consideration. Tampa Electric presented evidence that a fair and reasonable rate for return on equity is 12.0 percent. Testimony of the company's witnesses also explained the appropriateness of an equity ratio of 55.3 percent and the significant bearing that the company's capital structure will have on Tampa Electric's financial integrity. The record is replete with evidence that current market conditions have restricted the availability of capital and have increased the cost of capital to electric utilities.

Tampa Electric's need for a 12.0 percent return on equity fully factors in the company's lower business risks as a regulated utility, as compared to companies in more competitive industries, such as Publix Supermarkets (20 percent) and Mosaic (54 percent).

Financial Integrity

Another central focus of Tampa Electric's case is the importance of the company maintaining and improving its financial integrity in the face of the enormous capital requirements that are driven by Tampa Electric's construction program. Financial integrity is critically important to maintain unrestricted access to capital markets at a reasonable cost, particularly in light of their recent and on-going volatility and constriction.

A reasonable return on equity and an appropriate capital structure are critical to maintaining financial integrity. The record before the Commission demonstrates that the return on equity and capital structure advocated by intervenors will not meet that objective.

Accounting Treatment of CTs and Rail Unloading Facilities

Tampa Electric included in its test year, rate base and operating expenses for five 60 MW aero-derivative combustion turbine ("CT") generating units to be placed in service in May and September of 2009. The purpose of these units is to provide additional reserves and critically needed operating flexibility. The CTs will also result in lower fuel costs to customers.

Also included in its test year is a new rail solid fuel unloading facility that will begin receiving coal and petroleum coke at Big Bend Station in December 2009. This facility is being added as result of a prior Commission order and will result in lower fuel costs to Tampa Electric's customers.

Intervenors have suggested that the CTs and rail unloading facilities will not be in service on January 1, 2009 and, therefore, should be completely ignored for ratemaking purposes. This would be entirely shortsighted. Two of the five CTs will be in service in May 2009, coincident when new rates go into effect, and the other CTs and rail facility will provide customers benefits in the test year and beyond.

Failure to consider Tampa Electric's investments and the related expenses in this case will cause an immediate and severe drop in the company's earned return during 2009, essentially resulting in a need for further base rate relief in 2010. Such a severe and costly consequence should be avoided by recognizing these assets in a meaningful way in this proceeding.

Storm Damage Accrual

Notwithstanding intervenors' opposition, the Commission should approve Tampa Electric's proposed annual storm damage accrual increase to $20 million per year and the company's target reserve level of $120 million. The current accrual of $4 million and target level of $55 million in reserves was established in the early 1990's when insurance for T&D facilities was no longer available to electric utilities in this state. The value of Tampa Electric's assets is now approximately three times greater than it was when the current accrual amount was last set.

A simple updating of the valuation using the same rationale the Commission applied in adopting a $4 million accrual makes a $12 million annual accrual necessary now. The increased frequency and severity of storms Tampa Electric now faces accounts for the balance of the proposed $20 million annual accrual. Tampa Electric believes it is a better policy to collect an amount each year, just as the Commission ordered utilities to do since 1994, rather than charging customers a post-hurricane storm surcharge at a time when they would be personally impacted by other storm related costs.

Intervenor-Proposed Adjustments to Various Expenses

During the course of the hearing, intervenors presented a variety of proposed adjustments to rate base and operating expenses. Many of these recommended adjustments are fundamentally flawed with erroneous calculations and conclusions as explained in Tampa Electric's rebuttal case. Many of these proposed adjustments are also shortsighted and do not consider overall revenue requirements. If made, these adjustments will produce an immediate shortfall in actual earned return, further harming Tampa Electric's ability to serve its customers' needs.

Conclusion

Tampa Electric and each of its employees are acutely aware of the current economic turmoil. Tampa Electric has demonstrated a concerted effort to avoid seeking rate relief over the past 16 years. However, the company's duty as a public utility to meet its customers' needs, expectations and statutory right to receive safe, reliable, and cost effective electric service, makes this request essential. Tampa Electric urges the Commission to recognize that the company's proposed rates are necessary to enable it to continue meeting its commitment and obligation to serve its customers with the quality electric service they deserve and expect.

In the balance of this brief, Tampa Electric will address key issues raised and considered during the course of the hearing which merit special commentary beyond the limited presentations set forth in the company's Post-Hearing Statement of Issues and Positions.

I. THE APPROPRIATE RETURN ON COMMON EQUITY CAPITAL FOR TAMPA ELECTRIC IS 12.0 PERCENT. (Issue 37)

An allowed return on common equity capital of 12.0 percent is appropriate for Tampa Electric. This return was supported by the expert testimony of Dr. Donald Murry. Dr. Murry's recommended 12.0 percent return on equity is clearly in line with the Commission's May 2008 11.0 percent return on equity decision for Florida Public Utilities Company ("FPUC")[3], especially in view of FPUC's less risky status as a non-generating electric utility and the significantly higher risks associated with the crises that have unfolded in the domestic and worldwide capital markets since the decision was rendered. (Tr. 379, lines 2 – 4)

In determining his recommended 12.0 percent return, Dr. Murry studied the recent volatile credit and equities markets, a number of financial statistics, current electric utility earnings and market-based measures of capital costs. (Tr. 722, lines 3 – 9). As Dr. Murry noted, during this credit crisis, the Federal Reserve has aggressively enhanced credit availability in an effort to counter economic decline. This has forced down the short-term interest rates of Treasury securities, but the long-term rates of corporate bonds continue to increase. (Tr. 722, lines 10 – 13)

Dr. Murry studied a group of comparable companies representing healthy electric utilities as a standard for deriving an appropriate return on equity for Tampa Electric. On average, the comparable companies expect common equity returns of 12.2 percent in 2008. (Tr. 722, lines 14 – 17)

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[3] In re: Florida Public Utilities, Docket No. 070304-EI, Order No. PSC-08-0327-FOF-EI (5/19/08), pp. 34-38.

Dr. Murry also relied on a Discounted Cash Flow ("DCF") analysis for the comparable companies that support a cost of equity range of 11.2 percent to 13.27 percent. (Tr. 722, lines 22 – 23). As Dr. Murry explained, the more stable capital asset pricing model ("CAPM") estimates covered a range of 11.24 percent to 12.42 percent for the average of the comparable companies. (Tr. 722, line 24 – Tr. 723, line 1). After performing his market-based analyses, Dr. Murry concluded that the market volatility that currently exists and increasing interest rate expectations suggest a return closer to the middle of the market-based results at this time. (Tr. 723, lines 2 – 5)

Dr. Murry also looked to the current competitive market returns of common equity of a group of comparable electric utilities. This comparison also confirmed that his cost of equity recommendation was reasonable. Additionally, Dr. Murry verified the appropriateness of his recommended return by comparing Tampa Electric's interest coverage under his recommended range to the coverages of the comparable companies. That comparison verified that his recommended allowed return is reasonable in the current market. (Tr. 723, lines 12 – 16).

As against the foregoing, OPC presented cost of equity testimony of Dr. J. Randall Woolridge, FIPUG and FRF presented testimony of Mr. Tom Herndon and FRF separately presented testimony by Mr. Kevin O'Donnell. The deficiencies in these witnesses' testimonies were addressed in the rebuttal testimony of Dr. Murry.

Dr. Woolridge's Analysis is Factually and Remarkably Wrong

Dr. Murry pointed out that Dr. Woolridge's testimony did not adequately consider the consequences of the current financial meltdown and the worldwide economic crisis. In fact, he pointed out that significant portions of Dr. Woolridge's testimony were virtually verbatim restatements of his older testimony from previous rate cases in other jurisdictions. (Tr. 2415, lines 1 – 7). The data used in Dr. Woolridge's analysis, for the most part, predates the recent economic turmoil. (Tr. 2415, lines 15 – 19)

As Dr. Murry observed, Dr. Woolridge's conclusion that long-term capital cost rates for U.S. corporations are currently at their lowest level in more than four decades, which is a theme that appears throughout his testimony, is factually and remarkably wrong. (Tr. 2416, lines 5 – 9). At no place in Dr. Woolridge's testimony, did he review or consider the current utility market bond rates or current risk premiums. (Tr. 2416, lines 12 – 16)

The disconnect between Dr. Woolridge's testimony and current economic reality was vividly demonstrated by Dr. Woolridge's suggestion that stock prices have increased when, in fact, stock values have declined approximately 40 percent over the past year. (Tr. 2417, lines 18 – 25). As Dr. Murry noted, Dr. Woolridge's conclusion in this regard clearly must have been copied from testimony he submitted in an earlier era. (Tr. 2417, line 25 – 2418, line 1)

Other deficiencies in Dr. Woolridge's testimony were highlighted by Dr. Murry on rebuttal. Dr. Woolridge erroneously excluded four companies in his electric proxy group that by his own selection criteria should have been included and included one company that should have been excluded. (Tr. 2419, lines 20 – 23). Other deficiencies include Dr. Woolridge's use of geometric rather than arithmetic averages to represent expected returns, his miscomprehension of the importance of the size of adjustment in a CAPM analysis, his misrepresentation of the market growth rates and his internally inconsistent contradictory positions regarding market volatility and risk. (Tr. 2424, line 20 – Tr. 2425, line 1). Dr. Murry also observed that if Dr. Woolridge had utilized growth rates from his own consulting service, www.ValuePro.net, in his DCF analysis it would have produced an 11.9 percent return on equity. (Tr. 2429, lines 16 – 21)

O'Donnell's Analysis Contains Serious Mechanical Flaws

Witness O'Donnell's testimony also contained a number of serious mechanical flaws. As Dr. Murry stated, Mr. O'Donnell placed too much emphasis on historical financial performance as opposed to the recent precipitous drop in the values of common stock. (Tr. 2433, lines 12 – 19). Mr. O'Donnell's historical growth rate average of 1.1 percent cannot represent the comparative cost of capital of a healthy comparable electric utility, which should be the standard for determining the perspective future cost of capital of Tampa Electric. (Tr. 2434, lines 1 – 6). Dr. Murry also noted that Mr. O'Donnell's "plow back" method for calculating a growth rate includes circularity that prevents it from being a serious estimate of investors' earnings growth expectations. (Tr. 2434, lines 16 – 24)

Dr. Murry performed a DCF recalculation using the source data that he and Mr. O'Donnell both considered relevant. This recalculation produced returns on equity ranging from 11.0 percent to 12.8 percent for Mr. O'Donnell's comparable group of proxy companies. The mid-point of these calculations was 11.9 percent. (Tr. 2435, lines 5 – 22)

Herndon's Recommendation is Out of Bounds

Dr. Murry pointed out that Mr. Herndon's recommended allowed return of 7.5 percent is actually less than the current cost of utility debt. Dr. Murry concluded that this non-market recommended allowed return is so low relative to the costs of competitive, alternative investments in current markets that it has no value whatsoever in this proceeding. As Dr. Murry stated, Mr. Herndon's recommendation fails to meet the most basic economic principles as expressed in the regulatory standards set out in the U. S. Supreme Court's decisions in Bluefield and Hope[4]. That standard, as articulated by Dr. Murry, is that a rate of return is "fair" if it provides earnings to investors similar to returns on alternative investments in companies of equivalent risk. Such return will be sufficient to enable the company to compensate investors for assumed risk, attract capital, operate successfully and maintain its financial integrity. (Tr. 662, line 18 – Tr. 663, line 12)

Even OPC's witness, Dr. Woolridge, conceded that his CAPM result of 8.2 percent, which was higher than Mr. Herndon's recommended 7.5 percent return on equity, would be below market expectations and would send the wrong message to the capital markets. (Tr. 1982, lines 6 – 23). Both Dr. Woolridge (Tr. 1982, lines 16 – 23) and Dr. Murry (Tr. 778, line 19 – Tr. 779, line 5) recognized that a return which is some 330 to 400 basis points below Tampa Electric's currently authorized return on equity would be well below a fair and reasonable return, would send the wrong signal to the capital markets, and would cause a flight of capital to more attractive investments.

Tampa Electric's Chief Financial Officer, Mr. Gordon Gillette, testified that an authorized return on equity similar to that urged by Mr. Herndon would present huge problems for Tampa Electric on Wall Street and the company would likely be downgraded, possibly below investment grade, with the company's cost of debt possibly becoming as high as some of the issuances in September 2008 at 12 percent or higher. (Tr. 374, lines 15 – 22)

As Dr. Murry testified, Mr. Herndon was factually wrong in his conclusion that interest rates are at an all time low with no sign of increase in sight. The current market facts directly contradict Mr. Herndon's statement.

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[4] Bluefield Waterworks and Improvement Company v. Public Service Commission, 262 US 679 (1923) ("Bluefield"), as further modified in Federal Power Commission v. Hope Natural Gas Company, 320 US 591 (1944) ("Hope")

Herndon Confused Overall Rate of Return with Return on Equity

Amazingly, Mr. Herndon misinterpreted the nature of the return on common stock equity by confusing overall rate of return (with a blend of debt and equity) with return on equity. As Dr. Murry points out, he apparently does not understand the difference between a mixed portfolio of debt and equity investments and the higher risk and higher cost common equity component of that portfolio. Dr. Murry stated that portfolios containing both debt and equity returns are not appropriate proxies for estimating the cost of common equity of a utility and Mr. Herndon's reliance on them is nonsensical and understandably lacks the support of both regulatory precedent and recognized financial theory. (Tr. 2439, line 4 – Tr. 2440, line 4)

Current Market Conditions have Raised the Cost of Equity

The testimonies of Dr. Woolridge, Mr. O'Donnell and Mr. Herndon did not cause Dr. Murry to recede from his recommended allowed return on equity of 12.0 percent for Tampa Electric. In fact, current market conditions, overlooked by those three witnesses, further bolster the case for the return on equity Dr. Murry has recommended. As Dr. Murry observed, the market-based calculations of cost of equity have generally shown increased costs since he made his initial recommendation because of the rising costs of capital to private corporations. (Tr. 2440, line 22 – Tr. 2441, line 12). In the final analysis, the return on equity recommendations of Dr. Woolridge, Mr. O'Donnell and Mr. Herndon are below or barely the equivalent of utility debt costs and do not represent realistic measures of the cost of common equity of Tampa Electric. (Tr. 2442, lines 1 – 8)

Appropriate Considerations of Business and Financial Risk

During the course of the hearing, comments were occasionally made regarding the monopoly status of regulated electric utility companies and how that status impacts their business and financial risks. Dr. Murry testified that, as an economist, he believes one should recognize that the fair rate of return standard of the Bluefield and Hope decisions takes into account the fact that utilities typically do not face the same market influences as more competitive markets, and that a single supplier is likely to exist in a market because of economies of scale and scope in providing retail service. That market structure serves as the common economic rationale for regulation and is reflected in the returns on common equity approved for investor-owned electric utility companies that participate in that market. (Tr. 663, lines 6 – 12). This helps explain why Dr. Murry has recommended a 12.0 percent return on equity for Tampa Electric, whereas the return on equity of Publix Supermarkets is about 20 percent, with Mosaic recently earning a return on equity of approximately 54 percent. (Tr. 252, line 23 – Tr. 253, line 4)

II. TAMPA ELECTRIC'S PROPOSED CAPITAL STRUCTURE IS NECESSARY TO ACHIEVE FINANCIAL INTEGRITY. (Issue 34)

Tampa Electric's projected 2009 13-month average financial capital structure consisting of 44.7 percent debt, including off balance sheet purchased power obligations, and 55.3 percent common equity should be approved in recognition of current and on-going equity infusions from TECO Energy. The 55.3 percent equity ratio is critically important if Tampa Electric is to have an opportunity to produce coverage ratios that should enable the achievement of credit parameters commensurate with debt ratings in the single A range.

Significant Equity Infusions in 2008 and 2009 Must be Recognized

TECO Energy is in the midst of a focused program to make equity infusions in Tampa Electric for 2008 and 2009 to achieve the 2009 year-end equity ratio of 55.3 percent. Over the period, equity infusions of $635 million will be made from available operating cash flows of

TECO Energy, including almost $300 million in 2008 bringing the actual equity ratio to 52.6 percent by year end 2008. (Tr. 437, lines 7 – 9). TECO Energy is committed to continuing to make these contributions and anticipates they will be completed by year-end 2009. (Tr. 206, lines 4 – 8). The company believes that with adequate levels of fuel recovery and base rate increases, the 55.3 percent equity ratio can be achieved before year-end 2009. (Tr. 206, lines 16 – 19)

Tampa Electric's Requested Equity Ratio is Consistent with Commission Precedent

The company's proposed 55.3 percent equity ratio is consistent with past Commission decisions that approved equity ratios above the level requested in this proceeding. In the company's 1996 earnings review, the Commission capped Tampa Electric's equity ratio at 58.7 percent. In Florida Power & Light's ("FPL") 2005 rate settlement, the Commission confirmed an equity ratio of 55.83 percent.[5] A 57.83 percent equity ratio was approved in Progress Energy Florida, Inc.'s ("PEF") recent rate case settlement.[6] (Tr. 202, lines 12 – 21)

Approval of the proposed 55.3 percent equity ratio will significantly contribute to Tampa Electric's ability to secure a single A debt rating by improving the company's coverage ratios in the face of a very substantial construction program for the period 2009 through 2013. (Tr. 197, line 24 – Tr. 198, line 11)

Increased Equity is Needed for Tampa Electric's Significant Construction Program

For 2008 through 2010, Tampa Electric's projected capital expenditures are estimated at $1.8 billion with more than 60 percent of this amount needing to be sourced externally. The company's projected capital expenditures through 2010 represent about 44 percent of the company's market value as compared to electric utilities nationwide needing capital expenditures

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[5] In re: Florida Power and Light Docket No. 050045-EI, Order No. PSC-05-0902-S-EI (/14/05) approving stipulation filed 8/22/05. See Stipulation, p. 11, paragraph 15.

[6] In re: Progress Energy Florida Docket No. 050078-EI, Order No. PSC-0945-S-EI (9/28/05), p. 3.

over the same period representing approximately 41 percent of the industry's market value. This clearly illustrates that the company's capital expenditure needs are significant relative to the industry's significant needs and underscores the importance of maintaining a high level of financial integrity and a strong credit rating going forward. (Tr. 242, lines 6 – 20)

Equity Ratios Proposed by Intervenors will Prevent Upgrades

The significantly lower equity ratios of 48.9 percent and 49.6 percent proposed by intervenor witnesses Woolridge and O'Donnell would preclude Tampa Electric from achieving its goal of having credit parameters in the single A range. (Tr. 233, line 17 – Tr. 234, line 10). The recommended equity ratios of Dr. Woolridge and Mr. O'Donnell are substantially lower than the most recently approved capital structures for PEF and FPL, as discussed above. Those equity ratio decisions demonstrate the long history of this Commission's support for utility financial integrity and the reasonableness of the company's requested 55.3 percent equity ratio.

Historic Averages Ignore Infusions Made in 2008 and Planned for 2009

Dr. Woolridge's use of a two year historical average capital structure does not account for the full effect of the equity infusions TECO Energy has already made and plans to make to Tampa Electric. It is significantly below the company's equity ratio as of September 2008 of 51.9 percent (Tr. 235, lines 19 – 20) and the company's year-end 2008 equity ratio of 52.6 percent. (Tr. 437, lines 7 – 9). Given what we know about the current situation in the financial markets, the risk of hurricanes and the extensive capital expenditure needs of Tampa Electric going forward, it would be a serious mistake to leave the capital structure and resulting debt ratings where they were in 2007 and early 2008. (Tr. 235, line 25 – Tr. 236, line 5)

Tampa Electric's Adjustment to Equity to Offset S&P's Imputation of Debt Relative to Long-Term Purchased Power Agreements Should be Approved

Standard & Poor's ("S&P") adjusts Tampa Electric's credit metrics by imputing additional debt in the amount of $77 million representing the present value of the company's long-term purchased power agreements. As explained by Tampa Electric witness Gillette, S&P discounts future capacity payments under long-term purchased power obligations using a discount rate based on the cost of debt and then applies a "risk factor" to determine the amount of imputed debt to include in the adjusted debt to total capital. For companies similarly situated as Tampa Electric, S&P uses a risk factor of 25 percent and imputes an annual amount of interest expense in cash coverage ratios for the imputed debt. (Tr. 203, lines 13 – 20)

The present value to January 2009 of Tampa Electric's future capacity payments for its purchased power agreements is $307 million which, when multiplied by the S&P risk factor of 25 percent, results in $77 million of imputed debt and $5 million of additional interest expense. (Tr. 204, lines 1 – 5). This approach is described in the ratings analysis S&P publishes. (Tr. 413, lines 3 – 12). Moody's Investor Service ("Moody's") and Fitch Ratings ("Fitch") also consider purchased power agreements and factor them into their ratings processes. (Tr. 285, lines 8 – 11; Tr. 286, lines 3 – 5)

The Commission should recognize, on a pro forma basis, the $77 million of additional equity that is necessary to offset imputed off-balance sheet debt. Recognition of $77 million of additional equity to offset the imputed debt leaves the company's capital structure at the same common equity ratio before and after the imputation of the debt to account for purchased power obligations. (Tr. 205, lines 1 – 12)

As discussed in Mr. Gillette's testimony, the Commission in the past has recognized the effect of off-balance sheet obligations, like purchased power agreements, on a utility's capital structure, both in the Commission's rule on determinations of need and in two recent rate settlements. (Tr. 204, lines 12 – 21)

During the hearing, a number of questions were posed to Mr. Gillette regarding the recoverability of prudently incurred purchased power expenses and the likelihood that the Commission would, in fact, allow cost recovery of those expenses. As he explained during cross-examination, S&P's imputation of 25 percent of the present value of purchased power obligations is not concerned with or dependent on resolution of the issue of whether or not the Commission will allow prudently incurred costs to be recovered. Instead, it is the simple <u>fact</u> that S&P incorporates the adjustment in their calculation of coverage ratios that makes those ratios, in fact, lower by virtue of the imputed interest. It follows that the imputation becomes part of the analysis that S&P performs, and this happens whether or not anyone believes that it is correct or incorrect. Whether this Commission agrees with S&P's rating methodology is irrelevant. The fact is that the rating agencies made this adjustment and investors rely on the rating agencies. (Tr. 412, line 20 – Tr. 413, line 12). Investors are influenced by S&P's practice in this regard, which necessitates the equity adjustment Tampa Electric has proposed.

Mr. Gillette also explained the importance of a utility's equity ratio in relation to its access to capital markets. In particular, in the case of the debt markets, higher equity ratios translate to higher coverage ratios, which in turn, translate into higher ratings. Higher debt ratings, in turn, translate into better access to debt capital, and particularly in this market, lower interest rates. (Tr. 443, lines 9 – 17)

III. TAMPA ELECTRIC'S REQUESTED AUTHORIZED RETURN ON EQUITY AND PROPOSED CAPITAL STRUCTURE ARE ESSENTIAL FOR THE PRESERVATION AND NEEDED IMPROVEMENT OF TAMPA ELECTRIC'S FINANCIAL INTEGRITY.

Tampa Electric is currently rated in the BBB range by the three major rating agencies: S&P, Moody's and Fitch. (Tr. 195, lines 17 – 20). As Mr. Gillette testified, Tampa Electric is targeting ratings in the single A range for two reasons. First, the company is facing higher capital spending requirements and a better debt rating would insure that Tampa Electric has adequate credit quality to raise the capital necessary to meet these requirements. Second, having ratings in the single A range will help prevent a downgrade in the company's ratings in the event of a catastrophe such as a hurricane. (Tr. 196, lines 3 – 10)

Tampa Electric's Substantial Construction Program Requires Access to Capital

Mr. Gillette explained that in order to reliably serve its customers, Tampa Electric is planning a very substantial construction program for the period 2009 through 2013 amounting to about $2.5 billion. This capital expenditure program is driven by several factors including: 1) the need for continued investment in generation, 2) needed investment in hardening the T&D system to improve overall reliability, 3) funding the company's share of investment in transmission facilities supporting peninsular Florida, 4) continued compliance with environmental requirements mandated by the Environmental Protection Agency and Florida Department of Environmental Protection, and 5) renewable investments. The magnitude of this capital program is compounded by the impact of the significantly higher costs of materials and labor that have occurred in the last several years. (Tr. 197, line 24 – Tr. 198, line 11)

Tampa Electric's Capital Program is Unprecedented

Tampa Electric has funded large capital programs in the past, but never as large as the one the company currently faces. (Tr. 198, lines 16 – 18). Adding to this challenge is the fact that the cost of new equipment has increased very significantly, in some cases, almost doubling in recent years. (Tr. 247, lines 14 – 17). As Mr. Gillette further explained, these factors have come together to cause the recent and expected future rate of growth in the company's rate base to be much greater than the expected growth in base revenues. This makes an increase in the company's base rates necessary to stop significant erosion in Tampa Electric's return on equity and overall financial integrity. (Tr. 247, lines 18 – 24)

Tampa Electric needs to be financially strong to be able to access the capital markets when necessary in order to procure the capital required. As stated earlier, over the next few years, Tampa Electric's needs for external financing will exceed its internally generated funds to the point that 60 percent of its financing will need to be done externally. This percentage is much higher than in the past for Tampa Electric and it is high for electric utilities in general. (Tr. 247, line 25 – Tr. 248, line 10)

Tampa Electric's requested return on equity of 12.0 percent and its proposed 55.3 percent equity ratio are critically important if the company is to maintain its financial integrity and be able to reach its targeted credit rating parameters and targeted single A debt ratings. Consistent with the majority of other utilities in the Southeast, debt ratings for Tampa Electric in the single A range are necessary, because of the company's future capital spending program necessary at a time of significant risks of hurricanes and of the very high financial market uncertainty that Tampa Electric faces today. (Tr. 248, line 17 – Tr. 249, line 2). Approval of the company's proposed rate increase and capital structure should enable the company's coverage ratios to be within the range necessary to achieve the targeted single A credit rating. (Tr. 249, lines 2 – 5)

Tampa Electric presented the testimony of Susan Abbott regarding the importance of financial integrity to electric utilities and specifically the importance of an A rating to provide Tampa Electric access to capital at reasonable costs. Ms. Abbott, who has worked in the financial services industry for 30 years, including 20 years with Moody's, identified and described the general opinions of rating agencies and institutional investors and emphasized the importance of the outcome of these hearings to Tampa Electric's creditworthiness. (Tr. 554, line 23 – Tr. 555, line 1; Tr. 603, lines 3 – 8). Ms. Abbott testified in support of the company's position that an A rating is desirable and important and that such a rating will benefit customers by affording it access to the capital markets when needed, and at lower debt costs than with a lower debt rating. This access is not only important to meet the traditional infrastructure capital needs of Tampa Electric, but it is also essential in allowing the company the capital it needs to invest in renewable and low carbon technologies required by policies in Florida and nationally. (Tr. 606, lines 9 – 19)

As Ms. Abbott further explained, it is important to recognize that for the next decade or more, utilities will need to have unrestricted access to capital markets to continue to make investments in their existing systems and invest in new technologies. Many of these factors will be viewed as risks in the capital markets. Only the strongest companies will be able to have access to the markets to compete for capital on favorable terms. (Tr. 603, line 19 – Tr. 604, line 1)

Tampa Electric's bond ratings are constrained by expected high capital expenditure requirements for essential system reliability and environmental compliance. This substantial construction program is being pursued to fulfill the company's obligation to safely and reliably serve its customers and requires substantial borrowing in the capital markets. The financial markets, even under normal circumstances, are extremely competitive as utilities and other infrastructure entities seek funds necessary to invest approximately $20 trillion over the next 25 years. In addition to traditional electric service infrastructure needs, as Tampa Electric looks to implement Florida's energy initiatives, it knows investors will have many choices and will inevitably be attracted to stronger companies. During turbulent times such as these, an A rating is particularly important since higher-rated utilities have led the way in accessing capital when recently closed markets opened again. (Tr. 604, lines 2 – 20). Pursuing a large construction program in order to ensure safe and reliable electricity for its customers necessitates that Tampa Electric have access to public market funds at all times. No options exist under these circumstances to decide to raise funds some other time. (Tr. 604, lines 21 – 25)

Tampa Electric' credit rating is important because its construction program will place enormous stress on the company's ability to maintain its financial integrity. Therefore, the ability to generate adequate cash flow in order to maintain healthy financial metrics as the company enters the next spending cycle is critical. Only then will the company have access to the markets at reasonable costs. (Tr. 605, lines 1 – 7)

As Mr. Gillette and Ms. Abbott discussed in their rebuttal testimony, access to the credit markets has been especially challenging during recent months because there have been periods of time when the debt capital markets were closed for all new issuances, as was the case from September 10 through September 22, 2008. When those debt capital markets eventually opened, only highly rated (single A or better) issuers were able to access the markets. Once BBB rated issuers were able to re-access the debt markets, those issuances were mostly secured offerings at very high interest rates. (Tr. 228, lines 8 – 24)

Contrary to the assertions of intervenor witnesses during the course of the hearing, the financial crisis that currently exists in this nation and throughout the world has served to limit

Tampa Electric's access to debt and equity financing and has caused interest rates and the overall cost of capital to rise very significantly. Rather than supporting a lower return on equity as the intervenors suggest, conditions in today's markets underscore the need for an authorized return on equity in line with the company's proposed 12.0 percent return. (Tr. 250, lines 6 – 14)

The Commission's decisions in this proceeding are critical to Tampa Electric's financial integrity. Granting the company's requests in the areas of cost of equity capital and capital structure is especially important in the tenuous financial market environment that exists today. (Tr. 250, lines 15 – 20)

Mr. Gillette's Exhibit 18, Document 5 demonstrates that Tampa Electric needs both the rate relief requested in this proceeding and approval of the company's proposed 55.3 percent jurisdictional financial equity ratio in order to have an opportunity to achieve the credit rating parameters commensurate with the company's targeted single A debt rating. (Tr. 226, lines 7 – 16)

IV. NO PARENT DEBT ADJUSTMENT IS WARRANTED. (Issue 76)

TECO Energy invests equity in Tampa Electric. Tampa Electric raises its own debt externally and has its own debt ratings. This is in contrast with the unregulated subsidiaries of TECO Energy for which TECO Finance raises debt and TECO Energy invests equity. (Tr. 478, lines 1 – 7). As witness Gillette explained, never in the history of Tampa Electric has TECO Energy borrowed money and then injected that money into the regulated utility in the form of equity. Mr. Gillette further testified that the holding company was formed when he started with the company and he has had direct experience of its activities for the entire time the holding company has been in existence. (Tr. 372, lines 5 – 24)

Rule 25-14.004, Florida Administrative Code sets forth a rebuttable presumption that a parent's investment in any subsidiary or its own operation shall be considered to have been made in the same ratios as exist in the parent's overall capital structure. However, TECO Energy has not raised debt to invest in Tampa Electric, nor has it ever invested the proceeds of the debt it has raised in Tampa Electric as equity. It follows that a parent debt adjustment in this proceeding is not appropriate. (Tr. 207, lines 22 – 25)

No Adjustment is Warranted

Specifically, Tampa Electric presented evidence through the testimony of Mr. Gillette that the Commission should not make a parent debt adjustment for the following reasons: 1) as stated above, the debt that exists at the parent was raised for TECO Energy's merchant power plant investments at TECO Power Services ("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 dividend policy for its subsidiaries to dividend 100 percent of net income 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, lines 5 – 23)

Mr. Gillette rebutted the presumption in the rule when he described in detail TECO Energy's exclusive use of debt in connection with its unregulated operations and how equity infusions to Tampa Electric were funded solely with the parent company's internally generated funds and externally raised equity. (Tr. 209, line 3 – Tr. 218, line 3)

Although TECO Energy currently has $400 million of debt, the record is clear that this debt was not used to invest as equity in Tampa Electric. This debt, which was raised between 1998 and 2003, exists because of the parent company's investments in its unregulated subsidiaries at that time, specifically the failed TPS merchant power investments. Furthermore, given TECO Energy's and Tampa Electric's internal and external dividend policies, a parent company debt adjustment would impute parent company debt to an overstated paid in capital balance. A parent company debt adjustment in this case is simply inappropriate. (Tr. 218, line 8 – Tr. 219, line 2)

V. TAMPA ELECTRIC'S PRO FORMA ADJUSTMENT TO ANNUALIZE GENERATION PROJECTS UNDERWAY SHOULD BE APPROVED. (Issues 5, 71 and 74)

The Five CTs Provide Customers with Significant Benefits in 2009 and Beyond

As described by Tampa Electric witness Mr. Mark Hornick, projects are underway to place in service five 60 MW CTs at Bayside and Big Bend Stations in 2009. These generating units are aero-derivative CTs, each with a nominal capacity of 60 MW and they offer a more economic option for meeting the company's operating reserve requirements than by having spinning reserve, which requires keeping larger units running. The use of quick start CTs in lieu of spinning reserve will benefit customers by allowing the in-service generating units to operate at higher average outputs, which improves efficiency and reduces heat rates. (Tr. 822, lines 5 – 25)

Bayside CT Units 5 and 6 will be placed in service in May and are now largely complete and will begin generating electricity used by Tampa Electric customers in April. (Tr. 894, lines

13 – 21). Big Bend CT Unit 4 and Bayside CT Units 3 and 4 have projected in-service dates of September in the test year. These five generating units will provide needed generating capacity and operating flexibility with a high level of efficiency and environmental performance. (Tr. 824, lines 10 – 15). Big Bend CT Unit 4 will have the capability to use either natural gas or distillate oil as a fuel source. It will have "black start capability", which will allow for faster restoration of electric service to customers following events such as hurricanes that may cause widespread damage to the electric grid. (Tr. 823, lines 1 – 17). The additional units at Bayside Power Station will have black start capability as well. (Tr. 823, line 23 – Tr. 824, line 4). As Mr. Hornick explained, these aero-derivative CTs can be started and brought to full load in less than 10 minutes, satisfying the company's reserve requirement that reserves be available within 15 minutes. (Tr. 859, lines 8 – 12)

Because these five CTs will be generating electricity for customers for the period of time new rates set in this proceeding will be in effect, it is appropriate for the revenue requirement requested to reflect the significant investment and operating costs associated with these assets.

Failure to Accept the Pro Forma Adjustments Ignores Commission Precedent

The investment in the CTs is known and measurable. The company's pro forma adjustment reflecting these new units 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. The jurisdictional net operating income adjustments are decreases of $2,352,000 for the May units and $4,864,000 for the September units. The jurisdictional rate base adjustments are increases of $36,125,000 for the May units and $94,562,000 for the September units. (Tr. 1440, line 16 – Tr. 1441, line 12)

Tampa Electric's annualization of its 2009 CTs meets the test OPC's witness Hugh Larkin stated as follows:

> The end result in setting rates should be an appropriate matching of the period used for forecasting generally coinciding with the period in which rates would become effective, there would be a matching of investment and operating revenues and expenses.

The company's proposed pro forma adjustments for setting rates are met by using 2009 as an appropriate test year that generally coincides and reflects the period in which rates will be effective. Failure to recognize these investments in their entirety by annualizing them over the forecasted test year would result in a mismatch on a going forward basis and would deprive Tampa Electric of an opportunity to earn a fair rate of return on property that will be used and useful during the period in which the proposed rates will be in effect. All of the benefits of these investments, including enhanced reliability and decreased fuel costs, likewise will be available to customers during the period the proposed rates will be in effect. The company's recommended adjustments to annualize the five CTs appropriately account for this investment in rate base. (Tr. 1456, line 18 – Tr. 1457, line 14)

The Commission has previously approved the annualization of assets being placed in service during a projected test year. In Docket Nos. 830470-EI and 910890-EI, the Commission accepted adjustments that PEF (formerly Florida Power Corporation) made to its projected test years to annualize the impacts of new units being placed into service.[7] Also, in the most recent base rate proceeding for FPUC,[8] the Commission determined that it was appropriate to include the full 13-month average amount of a new asset and associated accumulated depreciation and depreciation expense in the test year for ratemaking purposes because it was representative of the

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[7] In re: Florida Power Corporation, Docket No. 830470-EI, Order No. 13771 (10/12/84), pp. 3-4, 6-8 and 56; Docket No. 910890-EI, Order Numbers PSC-92-0606-PHO-EI (7/7/92), pp. 180-182 and PSC-92-1194-FOF-EI (10/22/92), p. 88

[8] In re: Florida Public Utilities, Docket No. 070300-EI, supra, pp. 21-24

future even though it went in service after the beginning of the test year. Based on this precedent, it is appropriate to annualize the CTs in 2009. (Tr. 1457, line 16 – Tr. 1458, line 7)

As stated above, the CT peaking unit additions in 2009 are needed primarily to ensure the reliability and operating efficiency of Tampa Electric's system, not to increase sales of electricity. These peaking units, as their name suggests, will serve the demand of customers at peak periods. They will replace existing CTs at Big Bend Station and provide additional peaking capacity. The energy sales from these machines will be relatively small and have been included in the test year projections for energy production. (Tr. 845, lines 14 – 23)

During the hearing, there was some discussion by Tampa Electric President Charles Black that the company has some flexibility with the in-service date of the three September CTs and the possibility of their being deferred beyond 2009. However, as Mr. Hornick testified, they are substantially mechanically complete. Subsequent to the hearing, the company decided that the three units will not be deferred. The in-service date for two of the September CTs will be in mid-August 2009 and the third CT will be placed into service in mid-October 2009. (LF Ex. 112)

The CT additions will benefit customers primarily through fuel savings and these fuel savings will be made possible by enabling the company to operate its generating units in a more efficient manner. Contrary to the suggestion by OPC's witness Larkin, there are no significant O&M savings associated with these units in 2009. (Tr. 846, line 17 – Tr. 847, line 2)

Potential Alternative Treatment

Tampa Electric firmly believes that the five CTs being added in 2009 should be annualized and recovered through rates set at the conclusion of this proceeding. Two of the five CTs will be in service in May 2009[9] coincident when new rates go into effect and the other CTs will provide customers benefits in the test year and beyond. However, should the Commission

[9] Most recent estimates have the units in service by mid-April.

determine that one or more of the September 2009 CTs should not be annualized, Tampa Electric would urge that a subsequent year adjustment to base revenues be ordered effective January 1, 2010. This adjustment would allow the company an opportunity to earn a fair return on this significant investment while delaying the associated base rate increase until after the units are placed in service. It would also help avoid the effort and expense of having an additional base rate proceeding to recover the significant costs attributable to the addition of these CTs. The jurisdictional rate base and net operating income adjustments to remove the full year revenue requirement for the September CTs and to establish a subsequent year adjustment would include a reduction of $140,390,000 to Plant In Service, a reduction of $3,018,000 to Accumulated Reserve for Depreciation, an increase of $987,000 to O&M, an increase of $3,227,000 to Property Taxes and an increase of $6,051,000 to Depreciation.

VI. FAILURE TO RECOGNIZE THE RAIL UNLOADING FACILITIES IN RATES WILL DEPRIVE TAMPA ELECTRIC FROM EARNING A FAIR RETURN. (Issues 7 and 72)

The Rail Unloading Facilities Provide Customers with Significant <u>Benefits in 2009 and Beyond</u>

In October 2004, the Commission required Tampa Electric to engage in competitive bidding in connection with solid fuel transportation requirements beginning in 2009.[10] That competitive bidding process was conducted in 2007 and 2008. (Tr. 935, lines 12 – 20). Another requirement of the order was that Tampa Electric conduct a study on the feasibility of bimodal transportation. The company retained Hill & Associates, which conducted a comprehensive review of all possible coal sources that meet the company's quality specifications and the associated costs of delivering the coal by rail or water to Tampa Electric's generating stations. The conclusion of the study was that there are certain coals that are more cost effective when

[10] In re: Review of Tampa Electric's 2004-2008 Waterborne Transportation Contract, etc., Docket No. 031033-EI, Order No. PSC-04-0999-FOF-EI issued (10/12/04), pp. 20-22.

delivered by rail. The company's recent competitive bid solicitation supported the same conclusions. (Tr. 935, line 22 – Tr. 936, line 3)

Based on the Hill & Associates study and the company's competitive bid solicitation, Tampa Electric determined that bimodal solid fuel transportation to Big Bend Station would afford the company and its customers 1) access to more potential coal suppliers providing a more competitive, overall delivered cost, 2) the flexibility to switch to either water or rail in the event of a transportation breakdown or interruption on the other transportation mode, and 3) competition for solid fuel transportation contracts for future periods. The Commission agreed with this conclusion and determined that the company had performed a competitive procurement process that produced a beneficial outcome for its customers. (Tr. 937, lines 10 – 25)

In order to take advantage of these benefits, Tampa Electric is required to construct rail unloading facilities. These unloading facilities must be built and tested in 2009, with test shipments by rail scheduled to arrive in December and contract deliveries to commence January 1, 2010. These facilities will benefit customers for the five-year term of the company's new rail transportation agreement with CSXT and beyond. (Tr. 938, lines 4 – 9)

Given that the rail unloading facilities are currently being constructed and will be operational prior to the end of the test year, the company has included a pro forma adjustment to bring the company's total cost profile to an amount that reflects a full year of operations. The jurisdictional net operating income adjustment is a decrease of $1,195,000 and the jurisdictional rate base adjustment is an increase of $44,754,000. (Tr. 1442, lines 1 – 8)

<u>The Rail Facility will Lower Fuel Costs</u>

The Big Bend Station rail unloading facilities are needed to cost effectively and reliably transport solid fuel by rail. Contrary to OPC witness Larkin's conclusion, the reduction in associated fuel costs will have very little, if any, impact on energy sales. The unloading facilities are not being constructed to enhance electric sales; they are being constructed to help ensure that Tampa Electric's customers achieve the lowest delivered cost for coal. The facilities are being designed and built only to unload solid fuel from rail cars at Big Bend Station. Tampa Electric's customers are and will remain the direct beneficiaries of this project. It follows that the company's pro forma adjustment annualizing these facilities is appropriate. (Tr. 847, line 5 – Tr. 848, line 6)

Potential Alternative Treatment

Tampa Electric firmly believes that its annualization of the rail unloading facilities at Big Bend Station is appropriate and should be approved, especially in view of the cost savings these facilities will provide to the company's customers beginning at the end of this year and continuing on into the future when the new rates will be in effect. Without conceding that the proposed annualization is appropriate, if the Commission elects not to approve such an adjustment, Tampa Electric requests that a subsequent year adjustment to base rates be ordered to take effect January 1, 2010. This adjustment would allow the company an opportunity to earn a fair return on this investment while delaying the associated base rate increase until after the facilities are placed in service. The jurisdictional rate base and net operating income adjustments to remove the full year revenue requirement for the rail unloading facilities and to establish a subsequent year adjustment would include a reduction of $45,206,000 of Plant In Service, a reduction of $452,000 to Accumulated Reserve for Depreciation, an increase of $1,039,000 to property taxes, and an increase of $906,000 to Depreciation.

VII. THE COMMISSION SHOULD APPROVE TAMPA ELECTRIC'S PROPOSED METHOD FOR APPLYING THE CSXT CONSTRUCTION REIMBURSEMENT ASSOCIATED WITH THE RAIL UNLOADING FACILITIES. (Issue 6)

In its contract negotiations, Tampa Electric was able to negotiate a significant contribution by CSXT toward the cost of constructing the rail unloading facilities at Big Bend Station. Tampa Electric originally projected the cost to construct the rail unloading facilities to be $46.9 million. The total cost of the project is now projected to be $64 million. (Tr. 1524, lines 13 – 22). The additional cost is due to design modifications that will significantly reduce unloading time.

The construction reimbursement amount in the CSXT-Tampa Electric contract, while confidential, will be sufficient to cover the shortfall between what Tampa Electric has included in rate base in this proceeding and the final total cost of the facilities. As explained in Tampa Electric witness Joann Wehle's testimony, the company proposes to apply the construction cost reimbursement first to offset the capital costs associated with the facilities that are in excess of those granted in base rates, with all remaining amounts then being credited to customers through the Fuel and Purchased Power Cost Recovery Clause. (Tr. 938, line 17 – Tr. 939, line 3). Tampa Electric believes this is a fair means of appropriately treating the construction costs and associated CSXT reimbursement and providing direct benefits to ratepayers as well. Whether the company's proposed annualization is approved and the associated costs are included in its May 2009 base rates or the investment and associated costs are reflected in a step increase in 2010, Tampa Electric's proposed application of the negotiated construction reimbursement is appropriate and fair to customers.

VIII. TAMPA ELECTRIC'S PROPOSED STORM DAMAGE ACCRUAL AND TARGET RESERVE LEVEL ARE PRUDENT. (Issues 16 and 59)

Since Hurricane Andrew struck south Florida in 1992, Tampa Electric and the other Florida investor-owned electric utilities have been unable to purchase property insurance for their T&D facilities. Since 1994, Tampa Electric has been authorized by Commission order to accrue $4 million annually to establish a storm damage reserve. (Tr. 1229, lines 9 – 10). Tampa Electric's T&D assets are now valued at approximately three times what they were worth when the accrual level was originally set by the Commission in 1994. (Tr. 1229, lines 19 – 22). For this reason alone, Tampa Electric's storm damage accrual should be increased by three-fold, to $12 million per year, simply to maintain the level of coverage the Commission originally deemed reasonable and prudent.

In addition to the three-fold increase in the value of its T&D assets, Tampa Electric's proposed storm damage accrual level of $20 million per year takes into account the increased frequency and severity of hurricanes and tropical storms reflected in the comprehensive Storm Loss and Reserve Performance Analysis performed by ABS Consulting and sponsored by Tampa Electric witness Steven Harris. This study, likewise, supports the company's request for an increase in its target level of reserves to $120 million.

The annual storm damage accrual serves as a surrogate for the annual cost of insurance premiums covering catastrophic losses. If Tampa Electric could obtain T&D insurance coverage, the Commission no doubt would approve the premiums for that coverage as a reasonable and prudent cost of doing business, the same as it did prior to the non-availability of such insurance following Hurricane Andrew. The very same rationale supports approval of the company's proposed storm damage accrual and target level. Just as a homeowner is better off paying annual premiums for homeowner's insurance as opposed to going without insurance and having no protection when a catastrophic loss occurs, utility customers fare better on a pay-as-you-go basis for storm loss protection, rather than by being burdened with a significant surcharge in the aftermath of a hurricane. While securitization can be a very effective financing mechanism, it may not be economic or feasible for system losses less than $150 to $200 million due to the fixed costs of securitized debt issuance and the ongoing cost of administration. (Tr. 243, line 21 – Tr. 244, line 15)

Nothing has changed since the Commission's storm damage accrual policy was established in 1994 other than the increased valuation of Tampa Electric's T&D facilities and the increased frequency and severity of damaging hurricanes as reflected in Mr. Harris's study. Tampa Electric's proposed annual storm damage accrual and target level would simply continue and update that policy to reflect current day circumstances. The proposed annual accrual and target reserve level should be approved.

IX. TAMPA ELECTRIC'S CONTRACTUAL SERVICES AGREEMENTS FOR MAINTENANCE ARE REASONABLE AND PRUDENT AND THEIR COSTS ARE PROPERLY INCLUDED IN OPERATING EXPENSES. (Issue 53)

The CTs used by Tampa Electric at Polk and Bayside Power Stations are General Electric ("GE") 7F class machines and they have a high level of performance and low emissions. The availability of parts and technical support services for these machines is limited; therefore, Tampa Electric 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 in an effort to maintain availability and reliability while operating in a cost effective and safe manner. (Tr. 833, lines 9 – 22)

Tampa Electric and its customers derive significant benefits from the CSAs. Under these agreements, the availability of spare parts has improved and the inventory requirements for these parts are reduced. The risk of cost increases due to reduced maintenance interval requirements, parts life risk 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. (Tr. 834, lines 1 – 10)

CSAs are an accepted industry practice for the maintenance of CTs. According to GE, 504 of the 590 operating 7F class CTs in North America are covered by CSAs. In the southern region of the United States, 307 of the 334 units are covered by CSAs. (Tr. 834, lines 12 – 20) Tampa Electric's CSAs are reasonable and prudent and their costs are appropriately included in operating expenses.

X. TAMPA ELECTRIC'S PROPOSED FUEL INVENTORY RECOGNIZES APPROPRIATE INVENTORY LEVELS AND COSTS. (Issues 21 – 24)

The record fully supports Commission approval of the following 2009 proposed fuel inventory components and amounts in working capital as follows:

2009 PROPOSED FUEL INVENTORY

	Amount ($000)
Coal	$83,819
Natural Gas	4,495
Light (#2) Oil	9,312
Heavy (#6) Oil	780
Total 2009 Proposed Fuel Inventory	**$98,406**

Each of the above fuel types is burned in the company's power plants to provide base load, intermediate and peaking capacity reliability. Overall the company generates energy for its customers from a diversified portfolio of coal, natural gas and oil fired units. The company's 2009 total proposed fuel inventory levels are necessary for Tampa Electric to be able to continue providing reliable service to its customers. (Tr. 944 lines 2 – 12). The record in this proceeding fully supports the quantity and value of each fuel type in the company's proposed fuel inventory.

Coal

Tampa Electric witness Wehle supported the coal fuel inventory amount and established that the fuel inventory represents the value of 98 days burn of solid fuel including coal and petroleum coke. (Tr. 942, lines 15 – 18). The proposed coal inventory target level of 98 days of projected burn is consistent with the 98 day projected burn approved by the Commission in the company's last rate case and it has not been contested by any party to this proceeding.

Since Tampa Electric prepared its rate case fuel inventory projection in March of 2008, coal prices increased dramatically during the summer months of 2008 for all types of coal deliveries. Coal prices have settled somewhat of late but have not retreated to prices in effect in March of 2008 when the coal inventory price projection was prepared. (Ex. 13, Document 66, p. 19, lines 12 – 16)

Ms. Wehle also pointed out in her deposition that coal prices that were used as part of the inventory evaluation in the company's MFRs for this proceeding are contractual coal prices, which do not adjust downward. Tampa Electric has secured its coal inventory through 2009 at those prices, for both the commodity and the transportation portions. (Ex. 13, Document 66, p. 21, lines 16 – 23)

Ms. Wehle described in detail the many considerations that influenced the company's proposed 2009 coal inventory level. Those factors were discussed in detail under three major categories of inventory planning: 1) coal supply and transportation uncertainty, 2) coal burn variability, and 3) other risk factors. (Tr. 918, line 4 – Tr. 923, line 12)

Ms. Wehle explained that the company's proposed coal inventory level compares favorably with the company's actual coal inventory levels over the past five years. (Tr. 924, lines 18 – 22). Tampa Electric has fully justified its request for 98 days of coal inventory – an inventory level not challenged by any party to this proceeding.

Natural Gas

Since 1998, Tampa Electric has added four simple cycle CTs at Polk and repowered Gannon Station utilizing seven CTs as natural gas combined cycle Bayside Units 1 and 2. These units became operational in 2003 and 2004, respectively. Tampa Electric has continually enhanced its natural gas supply portfolio since 1998, including adding underground natural gas storage capacity beginning in 2005. (Tr. 926, lines 1 – 10)

Tampa Electric currently has a contract with Bay Gas Storage for up to 850,000 MMBtu of storage capacity and expects to increase that storage to 1,250,000 MMBtu in the summer of 2009. That level of capacity will provide Tampa Electric approximately six summer days of gas supply. (Tr. 927, lines 19 – 25)

The volume of natural gas in storage in 2009 is projected to average about 545,000 MMBtu of gas in storage with a 13-month average value of $4,495,000. (Tr. 927, line 25 – Tr. 928, line 3)

Since the company's rate proceeding was filed, the price for natural gas has moved in similar directions as those of oil (Ex. 13, Document 66, p. 20, line 18 – p. 21, line 2). Although oil and natural gas prices have retreated, they do not appear representative of prices that will be in place in 2009. (Ex. 13, Document 66, p. 19, line 17 – p. 20, line 2)

Oil

Oil represents less than one percent of the company's generation, but this generation is critical for peak demand periods. Therefore, the company must maintain proper levels of oil inventory. (Tr. 928, lines 8 – 12). The company projects to average 9,203 barrels of heavy oil in inventory in 2009 with an average value of $780,000. (Tr. 929, lines 15 – 17). The company has included 77,068 barrels of light oil in inventory for 2009, which equates to a 13-month average of $9,312,000. (Tr. 929, line 21 – Tr. 930, line 1). This inventory level is necessary to maintain, at a minimum, the level of oil necessary to provide peaking capacity reliability in Tampa Electric's system. (Tr. 929, lines 21 – 23)

As stated earlier, although oil prices have retreated, they do not appear representative of prices that will be in place in 2009. (Ex. 13, Document 66, p. 19, line 17 – p. 20, line 2). The prices of lesser used residual oil have been volatile as well. (Ex. 13, Document 66, p. 20, lines 3 – 10). Just since the beginning of 2009, prices for distillate and residual oil have increased dramatically by 20 percent to 30 percent. (Ex. 13, Document 66, p. 20, lines 11 – 17)

Tampa Electric believes that the prices that were utilized in the March 2008 time frame to develop inventory values for this proceeding are very reasonable. As Ms. Wehle testified, if one were to chart the commodity prices for oil and natural gas, they are right at the midpoint of their range of activity from March 2008 to the present. The company believes its proposed fuel prices reasonably and accurately represent what the prices will be on a 13-month rolling average basis. (Ex. 13, Document 66, p. 21, lines 6 – 15)

<u>OPC's Arbitrary Proposed Adjustment Should be Rejected</u>

OPC's witness, Mr. Larkin, would have the Commission impose an arbitrary 10 percent reduction in fuel inventory amounts based on what he perceives to be reductions "which <u>might</u> have occurred in coal, oil and gas prices." (Tr. 939, lines 10 – 14). Mr. Larkin's recommended adjustment is entirely inappropriate and, by Mr. Larkin's own admission, baseless and arbitrary. In this regard Mr. Larkin states that his proposed adjustment "does not accurately reflect an estimate of the decline in fuel prices because I do not have all necessary information available to me." (Tr. 2030, lines 21 – 23). Clearly he is not in a position to recommend such an adjustment. As a result, no credible evidence has been offered in the record of this proceeding to recede from the company's proposed 2009 total fuel inventory amount in working capital.

XI. TAMPA ELECTRIC'S TOTAL SALARIES AND BENEFITS EXPENSE IS REASONABLE; THE COMMISSION SHOULD REJECT ADJUSTMENTS TO INCENTIVE COMPENSATION. (Issues 48 – 50 and 52)

<u>Overall Compensation Level is Reasonable</u>

The company presented extensive evidence that its overall compensation and benefits expenses are reasonable. During a period when customers grew by over 200,000, or 42 percent, Tampa Electric has reduced its workforce by 18 percent from approximately 3,200 team members at the end of 1992 to 2,638 projected in 2009. (Tr. 1105, line 23 – Tr. 1106, line 1) The company's total compensation and benefits expense for the test year are reasonable. (Tr. 1106, lines 3 – 6)

Tampa Electric demonstrated that its compensation levels are reasonable by using nationally recognized third-party survey sources to aggregate and provide comparative data from national and regional employers, both generally and utility specific. (Ex. 25, Documents 2 – 5)

The company performs a detailed annual benchmarking analysis of its pay rates to those of its competitors to ensure that the compensation levels for specific jobs are consistent with the market. (Tr. 1108, lines 19 – 23). The company compares its annual salary budget with key market indices, and has shown in this case that it has consistently trended below the average rates of key market indices and has managed to keep compensation expense increases below a blend of indices across general and utility industries. (Tr. 1109, lines 7 – 12; Ex. 25, Documents 3 and 4). Likewise, Tampa Electric has shown that salary and wage levels are comparable to those of other utilities as reported in the Federal Energy Regulatory Commission ("FERC") Form-l annual report. (Tr. 1109, lines 14 – 22; Ex. 25, Document 5)

Tampa Electric also demonstrated that its benefits expense is reasonable. Towers Perrin's BENVAL Index has Tampa Electric's total benefits program rated at 91.5, which is below the index average of 100, and therefore slightly below the national average, yet is comparable and competitive within the industry. (Tr. 1112, lines 21 – 23; Ex. 25, Document 6) Likewise, the relative value of Tampa Electric's BENVAL Index for medical benefits is 95.2, which is below the index average of 100, indicating that Tampa Electric's medical plan is comparable and the company is competitive relative to the national average. (Tr. 1113, lines 13 – 20; Ex. 25, Document 7). Furthermore, Tampa Electric's average medical cost per team member is increasing at a lower rate than the average increase on a national level. (Tr. 1114, lines 2 – 8; Ex. 25, Document 8)

Incentive Compensation is an Important Part of Total Compensation

The evidence demonstrates that Tampa Electric's total compensation and benefits expense for the test year is reasonable and based on this evidence, the Commission should decline the intervenors' invitation to micromanage the individual components of the company's compensation plan. Tampa Electric's philosophy is to provide a compensation system that aligns with business strategies and offers competitive rewards for outstanding accomplishments toward the success of the organization and the total compensation of each employee is designed to be competitive so that the company can attract and retain the most qualified individuals. (Tr. 1127, lines 1 – 7). Tampa Electric's total compensation, including the "at risk" portion that is contingent on achieving operational and financial incentive goals, is designed to target the 50th percentile of market compensation. (Tr. 1127, lines 14 – 17). It is inappropriate to single out one discrete element of overall compensation without understanding all elements. After all, total compensation is the relevant expense to be considered for ratemaking purposes.

Using incentive compensation programs like Tampa Electric's is less costly than increasing base salaries because incentive compensation is "at risk" and, by definition, not guaranteed. (Tr. 1133, lines 11 – 13). The "at risk" component motivates employees to perform at higher levels and results in more efficiency, which translates to direct benefits for the company's customers. (Tr. 1133, lines 13 – 16). For the Commission to begin disallowing discrete elements of the company's compensation package based on whether it is "at risk" or not would undermine an effective means of incenting employees to perform at high levels which results in more efficiency with direct benefits for customers. (Tr. 1132, line 13 – Tr. 1133, line 16; Tr. 1179, lines 10 – 14)

The intervenors' various criticisms of the company's incentive compensation programs are shortsighted and misguided. Incentive compensation plans are not new and they are commonly used by most companies, including other utilities in Florida. (Tr. 1131, lines 12 – 19). The *World At Work 2008/2009 Annual Salary Budget Survey*, discussed by Tampa Electric witness Dianne Merrill, shows that over 80 percent of the 2,375 companies surveyed use an incentive pay program. (Tr. 1131, lines 15 – 17). Tampa Electric's Success Sharing plan has been in place since 1990 and was approved by the Commission in the company's last rate case in 1992. (Tr. 1131, lines 19 – 22). The Commission has also approved incentive compensation for Gulf Power Company ("Gulf"). (Tr. 1131, line 22 – Tr. 1132, line 11)

In Gulf's most recent base rate proceeding, OPC witness Helmuth Schultz made the same kinds of arguments about Gulf's incentive plan that he is making is this case, but the Commission did not agree with him and made no adjustment. Indeed, the Commission noted that Gulf offered a plan consisting of base salary and incentive compensation and that receiving a base salary only would cause Gulf employees to be compensated at levels below employees at other companies. Importantly, Tampa Electric's proposed target level of compensation at the 50th percentile is within the guidelines previously approved by this Commission.[11] (Tr. 1131, line 22 – Tr. 1132, line 11)

The various criticisms of the intervenors about specific goals set by the company and whether those goals relate to parent company or financial performance should be disregarded. The company's Success Sharing program has operational and financial performance measures that are heavily weighted toward providing benefits to customers. The goals promote safety, reliable service and cost containment, among other things. The test year expense associated with this program only includes expenses associated with the operational goals because the financial goals must be self-funding. The entire test year expense should be allowed because the goals in total are designed to achieve favorable customer results. (Tr. 1138, lines 11 – 17)

The same is true of the short- and long-term incentive plans for officers and key employees. While more of the goals in these plans are tied to financial performance, the overall focus of the programs remains on Tampa Electric's operational and financial results.

[11] In re: Gulf Power Company, Docket No. 010949-EI, Order No. PSC. 02-0787-FOF-EI (6/10/02), pp. 43.45.

Participants in these plans help ensure the company's goals of providing customers with safe and reliable service while also focusing on adequate shareholder returns, both of which benefit customers. The first directly benefits customers who rely on electric service to meet their needs and the second indirectly benefits customers by helping ensure they receive service from a company that is able to attract needed capital at a reasonable cost to provide safe and reliable electric service. If the Commission were to agree with FIPUG's witness Jeffry Pollock on a policy basis, which it should not, the amount of incentive compensation expense included in the 2009 test year associated with parent company financial performance is only about eight percent, not 100 percent as he proposes. (Tr. 1139, line 18 – Tr. 1140, line 7). The amount of any resulting adjustment should be no more than five percent (five percent of 100 percent for officers) and three percent (20 percent of 15 percent for key employees) of total projected incentive compensation expense, or $560,000, not the $6.45 million recommended by Pollock. (Tr. 1485, lines 1 – 18)

The company's short- and long-term incentive program is part of Tampa Electric's total compensation package, and allows the company to attract and retain its key talent. Its associated costs are reasonable and appropriately included in its cost of service.

401(k) Costs are Reasonable

OPC's criticisms of the company's 401(k) program are without merit. The company's 401(k) plan is part of the company's overall compensation package, which, as shown above, is reasonable. Although Tampa Electric did change the company's fixed match from 30 cents to 50 cents in 2007, this move was made in order to be more comparable to other utilities. As Ms. Merrill explained in her rebuttal testimony, Towers Perrin's 2007 Energy Services BENVAL study showed that the employer contribution aspect of the company's 401(k) plan ranked fourth from the bottom and significantly below the industry average. The study also illustrated that the majority of companies in the "Energy Services" category have a defined benefit plan along with a defined contribution plan. Even with the change complained of by Mr. Schultz, Documents Nos. 1 and 2 in Ms. Merrill Exhibit No. 85 show that the 401(k) plan at issue is still next to last among energy service companies providing both a defined benefit plan and a defined contribution plan. (Tr. 1142, lines 10 – 23). In light of this evidence, the expense associated with the company's 401(k) plan is clearly reasonable and should not be adjusted.

Medical Costs are Reasonable

OPC witness Schultz's claim that the company's medical plan does not reflect the "proper" level of employee contribution should be ignored, because the costs associated with the medical plan are reasonable. Document No. 8 of Ms. Merrill's Exhibit No. 25 shows that the company's average medical cost per employee in 2007 was $6,377, versus the national average of $7,983. (Tr. 1144, lines 5 – 10). The company attributes this favorable result to successful cost control strategies including designing employee contribution amounts that encourage cost effective plan selections through annual adjustments and indexing of deductibles, co-payments and out-of-pocket amounts. (Id.). The company's level of expense for employee healthcare is reasonable and prudent and should not be adjusted.

Headcount and Overtime are Appropriately Accounted For

The intervenors have criticized the company's budget system as it relates to employee headcount and overtime; however, these criticisms are not valid and do not provide a basis for any adjustment to compensation expense. As explained by Tampa Electric witness Jeffrey Chronister, the company tracks and maintains detailed records on overtime in its actual accounting records, but the same level of detail is not generated for budgeting purposes because it is not necessary to perform a simulated time entry process to develop a reasonable and useful budget. For budgeting purposes, the company monitors overtime as part of total compensation expense at the business unit (department) level. Overtime is properly estimated and included in projected expense based on the expertise and experience of the departments creating their budgets, and is evaluated during the budget approval process via variance analyses which measure performance by comparing both actual overtime and total payroll to budgeted amounts. (Tr. 1482, line 8 – Tr. 1483, line 3)

The same approach is true for employee headcount, which is tracked in detail in the company's historical personnel records, but is not rolled up to a total level for budgeting purposes. As explained by Ms. Merrill, the company does not focus its attention on whether positions are filled or vacant, but focuses on applying the proper resources to the goal of providing good customer service. Accordingly, the company focuses on overall expense levels and may fill a vacant position or get the work done using a contractor or temporary worker. (Tr. 1166, line 8 – Tr. 1167, line 2). That being the case, the Commission should not focus on whether positions are vacant or filled, but on whether compensation expense levels are reasonable, which the company clearly has shown.

2009 Base Pay Increases Changed

During the hearing, Ms. Merrill advised the Commission that the assumptions used for employee and officer salary merit increases for the company's 2009 budget were reduced in late 2008. Specifically, officer salaries were frozen at 2008 levels. (Tr. 1195, lines 3 – 4; LF Ex. 107). Exempt and non-covered, non-exempt employees were originally budgeted to receive a four percent merit increase but that was reduced to two percent and 3.5 percent, respectively.

(Tr. 1193, line 17 – Tr. 1195, line 12). Based on these salary level changes, the company agrees that test year compensation and benefits expense should be reduced by $1,378,987.

XII. INTERVENORS' ADJUSTMENTS TO OPERATING EXPENSES SHOULD BE REJECTED.

The intervenors have proposed various unrelated adjustments to Tampa Electric's operations and maintenance expenses, all of which should be rejected for the reasons set forth below.

Dredging (Issues 15 and 56)

The company estimates the cost for channel dredging in 2009 to be $6.9 million, which 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, lines 1 – 7). The company proposes to amortize this cost over five years. (Tr. 1442, line 14 – Tr. 1443, line 2)

The company's projected channel dredging expense reflects a reasonable and necessary level of prudent expenses to be incurred for the benefit of ratepayers. As explained by Mr. Hornick, the delivery of solid fuel to Big Bend Station is performed using waterborne vessels and the shipping channels near the station accumulate sediment over time, which eventually impedes the vessels' ability to navigate when fully loaded. (Tr. 840, line 18 – Tr. 841, line 18). Without dredging in 2009, vessels would need to be "light loaded" to reduce their required draft to navigate the channel. The light loading of vessels results in transportation inefficiencies and increased fuel costs in the form of financial penalties. Dredging of the inlet canal is also needed due to silt and sediment accumulation at the circulating water pump inlets. This accumulation reduces unit efficiency, thereby increases fuel costs, and causes additional maintenance expense.

Although the intervenors argue that the level of dredging expense is higher than in the past and therefore unreasonable, the company has shown by competent substantial evidence why the costs have increased and that the total is reasonable. As Mr. Hornick explained, in previous years the spoil material removed from the channel was conveyed to disposal areas adjacent to the Big Bend Station in an efficient and cost effective manner. With each successive dredge, the available storage at adjacent disposal areas has been depleted. The 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. The additional cost of expanding an existing disposal area or paying for off-site spoil disposal was included in the 2009 budgeted amount and the estimate from the dredging contractor to perform the work has increased significantly since 2002. (Tr. 842, line 1 – Tr. 843, line 20)

The adjustments proposed by the intervenors and their arguments are flawed and should be rejected. Mr. Hornick explained that only the company's portion of dredging costs is reflected in the 2009 projection so there is no basis to support the notion that the $6.9 million estimate should be divided in two because a third party will be sharing the cost. (Tr. 843, lines 16 – 20). The cross-examination of Mr. Larkin demonstrated that his proposed adjustment is erroneous from a mathematical perspective and otherwise. (Tr. 2049, line 19 – Tr. 2055, line 10). In fact, under Mr. Larkin's proposal it would take 50 years to recover the company's cost of dredging. (Tr. 2053, line 12 – Tr. 2055, line 10). Mr. Larkin's other argument that because the company deferred dredging beyond 2007 there is not a need to dredge in 2009 is just as illogical as his first. (Tr. 844, lines 1 – 20)

Dredging the Big Bend Station shipping channel in 2009 is necessary. The company has reasonably estimated its share of dredging expense at $6.9 million and the company's proposed treatment of dredging in the test year is appropriate without adjustment.

Rate Case Expense (Issue 63)

The company estimates rate case expense to be $3,153,000 and proposes to amortize the expense over a three-year period beginning in 2009. (Tr. 1443, line 19 – Tr. 1444, line 10). The amount of rate case expense and the amortization period proposed by the company are reasonable and should be approved by the Commission, without adjustment, except for a reduction of $116,000 related to J.M. Cannell, who was never contracted to serve as a witness. (Tr. 1492, lines 15 – 23)

Mr. Schultz's suggestion that Tampa Electric should not need outside consultants to assist with rate case activities has no merit. Like the intervenors have done, Tampa Electric has hired consultants to assist in case preparation and to serve as expert witnesses. (Tr. 1491, lines 1 – 18). Huron Consulting, the focus of intervenor attention, performed numerous tasks related to the rate case that the company is not staffed to perform in the ordinary course of business, including MFR detailed review, tax analysis and support, testimony preparation, review of pro forma adjustments and revenue requirement components, and responding to discovery requests. Mr. Chronister acknowledged that hiring consultants for rate case assistance is not new and, in fact, principal members of Huron Consulting helped in prior Tampa Electric rate cases and their familiarity with the company was one reason why they were engaged in this proceeding. (Tr. 1514, lines 22 – 25; Tr. 1552, line 14 – Tr. 1553, line 18). He explained that different firms met with the company and presented their experience in rate cases. The company ultimately selected consultants that it felt had the appropriate expertise. (Tr. 1551, line 25 – Tr. 1552, line 6)

In managing Huron's expenses, Mr. Chronister explained that the company divided their tasks into groups and Huron was not authorized to proceed with certain tasks until specifically approved by Tampa Electric. The first grouping of tasks, which included MFR review, was for services estimated to cost $468,000. Since then, additional tasks were authorized and the company's estimate of $1.31 million for Huron's services for the rate case remains appropriate. (Tr. 1492, lines 1 – 13)

Bad Debt Expense (Issue 64)

The company's proposed level of bad debt expense for the test year (MFR Schedule C-4) is based on a 0.349 percent bad debt factor, which was developed using a methodology the company has historically utilized for budget purposes. Tampa Electric's bad debt expense amount is reasonable should be approved without adjustment.

Mr. Larkin proposes to arbitrarily and erroneously reduce bad debt expense by $2,409,000. Contrary to his assertion, the revenues used 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. The company properly used Accounts 440 through 446 – Retail Revenues Billed and Account 451 – Miscellaneous Service to calculate uncollectible expenses. (Tr. 1477, lines 10 – 16)

Furthermore, Mr. Larkin's proposed adjustment simply ignores the reality of the present economic downturn. The company's bad debt expense factor is a calculated number that is based on actual results from 2007 and 2008. As a result of the present economic conditions which are expected to continue for some time, more customers are, in fact, not paying their bills. This means that the actual bad debt write-offs experienced by the company are increasing and will, in all likelihood, exceed the historical rate of bad debt used to calculate the company's 2009 bad debt expense. Given the uncertainty of future economic conditions, the company's proposed level of bad debt expense is more than reasonable and should be approved. (Tr. 1477, line 4 – Tr. 1479, line 9)

Office Supplies (Issue 65)

The company has included jurisdictional office supplies expense of $10,858,000 in test year net operating income. (MFR Schedule C-4). The adjustments to this amount proposed by the intevenors are flawed and should not be accepted by the Commission. Although Mr. Schultz claims that the company has not provided sufficient justification for the increase in office supplies expense, the company has explained why 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. (Tr. 1494, lines 1 – 12). The Commission should approve the company's proposed level of office supplies expense without adjustment.

Tree Trimming (Issue 66)

Tampa Electric has included $16,073,000 of tree trimming expense for 2009. (Tr. 999, lines 24 – 25). This amount is sufficient to allow the company to trim approximately 29 percent of its distribution system in 2009 and then one-third in 2010. The company 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.[12] (Tr. 1033, lines 16 – 24). The company's proposed amount of tree trimming expense in the test year is reasonable and should be approved.

The intervenors' various objections to the company's proposed level of tree trimming expense should be rejected. OPC witness Schultz does not disagree that the company should be

[12] See In re: Requirement for investor owned utilities to file ongoing storm preparedness plans, etc., Docket No. 060198-EI, Order Nos. PSC-06-0351-PPA-EI (4/25/06) and PSC-06-0781-PAA-EI (9/19/06)

on a three-year cycle. (Tr. 2116, lines 2 – 4; Tr. 2118, lines 5 – 6). The company established through cross-examination of Mr. Schultz (Tr. 2112, line 3 – Tr. 2118, line 7), that there is no material difference between OPC's and the company's cost of trimming per mile; both parties agree that the amount per mile is approximately $7,900. (Tr. 2112, lines 3 – 21). Mr. Shultz also agreed that the cost to trim one-third of the company's system using his cost per mile is approximately $16 million (Tr. 2115, lines 8 – 14), the amount proposed by the company for the test year.

It appears, therefore, that the only real dispute over tree trimming is whether the Commission should allow the company to recover the level of tree trimming expense necessary to allow the company to achieve the three-year cycle it approved in the storm hardening docket. The company's current Commission-approved plan calls for a three-year cycle for the entire distribution system, not six years for laterals. (Tr. 1033, lines 22 – 24). As noted by Tampa Electric witness Regan Haines during his discussion with Commissioner Argenziano, a six-year cycle for laterals would require the company to trim trees back far enough so they would not grow back into the lines within six years, which would have a huge negative impact on aesthetics. (Tr. 1093, lines 12 – 19). Approving expenses for a four-year cycle as proposed by OPC while still requiring the company to meet a three-year cycle would be unfair and inequitable. The company's proposed amount of tree trimming expense in the test year is reasonable for a three-year cycle and should be approved.

Pole and Transmission Structure Inspections (Issues 67 and 68)

The company has included $1,550,309 and $540,739 of pole and transmission structure inspection costs, respectively, in test year net operating income. Tampa Electric's pole inspection plan was filed with and approved by the Commission in 2006.[13] (Tr. 1038, lines 14 – 19). The company's transmission structure inspection program was filed with and approved by the Commission as part of its Ten Point Storm Hardening Plan.[14] (Tr. 1040, lines 6 – 9). The proposed budget for the 2009 pole and transmission structure inspection program is appropriate and necessary to meet the Commission's requirements and should be approved.

OPC witness Schultz's proposed adjustments for pole and transmission structure inspections are based on a simplistic indexing approach that ignores the actual costs being incurred by the company and the Commission requirements. The $30.63 average cost per pole inspection for 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 company's contractor who performs this work has escalated its rates at a greater rate than the index referenced by Mr. Schultz. Furthermore, the 40,750 poles to be inspected each year include both distribution and transmission poles which have different rates. In 2008, the company experienced a rate of $33.03 per distribution pole inspection. Once a four percent contractor price increase is factored in, the projected 2009 cost per distribution pole inspection increases 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, line 22 – Tr. 1039, line 22) The company's estimate is based on actual contract rates and tasks to be performed rather than

[13] See In re: Review of all electric utility wooden pole inspection programs, Docket No. 060531-EU, Order No. PSC-06-0778-PAA-EI (9/18/06)

[14] See In re: Review of 2007 electric infrastructure storm hardening plan . . . submitted by Tampa Electric Company, Docket No. 070297-EI, Order No. PSC-07-1020-FOF-EI (12/28/07).

the arbitrarily adjusted rates used by Mr. Schultz; therefore, his recommendation should be rejected.

The same is true for Mr. Schultz's recommendation on transmission structure inspection expense. Because transmission structure inspection activities have increased for all utilities in the state, the costs for these inspections have increased significantly since 2005. The new inspection requirements include infrared and above-ground inspections, which were not performed in all of the years Mr. Schultz used in his cost averaging. The actual costs of infrared and above-ground inspections have increased since 2005 by 33 percent and 28 percent, respectively, not at the indexed rate used by Mr. Schultz. Additionally, the company's 2009 budget also 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 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 at an expected annual cost of $300,000. All of these factors combine to make Mr. Schultz's simplistic averaging/indexing approach inappropriate for use as the basis for an adjustment. (Tr. 1040, line 11 – Tr. 1041, line 6). The proposed budget for the 2009 pole and transmission structure inspection program is cost based, appropriate, and necessary to meet the Commission's requirements and should be approved.

Generation Maintenance Expense (Issues 54 and 69)

The company has projected a total of $91.5 million for generation maintenance expense for 2009, which includes $20.2 million for planned outage expense and $6.9 million for dredging expense. Intervenors have made several proposed adjustments that are erroneous and inappropriate.

First, Mr. Schultz performs an analysis that has a critical error. The details of his analysis are explained in his testimony and are shown in his Schedule C-10. (Tr. 2097, line 13 - Tr. 2099, line 19; Hearing Ex. No. 52). Mr. Schultz's analysis focuses only on Steam Maintenance Accounts 511, 512 and 513 and his position is that the company's steam generation maintenance expense should only be $60,671,000 based on his historical indexed analysis but the company has projected it to be $69,151,000. What Mr. Schultz ignores is that the company's 2009 projected expense includes $6.9 million of dredging expense, an activity/expense that did not occur in his historical years[15]. When dredging expense is removed from the company's projected steam generation expense, the resulting $62,151,000 is only $1,580,000 more than what Mr. Schultz asserts to be the appropriate amount of expense. (Tr. 2121, line 3 – Tr. 2122, line 14). Because the company's projected generation maintenance expense is based on detailed projections for actual projects, it is more accurate than Mr. Schultz's generalized calculation of indexed historical costs.

The next significant analytical flaws are attributable to FIPUG's witness Pollock. Tampa Electric included approximately $20.2 million of planned outage expense in its test year, which reflects 54 planned outage weeks for the company's 13 units. 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. As explained by Mr. Hornick, the planned maintenance forecasted for 2009 is consistent with past and expected future planned outage requirements. (Tr. 830, line 20 - Tr. 831, line 5; Tr. 853, lines 17 – 19)

[15] He also failed to realize that the company made a pro forma adjustment to amortize dredging expense over five years. This pro forma adjustment reduced the company's projected generation maintenance expense for 2009 by $5,520,000 (system).

Mr. Pollock's analysis focuses on planned outage expense, a subset of overall generation maintenance expense. First, he does not adjust historical amounts for known escalations and ignores significant factors that have contributed to increased production O&M expenses including 1) the cost of materials and supplies have increased dramatically in recent years, 2) qualified construction labor has been expensive and difficult to secure, and 3) the increased costs associated with operating environmental control equipment on the generating units along with other environmental requirements. Next, Mr. Pollock's analysis concludes that the total number of planned outage weeks in the test year is not representative of a normal year based on historical comparisons, which is false. (Tr. 848, line 21 – Tr. 851, line 20). Although the 2009 planned outage weeks are slightly higher than other years, they are reasonable given Tampa Electric's existing and future generating fleet maintenance needs. (Tr. 892, lines 11 – 23). The overall generation scheduled outages for the years 2008 through 2011, shown on Document No. 1 of Mr. Hornick's rebuttal exhibit (Hearing Ex. No. 82) indicate that the number of outage weeks per year are expected to range from 45 to 54 weeks and will average 48.4 weeks. (Id.). While the planned outage duration for 2009 is greater than that for 2008, 2010 and 2011, the projected generation expense for 2009 is reasonable (Id.) and should be approved by the Commission without adjustment.

It is interesting to note that Mr. Schultz's analysis proves Mr. Pollock's proposed adjustment inappropriate. Mr. Pollock's averaging approach focuses only on planned outage expense and ignores the relationship between planned outages, forced outages and routine (non-outage) maintenance expense (Tr. 850). Mr. Schultz's analysis, however, captures planned outages, forced outages and routine generation maintenance expenses over a historical period and indexes them to current dollars. When this is done and as noted above, the company's projected generation expenses are only $1,580,000 more than Mr. Schultz testified is the correct number (Id.). As a result, Mr. Schultz's analysis demonstrates that when planned outages, forced outages and routine maintenance are considered together, the company's projected test year's generation expenses are very consistent with its historical experience.

Furthermore, Mr. Schultz's historical calculation and the company's detailed projections are so close that no adjustment is warranted. Moreover, it is certainly clear that neither the $8,480,000 million adjustment to generation maintenance proposed by Schultz nor the $8 million adjustment to planned outage expense proposed by Mr. Pollock is appropriate. To make both adjustments to generation maintenance expense would be double dipping and totally unreasonable. The planned outage expense included in the test year is part of total production O&M, which is $7,693,000 below the Commission's O&M benchmark level. The expense is reasonable and should be approved without adjustment. (Tr. 827, lines 22 – 24)

Substation Maintenance (Issue 55)

The company has included $2,095,555 in 2009 for substation preventative maintenance expense, which includes annual substation inspections and the condition-based substation maintenance. The adjustments proposed by Mr. Schultz should be rejected because the 2007 costs Mr. Schultz uses in his adjustment do not include activities contemplated for 2009 and, therefore, cannot be used to make a valid comparison between 2007 and the test year 2009. For example, the 2007 base year Mr. Schultz used for his indexing calculation was not a typical year for circuit breaker maintenance and, therefore, should not be used to project 2009 costs. There are 23 more circuit breakers to be maintained in 2009 than there were in 2007 at an additional cost of $28,000. Another example is that changes made for classifying oil test costs from corrective maintenance to preventive maintenance in late 2007 make 2007 non-comparable to

2009 and result in an additional 2009 expense of $17,000. Additionally, contractor costs for North American Electric Reliability Corporation ("NERC") required relay testing have increased at a higher rate than CPI and also at a higher rate than was experienced in 2007, resulting in additional costs of $80,000 in 2009. In light of NERC's extensive relay standards and the company's experience with relay testing, Tampa Electric plans to test all of its relays on a periodic basis at an additional annual cost of $429,000, an activity that was not included in the 2007 amount used by Mr. Schultz. Finally, Mr. Schultz's Schedule C-9 included annual substation inspection costs for 2008 and 2009, but these types of costs were not included in 2003 through 2007 historical costs. For these reasons, the comparison Mr. Schultz has made between 2007 and the test year is not valid and should not form the basis for an adjustment to the company's proposed substation maintenance expense. (Tr. 1041, line 18 – Tr. 1043, line 2)

XIII. THE COMMISSION SHOULD APPROVE THE COMPANY'S PROPOSED TRANSMISSION BASE RATE ADJUSTMENT (Issue 112)

The company's proposed Transmission Base Rate Adjustment ("TBRA") would allow Tampa Electric to timely recover its transmission costs associated with 230 kV and above transmission projects submitted for Florida Reliability Coordinating Council ("FRCC") review. (Tr. 1448, lines 6 – 10). Under the company's proposal, once transmission projects and associated costs have been identified by the FRCC in its regional planning process, the company will provide to the Commission its specific construction plans, estimated construction costs and its expected in-service date. In the year the transmission project is expected to be substantially complete, Tampa Electric would file for cost recovery using a methodology similar to the Capacity Cost Recovery Clause projection filing. If actual capital costs of transmission projects are higher or lower than projected, the difference will be flowed back via a true-up to the Capacity Cost Recovery Clause. (Tr. 1449, lines 7 – 23)

The Commission should approve the proposed TBRA for the several reasons. First, the TBRA supports an important public policy, namely the construction and operation of additional transmission facilities designed to strengthen the electric grid. The Energy Policy Act of 2005 ("EPA 2005") put a new focus on transmission infrastructure and changed the process of coordinating and planning transmission lines. (Tr. 1017, line 21 – Tr. 1020, line 18). Under EPA 2005, the FERC has the right to mandate reliability standards and enforce them in multiple ways including assessing civil penalties for non-compliance. In 2007, the FERC approved the delegation of compliance, monitoring, and enforcement of reliability standards for Florida from the NERC to the FRCC. Under this framework, transmission projects identified and required to meet these reliability standards must be constructed and completed in a proper timeframe to meet the NERC criteria. (Tr. 1047, lines 6 – 21). Although the FRCC is not a governmental entity, it has the power to impose substantial fines and penalties if a company does not build transmission facilities as mandated by the FRCC. The Environmental Cost Recovery Clause ("ECRC") was designed to encourage investment in assets designed to protect the environment by fostering timely cost recovery of those assets. The same logic behind the ECRC cuts in favor of approving the TRBA.

Second, the TBRA is similar to the Generation Base Rate Adjustment clauses ("GBRAs") approved by the Commission in 2005.[16] (Tr. 1500, lines 6 – 14). Although the GBRAs approved by the Commission in those dockets were the result of stipulations between the parties involving a number of other issues, the Commission's approval of the GBRAs reflects a

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[16] In re: Florida Power and Light Docket No. 050045-EI, supra, pp. 3-4.
In re: Progress Energy Florida Docket No. 050078-EI, supra, p. 3.

proactive, forward-thinking, and innovative approach to cost recovery for generating asset additions similar to the approach advocated by the company in this case for transmission asset additions. Its prior approval of GBRAs does not oblige the Commission to approve the TBRA, but shows that the Commission can exercise its authority to approve the TBRA if it concludes, as it should, that doing so is in the public interest.

The intervenors have criticized the TBRA because Tampa Electric participates in the FRCC process and "controls" whether to build transmission assets and no other state commission has adopted a similar mechanism for transmission cost recover. Interestingly, FIPUG's own witness admitted the Texas Commission allows utilities to recover transmission costs in between base rate cases. (Tr. 2323, line 17 – Tr. 2324, line 1). Regardless, neither criticism is sufficient to overcome the strong public policy reasons supporting the TBRA.

First, Tampa Electric no longer controls the planning and construction of its transmission assets as it did in the past. While Florida never adopted a regional transmission organization with a cost allocation methodology for the sharing of regional transmission costs, the FRCC did develop a cost allocation methodology in response to FERC Order 890 in December 2007. This methodology is a settlement structure that parties agree to use when there are third party impacts resulting in the construction of new transmission facilities. (Tr. 1017, line 21 – Tr. 1020, line 18). Under the methodology, costs are allocated among multiple entities who contribute to the need for the third party facilities and who benefit from their construction. While this methodology is meant to allow for a fair allocation of costs based on who is causing the impact, the allocation of these costs will be an involved process among multiple parties and it will be very difficult to predict each party's share or cost responsibility. (Tr. 1048, line 16 – Tr. 1049, line 2)

Second, generator interconnection requests for firm transmission requests make planning and constructing transmission assets unpredictable. The FERC transmission tariff mandates that a transmission provider build transmission needed for generator interconnection requests for firm transmission service. Existing transmission capacity has been consumed over the last few years with these requests for generator interconnection and firm transmission service and new requests are requiring the construction of new transmission facilities. These requests are not predictable in nature but the construction of the facilities requested is necessary to maintain safe and reliable electric service in peninsular Florida. (Tr. 1049, lines 4 – 16)

Finally, the Commission should not be afraid of being first. Florida faces unique challenges with its transmission grid and those challenges call for unique regulatory responses. The Commission showed its willingness to be innovative when it approved GBRAs for FPL and PEF and can do the same for Tampa Electric with the TBRA. The Florida Public Service Commission has been rated as one of the top state regulatory commissions in the United States, primarily due to its forward looking and proactive stance on cost recovery. Approving the TBRA as proposed by the company would be consistent with and bolster the FPSC's reputation as an innovative regulatory body focused on advancing important public policy measures (timely construction and cost recovery of transmission projects) through reasonable regulatory innovations.

ASSIGNMENT OF REVENUE REQUIREMENT RESPONSIBILITY TO CLASSES OF CUSTOMERS

COST OF SERVICE

XIV. TAMPA ELECTRIC'S PROPOSED 12-CP AND 25 PERCENT COST METHODOLOGY AND THE CLASSIFICATION OF SCRUBBER AND GASIFIER AS ENERGY FAIRLY BALANCES THE INTERESTS OF ALL CUSTOMERS. (Issues 83 and 84)

Once the revenue requirements are established, the responsibility for paying the revenue requirements must be allocated among the various customer classes. Cost of service studies are this Commission's primary tool in assigning revenue requirements to customer classes. Selection of a cost of service methodology is a matter of judgment that should balance the interests of all customers.

Proposed 12-CP and 25 Percent Cost Methodology

Zero Sum Task

Once the Commission determines the overall revenue requirements for a utility in a rate proceeding, the recovery of those approved revenue requirements must be effected through rates designed to recover those revenue requirements. Costs removed from assignment to one class via a change in cost methodology must be made up by other classes of customers. This is what would occur if, for example, the Commission decided that Hillsborough County Schools should have a special discounted rate (discussed in more detail below)

Tampa Electric's proposed 12-CP and 25 percent cost of service methodology is fair for all customer classes. FIPUG's suggested changes to the company's proposal would shift $6.7 million of revenue requirement responsibility of interruptible and other demand customers to other customers of Tampa Electric – primarily residential. (Ex. 30, Document 6). Stated more specifically, FIPUG's members seek to avoid $6.7 million in revenue requirements responsibility by 1) reducing the amount of production plant allocated to energy usage from 25 percent as proposed by Tampa Electric to eight percent; and, 2) allocating the cost of the Big Bend Scrubber and Polk Unit One gasifier on demand rather than energy.

The Sweet Spot of Fairness

Tampa Electric's proposed 12-CP and 25 percent methodology is a fair methodology that places the energy allocation on the low side of the average of two cost of service study methodologies which previously have been approved by the Commission for Tampa Electric since 1980. The Equivalent Peaker Cost ("EPC") method, adopted by the Commission in Tampa Electric's 1985 rate case,[17] allocated about 70 percent of production plant to energy, as compared with the 25 percent proposed by the company and only eight percent proposed by FIPUG. While the EPC method was adopted in 1985 based on Staff testimony,[18] it was subsequently rejected in Gulf Power's 1990 rate case[19] in favor of the 12-CP and 1/13 (eight percent) methodology. This cost of service methodology was used in Tampa Electric's last rate case based on a settlement of rate design issues.[20]

The Selection of the Cost Methodology is a Matter of Judgment

The selection of the appropriate cost allocation method is a matter of judgment upon which reasonable people can disagree. Moreover, that judgment can change based on the circumstances of each case as evidenced by the Commission's selection of different methods over time as well as the advocated positions of various parties in different circumstances over time. More fundamentally, it comes down to a judgmental decision which affects how much of the revenue requirement should be allocated to each class. It is not an easy decision but it is a

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[17] In re: Tampa Electric, Docket No. 850050-EI, Order No. 15451 (12-13-85).
[18] See p. 34, Order 15451, supra.
[19] See Pollock footnote 23, In re: Gulf Power Company, Docket No. 891345-EI, Order 23573 (10-03-90), p. 48.
[20] In re: Tampa Electric, Docket No. 920324-EI, Order No. PSC-93-0165-FOF-EI, p. 77.

matter of reasoned judgment upon which the Commission has discretion based on the evidence presented in the case.

FIPUG's witness, Mr. Pollock, historically has opposed any allocation of production plant using energy. This position has allowed interruptible customers to escape paying any part of the revenue increases awarded in electric utility rate cases.[21] Consistently, in this case, Mr. Pollock and FIPUG have agreed that some allocation of production plant to energy is fair but attempt to limit that allocation to 8 percent.

While the 12-CP and 25 percent methodology has not been previously accepted by this Commission, that fact is entirely irrelevant. At one time, this Commission adopted the EPC methodology, which allocates more than twice the amount of production plant to energy than Tampa Electric proposes here. Tampa Electric believes that the EPC method allocates too much plant to energy and the 12-CP and 1/13 allocates to little. It is Tampa Electric and AARP's view that the 25 percent allocation is just right and that it is the fairest balancing of the energy allocation for all parties.

It is up to this Commission to decide, based on its judgment, if it wishes to shift cost responsibility from industrial customers such as Mosaic to residential customers. During the hearing in this case, FIPUG's counsel championed the cause of residential consumers, contending that customers are suffering in the current economic crisis. (Tr. 378, lines 6 – 8). If FIPUG is serious about its concern, it should abandon its efforts of advocating a cost of service methodology that directly shifts costs to residential customers. AARP, speaking primarily for residential customers, supports the company's position that the 12-CP and 25 percent cost of service methodology be adopted.

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[21] See In re: Tampa Electric, Docket No. 830012-EU, Order No. 12663 (11-07-83), p. 40; In re: Tampa Electric Docket No. 850050-EI, supra, p. 34.

Big Bend Scrubber and Polk Unit One Gasifier Should be Classified as Energy

Big Bend Scrubber

FIPUG's second attempt to shift revenue requirements away from large industrial customers is its attempt to reverse this Commission's long-standing policy of classifying environmental equipment costs as energy related in the cost of service study. The classification of the Big Bend Scrubber as energy related was adopted by this Commission in 1983[22] over FIPUG's objection as the Commission explained:

> We approved the company's classification since we certified the need for Big Bend 4 both because additional capacity was needed and because the new capacity would back out oil. Thus the plant was certified partly for demand related and partly for energy related reasons.

The allocation of environmentally related plant to energy was reaffirmed, with FIPUG's agreement, in Tampa Electric's 1992 rate cases[23] and since then has been reaffirmed in numerous ECRC proceedings. More specifically, the Commission reasoned in its 1994 Gulf Power order establishing the ECRC,[24] as follows:

> . . . We find that due to the strong nexus between the level of emissions which CAAA[25] seeks to reduce and the number of kilowatt hours generated, the costs associated with compliance with the CAAA shall be allocated to the rate classes on an energy basis because it is the most equitable way to apportion the compliance costs associated with the CAAA.

Similarly, the Commission, in approving Tampa Electric's petition to recover the cost of the Big Bend Units 1 through 3 Selective Catalytic Reduction facilities through the ECRC[26],

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[22] In re: Tampa Electric, Docket No. 830012-EU, Order No. 12663 (11-07-83) pp. 40-41.
[23] In re: Tampa Electric, Docket No. 920324-EI, Order No. PSC-93-0165-FOF-EI (1-02-93), p. 77.
[24] In re: Petition to Establish an Environmental Cost Recovery Clause by Gulf Power, Docket No. 930613-EI, Order No. PSC-94-0044-FOF-EI (1-12-94), pp. 23 – 25 rejecting FIPUG's objection ". . . to the 'carving out' of specific types of costs and allocating them on an energy basis. This is precisely what we did with respect to scrubber costs associated with TECO's Big Bend Four plant in TECO's last rate case."
[25] Clean Air Act Amendments.
[26] In re: Tampa Electric, Docket No. 041376-EI, Order No. PSC-05-0502-PAA-EI (5-09-05).

observed that in every order since the 1994 Gulf Power ECRC order, the Commission has required that costs associated with clean air compliance be allocated to rate classes on an energy basis because of the strong nexus.

Undoubtedly FIPUG will argue that under specific rate settlements for FPL and PEF, the Commission has accepted agreement of the parties that some environmental costs be recovered on a demand basis.[27] In other contexts, Mr. Pollock argues the Commission should ignore settlements as having no precedential value but argues for an exception when the terms of a settlement are favorable to FIPUG's position. Notwithstanding the FPL and PEF settlements, the Commission simultaneously has uniformly and consistently ordered that Tampa Electric's costs recovered through the ECRC be recovered on an energy basis.

Finally, the scrubber is not necessary from an engineering perspective for Big Bend Station to generate electricity. Indeed, the scrubber produces no energy, but instead, consumes energy to meet environmental requirements. The scrubber captures unwanted emissions from the plant and does not serve load or help maintain reliability. (Tr. 1700, lines 3 – 11)

Polk Unit One Gasifier

The Polk Unit One gasifier does just what its name implies. Coal is injected into the gasifier and is converted into a synthetic gas that is used to operate the power block. The operation of the gasifier is not an engineering requirement for the operation of Polk Unit One. The unit has dual fuel capability and can operate using oil should the gasifier be out of service. The gasifier converts one type of fuel (coal) to another (synthetic gas) for use in the power block. (Tr. 1700, line 13 – 1701, line 18). The gasifier produces fuel. Fuel and fuel handling

[27] Mr. Pollock dismisses the prior Commission approved energy classification from Tampa Electric's last rate case proceeding as merely the result of a stipulation but he champions the result of the 2005 FPL and PEF settlements in Dockets 050045-EI and 050078-EI, respectfully, which extracted that rate design concession as a part of a global settlements in each of those cases.

equipment have always been allocated and recovered on an energy basis.

Mr. Pollock's arguments that the scrubber and gasifier should be allocated on a demand basis are self-serving, flawed and illogical. They are merely a device intended to allow industrial customers to escape the responsibility for costs, which are directly related to their very substantial energy usage.

RATE DESIGN

XV. THE COMPANY'S PROPOSED CONSOLIDATED GSD RATE DESIGN FAIRLY CONSIDERS THE FULL RANGE OF THE USAGE CHARACTERISTICS OF ALL CUSTOMERS THAT WILL TAKE SERVICE UNDER THAT CLASS. (Issue 88)

The company's proposed rate design consolidates 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. FIPUG argued against the inclusion of IS customers in the GSD rate contending that IS customers are so different that a special separate rate class is required. This simply is not so, as was clearly demonstrated by Tampa Electric witness William Ashburn. Tampa Electric agreed that interruptibility is a feature that must be considered in rates, but the company demonstrated that interruptibility is fully and fairly considered in Tampa Electric'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 GSLM-3 interruptible service conservation programs. The programs provide appropriate compensation for interruptible service and they replace the non-cost effective compensation that has been provided under the current IS rates the company proposes to close.

Mr. Pollock attempted to distinguish interruptible customers in a number of ways but Mr. Ashburn debunked each of these arguments. Mr. Ashburn demonstrated that the differences in service characteristics within the three current classes are not significant enough that they cannot be combined as proposed. (Tr. 1693, line 1 – 1698, line 20) (Ex. 86, Documents 1 and 2). Moreover, Mr. Ashburn pointed out that many of these IS customers previously took service under GSD or GSLD rates prior to electing to become interruptible. (Tr. 1738, lines 19 – 23)

If the Commission determines that the IS class should remain separate from GSD, the class should remain closed to new business and should only consist of existing accounts. 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 the GSLM-2 and GSLM-3 riders and lower base rate charges. (Ex. 13, Document 15)

FIPUG's attempts to characterize the frequency and level of interruptions experienced by IS customers is misleading at best and factually incorrect. In attempting to show interruptible service is inferior, Mr. Moyle asserted in his opening statement that:

> The Mosaic Company since 1999 three times has been interrupted during the course of a year of more than 1,000 hours. (Tr. 53, lines 10 – 12)

The fact is that during the period cited, Tampa Electric's total hours of interruption for all IS customers was only 93.23 hours as shown in Tampa Electric's quarterly reports to this Commission filed under Rule 25-6.018, F.A.C. The greatest number and duration of interruptions was in 1999 with 16 interruptions for a total duration of 53 hours and 28 minutes. There were two full years when there were no interruptions at all and, in the remaining years, there were between one and five interruptions with total durations ranging from five minutes in one year to 11 hours and four minutes in another. Mr. Moyle's statement was a gross exaggeration. In no year - and indeed not in the entire 10-year period - did 1,000 hours of interruptions occur.

XVI. INTERRUPTIBLE SERVICE SHOULD BE PROVIDED AS A CONSERVATION PROGRAM, NOT AS A BASE RATE DISCOUNT. (Issue 87)

Regardless of whether interruptible customers are served under a new combined GSD rate as proposed by Tampa Electric or a separate IS rate as proposed by FIPUG, interruptible service is a demand-side load management conservation program. Customers who opt to be interruptible should be appropriately compensated for that commitment like all other load management customers.

Under the company's proposed approach, interruptible service would be provided under Tampa Electric's GSLM-2 and GSLM-3 conservation programs. These programs provide for a payment of interruptible demand credits to customers electing to take interruptible service. The credit approach was adopted for PEF with FIPUG's concurrence in 1992 and was reaffirmed in PEF's 2005 settlement agreement signed by FIPUG.[28] The only real issues raised by FIPUG in this docket appear to be 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 – all issues which are and should be matters determined in the Commission's conservation proceedings where the GSLM-2 and GSLM-3 programs are reviewed each year.

Level of the Credit

The agreement to be interruptible is a feature, which should be recognized for customers

[28] The credit approach was advocated by Staff in Tampa Electric's last rate case. However, the rate design issues in that case were settled and the credit approach was never specifically individually voted on by the Commission. The Commission did require Tampa Electric to file a cost of service study in its next rate case which develops a coincident CP kW credit based on avoided cost so that the matter could be litigated. In re: Tampa Electric Company, Docket No. 920324-EI, Order No. PSC-93-0165-FOF-EI (2/02/93), p. 76.

agreeing to assume the risks associated with that commitment. The value of that agreement is the same for all Tampa Electric customers. Interruptible service customers do not provide any incremental benefits over and above the benefits provided by residential demand-side load management customers selecting Prime Time service. Prime Time customers make a similar commitment to allow some portion of their service to be subject to interruption in exchange for a credit reflecting the value of that commitment. The Commission decides the level of such credits in the energy conservation cost recovery clause proceeding in November of each year and the credits are applied during the following year. The appropriate value of these credits for 2009 was decided in Docket No. 080002-EG, Order No. PSC-08-0783-FOF-EG to be $10.91 per coincident peak kW. That same rate should be applied to GSLM-2 and GSLM-3. The $10.91 conservation credit value ("CCV") level approved by this Commission for 2009 represents a 46 percent increase over the prior CCV. (Tr. 1713, lines 13-19)

Interruptible service customers deserve no special increased level of credit for their interruptibility. An interruptible credit based on the CCV approved for 2009 would enable interruptible customers to realize a 62 percent discount in their contribution to the cost of production capacity as compared with firm GSD customers. This is a very fair discount for agreeing to take interruptible service. It is entirely unnecessary to go beyond this level of discount to attract or retain interruptible customers. (Tr. 1713, line 21 – Tr. 1714, line 4)

Mr. Pollock's recommendation to raise the credit from $10.91 to $13.60 would shift costs to all other customers. If Mr. Pollock's recommendation was adopted, the higher CCV for IS customers would result in a 78 percent discount to interruptible customers. This level of discount is excessive and unnecessary to attract and retain general service interruptible load. (Tr. 1714, lines 9-15)

Duration of the Credit Levels

The GSLM-2 and GSLM-3 credits applied in the first year are locked in for a three-year period, which coincides with the three-year commitment required under the current tariff. At any point after the initial three-year period, the customer may choose to lock in at the current credit for a new three-year period. (Tr. 1663, lines 12 – 20). This approach provides more flexibility than FIPUG's suggestion that the credit be set and not changed until the company's next rate case. FIPUG offers no credible support why an IS credit should operate any differently than the GSLM-2 or GSLM-3 credits.

Load Factor Adjustment

FIPUG objects to Tampa Electric's proposed load factor adjustment to the credit. The CCV is an amount established per kW of demand coincident with the company's monthly system peaks. This 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.

Mr. Ashburn explained that the load factor adjusted credit is an equitable rate design for application of the wide range of usage characteristics inherent in the group of interruptible customers. PEF has consistently used this design for establishing credits since 1995. (Tr. 1714 line 21 – Tr. 1716, line 4). Mr. Pollock's suggestion to estimate customers' coincident peak by establishing and monitoring loads during a "base line" period, or alternatively measuring customers' loads in real-time, would impose a burdensome analytical requirement and would result in billing delays, without providing any assurance of meaningful improvement in the estimation of coincident demand. (Tr. 1715, lines 9 – 16). His suggestion should be rejected.

Payment for Cost of the Credits

All customers, including interruptible customers, should share in the cost of providing credits for all load management conservation programs that provide customer credits for interruptibility. Mr. Pollock's assertion that interruptible customers should not have to contribute to cost recovery of the credits reveals Mr. Pollock's complete misunderstanding of the purpose of the credits. Mr. Ashburn explained in some detail the fallacy of Mr. Pollock's proposed cost recovery avoidance. (Tr. 1716, line 10 - Tr. 1718, line 9)

In Tampa Electric's 1983 rate case[29] this Commission held:

> We continue to believe and the record supports our finding that because all conservation programs benefit all consumers of electricity, the expenses and revenues associated with them should be allocated to all classes on the basis of kWh consumption. (Emphasis supplied.)

Ironically FIPUG in that case ". . . made their perennial argument that a cost of a particular conservation program be allocated to the class for which the money is spent."[30] FIPUG supported that interruptible customers should pay the entire cost of the credit. It is clear that FIPUG in various cases changes its philosophy to its benefit and at the cost of other customers, primarily residential customers.

XVII. TAMPA ELECTRIC'S PROPOSED INVERTED RATE PROVIDES LOWER BILLS TO TWO-THIRDS OF RESIDENTIAL CUSTOMERS. (Issue 91)

Tampa Electric's proposed inverted residential base rate conforms to the residential rate structures of FPL, PEF and FPUC. In a series of cases, this Commission has adopted inverted rates to encourage conservation. The higher rate at the second block, above 1,000 kWh, provides

[29] In re: Tampa Electric, Docket No. 830012-EU, Order 12663 (11/07/83), p. 41.
[30] Order 12663 supra, p. 41.

a price signal to customers about energy usage that can serve as a way to encourage energy conservation while the lower first block rate provides a billing benefit to lower use customers.

The History of Inverted Residential Rates in Florida

This Commission first approved the inversion of residential rates in 1977 with a 750 kWh breakpoint[31] as an experimental attempt to encourage wise use of irreplaceable natural resources, while curbing the need for additional generating capacity. In 1981, the Commission found the inverted rate should be continued because "the inverted rate may have a positive conservation effect" but it decided that the difference between the first and second block was not high enough and should be increased.[32] Again in 1984 the Commission voted to retain the inversion as intuitively conservation oriented.[33]

The inverted base energy residential rate has become a standard in Florida. It was reaffirmed for FPL in 2005[34] and expanded to PEF in 2002.[35] The inversion was included for fuel rates in 2005 for FPL[36] and PEF,[37] in 2008 for FPUC[38] and in 2009 for Tampa Electric.[39]

The Inverted Rate Benefits Two-Thirds of Tampa Electric's Customers

Tampa Electric's proposed inverted base rate and approved inverted fuel rate provide one rate for the first 1,000 kWh usage per month and a higher rate for usage over the first 1,000 kWh per month. Although the breakpoint is at 1,000 kWh, customers who use up to 1,539 kWh per month will have lower bills on an inverted rate than on a flat rate.

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[31] See In re: Florida Power and Light, Order No. 8032 (11/02/77), p. 3.
[32] See In re: Florida Power and Light, Order No. 80306 (9/23/81), p. 46.
[33] See In re: Florida Power and Light, Order No. 13537 (7/24/84), p. 63.
[34] See In re: Florida Power and Light, Docket 050045-EI, Order No. PSC 05-0902-S-EI (9/14/05) – Inversion point raised from 750 kWh to 1,000 kWh/month.
[35] See In re: Progress Energy Florida, Docket No. 000824-EI, Order No. PSC-02-0655-AS-EI (5/14/02).
[36] See In re: Florida Power and Light, Docket No. 050045-EI, Order No. PSC-05-0902-S-EI (9/14/05).
[37] See In: Fuel Adjustment, Docket No. 050001-EI, Order No. PSC-05-1252-EI (12/23/05).
[38] In re: Fuel Adjustment, Docket No. 080001-EI, Order No. PSC-08-0030-FOF-EI (1/08/08), p. 5
[39] In re: Fuel Adjustment, Docket No. 080001-EI, Order No. PSC-08-0824-FOF-EI, (12/22/08), p. 11.

Over two-thirds of Tampa Electric's customers have bills below 1,539 kWh per month and will benefit from the inverted rate with an inversion point at 1,000 kWh per month. At the breakeven point of 1,539 kWh per month, a customer's electric bill would be the same under both rate designs (current and proposed). (LF Ex. 115). This effect is achieved because the first 1,000 kWh of usage for all customers (regardless of total usage above 1,000 kWh) is billed at the lower rate and only the usage above 1,000 kWh is billed at the higher rate. (Ex. 31)[40]

The Rate Comparison Benefit 1,000 kWh Inversion Point, Not 1,250 kWh

Although Tampa Electric's average monthly residential customer usage is 1,262 kWh, it is not necessary to set the inversion point at 1,250 kWh to benefit all customers with less than the average usage. Average customer usage does not have any special or significant effect on designing the inverted rates. Moving the inversion point from 1,000 to 1,250 kWh will reduce the benefits of inverted rates to customers with usage 1,000 kWh and lower, benefit customers between 1,000 kWh and slightly above 2,000 kWh, and then reduce the benefits for customers above that new breakeven level (Ex. 115, Table III).

The other Florida investor-owned utilities with inverted rates all utilize a 1,000 kWh inversion point for both base energy and fuel and utilizing this same point better facilitates rate comparisons between companies, as well as reduces confusion when customers are served by other Florida electric companies. It would be even more confusing to customers if Tampa Electric had a different inversion point for its fuel rate and base energy rate. The Commission recently adopted the 1,000 kWh inversion point for Tampa Electric's residential fuel rates. Therefore, Tampa Electric's inverted residential rate is appropriate as proposed.

[40] EX. 31 is Service Hearings Late-Filed Exhibit 12.

XVIII. TRANSFORMER OWNERSHIP DISCOUNTS, AS DESIGNED BY THE COMPANY, ARE APPROPRIATE AND REFLECT COMMISSION POLICY. (Issue 103)

Ratchet Issue

Mr. Pollock claimed the company misapplied ratcheted demands to the transformer ownership discounts. Mr. Ashburn showed in his rebuttal testimony, Mr. Pollock was incorrect. Although Mr. Pollock did not withdraw his testimony to this effect, his errata filing of January 26, 2009 provided a revised Exhibit JP-17, which showed the corrected ratcheted demands in the calculation of transformer ownership discounts for standby as proposed by Tampa Electric. This errata effectively demonstrates that Mr. Pollock has acknowledged the error in his direct testimony and now agrees with the company's design of the transformer discounts.

Credits for Equipment Other than Transformers

FIPUG's witness Mr. Pollock has suggested that despite the appropriate provision of transformer ownership credits by Tampa Electric for higher voltage service, such service should also be granted greater credit related to other equipment avoided. This suggestion has not been supported by FIPUG in this case and should be rejected. The Commission has recognized transformer ownership credits, along with recognition of demand and energy losses, as the appropriate differentiation for rates in the past[41] and nothing in this case supports changing this policy at this time.

XIX. SPECIAL SUBSIDIZED RATES FOR FAVORED CUSTOMERS SHIELDS THEM FROM THE TRUE COST OF SERVICE AND INAPPROPRIATELY RAISE RATES TO OTHER CUSTOMERS. (Issue 110)

A Special Subsidized K-12 School Rate Is an Inappropriate Undue Discrimination Against Other Customers.

The Superintendent of Hillsborough County Schools testified at the service hearing in

[41] See In re: Tampa Electric, Docket No. 850050-EI, Order No. 15451, p. 45

Tampa, and again at the outset of the procedural hearing in Tallahassee asking for a special subsidized rate for public schools to offset the schools' budget crisis. The Commission should resist the temptation to adopt specific end-use rates to benefit any favored customer or customer class.

This Commission, in a very informed move beginning in 1979, systematically eliminated the various favored, subsidized customer rates that had been previously approved, such as chicken farmer rates, citrus irrigation rates, sports field riders, specific residential garages, water pumps rates, etc.[42] The Commission found that these subsidized rates were simply unfair and should be eliminated in favor of rates classified on the basis of usage characteristics. This action avoided the consistent emotional appeals of various groups that their organization, business or activities were worthy causes that should be subsidized by the general body of ratepayers. Cattle farmers complained that chicken farmers were favored and truck farmers growing vegetables with irrigation complained that citrus irrigation got a special rate. Individuals with outdoor lighting could not understand why little league baseball fields got special rates for their lighting. The lessons of this history should be heeded or the adverse effects will be experienced once again.

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[42] See In re: Florida Power and Light, Docket No. 810002-EU, Order 10136 (7/14/81), p. 47 (separately metered facilities of residential customers –garage, water pumps, etc.) and poultry farms. In re: Florida Power and Light, Docket No. 820097-EU, Order No. 11437 (12/22/82), p. 53, poultry farms. In re: Florida Power Corp., Docket No. 820100-EU (2/17/83), p. 42 (rate MS-1 – municipal service rate eliminated including traffic signals, street lighting, sports fields, city halls, jails and convention centers, saying:

> In the company's last rate case the Commission found that a rate of this type was not cost based and, as a matter of equity, could not be justified. However, because the record in that case contained no information as to the impact of electricity the rate, the rate was continued and the company was ordered to furnish an analysis . . .

In this proceeding, the impact of eliminating the rate was thoroughly explored by the company, the CLG and the Staff. <u>Because the MS-1 rate is inequitable, it will be eliminated.</u> (Emphasis supplied)

In re: Tampa Electric, Docket No. 760846-EU, Order No. 7987, sports field provision adopted. In re: Tampa Electric, Docket No. 820007-EU, Order No. 11307 (11/10/82), pp. 45 – 46 declining to adopt a special rate for low load factor Florida Citrus Growers and eliminating the sports field rider and poultry farm rates.

When the Commission moved to cost-based rates following the adoption of the Public Utility Regulatory Policies Act of 1978, specific end-use rates were eliminated in favor of rate classification based on usage characteristics. Specifically, in Order No. 8950, issued on July 13, 1979, the Commission found that:

> Separate rate schedules should be allowed only to the extent that they reflect different use and load characteristics and hence, different costs associated with serving that class of customers. As a result, rate schedules to serve specific customers, (cotton gins, commercial bakeries, all-electric customers, etc.) will no longer be permitted and such classifications as "commercial" or "industrial" should be eliminated.

A Separate School Rate Cannot Be Supported Based On
<u>Specific Use Characteristics</u>

As emphasized by Mr. Ashburn on cross examination by Staff, Tampa Electric does not have data necessary to establish a separate rate for schools based on usage characteristics. (Tr. 1812, line 17 – Tr. 1814, line 14). Tampa Electric simply does not have enough information to develop a cost-based rate structure for public schools as a group. (Tr. 1813, lines 15 – 18).[43] Moreover, the usage characteristics of the county public schools that are included in Tampa Electric's load research sampling process indicate a higher cost of service for county public schools than current rate classes in which most of such schools accounts are currently included. (Tr. 1826, lines 1 – 23)

Two final observations are in order regarding the concept of a special rate for county public schools. First, Tampa Electric has numerous energy efficiency conservation programs available to commercial customers, including county public schools, which can assist in reducing electric costs.[44] While Hillsborough County Schools have taken advantage of some of the programs, there are further opportunities available for schools to help manage energy usage.

[43] See also response to Staff Interrogatory 227.
[44] See response to Staff Interrogatory 229.

Second, if a non-cost compensatory discount rate was approved for the schools, then rates for all other customers would be higher to subsidize the school rate.

As it has in the past, Tampa Electric will continue to work with school leaders to achieve the most cost effective and conservation-oriented service possible. This is a better alternative than attempting to establish a special subsidized rate for public schools.

POST-HEARING STATEMENT OF ISSUES AND POSITIONS

TEST PERIOD

STIPULATED[45]

ISSUE 1: **Is TECO's projected test period of the 12 months ending December 31, 2009 appropriate?**

TECO: *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 Customers, KWH, and KW by Rate class for the 2009 projected test year appropriate?**

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.*

QUALITY OF SERVICE

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

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 but presenting no evidence on the issue.*

RATE BASE

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

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.*

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[45] Stipulated positions on issues reflected herein are taken from the list of stipulated issues furnished by Staff counsel at the outset of the hearing which, with the exception of ISSUE 3, were approved unanimously by the Commission (at Tr. 28, line 4 – Tr. 29, line 6).

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

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 improve 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.*

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

TECO: *No. TECO has properly accounted for the Big Bend Rail Project. The credit is specifically associated with the construction costs. The Commission should approve 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.*

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

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. *

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

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.*

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

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.*

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?**

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

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?**

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

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

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

ISSUE 13: **Is TECO's requested level of Construction Work in Progress in the amount of $101,071,000 for the 2009 projected test year appropriate?**

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.*

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?**

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.*

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

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.*

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

TECO: * The Commission should approve TECO's proposed annual accrual and reserve target of $20 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.*

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

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

ISSUE 18: **Should an adjustment be made to working capital related to account 143-Other Accounts Receivable?**

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.*

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

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.*

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

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

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

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.*

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

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.*

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

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.*

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

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.*

STIPULATED
ISSUE 25: **Has TECO properly reflected the net overrecoveries or net underrecoveries of fuel and conservation expenses in its calculation of working capital?**

TECO: *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?**

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.*

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

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

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

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.*

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?**

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.*

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?**

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.*

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

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.*

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

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 is consistent with past Commission decisions, appropriate and should be approved.*

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

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.*

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

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.*

ISSUES 35[46] AND 36

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

[46] ISSUES 35 and 36 were dropped in the Prehearing Order.

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.*

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

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

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

STIPULATED
ISSUE 40: **What are the appropriate inflation factors for use in forecasting the test year budget?**

TECO: *Having reviewed TECO's inflation escalation factor for its forecasts and compared it with Florida's National Economic Estimating Conference (10/2/2008) CPI forecasts, we find that TECO's 2.06 percent 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?**

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.*

STIPULATED
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?**

TECO: *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.*

STIPULATED
ISSUE 43: **Has TECO made the appropriate test year adjustments to remove conservation revenues and expenses recoverable through the Conservation Cost Recovery Clause?**

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

STIPULATED
ISSUE 44: **Has TECO made the appropriate test year adjustments to remove capacity revenues and expenses recoverable through the Capacity Cost Recovery Clause?**

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

STIPULATED
ISSUE 45: **Has TECO made the appropriate test year adjustments to remove environmental revenues and expenses recoverable through the Environmental Cost Recovery Clause?**

TECO: *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?**

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

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

TECO: *Yes. TECO has made the appropriate adjustments 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?**

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.*

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

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

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

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 operational requirements. The budget system does not utilize headcount, only forecasted expenses.*

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

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.*

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

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.*

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

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.*

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

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.*

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

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

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

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

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

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

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

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

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

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 serve to normalize the level of storm damage expense over time.*

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

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

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

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.*

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

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.*

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

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.*

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

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.*

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

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

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

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.*

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

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.*

ISSUE 68: **Should an adjustment be made to reduce TECO's transmission inspection expense for the 2009 projected test year?**

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.*

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?**

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.*

ISSUE 70: **Is the pro forma adjustment related to amortization of CIS costs associated with required rate case modifications appropriate?**

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.*

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?**

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.*

ISSUE 72: **Is the pro forma adjustment related to the annualization of rail facilities to be placed in service in 2009 appropriate?**

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.*

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?**

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.*

ISSUE 74: **What is the appropriate amount of Depreciation Expense for the 2009 projected test year?**

TECO: *The appropriate amount of Depreciation Expense for the 2009 projected test year is $194,608,000 as shown on MFR Schedule C-1.*

ISSUE 75: **Should an adjustment be made to Taxes Other Than Income Taxes for the 2009 projected test year?**

TECO: *No. TECO has properly forecasted Taxes Other Than Income Taxes and no adjustment is warranted.*

ISSUE 76: **Is it appropriate to make a parent debt adjustment as per Rule 25-14.004, Florida Administrative Code?**

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.*

ISSUE 77: **Should an adjustment be made to Income Tax expense for the 2009 projected test year?**

TECO: *No. TECO has properly forecasted Income Tax expense and no adjustment is warranted.*

ISSUE 78: **Is TECO's projected Net Operating Income in the amount of $182,970,000 for the 2009 projected test year appropriate?**

TECO: *Yes. TECO's projected Net Operating Income of $182,970,000 for the 2009 projected test year is appropriate.*

REVENUE REQUIREMENTS

ISSUE 79: **What is the appropriate 2009 projected test year net operating income multiplier for TECO?**

TECO: *The appropriate net operating income multiplier for the 2009 test year is 1.63490 as shown on MFR Schedule C-44.*

ISSUE 80: **Is TECO's requested annual operating revenue increase of $228,167,000 for the 2009 projected test year appropriate?**

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.*

RATE ISSUES

STIPULATED
ISSUE 81: **Did TECO correctly calculate the projected revenues at existing rates?**

TECO: *Yes, TECO correctly calculated the projected revenues at existing rates.*

STIPULATED
ISSUE 82: **Is TECO's proposed Jurisdictional Separation Study appropriate?**

TECO: *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 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?**

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 1/13th (or about 8 percent) AD better reflects cost causation.*

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?**

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.*

<u>STIPULATED</u>
<u>ISSUE 85</u>: Is TECO's calculation of unbilled revenues correct?

<u>TECO</u>: *Yes, TECO's calculation of unbilled revenues is correct.*

<u>ISSUE 86</u>: What is the appropriate allocation of any change in revenue requirements?

<u>TECO</u>: *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.*

<u>ISSUE 87</u>: Should the interruptible rate schedules IS-1, IS-3, IST-2, 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?

<u>TECO</u>: *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.*

<u>ISSUE 88</u>: Should the GSD, GSLD and IS rate schedules be combined under a single GSD rate schedule?

<u>TECO</u>: *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.*

<u>STIPULATED</u>
<u>ISSUE 89</u>: Is the change in the breakpoint from 49 kW to 9,000 kWh between GS and GSD rate schedules appropriate?

<u>TECO</u>: *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.*

<u>STIPULATED</u>
<u>ISSUE 90</u>: What is the appropriate meter level discount to be applied for billing, and to what billing charges should that discount be applied?

<u>TECO</u>: *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.*

<u>ISSUE 91</u>: Should an inverted base energy rate be approved for the RS rate schedule?

<u>TECO</u>: *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.*

<u>STIPULATED</u>
<u>ISSUE 92</u>: 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?

<u>TECO</u>: *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.*

<u>ISSUE 93</u>: Should TECO's proposed single lighting schedule, and associated charges, terms, and conditions be approved?

<u>TECO</u>: *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.*

<u>ISSUE 94</u>: Are the two new convenience service connection option and associated connection charges appropriate?

<u>TECO</u>: *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.*

ISSUE 95: **Are TECO's proposed Reconnect after Disconnect charges at the point of metering and at a point distant from the meter appropriate?**

TECO: *Yes. TECO's proposed Reconnect after Disconnect charges at the point of metering and at a point distant from the meter are appropriate.*

STIPULATED
ISSUE 96: **Is the proposed new meter tampering charge appropriate?**

TECO: *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?**

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.*

ISSUE 98: **What are the appropriate service charges (initial connection, normal reconnect subsequent subscriber, field credit visit, return check)?**

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*

ISSUE 99: **What is the appropriate temporary service charge?**

TECO: *The appropriate temporary service charge is $235.*
ISSUE 100: **What are the appropriate customer charges?**

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/bill
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
SBF Time-of-Day Subtransmission 11	$955.00/bill*

<u>ISSUE 101</u>: What are the appropriate demand charges?

<u>TECO</u>: *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*

<u>ISSUE 102</u>: What are the appropriate Standby Service charges?

<u>TECO</u>: *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*

ISSUE 103: **Is TECO's proposed change in the application of the transformer ownership discount appropriate?**

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.*

ISSUE 104: **What is the appropriate transformer ownership discount to be applied for billing?**

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*

ISSUE 105: **What are the appropriate emergency relay service charges?**

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*

STIPULATED
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?**

TECO: *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?**

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*

STIPULATED
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?**

TECO: *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 and energy conservation cost recovery clause factors should be recovered on demand basis rather than an energy basis.*

ISSUE 109: **What are the appropriate monthly rental factors and termination factors to be approved for the Facilities Rental Agreement, Appendix A?**

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%*

ISSUE 110: **Is it appropriate to establish a customer specific rate schedule for county (K-12) public schools in this proceeding?**

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.*

STIPULATED
ISSUE 111: **What is the appropriate effective date for the rates and charges established in this proceeding?**

TECO: *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 be 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?**

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.*

STIPULATED
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 findings in this rate case?**

TECO: *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**

TECO: *Yes.*

DATED this 17TH day of February, 2009.

Respectfully submitted,

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CERTIFICATE OF SERVICE

I HEREBY CERTIFY that a true and correct copy of the Brief and Post-Hearing Statement of Issues and Positions, filed on behalf of Tampa Electric Company, has been served by hand delivery (*) or U. S. Mail on this 17th day of February, 2009 to the following:

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