BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

In the Matter of:

DOCKET NO. 130040-EI

PETITION FOR RATE INCREASE
BY TAMPA ELECTRIC COMPANY.
_______________________________/

VOLUME 6

Pages 960 through 1205

PROCEEDINGS: HEARING

COMMISSIONERS PARTICIPATING: CHAIRMAN RONALD A. BRISÉ
COMMISSIONER LISA POLAK EDGAR
COMMISSIONER ART GRAHAM
COMMISSIONER EDUARDO E. BALBIS
COMMISSIONER JULIE I. BROWN

DATE: Monday, September 9, 2013

TIME: Commenced at 9:37 a.m.
Concluded at 10:01 a.m.

PLACE: Betty Easley Conference Center
Room 148
4075 Esplanade Way
Tallahassee, Florida

REPORTED BY: LINDA BOLES, CRR, RPR
Official FPSC Reporter
(850) 413-6734

APPEARANCES: (As heretofore noted.)

I N D E X

WITNESSES

EXHIBITS

NUMBER:	ID.	ADMTD.

NO EXHIBITS MARKED OR ADMITTED IN THIS VOLUME

P R O C E E D I N G S

(Transcript follows in sequence from Volume 5.)

DIRECT TESTIMONY

OF

Jacob Pous

On Behalf of the Office of Public Counsel

Before the

Florida Public Service Commission

Docket No. 130040-EI

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Jacob Pous and my business address is 1912 W Anderson Lane, Suite 202, Austin, Texas 78757.

Q. WHAT IS YOUR OCCUPATION?

A. I am a principal in the firm of Diversified Utility Consultants, Inc. ("DUCI"). A copy of my qualifications appears as Exhibit JP-1.

Q. PLEASE DESCRIBE DIVERSIFIED UTILITY CONSULTANTS, INC.

A. DUCI is a consulting firm located in Austin, Texas with an international client base. The personnel of DUCI provide engineering, accounting, economic, and financial services to its clients. DUCI provides utility consulting services to municipal governments with utility systems, to end-users of utility services, and to regulatory bodies such as state public service commissions. DUCI provides complete rate case analyses, expert testimony, negotiation services, and litigation support to clients in electric, gas, telephone, water, sewer, and cable utility matters.

Q. HAVE YOU PREVIOUSLY TESTIFIED AS AN EXPERT WITNESS IN PUBLIC UTILITY PROCEEDINGS?

A. Yes. Exhibit JP-1 also includes a list of proceedings in which I have previously presented testimony. I have also been involved in numerous utility rate proceedings that resulted in settlements before testimony was filed. In total, I have participated in well over 400 utility rate proceedings in the United States and Canada and have testified as an expert in many areas, including depreciation, cash working capital, operations and maintenance expenses, corporate overhead allocations, fuel costs, fuel inventories, and class cost of service. Also worthy of note is that I have testified on behalf of the staff of five different state regulatory commissions and one Canadian regulator.

Q. WHAT IS YOUR PROFESSIONAL BACKGROUND?

A. I am a registered professional engineer. I am registered to practice as a Professional Engineer in the State of Texas, as well as several other states.

Q. ON WHOSE BEHALF ARE YOU PROVIDING THIS TESTIMONY?

A. Florida's Office of Public Counsel ("OPC") engaged me to address the amortization aspects of the revenue requirements request of Tampa Electric Company (the

"Company" or "Tampa Electric") pending before the Florida Public Service Commission (the "Commission" or "PSC") in this proceeding.

SECTION I: OVERVIEW

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. My testimony will address two issues associated with the Company's proposed amortization of software investment recorded in Account 303 – Miscellaneous Intangible Plant – Software. The first issue addresses the Company's proposal for continuation of a five-year amortization period for the vast majority of the investments in its software systems and a request for a 10-year amortization for its newly installed Enterprise Resource Planning ("ERP") software system. I recommend adjusting these amortization periods to 15 years. The second issue I address relates to the level of amortization reserve associated with the Company's newly installed ERP software system. The Company has booked amortization expense into the accumulated provision for amortization through the end of 2014 based on a 10-year amortization period, while it appears that the Commission has only approved a five-year amortization period for software in prior proceedings. Therefore, I recommend that the Company's 13-month amortization reserve in 2014 be increased from $3.327 million to $5.271 million. My testimony is also supported by Exhibit JP-2, which contains copies of referenced materials.

Q. WHAT IS THE IMPACT OF YOUR RECOMMENDATIONS?

A. Adjusting the Company's proposed five- and 10-year software system amortization periods to 15 years results in a $6.197 million decrease to the Company's proposed $10.126 million intangible software amortization expense for 2014 and an increase in 2014 rate base of $3.099 million.

The impact of my second recommendation results in a $1.948 million increase to the Company's proposed 2014 amortization reserve, which decreases overall rate base by the same amount.

<u>SECTION II: BACKGROUND</u>

Q. DID THE COMPANY FILE A DEPRECIATION STUDY WITH THE COMMISSION IN APRIL 2011?

A. Yes. In Docket No. 110131-EI, the Company filed its regular depreciation and decommissioning studies in compliance with Rules 25-6.0436(8)(a) and 25-6.04364(3), F.A.C. Order No. PSC-12-0175-PAA-EI, issued April 3, 2012, at p. 1. While amortization of intangible software is often a component of depreciation analyses, the Company's study and the corresponding proceeding before the Commission do not address any changes to software amortization. The Company's decision not to address software amortization in its depreciation filing was made with apparent knowledge that it was going to implement a new ERP software system later that year. Therefore, the Company had every opportunity to inform the Commission of any proposed change to software amortization that it was inclined to implement for its soon-to-be-implemented ERP software system. However, it chose not to do so.

Given that the Company did not address software amortization in its recent depreciation filing before the Commission, it is appropriate to review the Company's prior rate proceeding for guidance as to whether it specifically sought permission to apply a different amortization period to the new ERP software system compared to the Commission-approved five-year amortization period for investment in Account 303 – Intangible Plant - Software. A review of Docket No. 080317-EI, the last rate case, and the resulting Order No. PSC-09-0283-FOF-EI, reveals that the only discussion regarding software amortization corresponds to a five-year amortization period. (Order No. 09-0283-FOF-EI, issued April 30, 2009, at pp 11, 12, 73, and 74). Therefore, the Company's request to rely on a 10-year amortization period for its new ERP software system in this case represents the first formal request to change the Commission's authorized five-year amortization period for software investment.

<u>SECTION III: SOFTWARE AMORTIZATION PERIOD</u>

Q. WHAT IS AMORTIZATION?

A. In its publication entitled *Depreciation Practices*, the National Association of Regulatory Utility Commissioners ("NARUC") defines amortization as "[t]he process of allocating a fixed amount, such as total cost of an asset to an expense account over future accounting periods." (1996 edition of *Public Utility Depreciation Practices* at p. 314). The Federal Energy Regulatory Commission ("FERC") also defines amortization as ". . . the gradual extinguishment of an amount in an account by distributing such amount over a fixed period, over the life of the asset or liability to which it applies, or over the period during which it is anticipated the benefit will be realized." (FERC Uniform System of Accounts 18 CFR Part 101, at Definition 4).

Q. DOES THE COMPANY AMORTIZE ITS INVESTMENT IN ACCOUNT 303 – INTANGIBLE PLANT - SOFTWARE?

A. Yes. The Company records its $70 million investment in software in Account 303 – Miscellaneous Intangible Plant. The Company has previously relied on a five-year amortization service life or period for software capitalized to Account 303 – Miscellaneous Intangible Plant. (Response to OPC's Third Set of Interrogatories, No. 23). The Company proposes to continue its reliance on a five-year amortization period for all of its major software system investments except for its new ERP system, for which it proposes a 10-year amortization period. (Response to OPC's Ninth Set of Interrogatories, No. 130 (a)).

Q. WHEN DID THE COMPANY ESTABLISH ITS FIVE-YEAR AMORTIZATION PERIOD ASSUMPTION FOR INTANGIBLES SOFTWARE?

A. The Company initiated a five-year amortization for software in ". . . the late 1970s." (Response to OPC's Third Set of Interrogatories, No. 23). In other words, the Company has employed a five-year amortization period for approximately 35 years, without change.

Q. WHAT WAS THE COMPANY'S BASIS FOR ADOPTING A FIVE-YEAR AMORTIZATION PERIOD FOR SOFTWARE IN THE LATE 1970S?

A. The Company relied on what it claims is "guidance" from the FERC Commission's Audit Division Chief, to the FERC's Audits Division Field Staff concerning the proper accounting for software capitalized, which was issued on March 1, 1977. (Response to OPC's Third Set of Interrogatories, No. 23). Further, the Company states that it ". . . <u>believes</u> this life is still representative of the life of general use software due to technological obsolescence and upgrade cycles." (Response to OPC's Third Set of Interrogatories, No. 23). (Emphasis Added).

Q. IF THE FIVE-YEAR AMORTIZATION WAS ESTABLISHED IN THE LATE 1970S BASED ON GUIDANCE FROM FERC REGARDING CAPITALIZED SOFTWARE, IS THE FIVE-YEAR PERIOD STILL VALID TODAY?

A. No, at least not without the benefit of any verifiable basis. While common sense and logic dictate that "guidance" given 35 years ago for software systems is no longer valid given the changes in technology, the Company should have been aware that FERC formally documented its position on depreciation, and in effect amortization, which impacts capitalized software in FERC Order No. 618, issued July 27, 2000. In that order, FERC noted its statutory obligation to ensure that electric utilities charge proper amounts of depreciation (capital recovery) to expense each financial reporting period and amended its general instructions for Title 18 of the Code of Federal Regulations, Part 101, regarding the standards for determining depreciation for accounting purposes. The impact of FERC's action was ". . . to ensure that utilities allocate in a systematic and rational manner the cost of utility property to the periods during which the property is used in utility operations." (FERC Order No. 618 at p. 1).

Q. HAS THE COMPANY PROVIDED ANY SUPPORT AND JUSTIFICATION FOR ITS BELIEF THAT THE FIVE-YEAR AMORTIZATION PERIOD ESTABLISHED MORE THAN 35 YEARS AGO IS STILL VALID?

A. No. (Response to OPC's Third Set of Interrogatories, No. 23 (a)). In spite of FERC's mandate that the amortization life or time period be supported by engineering, economic, or other depreciation studies, the Company fails to provide any support for its claim other than by stating that it still "believes" the five-year period is right.

Q. DID YOU REQUEST ALL STUDIES OR ANALYSES PERFORMED BY THE COMPANY SINCE 1999 TO TEST THE CONTINUED REASONABLENESS OF THE FIVE-YEAR AMORTIZATION PERIOD EMPLOYED?

A. Yes. However, the Company specifically stated that no analyses had been done to support the five-year amortization period. It instead relies on the phrase "judgment and experience" to validate the continued use of a five-year amortization period. The phrase, "judgment and experience," without any quantifiable support in the form of the required engineering, economic, or other depreciation studies, is insufficient.

Q. DO THE COMPANY'S ACTIONS COMPLY WITH FERC DIRECTIVES REGARDING DEPRECIATION ACCOUNTING?

A. No. General Instruction 22 of the Uniform System of Accounts states that a utility ". . . must use a method of depreciation [amortization] that allocates in a systematic and rational manner the service value of depreciable property over the service life of the property." (Emphasis added) (USOA General Instruction 22 Depreciation Accounting (a) Method). General Instruction 22 further states that "[e]stimated useful service lives of depreciable property must be supported by engineering, economic, or other depreciation studies." The Company's admission that it has not performed any such studies demonstrates not only the lack of support for the Company's proposal, but also a violation of FERC's current requirement guidelines.

Q. IS THE COMPANY'S CLAIMED "JUDGMENT AND EXPERIENCE" BASIS FOR A FIVE-YEAR AMORTIZATION PERIOD FOR SOFTWARE AMORTIZATION APPLICABLE TO ALL SOFTWARE?

A. Apparently not. While defending its use of a five-year amortization period without any specific analyses, studies, or empirical evidence, the Company states that for its new ERP software system it is now proposing that a 10-year amortization be adopted. (Response to OPC's Ninth Set of Interrogatories, No. 130 (a)). Apparently, there are different aspects of undefined "judgment and experience" that the Company is not willing to share or identify.

Q. GIVEN THAT TAMPA ELECTRIC IS PROPOSING A NEW AMORTIZATION PERIOD FOR A SINGLE NEW SOFTWARE SYSTEM, HAS THE COMPANY PROVIDED ANY SUPPORT FOR THAT AMORTIZATION PERIOD?

A. No. However, given Tampa Electric's statements that it relies on "judgment and experience" to validate the continued use of a five-year amortization period for all its other software systems, it must be assumed that it is also relying on some undefined and unsubstantiated "judgment and experience" to now propose a new 10-year amortization period for the single new ERP software system.

Q. HAS THE COMPANY DIFFERENTIATED ANY ASPECT OF ITS NEW ERP SOFTWARE SYSTEM COMPARED TO ANY OF ITS OTHER SOFTWARE SYSTEMS AS IT PERTAINS TO AN APPROPRIATE AMORTIZATION PERIOD?

A. No. As was the case for its proposed continued use of a five-year amortization period for all types of software systems, the Company has not presented or performed any analysis or study to establish or determine the reasonableness of its assumed 10-year amortization period.

Q. DID YOU SPECIFICALLY REQUEST THE COMPANY TO PROVIDE A DETAILED DESCRIPTION OF THE FUNCTION AND IDENTITY OF EACH SEPARATE SOFTWARE SYSTEM?

A. Yes. While the Company was requested to provide both a detailed identification and a detailed narrative description of the function of each separate software system recorded in Account 303 – Miscellaneous Intangible Plant – Software, the Company chose to provide only two columns of information in a spreadsheet as its response. One column was identified as "Description" and another was identified as "Narrative Description." Some of these "detailed" identifications or descriptions of software systems that the Company presented are the word "Software," the abbreviation "NERC," phrases such as "Amortizable Equipment," the word "NONE," and other non-descriptive words or phrases. (Response to OPC's Third Set of Interrogatories, No. 20, electronic file). In other words, the Company chose to provide generalized and less-than-descriptive words or limited phrases to identify and explain its software systems.

Q. IN VIEW OF THE OFTEN NON-DESCRIPTIVE INFORMATION PROVIDED BY THE COMPANY FOR VARIOUS SOFTWARE SYSTEMS IN RESPONSE TO AN INTERROGATORY, DID YOU CONTINUE TO SEEK MORE DETAILED INFORMATION?

A. Yes. The Company was given a second opportunity to provide a detailed identification of each software system, as well as the purpose and function of each software system in OPC's Ninth Set of Interrogatories. (OPC's Ninth Set of

Interrogatories, No. 128 (a) and (b)). Yet, the Company again often provided one word or limited phrases of a few words, many of which provide no meaningful identification or explanation of the software that constitutes tens of millions of dollars of investment. In other words, the Company presented information that does not provide either a clear or meaningful indication of the type of software system, or its function. These shortcomings severely limit the ability to make any type of detailed analysis as to the proper life expectancy of such software.

Q. IN YOUR ATTEMPT TO IDENTIFY THE REASONABLENESS OF THE COMPANY'S PROPOSED USEFUL LIFE FOR SOFTWARE, DID YOU SEEK INFORMATION REGARDING SOFTWARE SYSTEMS STILL IN USE BUT WHICH WERE ALREADY FULLY AMORTIZED?

A. Yes. Identifying software systems that are still in use yet fully amortized under the Company's five-year amortization proposal would help demonstrate whether the Company's belief in an amortization period established in 1977 was still valid. However, the Company failed to identify any software system that was or is still in service following the expiration of the five-year amortization period and the corresponding retirement for "accounting" purposes. Indeed, the Company states that it ". . . does not maintain records that identify each separate software system removed from service (i.e., physically removed) for the past 10 years." (Response to OPC's Third Set of Interrogatories, No. 22). In addition, the Company noted its ". . . accounting practice for capital software projects. . ." is to ". . . retire [accounting wise] the asset when fully amortized." (Response to OPC's Third Set of

Interrogatories, No. 22). This practice bares no relationship to the FERC mandate that the capital recovery be systematic and rational, and supported by engineering, economic, or other depreciation studies.

Q. PLEASE SUMMARIZE THE COMPANY'S JUSTIFICATION AND BASIS FOR SEEKING IN EXCESS OF $10 MILLION IN ANNUAL AMORTIZATION EXPENSE FOR ITS INVESTMENT IN SOFTWARE.

A. The Company adopted a five-year amortization period for software systems in 1977. The Company has not performed any studies or analyses since 1977 to demonstrate the validity of retaining a five-year amortization or any other period of time. The Company either does not maintain detailed identification and functionality of its software systems, or chooses not to provide it even when specifically requested to do so. The Company states that it cannot even identify what software systems are still in place providing service after having been in service for five years or longer. In spite of these facts, the Company requests that the Commission and customers accept its undefined and unsubstantiated belief based on "judgment and experience" that a five-year amortization is still a reasonable value 35 years after it was adopted, except for its new software system. For that new system, the Company has not even explicitly stated that it believes that the proposed 10-year amortization period is reasonable.

Q. DO YOU BELIEVE THAT THE COMPANY'S PRESENTATION IS REASONABLE?

A. No. Before the Y2K situation many of the old legacy software systems in place, caused massive change out of major software systems in the late 1990s, had useful lives of 20 to 30 years. As software systems were replaced with more modern software systems, due in part to the Y2K situation, those early generations of software systems often were assigned short amortization periods given their unknown future status. However, in the past decade SAP, Oracle, and other major software developers have created platforms or architectures associated with their software packages or systems that are scalable and modularized. The practice of making modifications, enhancements, upgrades, etc. to systems rather than replacing entire systems has become common. Indeed, other utilities have been increasing amortization periods from initially shorter periods. Again, longer life expectancy for newer software systems is a function of either recognizing that the initial estimates were artificially short, or that the newer type of software systems that are being purchased or developed provided the ability to make modifications and expand the systems rather than simply replacing an entire system once it became less effective.

Q. NOTWITHSTANDING THE COMPANY'S FAILURE TO IDENTIFY ANY SOFTWARE SYSTEMS STILL IN SERVICE YET FULLY AMORTIZED, DO YOU BELIEVE THAT THE COMPANY IN FACT CONTINUES TO RELY ON SUCH SYSTEMS?

A. Yes. A review of what limited information the Company has provided demonstrates that many capital expenditures for newer software systems are actually "enhancements" or "upgrades" to existing systems. In other words, the Company has not physically retired some of its older software systems when they became fully amortized and retired from an accounting standpoint. (Response to OPC's Third Set of Interrogatories, No. 20, attachment on electronic file).

Q. DO UTILITIES RELY IN PART OR IN FULL ON SOFTWARE SYSTEMS AFTER SUCH SYSTEMS ARE FULLY ACCRUED?

A. Yes. Continued use of software systems after they become fully amortized is not uncommon. What this situation demonstrates is that often a utility's initial estimate of a useful life for its software system was artificially short. In effect, utilities have charged accelerated amortization levels to customers in the past, which resulted in those customers paying more than their fair share of the useful life for that software.

Q. IF THE COMPANY CONTINUES TO USE SOFTWARE AFTER IT IS FULLY AMORTIZED, DOES THAT VIOLATE REGULATORY PRINCIPLES?

A. Yes. If the Company employs an artificially short amortization period that results in accelerated capital recovery, then intergenerational inequity is created and the matching principle is violated. In other words, it forces one generation of customers to overpay for its use of a software system for the benefit of a future generation of customers who receive the benefit of such system, yet will not pay any amortization expense. Moreover, in certain instances, the accelerated capital recovery benefits shareholders without future generations of customers receiving a commensurate benefit.

Q. IS THE ADOPTION OR CONTINUATION OF ACCELERATED DEPRECIATION OR AMORTIZATION APPROPRIATE?

A. No. Once identified, all reasonable efforts should be implemented to correct such situations. Indeed, the reason why depreciation studies are performed on a regular basis and supported by studies is to identify changes in life and salvage characteristics that require correction of accelerated or deferred capital recovery practices. However, the Company's approach for more than three decades has been to ignore that responsibility even though it has performed depreciation studies on other assets.

Q. WHAT ANNUAL LEVEL OF AMORTIZATION EXPENSE IS THE COMPANY REQUESTING?

A. The Company is requesting approximately $10.126 million of annual amortization expense associated with its investment in Account 303 – Miscellaneous Intangible Software. (MFR Schedule B-9, p. 10 of 30).

Q. BEYOND THE VIOLATION OF THE MATCHING PRINCIPLE AND CREATION OF INTERGENERATIONAL INEQUITY, IS THERE A PARTICULAR PROBLEM WITH ARTIFICIALLY SHORT AMORTIZATION PERIODS?

A. Yes. When short amortization periods are requested for significant dollar levels of investments, resulting impacts must be analyzed in relation to the revenue requirements reflected in base rates and the timing of future rate cases. The concern associated with this situation is one where incremental and unintended return dollars can be created when investment becomes fully amortized.

Q. WHAT HAPPENS WHEN INVESTMENT BECOMES FULLY AMORTIZED BETWEEN RATE CASES?

A. When amortizable plant becomes fully amortized or accrued between rate cases, the collection of revenues from customers for that investment through base rates does not also stop. In other words, an expense is no longer being incurred, but customers are still charged as though the expense was still in place. In addition, since the expense is no longer being recognized from an accounting standpoint, customers no longer receive a benefit for paying the expense through the accumulated provision for amortization, which is an offset to rate base.

Q. HOW DOES THE COMPANY ACCOUNT FOR REVENUES FOR AN EXPENSE THAT IT NO LONGER INCURS?

A. Revenues received by a Company with no offsetting expense increase the Company's earnings, which can then become an incremental return for the benefit of shareholders.

Q. DOES THE COMPANY REPLACE FULLY AMORTIZED PLANT WITH NEW REPLACEMENT PLANT?

A. Not necessarily. When amortization periods are set at too short a period of time, investment in such plant often continues to be used and useful even though it is retired from an accounting standpoint. Absent a rate case that would capture the impact of plant becoming fully amortized, along with all other changes in revenue requirements, an opportunity is created for the Company to over-collect for the expense associated with the item of plant, and even earn more than its allowed rate of return.

Q. DO YOU AGREE WITH THE COMPANY'S PROPOSED FIVE-YEAR AMORTIZATION PERIOD FOR THE MAJORITY OF ITS SOFTWARE AND NEW 10-YEAR PROPOSAL FOR ITS NEW ERP SYSTEM?

A. No. While the movement to a 10-year amortization period for the new ERP system is a step in the right direction, it is still inadequate. Moreover, the five-year amortization period employed for the Company's remaining software system significantly understates reasonable life expectations for major software systems.

Q. WHAT DO YOU RECOMMEND?

A. I have two recommendations. First, I recommend that a 15-year amortization period be prescribed for all software systems recorded in Account 303. In conjunction with this recommendation, I also recommend that the Commission order the Company to perform detailed engineering, economic, or other depreciation studies of its software systems to establish the reasonable expected useful life of such systems and to present such findings, along with all support and justification corresponding to such amortization periods, in its next rate or depreciation proceeding. The Company's presentation should specifically identify those software systems that were fully amortized in the past but, still remained physically in service beyond the previous amortization period, and the period of continued use after being fully amortized.

Q. WHAT IS THE BASIS FOR YOUR RECOMMENDATION FOR A 15-YEAR AMORTIZATION PERIOD?

A. First, it must be noted that most of the software systems at issue are not what are normally thought of as desktop applications such as Microsoft Word or Excel. The investment in Account 303 is heavily weighted towards SAP and PowerPlan systems.

Therefore, any concept of a short life attributable to experiences with desktop software is not particularly pertinent.

Next, other utilities are moving to establish amortization periods for software as long as 20 years. Indeed, in its recent rate proceeding, Florida Power & Light Company disclosed that it was extending the amortization period for its new general ledger accounting software system from five years to 20 years. (Docket No. 120015-EI, Direct Testimony of Marlene Santos at p. 14). Some other utilities are already using 10 to 25 years for major software investments. Given that the Company has chosen not to adequately identify its software systems or the functions of such systems, and further chosen not to investigate the useful life of its software systems for over 35 years, it is reasonable to choose the middle ground between a high-end 20- to 25-year life and the realistic lower-end level 10- to 12-year life proposed by some other utilities for major software systems.

Q. WILL YOUR RECOMMENDATION FOR A 15-YEAR AMORTIZATION PERIOD DEPRIVE THE COMPANY OF ANY CAPITAL RECOVERY ASSOCIATED WITH ITS SOFTWARE INVESTMENT?

A. No. The Company is still entitled to the recovery of its investment. However, the establishment of a longer amortization period does protect customers from fully accrued amortization situations that result in creating additional artificial return for the Company.

Q. WHAT IS THE IMPACT OF YOUR RECOMMENDATION?

A. My recommendation results in a $6.197 million reduction in 2014 amortization expense associated with the Company's investment in Account 303 – Miscellaneous Intangible Software. This adjustment is derived by converting the Company's $8.466 million annual amortization request associated with the five-year amortization investment category to a 15-year amortization period ($8.466 million x 5 / 15 = $2.822 million), and converting the Company's 10-year amortization investment category to a 15-year amortization period ($1.660 million x 10 / 15 = $1.107 million), adding the two amounts, and subtracting the total from the Company's request ($10.126 - $2.822 - $1.107 = $6.197 million). In addition, there is a corresponding reduction to the 2014 reserve by one-half of the 2014 expense adjustment, or $3.099 million.

<u>SECTION IV: SOFTWARE RESERVE ADJUSTMENT</u>

Q. WHAT IS THE ISSUE IN THIS PORTION OF YOUR TESTIMONY?

A. This portion of my testimony will address the Company's incorrect booking of amortization reserve associated with its new ERP software system for 2012 and 2013.

Q. DOES THE COMPANY IDENTIFY TWO SEPARATE SUBACCOUNTS FOR ACCOUNT 303 – MISCELLANEOUS INTANGIBLE SOFTWARE?

A. Yes. Company MFR Schedules B-7, B-8, and B-9 all identify Accounts 303.00 and 303.01 as two separate software amortization categories (see pp. 10, 20, and 30 of 30 for Schedules B-7 through B-9).

Q. DOES THE COMPANY CONSISTENTLY IDENTIFY THE TWO SEPARATE SUBACCOUNTS?

A. No. On MFR Schedules B-7 and B-9, the Company identifies Account 303.01 – Software – Amortization corresponding to a 10-year period, while for Schedule B-8, the Company identifies a five-year amortization period for the same subaccount. However, based on a review of the depreciation provision recorded in years 2012 through 2014, it appears that the Company relied on a 10-year amortization period, even though such change in the amortization period would not be effective until 2014.

Q. WHAT IS THE COMMISSION APPROVED AMORTIZATION PERIOD FOR INVESTMENT IN SOFTWARE RECORDED IN ACCOUNT 303?

A. As previously noted, the Company's recent depreciation filing before the Commission did not address Account 303; therefore, the amortization period last approved by the Commission corresponds to the Company's 2008 rate filing as noted in Order No. PSC-09-0283-FOF-EI, issued on April 30, 2009. In that order, the only identifiable software amortization period is the continuation of the five-year amortization period employed by the Company since the late 1970s.

Q. IF THE COMMISSION HAS NOT SPECIFICALLY APPROVED ANY AMORTIZATION PERIOD FOR SOFTWARE INVESTMENT OTHER THAN FIVE YEARS, IS THE COMPANY'S CALCULATION OF ITS AMORTIZATION RESERVE IN 2012 AND 2013 CORRECT?

A. No. The Company has relied on a 10-year amortization period for calculating amortization expense during 2012 and 2013 for its investment in the new ERP software system. This corresponds to a time frame prior to the effective date of any change in amortization period that will transpire as a result of this proceeding.

Q. WHAT CORRECTIVE ACTION IS REQUIRED?

A. The level of amortization expense recorded in 2012 and 2013 should be increased to reflect a five-year amortization period rather than a 10-year amortization period calculated by the Company. Given my recommendation to increase the amortization period to 15 years beginning in 2014, the 2014 reserve should also be adjusted, but downward to recognize my recommended longer amortization period. The adjustments for 2012 and 2013 must be made regardless of any decision relating to the appropriate software system amortization approved by the Commission for 2014.

Q. WHAT IS THE IMPACT OF YOUR RECOMMENDATION TO THE AMORTIZATION RESERVE?

A. Correcting 2012 and 2013 amortization reserves to reflect a five-year period for Account 303.01 results in a $2.497 million *increase* in the reserve. Further, correcting the reserve to recognize a 15-year amortization for 2014 results in a $0.553

million *decrease* to the reserve in 2014. Therefore, the continued impact is a net *increase* of $1.944 million to the reserve.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes. However, to the extent that I have not addressed a specific issue, methodology, approach, etc., this should not be construed as my concurrence with the Tampa Electric's methodology, approach, calculation, etc.

DIRECT TESTIMONY

OF

HELMUTH W. SCHULTZ, III

On Behalf Of the Office of Public Counsel

Before the

Florida Public Service Commission

Docket No. 130040-EI

I. INTRODUCTION

Q. WHAT IS YOUR NAME, OCCUPATION AND BUSINESS ADDRESS?

A. My name is Helmuth W. Schultz, III. I am a senior regulatory analyst in the firm of Larkin & Associates, PLLC, with offices at 15728 Farmington Road, Livonia, Michigan 48154.

Q. PLEASE DESCRIBE THE FIRM LARKIN & ASSOCIATES, PLLC.

A. Larkin & Associates, PLLC, is a Certified Public Accounting and Regulatory Consulting Firm. The firm performs independent regulatory consulting primarily for public service/utility commission staffs and consumer interest groups (public counsels, public advocates, consumer counsels, attorneys general, etc.). Larkin & Associates, PLLC, has extensive experience in the utility regulatory field as expert witnesses in over 800 regulatory proceedings, including those involving numerous electric, water and sewer, gas and telephone utilities.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION AS AN EXPERT WITNESS?

A. Yes. I have testified before the Florida Public Service Commission ("PSC") as an expert witness in the area of regulatory accounting in more than 15 cases.

Q. HAVE YOU PREPARED AN EXHIBIT THAT DESCRIBES YOUR QUALIFICATIONS AND EXPERIENCE?

A. Yes. I have attached Exhibit HWS-1, which is a summary of my regulatory qualifications and experience. I have also attached Exhibit HWS-2, Schedules C-1 through C-8, which support the adjustments that I have recommended. I would note that my schedules in Exhibit HWS-2 begin with C-1, to correspond with the Net Operating Income "C" Schedules in Tampa Electric Company's Minimum Filing Requirements ("MFRs").

Q. BY WHOM WERE YOU RETAINED?

A. Larkin & Associates, PLLC was retained by the Florida Office of Public Counsel ("OPC"). Accordingly, I am appearing on behalf of the Citizens of Florida ("Citizens").

II. <u>PURPOSE OF TESTIMONY</u>

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. Our firm was asked by OPC to analyze the rate increase requested by Tampa Electric Company ("Tampa Electric" or "Company") and provide our analysis of Tampa Electric's revenue needs.

Q. WHAT ARE THE RESULTS OF YOUR ANALYSIS OF THE REQUESTED INCREASE FOR TAMPA ELECTRIC?

A. I am recommending that the Commission adjust various expenses requested by Tampa Electric, because the Company's requested expense levels are not justified. My testimony addresses issues related to payroll, the performance-sharing program, employee benefits, payroll taxes, directors and officers liability insurance, generation maintenance expense, rate case expense, the storm reserve and accrual, and tree trimming. My adjustments are incorporated in OPC's recommended revenue requirement calculations and have been reflected in the exhibits of OPC witness Donna Ramas.

III. PAYROLL

Q. PLEASE EXPLAIN THE PAYROLL ASSUMPTIONS THAT THE COMPANY HAS INCLUDED IN ITS PROJECTED TEST YEAR.

A. The Company's request assumes an average addition of 114 positions above the 2012 average for a projected number of employees of 2,455. Tampa Electric also projects an average annual compensation increase of approximately 3%. OPC is not taking issue with the Company's request for the 3% base compensation increase.

Q. ARE THERE CONCERNS WITH THE COMPANY'S PAYROLL REQUEST FOR THE PROJECTED TEST YEAR?

A. Yes. The Company's payroll assumption that an average of 114 additional employees will be required in 2014 is not reasonable and has not been justified by Tampa Electric.

Q. HAVE YOU FOUND ANY INCONSISTENCIES BETWEEN THE COMPANY'S FILING AND ITS RESPONSES TO DISCOVERY REGARDING THE PROJECTED NUMBER OF NEW POSITIONS IN 2014?

A. Yes, inconsistencies exist. The Company indicated in its response to Staff's Interrogatory No. 95 that it projects 82 new positions in 2014, instead of the 114 positions reflected in its MFRs on Schedule C-35 and in the Company's response to OPC Interrogatory No. 2. Additionally, the response to OPC Interrogatory No. 141 lists 96 new positions.

Q. WOULD YOU EXPLAIN WHY THERE IS A DIFFERENCE BETWEEN THE 114 AVERAGE ADDITIONAL EMPLOYEES IN THE COMPANY'S MFRS FOR 2014 AND TAMPA ELECTRIC'S RESPONSES TO STAFF'S INTERROGATORY NO. 95 AND OPC INTERROGATORY NO. 141?

A. In its response to Staff's Interrogatory No. 95, the Company does not appear to include unfilled budgeted vacant positions. As shown on Company MFR Schedule C-35, the increase in the average positions is 114 when one subtracts the 2012 average of 2,341 positions from the 2014 budgeted average of 2,455. The difference exists in the additional employee count provided in Tampa Electric's response to OPC Interrogatory No. 141 because the positions listed are new positions and do not include vacancies.

Q. WHY IS THE ADDITION OF AN AVERAGE OF 114 EMPLOYEES FOR THE RATE YEAR QUESTIONABLE?

A. The Company's proposed additions are questionable for three reasons: (1) in Tampa Electric's last rate case, Docket No. 080317-EI, the Company's approved increase in the number of employees did not materialize; (2) as of March 31, 2013, the actual employee count was below the projected employee count for March 2013; and (3) the Company does not provide sufficient support for the additional employees requested.

Q. DO YOU HAVE ANY ADDITIONAL CONCERNS REGARDING TAMPA ELECTRIC'S PAYROLL?

A. Yes. The fact that the Company does not typically budget payroll by projecting the number of employees adds to my concerns. Tampa Electric's response to OPC Interrogatory No. 2 states "Prior to the preparation of the 2013 budget in 2012, the number of employees was not projected; therefore, the number of budgeted employees cannot be provided for 2010, 2011 or 2012." The Company prepared its filing using budgeted employee counts but apparently did not use the same type of budgeted information to monitor its performance (i.e., whether actual employee count tracks the budgeted amount for that time period). This raises serious concerns to me as to how the Company can measure performance when a variance in employee count, an important component of payroll, is not tracked and/or monitored.

Q. PLEASE EXPLAIN THE HISTORY OF THE COMPANY'S REQUEST FOR ADDITIONAL EMPLOYEES.

A. In its last rate case, Docket No. 080317-EI, the Company proposed an increase of 151 positions from an average of 2,487 in 2007, to 2,638 in its 2008 projected test year. However, the actual 2008 average number of employees increased to only 2,538; or 100 fewer positions than projected. The Company's response to OPC Interrogatory No. 56 in Docket No. 080317-EI, showed a decrease in its employee complement in 11 out of 15 years during the period 1992 through 2007. Only in 2006 and 2007 did Tampa Electric have consecutive increases in the number of its employees. Moreover, the Company had declines in the average number of positions in 2009, 2010, and 2011 to 2,474, 2,312, and 2,303, respectively. In 2012, there was only a slight increase to an average of 2,341.

In the last rate case, the Commission agreed with my recommendation to reduce the requested employee complement by 90 positions to a complement of 2,548. When you compare the actual employee complement level that the Company maintained in 2008, the Commission's adjustment did not reflect a sufficient reduction. Even with the 90-position reduction, the 2,548-employee complement allowed the Company to over recover its payroll costs from 2009 through 2012. Based on Tampa Electric's history, especially after the last rate case, the current request for 114 additional employees beyond 2012 does not appear to be justified.

Q. WHAT CHANGE OCCURRED AFTER 2008 THAT WOULD HAVE IMPACTED THE EMPLOYEE COMPLEMENT?

A. Based on pages 6 and 7 of Company witness Register's direct testimony, TECO Energy, Inc. ("TECO Energy"), Tampa Electric's parent, undertook a reorganization that eliminated 169 positions at Tampa Electric. Additionally, in response to OPC Interrogatory No. 86, the Company indicated that 12 of the 169 positions eliminated were vacant.

Q. ARE THERE PLANS FOR A SIMILAR REORGANIZATION IN THE FUTURE?

A. According to the Company's response to Staff Interrogatory No. 53, it has no plans for a similar reorganization in the future.

Q. DID THE COMPANY PROVIDE ANY TESTIMONY TO SUPPORT THE ADDITION OF 114 EMPLOYEES IN THE CURRENT CASE?

A. The Company's attempt to justify its requested increase in employees is inadequate, in my opinion. Several of the Company's witnesses address its need for employees; however, careful analysis shows no basis to believe additional positions are necessary. On page 7 of her direct testimony, Company witness Young stated that Tampa Electric ". . . will hire new apprentice linemen, apprentice substation journeymen, two cable splicers, and a relay tester to meet NERC requirements." On page 34 of his direct testimony, Company witness Register references the "Continuation of a four-year apprentice program for developing and transferring knowledge and skills acquired by journeymen linemen." However, his testimony discusses the "continuation" of an apprentice program, not an implementation of a new hiring program. Page 36 of 41 of Document No. 3, attached to the testimony of Company witness Chronister, states: "All positions that are budgeted for 2014 will be filled with qualified employees at rates and in the timeframe that they were budgeted." While the employee complement for each month January through March 2013 is higher than the average for 2012, the January through March 2013 employee count is actually lower than the counts of November and December 2012. None of these witnesses' testimony provides justification for adding any of the new positions or that these new positions would actually be filled. As noted above, Tampa Electric has a history of requesting significant amounts of additional positions that never are filled, yet ratepayers are supporting these unfilled positions.

Q. WHAT ABOUT THE NEED FOR THE SKILLED POSITIONS DISCUSSED BY COMPANY WITNESS YOUNG?

A. The Company's response to Staff Interrogatory No. 49 indicates that 20 skilled positions will be added in 2013 and again in 2014. Based on the history of the Apprentice Linemen Program, the addition of 40 skilled positions is a suspect number for several reasons. First, Tampa Electric's response to OPC Interrogatory No. 100 indicates that from 2005 through 2013, the average class size in the Company's Apprentice Linemen Program was 11.

Second, the response also indicates that for 2013, the initial class size is 14 not the 20 identified in Tampa Electric's response to Staff Interrogatory No. 49. Further, Tampa Electric's response to OPC Interrogatory No. 141 indicates that of the 96 proposed new positions, there are 16 Apprentice Lineman positions planned for 2013 and 16 Apprentice Lineman positions for 2014. The response also indicates that in 2013 only 14 of the 16 positions were filled.

Third, the Company's response to Staff Interrogatory No. 49 states: "The number hired each year is based on anticipated retirements and the training time for replacements." While an additional complement of 14 skilled employees may be hired in 2013, there will be some anticipated retirements from the previous year and possibly the current year that will offset the cumulative effect to total skilled positions. As I indicated earlier, Company witness Register indicated that the Apprentice Linemen Program is a continuation of a program and not the implementation of a new program. Finally, Tampa Electric's response to OPC Interrogatory No. 2 shows that the union count was 906 as of December 2012, and that the count was 894 as of March 2013. So, even though the Company's Apprentice Linemen Program has 14 new hires in 2013, the union employee count has declined overall by 12 positions since 2012.

Q. WHAT ABOUT COMPANY WITNESS CHRONISTER'S STATEMENT THAT "ALL POSITIONS THAT ARE BUDGETED FOR 2014 WILL BE FILLED WITH QUALIFIED EMPLOYEES AT RATES AND IN THE TIMEFRAME THAT THEY WERE BUDGETED"?

A. The Company's response to OPC Interrogatory No. 2 indicates that Mr. Chronister's statement regarding all 2014 budgeted positions will be filled in the budgeted timeframe is already an overstatement. In January 2013, the actual employee count was 48 positions below the budgeted level. The trend continued through March 2013 with the actual count being below budget. Tampa Electric's projected timeframe commitment has not been met. Thus, the Company's average employee complement of 2,455 for the test year is overstated.

Q. WHAT ADJUSTMENT ARE YOU RECOMMENDING TO THE EMPLOYEE COMPLEMENT?

A. The Company's request should be reduced by 104 positions to a complement of 2,351. This allowance reflects 10 more positions than the actual average for the year ended 2012. As shown on Exhibit HWS-2, Schedule C-1, the reduction of 104 positions reduces operation and maintenance ("O&M") expense by $5,705,698 to a more reasonable expense level of $127,448,302. This is a reduction of $5,701,824 on a jurisdictional basis.

IV. PERFORMANCE SHARING PROGRAM

Q. HAVE YOU REVIEWED THE COMPANY'S REQUEST FOR INCENTIVE COMPENSATION THAT IT CALLS THE PERFORMANCE SHARING PROGRAM?

A. Yes. According to the Company's response to OPC Interrogatory No. 8, the Company has projected $12,383,000 for the 2014 Tampa Electric Performance Sharing Program ("PSP"). This amount reflects the Company's request for PSP payouts of $7,383,040 for safety goals, and $5,000,000 for operational goals. Of this amount, the Company projected that $9.8 million would be charged to O&M expenses during 2014. (See Tampa Electric's response to OPC Interrogatories Nos. 146 and 147) The Company made a proforma adjustment to reduce the Tampa Electric PSP in its MFRs by $946,000, as shown on MFR Schedule C-2, page 1, for the Tampa Electric officer and key employee target incentives directly related to TECO Energy results. Company witness Register testifies, on page 19, that this adjustment is consistent with the Commission's methodology in the last rate case. Mr. Register also states that Tampa Electric's PSP is the same basic variable compensation program that was included in previous rate cases (Success Sharing program).

Q. HAS THE COMPANY REVISED THE AMOUNT OF THE PROFORMA ADJUSTMENT TO REMOVE OFFICER AND KEY EMPLOYEE INCENTIVES THAT ARE TIED TO TECO ENERGY RESULTS?

A. Yes. First, on June 3, 2013, the Company revised Mr. Register's testimony to change this amount to $1,055,000. On July 8, 2013, the Company again revised Mr. Register's testimony, changing the adjustment to $1,247,000. I would note that, while Mr. Register's testimony has changed, the amount reflected in the MFRs has not been changed. Nor has the Company explained why the factor used to determine the adjustment has been changed other than to state that the change was per data calculated in OPC Interrogatory No. 57(b).

Q. WHAT IS THE INTENT OF TAMPA ELECTRIC'S INCENTIVE PROGRAM?

A. On pages 16 and 17 of his direct testimony, Mr. Register asserts that the intent of the incentive compensation program is to maintain Tampa Electric's position relative to the market in total annual compensation while putting a portion of pay at risk. The pay, according to Mr. Register, is "at risk" because it is based on meeting performance goals that are purported to "drive and motivate team members to achieve high levels of performance." Mr. Register then states that the program emphasizes safety, cost control and resource optimization through a link with business performance and personal contributions. Finally, Mr. Register states that the requested incentive pay is based on the target level payout. It is important to note that the Company's requested 5% for incentive payments is in addition to an across-the-board, 3% base pay increase.

Q. CAN YOU GENERALLY EXPLAIN THE TARGET AND GOAL LEVELS FOR INCENTIVE COMPENSATION PLANS?

A. The target is a goal level established by a plan. Generally, there are three levels for incentive plans. The "Threshold" is the minimum achievement on which a payout of the target percentage will be paid (i.e. less than 100% of the 2% safety goal). The "Target" achievement level is set at 100%. The "Maximum" or "Stretch" achievement level is generally set at 150% of the Target goal percent payout. That would mean that if the Maximum was achieved, the payout for the 2% safety goal would be 3% (i.e., 150% of 2%). The actual achievement for a payout can range anywhere from 50% to 150% of the goal percentage.

Q. WHAT ARE THE TARGET GOALS AND ACHIEVEMENT PERCENTAGES FOR TAMPA ELECTRIC'S PSP PROGRAM?

A. According to Company witness Register and the Company's response to Interrogatory No. 7, the potential PSP plan payout is 12% of eligible compensation in 2013, of which 2% is related to safety performance goals, 3% for operational goals, and 7% for net income goals (5% for Tampa Electric and 2% for TECO Energy). According to Mr. Register's direct testimony on page 18, the Company is not requesting recovery of the 7% net income incentives in this rate case.

Q. PLEASE DESCRIBE YOUR CONCERNS WITH THE COMPANY'S INCENTIVE PLAN OBJECTIVES.

A. First, the Company's explanation of the plan's objectives for the operational goals suggests that the payouts have historically been tied to financial goals which benefit the shareholders, not ratepayers. Based on this history, we would expect that the Company after the conclusion of this rate case is likely to again tie payout of operating goals with meeting the financial goals.

Second, there is significant doubt as to whether this incentive pay is truly "at risk" pay. In 2012, 2,394 employees were eligible for incentive compensation payments; only 11 did not receive a payment. The number of eligible employees not receiving the incentive compensation payment in 2010 and 2011 were 2 and 3, respectively. (See Company response to OPC Interrogatory No. 6) Common sense suggests that, when almost all employees' performance meets the requirements to receive a payment, the goals are not adequate. Thus, the incentive compensation request becomes a de facto 5% annual bonus on top of the 3% base pay increase the Company has already included in its revenue request.

Finally, the target amount requested for 2014 is based on achieving goals that have not yet been established. The Company is assuming for 2014 that performance will be at a level that actually exceeds the performance achieved in both 2011 and 2012. In 2011 and 2012, the only payout made by the Company was 2% related to safety goals.

Q. PLEASE COMPARE THE TARGET AMOUNT REQUESTED FOR 2014 TO AMOUNTS PAID IN 2011 AND 2012.

A. On page 17 of his direct testimony, Company witness Register states that 2014 goals have not been determined but are expected to be consistent with 2013 goals. In each of the years 2011 and 2012, the PSP distribution/payout was only 2% of eligible compensation. According to the response to OPC Interrogatory No. 8, the amount actually paid for 2011 and 2012 was $6,060,568 and $7,026,902, respectively; yet, the 2014 budgeted amount is $12,383,000. I would also note that the 2010 actual payout of $19.5 million exceeded the budgeted expense of $5.7 million by $13.8 million. The average PSP payout expensed was only $6,129,635 for the period 2010 to 2012. It is interesting to note that this highest level of payout was almost 3 times the budgeted amount and occurred in the year following the completion of Tampa Electric's last rate case.

Q. IS THE INCREASE IN THE PROJECTED AMOUNT FOR THE INCENTIVE PROGRAM PROBLEMATIC?

A. Yes. The Company maintains that goals are likely to remain consistent (i.e., no significant changes), yet the requested 2014 incentive payment is significantly higher than the historical payouts for the last two years. Moreover, the budgeted payout for 2014 is $12,383,000 compared to the 2013 budgeted payout of $7,168,000, even though the goals are not expected to change significantly. In addition, the increased budgeted amount improperly assumes an increase in performance without any established goals. Finally, the Company has indicated in its response to OPC Interrogatory No. 145 that the amount requested for 2014 is based on a plan change, which in my opinion is contrary to the Company's position that the goals are likely to remain consistent.

Q. WHY DO YOU BELIEVE THE 2014 PLAN CHANGE IS CONTRARY TO THE COMPANY'S CLAIM THAT THE GOALS ARE LIKELY TO REMAIN CONSISTENT?

A. The goals appear to be similar; however, there is a key difference between the payout determination applied in 2011 and 2012 and what the Company is proposing in 2014. The Company stated in its response to OPC Interrogatory No. 145 that a payment was not made in 2011 and 2012 for achievement of operational goals because the net income goal was not achieved. The 2013 budgeted PSP also assumes the operational payout will not be made because the net income goal will not be achieved. However, for 2014, the Company is proposing to remove the net income goal as a condition for payment of the operational goals. Thus, contrary to the Company's payout history in 2011 and 2012 and the Company's budget assumption for 2013, the Company is now requesting that it be allowed to collect from customers the money necessary to cover payments for achievement of operational goals even if net income goals are not achieved. It is inappropriate to ask ratepayers to cover such expenses during a rate case, when the Company is unwilling to make the same payment outside a rate case.

Q. WHAT IS THE BASIS FOR YOUR PRIMARY RECOMMENDATION REGARDING THE TAMPA ELECTRIC PSP COSTS?

A. I recommend that the Tampa Electric PSP costs should be limited to the 2% safety-related percentage distributed in 2011 and 2012. Tampa Electric has not justified why the incremental operational incentives are reasonable, why the plan change is reasonable, and why the allowed costs should be greater than the 2% safety-related PSP distributed in 2011 and 2012. My recommendation does not prohibit the Company's continued use of the PSP Program; I am saying only that shareholders should be responsible for the unsupported program costs.

Q. PLEASE EXPLAIN YOUR ANALYSIS ON SCHEDULE C-2 FOR YOUR PRIMARY RECOMMENDATION.

A. Exhibit HWS-2, Schedule C-2 reflects the calculation of the $8,535,570 of Tampa Electric's PSP included in the 2014 projected test year O&M expenses. The Company states in response to OPC Interrogatory No. 147 that the amount of incentive compensation included in O&M expense in this filing is $9.8 million out of the total Tampa Electric PSP of $12,383,000, which reflects an expense ratio of 79%. I then applied the Company's reduction to PSP for key employees and officers of $1,247,000 in arriving at the adjusted Tampa Electric PSP expense. I would note that the Company has not explained why the percentage of PSP costs expensed is 79%, when the percentage of payroll expensed is 66.8%.

Q. WHAT IS THE AMOUNT OF PSP THAT THE COMMISSION SHOULD ALLOW TAMPA ELECTRIC TO RECOVER IN RATES?

A. I calculated my recommended PSP allowance of $2,548,966 for Tampa Electric PSP based on 2% of my recommended payroll expense of $127,448,302 (see line 15 of Exhibit HWS-2, Schedule C-1). Again, the 2% incentive payout is what was earned in 2011 and 2012 and what the Company budgeted for in 2013. However, I consider even that level to be questionable, because the goals do not really require an improvement in performance. The result is a reduction of $5,986,604 for the PSP for Tampa Electric. The adjustment is calculated on lines 1 through 10 of Exhibit HWS-2, Schedule C-2.

Q. IF THE COMMISSION DOES NOT AGREE WITH YOUR PRIMARY RECOMMENDATION, DO YOU HAVE AN ALTERNATE ADJUSTMENT?

A. Yes. As an alternative to my primary recommendation, I have taken the 2013 budgeted PSP payout amount of $7,168,000 and escalated this by the 3% base salary increase, which equates to $7,383,000. The 2013 budget does not include the additional $5 million for a separate operational PSP payout. After applying the Company's 79% O&M expense factor for PSP, the adjusted PSP O&M expense is $5,832,570. Then I remove the Company's $1,247,000 proforma reduction adjustment (2nd revised) discussed by Company witness Register from the $5,832,570, resulting in an adjusted PSP expense payout of $4,585,570.

Q, WOULD YOU RECOMMEND THAT YOUR ALTERNATE RECOMMENDATION BE SHARED BETWEEN SHAREHOLDERS AND RATEPAYERS?

A. Yes. I believe that as an alternative the Commission should limit the customers' responsibility to 50% of the $4,585,570 expense, or $2,292,785. Using this 50/50 sharing alternative, my adjustment to the Tampa Electric PSP would be $6,242,785. This calculation is reflected on lines 15 through 23 of my Exhibit HWS-2, Schedule C-2. I would note that this amount is less than the amount of my primary recommended allowance which did not contemplate an equal sharing.

Q. IN DOCKET NO. 080317-EI, DID YOU RECOMMEND AN ADJUSTMENT TO INCENTIVE COMPENSATION?

A. Yes. I recommended a total disallowance because the goals were not sufficient to justify including the cost of incentive compensation in rates. The Commission did not agree with my recommendation. The Commission stated that lowering or eliminating incentive compensation would mean Tampa Electric employees would be compensated below employees at other companies, which would adversely affect the Company's ability to compete in attracting and retaining a high quality and skilled workforce. However, in Order No. PSC-09-0283-FOF-EI at page 58, the Commission did require the Company to remove the cost of incentive compensation associated with TECO Energy results.

Q. WHAT IF THE COMMISSION DOES NOT ACCEPT YOUR RECOMMENDATION OF SHARING UNDER THE ALTERNATIVE SCENARIO?

A. If the Commission were to take exception with the 50/50 sharing alternative, then the proper expense allowance would be $4,585,570, not the Company requested adjusted amount of $8,535,570. In Tampa Electric's last rate case, the Commission stated that disallowing the costs ". . . would mean TECO employees would be compensated below employees at other companies, which would adversely affect the Company's ability to compete in attracting and retaining a high quality and skilled workforce." See Order No. PSC-09-0283-FOF-EI, at page 58. However, there is no evidence in this case that the payment of incentive compensation is required to attract and retain employees. In fact, Tampa Electric did not pay out the 3% operational portion of the PSP plan in 2011 and 2012.

Q. ARE YOU AWARE OF OTHER CASES IN WHICH ADJUSTMENTS WERE MADE TO INCENTIVE COMPENSATION AND THE ABILITY TO ATTRACT AND MAINTAIN A QUALITY WORKFORCE WAS NOT AFFECTED?

A. Yes. In the Progress Energy Docket No. 090079-EI, the Commission disallowed all of the requested incentive compensation because it was determined to be merely additional compensation. This did not impact the ability of Progress Energy (now Duke Energy Florida) to attract and retain a high quality and skilled workforce.

In my 38 years of experience, I have never found a utility that has reduced the payout of incentive compensation or eliminated the incentive compensation plan because a commission disallowed all or some of its request to include incentive compensation in rates. To my knowledge, the Commission's disallowance of incentive compensation did not result in the elimination of the plan.

In my opinion, the disallowance of some or even all of the incentive compensation in rates does not impact the Company's ability to attract and retain a qualified and skilled workforce, because companies do not eliminate such plans.

Q. HAS THE COMPANY INCLUDED ANY ADDITIONAL COSTS IN ITS FILING FROM TECO ENERGY RELATED TO INCENTIVE COMPENSATION?

A. Yes. The Company has included $1,836,882 for the TECO Energy PSP included in A&G Expenses Allocable to Tampa Electric. However, no proforma adjustment was made to remove officer or key employee incentives from the TECO Energy allocated costs. Further, no explanation is given as to whether any component of the TECO Energy allocated incentives should be adjusted to be consistent with the Commission's adjustment in the prior rate case or whether the incentives are tied to financial goals.

Q. ARE YOU RECOMMENDING THAT AN ADJUSTMENT TO THIS PORTION OF THE COMPANY'S REQUEST BE MADE?

A. Yes. I believe that the entire $1,836,882 allocated amount from TECO Energy should be excluded from rates. The Company has failed to justify including the TECO Energy allocation of PSP, which was simply buried in the allocated dollars from TECO Energy. Absent evidence that the TECO Energy allocated costs are not tied to TECO Energy's net income, there is no reason why the costs should be allowed in rates.

Q. PLEASE SUMMARIZE YOUR ADJUSTMENTS FOR INCENTIVE COMPENSATION.

A. My primary recommendation reflects a reduction to the Company's requested total incentive compensation of $7,823,486 (or $7,818,174 jurisdictional) to allow a 2% incentive on adjusted payroll for safety goals, with no allowance for the TECO Energy allocated PSP costs. This adjustment reflects the sum of my recommended reduction to the PSP Expense for Tampa Electric of $5,986,604 and removal of the TECO Energy PSP allocation $1,836,882. If the Commission disagrees with that adjustment, I recommend that the Commission allow a sharing of the cost of Tampa

Electric PSP costs excluding the additional $5 million for operational goals that reflected a change in the Company's incentive benefit policy. The $5 million was not paid and/or budgeted by the Company in 2011, 2012 and 2013. The net alternative adjustment for the Tampa Electric PSP and TECO Energy allocation is a reduction to O&M Expense of $8,079,667 ($8,074,181 jurisdictional). Both of my adjustments are summarized on Exhibit HWS-2, Schedule C-2.

V. EMPLOYEE BENEFITS

Q. WHAT IS THE COMPANY REQUESTING FOR EMPLOYEE BENEFITS IN 2014?

A. The Company's request for 2014 includes $81,242,000 for employee fringe benefits. According to Tampa Electric's response to OPC Interrogatory No. 57, the amount expensed is $54,904,000. I should note that the Company's employee benefits amounts include payroll taxes.

Q. DO YOU RECOMMEND ANY ADJUSTMENTS TO THE COMPANY'S REQUESTED EMPLOYEE BENEFITS?

A. Yes. As noted earlier in this testimony, I have made a recommendation to adjust the Company's payroll complement for 104 positions that are not justified by the filing. A corresponding adjustment is also required to remove the employee benefit costs associated with my recommendation to disallow 104 of those proposed additional employees. Additionally, I am recommending that the cost associated with the Stock Compensation Plan be disallowed.

Q. PLEASE EXPLAIN THE ADJUSTMENT YOU ARE RECOMMENDING FOR THE ADDITIONAL EMPLOYEES TO WHICH YOU HAVE TAKEN AN EXCEPTION.

A. As shown on Exhibit HWS-2, Schedule C-3, the employee benefits expense should be reduced by $1,679,971. The jurisdictional adjustment is $1,678,721. My calculated adjustment is based on the Company's projected benefit expense excluding stock compensation and payroll taxes. Separate adjustments are recommended for the stock compensation and payroll tax expense.

Q. WHAT IS THE CONCERN WITH THE COMPANY'S STOCK COMPENSATION PLAN?

A. The response to OPC Interrogatory No. 9 indicates that this stock compensation plan is an executive-type plan. According to the Company's May 1, 2013 proxy, this plan is limited to five highly compensated executives. The plan is discriminatory since it only applies to these select executives, and is an excessive cost that should not be charged to ratepayers. Given the malaise of today's economy, it is unfair to ask ratepayers to pay the bill for these already highly compensated executives' stock options. In addition, the Company has expensed 100% of the plan costs, while the other employee benefits have approximately 63% of the cost charged to expense rather than capitalized to plant. In addition to the $5,084,200 of stock compensation included in Tampa Electric's benefit expense, the response to OPC Interrogatory No. 9 indicates that the Company has also included another $4,638,481 as an allocated expense from TECO Energy for stock compensation.

Q. WHAT ADJUSTMENTS TO THE STOCK COMPENSATION PLAN ARE YOU RECOMMENDING?

A. I am recommending that the $5,084,200 associated with the Tampa Electric stock compensation and the $4,638,481 allocated amount related to TECO Energy's stock compensation be excluded from the Company's rate request. The total of this adjustment is $9,722,681. The jurisdictional adjustment is $9,715,447. As I indicated earlier, this is excessive compensation that should not be borne by ratepayers.

Q. DO YOU RECOMMEND AN ALTERNATIVE ADJUSTMENT IF THE COMMISSION CONCLUDES THE STOCK COMPENSATION PLAN COSTS SHOULD BE ALLOWED?

A. Yes. I would then recommend that the $5,084,200 of expense for the Tampa Electric stock compensation be reduced by $1,881,154 so that only 63% is expensed. This would be consistent with the Company's expense factor for pensions and other employee benefits. The expense percentage has no impact on my recommended adjustment to remove the allocated amount for TECO Energy's stock compensation.

VI. PAYROLL TAXES

Q. ARE YOU RECOMMENDING AN ADJUSTMENT TO THE COST FOR PAYROLL TAX EXPENSE INCLUDED IN TAMPA ELECTRIC'S REQUEST?

A. Yes. As shown on HWS-2, Schedule C-4, the employee payroll tax expense should be reduced by $430,530. The jurisdictional adjustment is $430,164. The adjustment is necessary to account for the payroll tax expense associated with the 104 positions that I am recommending be removed from the Company's payroll request.

VII. DIRECTORS AND OFFICERS LIABILITY INSURANCE

Q. HAS TAMPA ELECTRIC INCLUDED THE COST OF DIRECTORS AND OFFICERS LIABILITY INSURANCE IN ITS REQUEST?

A. Yes. The Company's response to OPC Interrogatory No. 120 indicates the cost for Directors and Officers Liability Insurance ("DOL") allocated to Tampa Electric for 2014 is $798,546.

Q. IS THE COST OF THIS INSURANCE AN APPROPRIATE COST TO INCLUDE IN RATES?

A. Not entirely. DOL insurance protects officers and directors from claims that are made because of decisions that plaintiffs and agencies believe to be inappropriate.

Q. WHY SHOULDN'T THIS INSURANCE BE ALLOWED WHEN THE COST OF OTHER INSURANCE IS ALLOWED?

A. DOL insurance coverage is not the same as any other type of insurance. Other insurance protects the Company from accidents and unplanned events. This insurance protects officers and directors when decisions that they have made are challenged and/or determined to be bad business decisions. An added factor with

DOL insurance is that the primary plaintiffs are shareholders. In effect, DOL insurance provides shareholders protection against their own decisions in the hiring of the Board of Directors, who in turn hire the officers to manage the operation of the Company. The benefit from settlements of this type of insurance flows through to shareholders; therefore, shareholders should be responsible for the cost.

Q. DO RATEPAYERS BENEFIT FROM THIS INSURANCE?

A. The answer is subjective. In my experience, companies have argued that the insurance does benefit ratepayers to the extent the Company is not required to pay any claims associated with the poor decisions of management. In other proceedings in which I have testified, companies have claimed that ratepayers benefit because the insurance is necessary to attract and retain competent directors and officers. In fact, the Commission made this observation in the most recent Gulf Power decision, Order No. PSC-12-0179-FOF-EI, at pages 100 and 101. However, there has not been any evidence presented that the companies were unable to attract and/or retain officers and directors when shareholders were required to pay some of the cost of the coverage. Ratepayers do not receive any of the proceeds from decisions and/or settlements in directors and officer litigation, so ratepayers should not be responsible for the cost of protecting shareholders from their own decisions.

Q. WHAT ADJUSTMENT ARE YOU RECOMMENDING FOR DOL INSURANCE?

A. Based on what the Commission has determined as reasonable when I made recommendations to adjust DOL costs in Progress Energy Docket No. 090079-EI and Gulf Power Docket No. 110138-EI, I am recommending that the $798,546 cost be shared equally. Accordingly, I recommend that an adjustment of $399,273 is necessary; on a jurisdictional basis the adjustment is $398,974.

VIII. <u>GENERATION MAINTENANCE</u>

Q. DID YOU INQUIRE ABOUT TAMPA ELECTRIC'S REQUESTED GENERATION EXPENSE?

A. Yes. The Company has indicated that its projected cost of maintaining its generation facilities have increased because of inflationary factors, the aging of equipment, the implementation of new regulatory requirements, and postponement of non-critical maintenance during the economic downturn of the last couple of years. On page 34 of his direct testimony, Company witness Hornick indicated that the planned maintenance forecasted for 2014 is typical of the past and is expected to continue in the future, with one exception; the conversion of Polk Units 2-5 from simple cycle to combined cycle operation. Mr. Hornick also states that no costs related to the Polk Conversion projects are included in the test year expenses sought in this rate request. To evaluate the historic changes in cost and the Company's request for 2014 expense, OPC requested the historical information and a detailed listing of the maintenance projects for the period 2013 through 2016. Based on my review of the Company's historical expenditures based on Tampa Electric's response to OPC Interrogatory No. 75, Tampa Electric did not justify the increase in the projected 2014 costs.

Q. HOW DID YOU MAKE THIS DETERMINATION?

A. In response to OPC Interrogatory No. 75, the Company provided the maintenance costs for outages of the generation plants. As shown on Exhibit HWS-2, Schedule C-5, the Company averaged $11.811 million for outage maintenance expense from 2008-2012. The actual historical costs for the years 2003 through 2012, as shown in the response to OPC Interrogatory No. 75, averaged $10.832 million. The difference between the five-year and ten-year average is less than $1 million. This important fact illustrates that the maintenance cost over time has not changed significantly. Next, as shown on Exhibit HWS-2, Schedule C-5, line 9, I calculated the inflation-indexed average outage expense to be $13.497 million for the five years 2008-2012.

To determine the reasonableness of the Company's projection, I compared the historical average costs ($10.832-11.811 million), the historical inflation-indexed costs ($13.497 million), and the Company's 2014 request ($17.585 million) for reasonableness. Using the calculated estimate for 2014, which factors in price increases and the Company's detailed project information, the Company's request of $17.585 million is overstated by $4.088 million. As shown on Exhibit HWS-2, Schedule C-5, test year generation maintenance expenses should be reduced by $4.088 million to reflect an increased level of spending that I believe is more reasonable. The adjustment on a jurisdictional basis is $4.088 million.

Q. WOULD THE POLK CONVERSION MAINTENANCE PROJECTS IMPACT YOUR RECOMMENDATION?

A. No. The Polk Unit costs are summarized separately on Exhibit HWS-2, Schedule C-5. The average cost for the years 2008-2012 was $3.729 million. The inflation-indexed costs for the years 2008-2012 was $4.255 million. The Company's request for 2014 is $3.1 million for the Polk units. The 2014 costs in my analysis do not reflect an increased spending level for the Polk units that which exceeds the historical actual and/or indexed averages; therefore, the impact of any of the Polk Unit conversion costs do not justify the Company's proposed increase.

IX. RATE CASE EXPENSE

Q. PLEASE DISCUSS THE COMPANY'S REQUESTED RATE CASE EXPENSE.

A. The Company projects total rate case expense of $2,200,000 and requests a three-year amortization period. The Company included $1,490,000 for legal, $304,000 for assistance in MFR preparation, $173,000 for cost of capital consulting, $136,000 for rate design/cost of service consulting, $51,000 for revenue forecasting and $46,000 for storm damage analysis. Based on my analysis, the Company's rate case expense request is excessive, and the three-year amortization period is too short.

Q. WHY DO YOU BELIEVE THAT THE PROJECTED AMOUNT IS EXCESSIVE?

A. Tampa Electric (along with its parent, TECO Energy) is not a small company with limited human resources that would require significant assistance in assembling a rate filing. The Company has projected a total request of $2.2 million of expense for this rate case. A Company of this size is well aware of filing requirements and should not have to rely on two outside contractors, PowerPlan and William Slusser, Jr., to oversee its rate request. However, Tampa Electric has projected contracted services other than legal of $710,000 for this proceeding. In addition, the Company is requesting excessive amounts for its cost of capital witness and outside legal fees.

Q. WHY DO YOU BELIEVE THAT THE AMOUNT PROJECTED FOR OVERSIGHT BY POWERPLAN IS EXCESSIVE?

A. Tampa Electric should be capable of assembling a filing as well as processing a rate proceeding without an outside consultant to essentially "supervise" the filing. As discussed below, Tampa Electric's response to OPC Interrogatory No. 108 indicates the purpose for hiring PowerPlan is to make sure the filing is accurate, even though none of the consultants will be filing testimony. On MFR Schedule C-10, the Company requested $225,000 for consulting services, $34,000 for travel, and $45,000 for other unexplained costs associated with the services for PowerPlan.

Q. DID TAMPA ELECTRIC REQUEST RATE CASE EXPENSE FOR A SIMILAR FIRM IN ITS LAST RATE CASE?

A. Yes. In its last rate case, Tampa Electric employed a firm named Huron (which is no longer in business) to perform many of the same types of services that the Company engaged PowerPlan to provide in this case. In that docket, I testified that Tampa Electric's requested rate case expense for Huron was 3 times higher than the estimate included in the vendor's contract. I recommended that the $1.3 million cost for that firm be reduced to the $468,000 contract level. The Commission agreed with my recommendation that the Company had not supported the reasonableness of the expense or actual amount spent in its "final actual and estimate to complete" for the rate case expense.

In my experience, for a utility to seek the assistance of outside consultants because it is incapable of assembling and overseeing a rate request in-house, is very unusual. According to the response to OPC Interrogatory No. 108, the Company has 18 specific Company employees plus "several other regulatory team members" providing support as needed to prepare and administer the rate case filing and answer discovery requests. In my opinion, based upon the expertise and experience of Tampa Electric, this type of outside consultant oversight by PowerPlan created an unnecessary and unreasonable expense. At the very least, the cost should be minimized.

The cost for PowerPlan's oversight included in the filing is $304,000. In my opinion, this is an unnecessary expense. Contributing to the high cost are the excessive average hourly rates that the Company has agreed to pay. (Tampa Electric's confidential response to OPC Document Request No. 83) Moreover, Tampa Electric has not included a direct witness from PowerPlan to justify including this cost even though ratepayers are asked to pay $304,000 for PowerPlan's assistance.

Q. WHAT SERVICES ARE POWERPLAN PROVIDING TO TAMPA ELECTRIC?

A. In Interrogatory No. 108, OPC asked Tampa Electric to explain in detail why PowerPlan was hired and the types of services that were required. The response states that PowerPlan services include reviewing:

> …the MFR's for overall accuracy, completeness and reasonableness, consistency of the MFR's with surveillance report filings and the prior rate case filing for income, rate base and capital structure items, tax analysis and support on MFR's as well as prepared testimony with regard to income tax issues, the review of pro-forma adjustments for reasonableness, possible preparation and analysis of discovery responses and the potential review of intervenor and Commission Staff testimony.

Generally, in a rate case the Company's employees will respond to discovery and the lawyers will review the responses. In this case, it appears that the Company has added multiple layers of review, which has caused costs above and beyond what is necessary and/or reasonable. Further, the Company has not supported why these amounts should be allowed as rate case expense, as it did not provide any supporting documentation to show the reasonableness of the amounts charged, the description of the work actually performed, and the actual hourly rates and other expenses incurred. It is the Company's burden to show that its requested costs are reasonable, and it has failed that burden. As such, I recommend that the $304,000 for PowerPlan be removed.

Q. PLEASE DISCUSS THE RATE CASE EXPENSE ASSOCIATED WITH THE COST OF WILLIAM SLUSSER.

A. Tampa Electric's response to OPC Interrogatory No. 109 states that Mr. Slusser's services:

> . . . include assisting with the preparation of the jurisdictional and cost of service studies, evaluation of rate design alternatives as well as development and review of the final rate design, reviewing the rate and cost of service Schedule E MFRs for overall accuracy, completeness and reasonableness, consistency of the MFRs, as well as testimony review and review of pre-forma adjustments for reasonableness. Mr. Slusser is also assisting in preparation and analysis of discovery responses and the review of potential intervenor and Commission Staff testimony.

The fee for Mr. Slusser's consulting services is $136,000.

Q. IN YOUR OPINION, IS MR. SLUSSER PROVIDING A SERVICE THAT THE COMPANY IS UNABLE TO PROVIDE FOR ITSELF?

A. No. Mr. Slusser is not a witness, and Tampa Electric has not explained why the services he performed were necessary or required. Tampa Electric has not justified or explained why its staff is not capable of handling the rate request without adding unnecessary outside consulting costs. The description of Mr. Slusser's responsibilities is very similar to the services to be provided by Power Plan and appears to be work that could be performed by Company employees. In fact, Tampa Electric's employee Mr. Ashburn, not Mr. Slusser, is sponsoring Tampa Electric's rate design. Moreover, if Mr. Slusser's services were required to justify the rate design, the jurisdictional cost of service and the overall accuracy of the MFRs, the Company would have had him file direct testimony. Further, it does not appear from the response that Mr. Slusser is a potential rebuttal witness. I believe that this $136,000 fee is excessive and these costs should be removed. No sufficient justification has been presented by the Company for Mr. Slusser's services, thus Tampa Electric has failed to meet its burden to include these costs.

Q. PLEASE DISCUSS THE COST ASSOCIATED WITH THE COMPANY'S COST OF CAPITAL WITNESS.

A. Tampa Electric witness Robert Hevert of Sussex Economic Advisors is testifying as to what he believes is a reasonable return on equity ("ROE"). Mr. Hevert's cost of $173,000 is roughly two and one-half times the $70,000 that OPC has contracted to pay for the same service in this proceeding, and is almost twice the amount that was requested by Pepco for his services in Maryland Docket No. 9311. There is no justification for including $173,000 of costs for a ROE witness. In my opinion, the cost is without question excessive for a cost of capital and return on equity witness, especially when Company witnesses are also addressing these issues. Therefore, I recommend that the Sussex Economic Advisors cost for $173,000 be reduced to $70,000.

Q. DO YOU HAVE A CONCERN WITH THE LEVEL OF THE COMPANY'S LEGAL FEES INCLUDED IN RATE CASE EXPENSE?

A. Yes. The legal fees being requested by Tampa Electric are also excessive, especially when compared to the level allowed in Docket No. 080317-EI. The Company is requesting $1.490 million for rate case legal services. This request amounts to a 44.66% increase over the $1.030 million allowed in Docket No. 080317-EI. In my opinion, a 44.66% increase in five years is excessive. I recommend that the legal fees be reduced by $280,000. I calculate this reduction by escalating the $1.030 million allowed in Docket No. 080317-EI by the combined growth and inflation indices on Company MFR Schedule C-40.

Q. PLEASE EXPLAIN WHY YOU BELIEVE THE 3-YEAR AMORTIZATION PERIOD IS TOO SHORT.

A. The Company's last rate case was five years ago in 2008. In that request the Company also proposed a three-year amortization period. In Docket No. 080317-EI, Company witness Chronister testified that he was relatively certain that Tampa Electric would request another rate increase sooner than 5 years. The Commission determined a four-year amortization to be reasonable. If the approved rates in this docket go into effect January 1, 2014, the Company will have recovered 56 months (4.7 years) of amortization for the rate case expense from the 2008 docket. Based on the annual expense of $493,250 allowed in that docket, Tampa Electric has collected approximately $329,000 more from ratepayers than the actual rate case expense that was approved by this Commission. The continued recovery of rate case expense beyond when the expense has been fully recovered is not appropriate. A five-year amortization period is more reasonable given the over-recovery that has occurred due to the shortened amortization period in the last rate case and Tampa Electric's normal pattern of long time periods between rate cases.

Q. WHAT IS THE TOTAL ADJUSTMENT THAT YOU ARE RECOMMENDING TO RATE CASE EXPENSE?

A. Based on the adjustments discussed above and shown on Exhibit HWS-2, Schedule C-6, rate case expense should be reduced by $823,000. I am recommending that the Company's projected costs of $2.2 million (3-year amortization of $733,000) be reduced to $1.377 million (5-year amortization of $275,000). The result is a reduction to amortization expense of $458,000.

X. STORM ACCRUAL AND TARGET RESERVE

Q. PLEASE EXPLAIN THE COMPANY'S REQUESTED STORM ACCRUAL AND TARGET RESERVE.

A. The Company is requesting that it be allowed to continue to accrue $8,000,000 annually to the storm reserve and to increase its storm reserve target to $100,000,000. Tampa Electric witness Harris presents the results of his storm loss and reserve performance analyses ("Storm Study") for Tampa Electric's system. Tampa Electric witness Carlson testifies to the Company's requested annual storm accrual and target reserve.

Q. ARE THERE SOME CONCERNS WITH THE COMPANY'S REQUEST TO CONTINUE ITS $8 MILLION ACCRUAL AND INCREASE THE STORM RESERVE TARGET TO $100 MILLION?

A. Yes. The Company's request to maintain the accrual and increase the reserve target is not supported by the historical storm activity. The study relied upon by the Company ignored a significant factor and is based on improper assumptions. In the last rate case, the Commission increased the Company's annual accrual from $4 million to $8 million and increased the reserve target from $55 million to $64 million. The amounts allowed were significantly less than the Company's request to increase the annual accrual to $20 million and the reserve target to $120 million.

Q. WOULD YOU EXPLAIN WHY HISTORICAL STORM ACTIVITY DOES NOT SUPPORT MAINTAINING THE ACCRUAL AND THE RESERVE TARGET REQUESTED?

A. As indicated in its response to OPC Interrogatory No. 91, Tampa Electric has charged only $5,684,327 against the reserve for storms since 2004. That is an average of $668,744 per year over the last eight and one-half years. As shown on Exhibit HWS-2, Schedule C-7, from December 31, 1999 to December 31, 2003, there were no charges against the reserve. Clearly, with the exception of 2004, the amount charged to the reserve has been minimal.

Q. SHOULD THE 2004 STORMS BE CONSIDERED IN SETTING THE TARGET STORM RESERVE?

A. No. The storms in 2004 were an anomaly and were, as they should be, treated differently by the Commission. The 2004 storms were of an intensity that caused a level of damage that the Commission has historically stated is not the type intended to be covered by the reserve. Moreover, the storm study ignores the significance of the actual history of Tampa Electric's storm damages, in favor of theoretical storm impacts.

Q. WAS STORM HARDENING FACTORED INTO THE STUDY RELIED ON BY THE COMPANY?

A. No. As indicated in the response to OPC Interrogatory No. 90, "The Company does not have an estimate of the effect the storm hardening plan may have in reducing storm repairs." The storm hardening costs included in rates over the past seven years are assumed to provide some benefit when restoration is required. I acknowledge that, because of the limited number of storms and the limited amount of damages incurred since 2004, the full extent of the storm hardening benefit cannot be determined. However, the storm hardening costs can be justified only by the assumption that the benefits of lower restoration costs and outage times will occur. To ignore any estimate of that benefit in the study is inappropriate.

Q. WHAT IMPROPER ASSUMPTIONS ARE RELIED ON BY THE COMPANY?

A. First, the Company is assuming a 4.5% annual cost increase for inflation on the cost of its transmission system that is not consistent with recent rates of inflation. Second, the study factors in the intensity and impact of approximately 100,000 hypothetical storms. A vast majority of these hypothetical storms are not geographically focused on the Tampa Electric system. This fact was confirmed in Tampa Electric's response to OPC Interrogatory No. 112. Additionally, as indicated in its response to OPC Interrogatory No. 113, only 12,000 of the hypothetical storms would cause damage to the Tampa Electric system.

Third, Tampa Electric's response to OPC Interrogatory No. 93 states that cost inputs in the study do not comply with the Commission's rule on storm cost recovery. The Company's response stated: "No, the Expected Annual Loss ("EAL") computed in the Storm Loss Analysis is not consistent with Rule 25-6.0143(1)(d), Florida Administrative Code." The Company's requested storm accrual and its response indicates the study uses the replacement values as inputs, whereas the rule states that costs charged for storm related damage shall include only incremental costs. That means the study is a tool that may be considered but should not be relied on as the sole means for determining the annual accrual and in determining the reserve target.

Q. HAS THE COMMISSION ALLOWED COMPANIES TO RECOVER STORM RELATED COSTS BY MEANS OTHER THAN A STORM ACCRUAL?

A. Yes. In Order No. PSC-10-0131-FOF-EI, the Commission disallowed Progress Energy's request to continue its accrual to the storm reserve. In that Order, the Commission concluded:

> The Company has the option of petitioning this Commission for a surcharge to recover the storm damage costs not recovered through the storm damage reserve. As demonstrated in the past, we have allowed companies to recover extraordinary hurricane losses, such as the ones experienced by PEF in 2004, through a separate surcharge.
>
> Order No. PSC-10-0131-FOF-EI, issued March 5, 2010, at p. 71.

Q. WHAT ARE YOU RECOMMENDING FOR THE STORM RESERVE TARGET?

A. The previous storm reserve target of $55 million was considered sufficient from 1994 through 2008. Both system and customer growth have occurred, as has inflation;

however, the Company has undertaken storm hardening projects designed to mitigate the compounding increases in growth and inflation and limit the damage that a storm might inflict. In my opinion, growth and inflation have not been at levels that would justify increasing the reserve. Moreover, I note that the Company is now requesting a target of $100 million even though it requested a reserve target of $120 million back in 2008.

The current reserve target of $64 million is sufficient. Any change would be premature based on past Commission practice and based on the Company's recent storm activity. Also, it should be noted that the reserve is not intended to provide for recovery of storm damage of the magnitude that occurred in 2004. As of June 30, 2013 the reserve is at $53.292 million. Tampa Electric's storm study indicates that there is only an 8.68% probability that this reserve level would be exceeded in any one year. As noted above, the Commission has ruled that the reserve is not intended to recover the cost of storms as significant as those incurred in 2004.

Q. WHAT ARE YOU RECOMMENDING FOR THE STORM ACCRUAL?

A. Assuming the continuation of a storm reserve target of $64 million, I am recommending an annual accrual of $3 million. Using a $3 million accrual, the Company's request should be reduced by $5 million.

Q. DOES YOUR RECOMMENDATION IMPACT RATE BASE?

A. Yes. Assuming a reduction of $5 million in the accrual, the reserve reflected in rate base will also decrease by approximately $2,500,000, the average of my recommended adjustment. Because the storm reserve is a reduction to working capital, my recommended adjustment increases rate base by $2,500,000.

Q. HOW DID YOU DETERMINE YOUR RECOMMENDED STORM ACCRUAL OF $3 MILLION?

A. Assuming that charges against the storm reserve continue at the average level of $1.342 million as recorded over the past three years, and assuming the Company will not seek another rate increase until 2017 (4 years), I calculated that the reserve would reach the target level of $63.923 million by December 31, 2017. This recommendation is reasonable, when you consider that the Company's average annual charge to the reserve for storms since 2004 has been $668,744 and we are now four years beyond the last change in rates.

XI. <u>TREE TRIMMING</u>

Q. WOULD YOU EXPLAIN THE COMPANY'S REQUEST FOR TREE TRIMMING?

A. The Company is asking for $8,261,622 for distribution tree trimming, $692,678 for enhanced tree trimming and $349,454 for mowing, for a grand total of $9,303,754 for vegetation management. In her direct testimony, Company witness Beth Young states that the Company is on a four-year trim cycle for distribution and that Tampa Electric has devoted a great deal of effort to reduce costs while maintaining quality. At pages 8-9 of her direct testimony, Ms. Young states that the cost per mile has declined from $6,920 in 2008, to a forecasted $4,866 for 2014. Ms. Young further states that the cost per mile has declined steadily by 30 percent in six years. Ms. Young continues on pages 31-32 that the aggressive trim cycle implemented by Tampa Electric has successfully reduced the old growth, resulting in a much lighter trim requirement.

Q. HAS THE COST FOR DISTRIBUTION TREE TRIMMING DECLINED AS THE COMPANY HAS INDICATED?

A. Yes. Tampa Electric's response to OPC Interrogatory No. 117 indicates the Company's cost for tree trimming has declined from a high of $12,375,631 in 2010 to $7,980,303 in 2012. The increase that actually began in 2009 was due to the Company's transition to a three-year tree trimming cycle.

Q. WHAT IS YOUR CONCERN WITH THE COMPANY'S TREE TRIMMING REQUEST IN THIS PROCEEDING?

A. First, my calculations reflect that Tampa Electric's cost per mile for tree trimming is higher than Ms. Young indicates based on responses OPC has received in discovery. As noted above, the Company states that it has projected its 2014 cost per mile to be $4,866; however, my calculations using the Company's response to OPC Interrogatory No. 117 for tree trimming reflects a higher cost of $5,245 per mile. I calculated this using the Company's 2014 cost of $8,261,622 divided by the 1,575.2 scheduled trim miles for 2014. The scheduled 2014 trim miles of 1,575.2, is one-fourth of the 6,301 miles that are subject to trimming. Using the response to OPC

Interrogatory No. 117, I also calculated an actual cost per mile for 2012 of $4,647 for tree trimming alone.

Second, the Company has never expended what was allowed for annual tree trimming expense in the last rate case. The Commission approved an annual expense of $14,759,000 in its order in that case. However, the most the Company expended in any year since the rates from the last rate case went into effect was $12,375,631 in 2010. Even if enhanced tree trimming and mowing were included, the highest amount expended was $13,398,688 in 2010. In 2012, the Company expended only $7,980,303, which is $6,778,697 less than what was included in rates from the last rate case. I believe that the extent to which the level approved in the last rate case proved to be unnecessary should be taken into account when the Commission determines the appropriate level of tree trimming expense in this proceeding.

Q. WHAT ARE YOU RECOMMENDING FOR TREE TRIMMING?

A. As shown on HWS-1, Schedule C-8, the Company should be allowed no more than $8,370,613 for tree trimming. That reduces the Company's $9,303,754 request for distribution tree trimming by $933,141.

Q. HOW DID YOU DETERMINE YOUR RECOMMENDED COSTS?

A. The estimated cost is based on 1,575.2 trim miles at the 2012 rate of $5,314 per mile, which is inclusive of scheduled tree trimming, enhanced tree trimming and mowing. The trim miles are the number of miles the Company has indicated that it would trim in 2014. My 2012 rate per mile was calculated from the Company's response to OPC

Interrogatory No. 117, which includes the scheduled tree trimming, enhanced tree trimming and mowing. This recommendation is an all-inclusive amount for vegetation management. My recommendation is more than reasonable given today's economic conditions and the volatility in Tampa Electric's cost per mile over the past ten years.

Q. DID YOU MAKE A SIMILAR RECOMMENDATION IN DOCKET NO. 080317-EI?

A. Yes. In Docket No. 080317-EI, I recommended using the last actual cost per mile multiplied by one-fourth of the number of miles the Company had indicated were included in its system. The Company took exception to my calculation, claiming that my cost per mile was understated because the trim miles I used purportedly included miles without trees. The Commission adjusted my recommendation for the trim miles upward from 1,530 miles to 1,775 miles and increased the cost per mile from $7,897 to $8,315. The Company's request was reduced by $1,314,000 in Order No. PSC-09-0283-FOF-EI at pages 69-70. As shown on Exhibit HWS-2, Schedule C-8, the average cost per mile after 2008 has been significantly lower than the Commission allowed cost per mile of $8,315.

Q. PLEASE EXPLAIN THE DIFFERENCES BETWEEN THE COMMISSION'S ADJUSTMENT TO TREE TRIMMING IN THE LAST RATE CASE AND YOUR RECOMMENDATION IN THIS CASE.

A. In the last rate case, Docket No. 080317-EI, the Commission agreed that the Company's request was overstated. The Commission used my method of taking the Company's 6,121 miles of overhead distribution miles included in the system because the Company could not identify how many miles of distribution required trimming. The Commission opted to use a 29% factor instead of my recommended 25% in determining the number of miles to be trimmed. In this case, I am using the specific number of miles the Company has indicated would be trimmed in 2014. This number is one-fourth of the number of miles the Company has indicated is "subject to trimming," so there is no question as to the number of miles used in my calculation. My rate per mile is based on the actual cost for vegetation management and the miles trimmed, as provided by the Company's response to OPC Interrogatory No. 117. As discussed above, the Company's calculated cost per mile of $5,245 (see OPC Interrogatory No. 117) is not consistent with the forecasted rate of $4,866 per mile for 2014 found on page 9 of Ms. Young's testimony. In addition, the Company has said the cost per mile is declining; therefore, using the last actual rate per mile may overstate the cost. My cost per mile calculation is based on the combined cost for vegetation management, which includes tree trimming, enhanced tree trimming and mowing. Should the Commission want to address only the scheduled tree trimming instead of an overall cost for vegetation management, I have performed that calculation.

Q. WHAT WOULD YOUR ALTERNATIVE RECOMMENDATION BE IF YOU USE ONLY THE TREE TRIMMING COSTS AND NUMBER OF MILES SUBJECT TO TRIMMING?

A. The response to OPC Interrogatory No. 117 indicates the 2014 tree trimming cost alone is $8,261,622. Multiplying the actual cost per mile for tree trimming from 2012 of $4,646.74 ($7,980,303/1,717.4) by the projected 1,575.2 miles the Company has indicated will be trimmed in 2014 results in a cost of $7,319,537. The difference is a reduction of $942,085 for tree trimming alone.

Q. ARE THERE ANY OTHER RECOMMENDATIONS WITH RESPECT TO TREE TRIMMING THAT YOU WOULD LIKE TO MAKE?

A. Yes. In past years, the Company has not expended the amount allowed in rates. If the Company does not expend the level of tree trimming allowed by the Commission, the Company should record a regulatory liability for any unexpended funds and utilize that in subsequent years.

Q. DOES THIS COMPLETE YOUR TESTIMONY?

A. Yes.

DIRECT TESTIMONY

OF

DONNA RAMAS

On Behalf of the Office of Public Counsel

Before the

Florida Public Service Commission

Docket No. 130040-EI

INTRODUCTION

Q. WHAT IS YOUR NAME, OCCUPATION AND BUSINESS ADDRESS?

A. My name is Donna Ramas. I am a Certified Public Accountant licensed in the State of Michigan and Principal at Ramas Regulatory Consulting, LLC, with offices at 4654 Driftwood Drive, Commerce Township, Michigan 48382.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION?

A. Yes, I have testified before the Florida Public Service Commission ("PSC" or "Commission") on several prior occasions. I have also testified before several other state regulatory commissions.

Q. HAVE YOU PREPARED AN EXHIBIT DESCRIBING YOUR QUALIFICATIONS AND EXPERIENCE?

A. Yes. I have attached Exhibit DMR-1, which is a summary of my regulatory experience and qualifications.

Q. ON WHOSE BEHALF ARE YOU APPEARING?

A. I am appearing on behalf of the Citizens of the State of Florida ("Citizens") for the Office of Public Counsel ("OPC").

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. I am presenting OPC's overall recommended revenue requirement for Tampa Electric Company ("Tampa Electric" or "Company") in this case. I also sponsor several adjustments to the Company's proposed rate base and operating income.

Q. ARE ANY ADDITIONAL WITNESSES APPEARING ON BEHALF OF THE FLORIDA OFFICE OF PUBLIC COUNSEL IN THIS CASE?

A. Yes. Helmuth W. Schultz, III, of Larkin & Associates, PLLC, is presenting testimony on several issues which impact the revenue requirements. Jacob Pous' testimony addresses the appropriate amortization rate to apply to software included in Tampa Electric's test year rate base and presents the adjustment needed to reflect his recommendation. Kevin O'Donnell's testimony addresses the appropriate capital structure for purposes of determining the revenue requirements of Tampa Electric in this case as well as the financial integrity of Tampa Electric taking into consideration the recommendations made by OPC's witnesses in this case. Dr. Randall Woolridge presents Citizens' recommended rate of return on equity in this case using the capital structure recommended by Mr. O'Donnell, and the appropriate rate of return on equity if Tampa Electric's proposed capital structure is adopted by the Commission.

Q. HOW WILL YOUR TESTIMONY BE ORGANIZED?

A. I first present the overall financial summary for the base rate change, showing the primary revenue requirement recommended by Citizens. I then discuss several of my proposed adjustments which impact the test year revenue requirements. Exhibit DMR-2 presents the schedules and calculations in support of this section of my testimony.

I then present the outcome of an alternative revenue requirement using Tampa Electric's proposed capital structure instead of the capital structure recommended by OPC in this case. The calculations of the alternative revenue requirement are presented in Exhibit DMR-3.

OVERALL FINANCIAL SUMMARY

Q. PLEASE DISCUSS THE EXHIBIT YOU PREPARED IN SUPPORT OF YOUR TESTIMONY AS IT PERTAINS TO OPC'S PRIMARY RECOMMENDATION.

A. Exhibit DMR-2, totaling 12 pages, consists of Schedules A-1, A-2, B-1, C-1 through C-6, and D.

Schedule A-1 presents the revenue requirement calculation, giving effect to all of the adjustments I am recommending in this testimony, along with the impacts of the recommendations made by Citizens' witnesses Schultz, Pous, O'Donnell and Woolridge. Schedule B-1 presents OPC's adjusted rate base and identifies each of the adjustments impacting rate base that are recommended by Citizens' witnesses in this case. OPC's adjustments to net operating income are listed on Schedule C-1. Schedules C-2 through C-6 provide supporting calculations for the adjustments I am sponsoring to net operating income, which are presented on Schedule C-1.

Q. WOULD YOU PLEASE DISCUSS SCHEDULE D?

A. Schedule D presents Citizens' recommended capital structure and overall rate of return, based on the revisions to Tampa Electric's proposed debt-to-equity ratio recommended by Mr. O'Donnell and the rate of return on equity recommended by Dr. Woolridge. The capital structure ratios are based on the ratios recommended by Mr. O'Donnell; however, the capital structure dollar amounts differ, as I have applied the adjustments to the capital structure necessary to synchronize Citizens' recommended rate base with the overall capital structure. On Schedule D, I then applied Dr. Woolridge's recommended cost rates to the recommended capital ratios, resulting in OPC's overall recommended rate of return of 5.66%.

Q. WHAT IS THE RESULTING REVENUE REQUIREMENT FOR TAMPA ELECTRIC COMPANY?

A. As shown on Exhibit DMR-2, Schedule A-1, OPC's recommended adjustments in this case result in a recommended revenue reduction for Tampa Electric of $5,589,000. This is $140.429 million less than the $134.84 million base rate increase requested by Tampa Electric in its filing.

<u>REVENUE EXPANSION FACTOR</u>

Q. WHAT IS THE PURPOSE OF YOUR EXHIBIT DMR-2, SCHEDULE A-2, "REVENUE EXPANSION FACTOR"?

A. In determining the amount of change in revenues to achieve a specific required change in net operating income, it is necessary to apply the revenue expansion factor. The revenue expansion factor is also sometimes called the Net Operating Income Multiplier or the Gross Revenue Conversion Factor. This gross-up or revenue expansion factor is needed because a portion of every additional dollar of revenue collected by Tampa Electric will go to regulatory assessment, state income taxes and federal income taxes. Additionally, a portion of additional revenues would also be considered uncollectible. In its filing, Tampa Electric has included a Revenue Expansion Factor of 1.63220, which was calculated on its MFR Schedule C-44. This Revenue Expansion Factor is applied to Tampa Electric's projected net operating income deficiency in determining the amount of revenue increase shown on Tampa Electric's MFR Schedule A-1.

Later in this testimony, I recommend that the projected test year bad debt rate (or uncollectible rate) be reduced from the rate of 0.185% incorporated in Tampa Electric's filing to a rate of 0.122%. As shown on Exhibit DMR-2, page 2 (Schedule A-2), incorporating the revised bad debt rate in the calculation of the revenue expansion factor reduces the factor from the 1.63220 rate used by Tampa Electric to 1.63117. This revised revenue expansion factor is used on Exhibit DMR-2, Schedule A-1 in calculating OPC's recommended reduction in revenues.

RECOMMENDED ADJUSTMENTS

Q. WOULD YOU PLEASE DISCUSS EACH OF YOUR SPONSORED ADJUSTMENTS TO TAMPA ELECTRIC'S FILING?

A. Yes, I will address each adjustment I am sponsoring below.

Other Operating Revenues – Calpine Contract Adjustment

Q. WHAT AMOUNT IS INCLUDED IN THE TEST YEAR FOR OTHER ELECTRIC REVENUES?

A. MFR Schedule C-5 shows at lines 26 and 29 that the unadjusted test year Other Electric Revenues in Federal Energy Regulatory Commission ("FERC") Account 456 – Other Electric Revenues are $19,890,000 ($18,757,000 jurisdictional) and the adjusted test year jurisdictional amount is $11,248,000. The test year jurisdictional balance on MFR Schedule C-5 was reduced by $3,969,000 for a "Calpine Contract Adjustment" and $3,540,000 for an "Auburndale Wheeling Revenue" adjustment.

Q. HOW DO OTHER ELECTRIC REVENUES PROJECTED FOR 2014 COMPARE TO PRIOR PERIODS?

A. Tampa Electric's response to OPC Interrogatory No. 122 shows that the Other Electric Revenues were $17,694,000 in 2009, $20,041,000 in 2010, $24,433,000 in 2011, and $25,777,000 in 2012. The adjusted test year balance of Other Electric Revenues in FERC Account 456 of $11,248,000 is substantially lower than the amount recorded in prior periods.

Q. WOULD YOU PLEASE DISCUSS THE ADJUSTMENT MADE BY TAMPA ELECTRIC TO REMOVE CALPINE TRANSMISSION REVENUES FROM THE TEST YEAR?

A. Yes. At page 47 of the direct testimony of Tampa Electric witness Jeffrey Chronister, he indicates that the Calpine Purchase Power Agreement ("PPA") is set to expire at the end of May 2014, and that "Tampa Electric has not been informed that any portion of that 526 MW transmission agreement will be extended beyond that date." As a result, the Company removed $3,969,000 from the test year jurisdictional Other Operating Revenues on MFR Schedule C-2, page 3 of 7. The $3,969,000 adjustment removes the revenues included in the unadjusted test year for January through May, 2014. At page

47, Mr. Chronister also proposes that the transmission revenues from Calpine for the first five months of the test year (i.e., January through May) be spread over a 12-month period and credited back to customers through the fuel clause.

Q. HAS TAMPA ELECTRIC PROVIDED ANY UPDATED INFORMATION REGARDING WHETHER THE TRANSMISSION AGREEMENT WITH CALPINE WILL BE EXTENDED BEYOND THE MAY 2014 EXPIRATION DATE?

A. Yes. OPC Interrogatory No. 64(b) asked the Company to explain why it was not anticipated that the Calpine PPA will be extended or renewed after the current expiration date in May 2014. The response, filed on May 20, 2013, indicated as follows:

> Calpine owns two generating plants connected to a Tampa Electric substation. The Osprey Energy Center is a 526 MW combined cycle unit and the Auburndale Peaker Energy Center is a 135 MW peaking unit. Calpine currently sells 350 MW of firm power to Seminole Electric under a PPA that ends May 31, 2014. They also sell 117 MW to Tampa Electric under a PPA that ends December 31, 2016. Calpine has two, long-term, firm transmission service reservations on the Tampa Electric transmission system. One is for 249 MW on a path to Duke and the other is for 277 MW on a path to FPL. The original TSA for these reservations ends May 31, 2014, and to date Calpine has not committed to roll over the service as Seminole Electric has indicated that they will not continue their PPA with Calpine past that time. Calpine is the customer of record and has the right to roll either or both of these reservations over, for the full MW amount of each reservation or for some amount less. The customer must make the roll over request on OASIS one year or more prior to the services' termination (May 31, 2013). At this time, Tampa Electric is not aware if the contract will be rolled over, and if so for how many MW.

Subsequently, in response to OPC Interrogatory No. 124 filed on June 24, 2013, the Company indicated that Calpine recently committed to 249 MW for calendar year 2014. Thus, the agreement has apparently been extended with the annual load commitment declining from 526 MW to 249 MW.

Q. DID THE COMPANY'S FILING ENVISION UPDATING THE OTHER ELECTRIC REVENUES?

A. Yes. Mr. Chronister states at page 47 of his testimony that "[i]f Calpine or Auburndale extend or partially extend their agreements, the company will calculate the appropriate amount of associated revenues and appropriately pro forma adjust them back to revenues."

Q. DO YOU RECOMMEND THAT TEST YEAR OTHER ELECTRIC REVENUES BE ADJUSTED TO REFLECT THE REVENUES THAT WILL BE RECEIVED FROM CALPINE DURING THE TEST YEAR UNDER THE NEW AGREEMENT?

A. Yes. While the Company provided the new Calpine commitment amount of 249 MW in response to OPC Interrogatory No. 124, it did not provide the amount of test year revenues that result from the new commitment. Based on the statement in Mr. Chronister's testimony, I assume that Tampa Electric will provide the updated information reflecting the revenues. Since that information has not yet been provided by Tampa Electric, Exhibit DMR-2, Schedule C-2 estimates the revenue that would result from the new Calpine Transmission Service Agreement ("TSA") as $4,509,267. As indicated above, included in the unadjusted test year was $3,969,000 in Calpine transmission revenues on a jurisdictional basis for a 526 MW commitment for five months (January – May 2013). These amounts were then used to estimate the revenues for a twelve-month period based on a 249 MW commitment on Exhibit DMR-2, Schedule C-2. Since Tampa Electric's MFR Schedule C-2, page 3 and MFR Schedule C-5 identify the Calpine contract revenues as being jurisdictional amounts, I applied a jurisdictional separation factor of 1.000 to the resulting adjustment on Exhibit DMR-2, Schedule C-1. It is not clear why these amounts are reflected by the Company as jurisdictional revenues in its filing; however, I have reflected the amount provided as jurisdictional at this time, consistent with how it is presented in Tampa Electric's filing.

The estimated revenues of $4,509,267 assume that the 249 MW commitment is in place for the entire 2014 test year. However, Mr. Chronister's testimony indicated at page 47 that the 526 MW TSA is set to expire at the end of May 2014. It is not clear from the information provided by Tampa Electric if the original commitment for 526 MW remains in place through May 2014. If that is the case, then I recommend that the additional transmission revenues for the first five months of the test year that exceed the amount to be incorporated in base rates (i.e., the difference between the revenues from the 526 MW commitment compared to the new 249 MW commitment) be credited to the fuel clause and spread out over a 12-month period, similar to Mr. Chronister's recommendation.

Q. IS THERE A COMPELLING REASON FOR INCLUDING THE KNOWN TRANSMISSION REVENUES IN BASE RATES AS OPPOSED TO TRANSFERING THEM AS A CREDIT TO THE FUEL CLAUSE?

A. Yes. The transmission revenues impact the jurisdictional separation factors. Thus, they should be included in calculating the jurisdictional separation factors in this case. This is discussed in further detail later in this testimony.

<u>Other Operating Revenues – Auburndale Wheeling Revenue</u>

Q. YOU PREVIOUSLY INDICATED THAT TAMPA ELECTRIC COMPANY REDUCED THE JURISDICTIONAL TEST YEAR OTHER ELECTRIC

REVENUES BY $3,540,000 TO REMOVE "AUBURNDALE WHEELING REVENUE." WHY WAS THIS ADJUSTMENT MADE BY TAMPA ELECTRIC?

A. According to Mr. Chronister at page 47 of his direct testimony, the wheeling revenues associated with the Auburndale PPA with Progress Energy Florida were removed from the test year because "Auburndale was recently sold to Quantum Energy and the contract is not expected to be renewed when it expires at the end of 2013." The response to OPC Interrogatory No. 64 indicates that the grandfathered TSA with Auburndale Power Partners (the transmission customer of record) to deliver the Auburndale Purchase Power to the border of Duke Energy Florida (previously Progress Energy Florida) may terminate sooner than August 4, 2024 should the Duke Energy Florida PPA terminate. The response also indicates that Auburndale Power Partners told Tampa Electric, through discussions, that it has been told that Duke Energy Florida intends to terminate the PPA at the end of 2013 and that it does not desire to extend the contract past December 31, 2013. The subsequent response to OPC Interrogatory No. 124 indicates that, as of the date of the response (June 24, 2013), there is no change to the Auburndale commitment and there is no indication from Auburndale Power Partners that this will change.

Q. ARE YOU RECOMMENDING AN ADJUSTMENT TO PLACE THE REVENUES BACK INTO THE TEST YEAR?

A. No, not at this time. However, Mr. Chronister indicated at page 47 of his direct testimony that if Auburndale extends or partially extends their agreement "…the company will calculate the appropriate amount of associated revenues and appropriately pro forma adjust them back to revenues." Thus, if circumstances change and Tampa Electric is informed that either the grandfathered TSA is being extended or rolled over into an Open Access Transmission Tariff ("OATT") point-to-point TSA, then the resulting revenues should be adjusted into the test year. On Exhibit DMR-2, Schedule C-1, page 2 of 2, I have included a line for the Auburndale transmission agreement revenues with the amount shown as "unknown" at this time. The impact of such change, if it occurs, should also be reflected in the calculation of the jurisdictional separation factors in this case.

<u>Jurisdictional Separation Factors</u>

Q. HAVE THE ADJUSTMENTS MADE BY THE COMPANY TO REMOVE THE TRANSMISSION SERVICE AGREEMENTS IMPACTED THE JURISDICTIONAL SEPARATION FACTORS?

A. Yes. For example, the jurisdictional separation factor for transmission operating expense has gone from 82.2945% in the 2012 test period to 98.585% in the 2014 test year. Additionally, the jurisdictional separation factor for transmission plant has gone from 81.2936% in the 2012 historic test period to 98.4887% in the 2014 test year. This shifts more costs associated with the transmission plant and operations onto retail customers. The response to OPC Interrogatory No. 54 indicates that the adjustments made to remove the load effects of the Auburndale Power Partners and the Calpine TSA have caused the large increase in the transmission jurisdictional separation factors.

In fact, the direct testimony of Tampa Electric witness William Ashburn at pages 17 and 18 indicates that the load effects of the Auburndale Power Partners and Calpine TSA have been removed from the jurisdictional separation study for the 2014 test year and that the removal ". . . best reflects the appropriate jurisdictional separation effects on retail revenue requirement measurement for the test year and going forward." Mr. Ashburn's testimony also indicates that each of these transmission customers has the option to request rollover of the existing contracts before they end and that if such a request is made and either the existing contract is extended or a new contract is created during the pendency of the case, ". . . Tampa Electric is prepared to reflect that change, for whatever portion of their existing contracted capacity that they secure for extension, in revised transmission separation factors."

Q. HAS EITHER OF THE CONTRACTS BEEN EXTENDED OR REVISED?

A. Yes. As previously mentioned, Calpine recently committed to a 249 MW TSA for calendar year 2014.

Q. HAS TAMPA ELECTRIC PROVIDED THE IMPACT OF THE NEW CALPINE COMMITMENT ON THE JURISDICTIONAL SEPARATION FACTORS CONTAINED IN ITS FILING?

A. Yes, in part. In response to OPC Interrogatory No. 124, the Company provided the jurisdictional allocation factors under three scenarios. The first scenario was based on the original filing amount with all load responsibility removed for Calpine and Auburndale Power Partners. The second scenario reflected the removal of the pro forma adjustments and the inclusion of the 526 MW load responsibility for Calpine included for January through May 2014, as well as the inclusion of the 132 MW load responsibility for Auburndale Power Partners for the full test year. The third scenario provided updated information based on Tampa Electric's most recent forecast, which included Calpine's monthly load responsibility of 249 MW for the entire year and no load responsibility for Auburndale Power Partners. The factors under each scenario were provided by broad categories (i.e., operations and maintenance ("O&M") expense, depreciation expense, taxes other than income, income tax, other expenses, plant in service, Plant Held for

Future Use ("PHFFU"), working capital, construction work in progress ("CWIP"), fuel inventory and depreciation reserve) instead of by FERC account. While the new factors were provided under the updated forecast, the impact on the filing and on the revenue requirement contained in the filing was not provided.

Q. HAVE YOU ESTIMATED THE IMPACT OF THE MOST RECENT FORECAST OF JURISDICTIONAL SEPARATION FACTORS PROVIDED BY TAMPA ELECTRIC COMPANY ON THE FILING?

A. Yes. Since the most recent forecast of the jurisdictional separation factors was provided by broad category in Tampa Electric's response to OPC Interrogatory No. 124 instead of by FERC account, I have calculated the estimated impact of the revised factors by rate base and net operating income categories on OPC's recommended adjusted test year rate base on Exhibit DMR-2, Schedule B-1 and on OPC's recommended adjusted test year net operating income on Exhibit DMR-2, Schedule C-1. As shown on each of these pages, the revised jurisdictional amounts were determined by dividing OPC's adjusted jurisdictional balance for each item (which used the jurisdictional allocation factors applied by Tampa Electric in its filing) by the jurisdictional separation factor contained in the original filing, and then multiplying the resulting balance by the revised jurisdictional separation factor provided by Tampa Electric.

For example, the response to OPC Interrogatory No. 124 shows that the original 2014 jurisdictional separation study used in the filing included a retail factor of 98.7455% applied to PHFFU, and the retail factor for PHFFU based on the inclusion of Calpine's revised committed capacity is 93.7949%. The amount of jurisdictional PHFFU contained in Tampa Electric's filing, which was not adjusted by OPC, was $35,409,000. This is shown on Exhibit DMR-2, page 3 (Schedule B-1). Under the revised jurisdictional separation factor, the amount of jurisdiction PHFFU would be $33,634,000, or $1,775,000 less than the amount in Tampa Electric's filing. The revised amount is calculated as: $35,409,000 / 98.7445% retail jurisdictional factor in the original filing x 93.7949% updated retail jurisdictional factor ($35,409,000 / 98.7445% x 93.7949% = $33,634,000).

Additionally, on Exhibit DMR-2, Schedule A-1, I present two separate columns for OPC's recommended revenue requirements. Column B of Schedule A-1 is based on the jurisdictional separation factors contained in the Company's filing. Column C of Schedule A-1 is based on the estimated amounts that would result from the application of the updated forecast of the jurisdictional separation factors. Thus, OPC's recommended revenue requirement is presented based on the original jurisdictional separation factors contained in Tampa Electric's filing and as estimated based on the revised jurisdictional separation factors that incorporate the new Calpine commitment.

<u>Industrial Revenues</u>

Q. ARE YOU RECOMMENDING ANY ADJUSTMENTS TO THE AMOUNT OF REVENUES FROM SALES IN THE 2014 TEST YEAR?

A. Yes. According to Tampa Electric's response to OPC Interrogatory No. 62, there was stronger customer growth in the General Services rate class in 2012 than expected. The response to OPC Interrogatory No. 121 indicates that the impact of the higher level of GS customers is estimated to be approximately $35,000 per year. I have reflected the projected $35,000 increase in revenues on Exhibit DMR-2, Schedule C-1.

<u>Outside Services – Pole Attachment Litigation Expense</u>

Q. DO YOU RECOMMEND ANY ADJUSTMENTS TO THE PROJECTED TEST YEAR OUTSIDE SERVICES EXPENSE?

A. Yes. Company MFR Schedule C-16, revised on May 17, 2013, shows that the Company has projected a significant increase in outside profession services expenses for the test year in the legal area. The schedules shows actual 2012 outside services legal expenses recorded in various O&M expense accounts as $1,861,000 and a projected test year expense of $4,116,000. The response to OPC Interrogatory No. 119 indicates that the Company budgeted a $2,255,000 increase in legal costs between 2012 and 2014. Of the $2,255,000 increase, $733,333 is for the amortization of rate case legal expense, $520,000 for incremental Energy Delivery costs associated with pending litigation with Verizon regarding pole attachment charges, and $560,000 associated with long-term fuel commodity and fuel transportation contracts that are expiring. Once the rate case legal costs of $733,333 are removed, the increase in the test year is $1,521,667 or 82% above the 2012 actual level. I recommend that the $520,000 included in projected test year expenses for the pending litigation with Verizon regarding pole attachment charges be removed. The removal is shown on Exhibit DMR-2, Schedule C-1, page 2.

Q. WHY DO YOU RECOMMEND THAT THE AMOUNT INCLUDED IN THE TEST YEAR FOR PENDING LITIGATION WITH VERIZON BE REMOVED?

A. First, the charges are not likely to be recurring in nature. Thus, I recommend they be excluded from the test year used to set future rates in this case. No evidence has been provided to demonstrate that the significant increase in the test year is reflective of a normal, on-going level of outside services legal expenses. Second, presumably the litigation may result in additional revenues being recovered by Tampa Electric and, to the best of my knowledge, the potential additional revenues have not been included in the test year. Thus, the costs of the pending litigation are not matched with the benefits of the litigation. While the Company's response to OPC Interrogatory No. 119 provided no information regarding the pending litigation beyond the statement that the $520,000 consists of ". . . incremental Energy Delivery costs associated with pending litigation with Verizon regarding pole attachment charges, . . .", I do note that an October 26, 2012 article in The Tampa Tribune indicates that Tampa Electric filed suit against Verizon in circuit court in October 2012 regarding pole attachments, and that Tampa Electric is seeking $4.2 million in damages.

TECO Energy, Inc. Charges to Tampa Electric

Q. WHAT SERVICES ARE PROVIDED TO THE COMPANY FROM TECO ENERGY, INC.?

A. According to MFR Schedule C-30 and Tampa Electric's response to Staff Interrogatory No. 38, TECO Energy, Inc. ("TECO Energy") provides the following services to Tampa Electric: Management Services, Legal and Governmental Affairs, State and Community Relations, Finance, Business Strategy and Compliance, Human Resources & Benefits, and General Corporate Responsibility. These costs are incurred at the TECO Energy level and are then directly charged and allocated to Tampa Electric and other affiliates.

Q. HOW MUCH HAS TAMPA ELECTRIC INCLUDED IN THE PROJECTED TEST YEAR ENDING ON DECEMBER 31, 2014 FOR THE SERVICES FROM TECO ENERGY?

A. In its filing, Tampa Electric projected that the charges from TECO Energy would be $28,196,000 in the test year. In response to Staff Interrogatory No. 38, Tampa Electric provided a breakdown of the $28,196,000 as follows: Management Services of $2,678,840; Legal and Governmental Affairs of $3,365,797; State and Community Relations of $108,690; Finance of $6,935,586; Business Strategy and Compliance of $3,023,575; Human Resources & Benefits of $9,393,827; and General Corporate Responsibility of $2,690,062. Of the $28,196,000, $8,549,000 is for labor costs and $19,647,000 is for non-labor costs. Based on the response to OPC Interrogatory No. 125, $27,754,000 of TECO Energy's $28,196,000 in projected charges is reflected in FERC Account 930 – Miscellaneous General Expenses in Tampa Electric's filing.

Q. IS THE PROJECTED LEVEL OF COSTS CHARGED TO TAMPA ELECTRIC FROM TECO ENERGY DURING THE TEST YEAR CONSISTENT WITH THE LEVEL HISTORICALLY CHARGED TO TAMPA ELECTRIC?

A. No. The level of expenses projected to be charged from TECO Energy is substantially higher in the projected test year than the actual amounts historically charged to Tampa Electric. The amount of charges from TECO Energy to Tampa Electric that were booked to expense in each year were $22,733,000 in 2008, $23,111,000 in 2009, $22,304,000 in 2010, $21,895,000 in 2011, and $24,148,000 in 2012. The amount of charges from TECO Energy that is included in Tampa Electric's projected test year expenses of $28,196,000 is 16.8% higher than the actual amount booked in 2012 and 28.8% higher than the amount booked in 2011.

Q. WHAT FACTORS ARE CAUSING THIS SIGNIFICANT PROJECTED INCREASE IN COSTS CHARGED FROM TECO ENERGY IN THE TEST YEAR?

A. In explaining the various causes of the projected increase in the amount of expense recorded in Account 930 – Miscellaneous General Expenses between 2012 and the 2014 test year, in response to OPC Interrogatory No. 50(c), Tampa Electric indicated that $4.0 million of the increase in the account was due to higher allocations from TECO Energy due to a higher allocation percentage to Tampa Electric and salary increases. TECO Energy assumed a three percent increase in salaries, which amounted to approximately $300,000 in additional salary expense allocated to Tampa Electric. (Response to OPC Interrogatory No. 126) Thus, most of the increased charges from TECO Energy to Tampa Electric that are reflected in the 2014 test year result from the application of a higher allocation percentage of TECO Energy costs going to Tampa Electric.

Q. HAS THE COMPANY EXPLAINED WHY THE PERCENTAGE OF TECO ENERGY COSTS BEING CHARGED TO TAMPA ELECTRIC WAS PROJECTED TO INCREASE?

A. Yes. In response to OPC Interrogatory No. 126(d), Tampa Electric provided the following explanation:

> The allocation percentage to Tampa Electric is projected to increase in 2014 due to the sale of TECO Guatemala in late 2012 (TECO Guatemala is no longer receiving a portion of the allocation), as well as a decrease in the allocation to the other affiliates, caused by lower projected revenue, net income and operating assets in 2014, which is the basis for the allocation rates. The allocation rates are calculated based on each subsidiary's relative share of total revenue, net income and operating assets, therefore, a change in other subsidiaries' inputs, could impact the allocation received by Tampa Electric.

In response to OPC POD No. 86, the Company provided workpapers showing how the allocation factors used for charging costs from TECO Energy to Tampa Electric were derived for each year, from 2009 through March 2013. A confidential document also provided with the response contained the calculation of the projected allocation factor for the 2014 test year that was used in projecting the amounts contained in Tampa Electric's 2014 Business Plan that would presumably be the factors used in preparing Tampa Electric's filing.

The allocation factors are based on a three-factor approach based on each subsidiary's share of total assets, total unconsolidated revenues, and operating income. Each of the three factors are weighted equally in determining the blended allocation factor that is applied to the TECO Energy costs that are allocated to the subsidiaries, including Tampa Electric. The allocation factor for TECO Guatemala was 5.42% based on the twelve months ended November 30, 2009; 7.11% based on the twelve months ended November 30, 2010; 4.49% based on the twelve months ended November 30, 2011; and 5.21% based on the twelve months ended September 30, 2012. (Response to OPC POD No. 86 – non-redacted portion). Tampa Electric indicated that the disposition of one or more affiliated subsidiaries would not necessarily result in a proportionate decrease in overhead, corporate-level type costs. Thus, the removal of TECO Guatemala from the calculation of the allocation factors resulted in a higher percentage and amount of TECO Energy costs being shifted to Tampa Electric in the projected test year. According to the response to OPC Interrogatory No. 126(d), other assumptions made in determining the 2014 allocation factors with regards to the budgeted revenue, net income and operating assets of Tampa Electric and the remaining subsidiaries also caused additional charges to shift to Tampa Electric from other subsidiaries in the test year projections.

Q. HAVE ANY EVENTS OCCURRED SINCE THE TIME TAMPA ELECTRIC FILED ITS CASE THAT WOULD IMPACT THE PROJECTED TEST YEAR CHARGES FROM TECO ENERGY?

A. Yes. On May 28, 2013, TECO Energy announced an agreement to acquire New Mexico Gas Company for an aggregate value of $950 million, including the assumption of $200 million of New Mexico Gas Company debt. Based on a May 28, 2013 press release from TECO Energy, the transaction is expected to close in the first quarter of 2014, or early in the test year. Thus, while TECO Energy has recently sold the TECO Guatemala operations, it plans to acquire New Mexico Gas Company ("NMGC"). This will impact the allocation of TECO Energy costs to Tampa Electric.

Q. HAS THE COMPANY PROVIDED THE PROJECTED IMPACT OF THE ACQUISITION OF NEW MEXICO GAS COMPANY ON CHARGES TO TAMPA ELECTRIC FROM TECO ENERGY?

A. Yes. In response to OPC Interrogatory No. 131, Tampa Electric indicated that: "Assuming current revenue, income and asset levels of existing companies including NMGC and using the company's standard allocation process i.e., the modified Massachusetts methodology, as well as 2014 budgeted parent costs, it is estimated that the 2014 TECO Energy allocation to Tampa Electric would be reduced by approximately $2.1 million if closing were to occur in March 2014." The response to OPC Interrogatory No. 138, stated in part: "Assuming current revenue, income, asset levels, and existing parent costs, the projected cost allocation reduction to Tampa Electric for 2015 through 2016 is estimated to be approximately $2.9 million annually." While OPC did ask for all assumptions used in deriving the estimated impacts as well as the amounts assumed for the NMGC operations in calculating the 2014 TECO Energy allocation factors in Interrogatories Nos. 131 and 136, the assumptions and amounts used in estimating the impacts were not provided.

Q. SHOULD THE AMOUNT OF EXPENSE INCLUDED IN THE TEST YEAR FOR CHARGES FROM TECO ENERGY BE REDUCED?

A. Yes. As indicated previously in this testimony, the amount of expense included in the test year for charges from TECO Energy increased significantly when compared to historic levels as a result of revisions made to the projected allocation factors resulting from of the sale of TECO Guatemala and other projected revisions to the allocation factor calculation. At a minimum, I recommend that test year expenses be reduced by $2,900,000 to reflect the projected annual impact of the NMGC acquisition that was provided by Tampa Electric. Since Tampa Electric did not provide the assumptions used in revising the projected 2014 cost allocation factors, the $2.9 million annual impact provided in response to OPC Interrogatory No. 138 is the best information that has been made available to date to estimate the impact on Tampa Electric's test year expenses. My recommended $2.9 million reduction to test year expenses is reflected in Exhibit DMR-2, Schedule C-1.

Q. WHY DO YOU RECOMMEND TEST YEAR EXPENSES BE REDUCED BY THE PROJECTED ANNUAL IMPACT OF THE NMGC ACQUISITION INSTEAD OF THE 2014 TEST YEAR IMPACT PROVIDED BY TAMPA ELECTRIC?

A. There are several reasons that the annual impact should be reflected instead of the projected impact for the twelve months ended December 31, 2014 (i.e., the test year). The press release announcing the NMGC acquisition indicates that it is expected to close in the first quarter of 2014. The acquisition will continue to impact charges from TECO Energy for the foreseeable future after the acquisition is completed. It is also likely that the new distribution base rates that will become effective as a result of this case will stay in place beyond the test year ended December 31, 2014.

Additionally, reflecting the annual level of impact of the NMGC acquisition on the cost allocations to Tampa Electric from TECO Energy will help to offset the increase in charges to Tampa Electric that resulted from TECO Energy's choice to sell the TECO Guatemala operations. Prior to the sale of the TECO Guatemala operations, based on the twelve-month period ended September 30, 2012, the allocation percentage to Tampa Electric was 68.00%. (Response to OPC POD No. 86 – non-redacted portion). After the sale of the TECO Guatemala operations, the allocation percentage to Tampa Electric increased to 72.3%. (Response to OPC POD No. 86 – non-redacted portion and Staff No. 40).

Q. YOU PREVIOUSLY INDICATED THAT OTHER ASSUMPTIONS MADE IN DETERMINING THE 2014 ALLOCATION FACTORS WITH REGARDS TO THE BUDGETED REVENUE, NET INCOME AND OPERATING ASSETS OF TAMPA ELECTRIC AND THE REMAINING SUBSIDIARIES ALSO CAUSED ADDITIONAL CHARGES TO SHIFT TO TAMPA ELECTRIC FROM OTHER SUBSIDIARIES IN THE TEST YEAR PROJECTIONS. WOULD YOU PLEASE ELABORATE?

A. Yes. In response to OPC Interrogatory No. 126(d), the Company indicated that the allocation percentage to Tampa Electric was also projected to increase in 2014 as a result of a decrease in the allocation to the other affiliates caused by a change in the other subsidiaries' projected revenue, net income and operating assets. Many factors would go into estimating the 2014 revenues, net income and operating assets of Tampa Electric and of each of the remaining subsidiaries that are allocated costs from TECO Energy. As of April 2013, which is post-TECO Guatemala sale, Tampa Electric's percentage of the TECO Energy allocable costs was 72.30%, while the percentage to People's Gas was

13.57%, TECO Coal was 13.39% and TECO Pipeline was 0.74%. These amounts were based on the revenues and net operating income for each of these entities for the twelve months ended March 2013 and the operating assets of each entity as of March 31, 2013. (Response to Staff Interrogatory No. 40).

****BEGIN CONFIDENTIAL****

[redacted]

[redacted]

****END CONFIDENTIAL****

Q. DO YOU RECOMMEND AN ADDITIONAL REDUCTION TO THE PROJECTED EXPENSES ALLOCATED FROM TECO ENERGY TO TAMPA ELECTRIC IN THE TEST YEAR?

A. Yes. As previously indicated in this testimony, I recommend that test year expenses charged from TECO Energy to Tampa Electric be reduced by $2.9 million. OPC witness Schultz recommends in his testimony that $1,836,882 of incentive compensation costs and $4,638,481 of stock compensation expenses charged to Tampa Electric from TECO Energy in the test year be removed. Additionally, in MFR Schedule C-2, Tampa Electric removed $219,000 of allocated expenses from the test year associated with Stockholder Relations. As shown on Exhibit DMR-2, Schedule C-3, after each of these adjustments, $18,601,637 of expense from TECO Energy remains in the test year. I recommend that the projected TECO Energy expenses remaining in the test year after each of the above identified adjustments be reduced by an additional $378,082 to remove the shifting of costs from other current subsidiaries of TECO Energy to Tampa Electric in the test year. There are too many uncertainties regarding the balance of revenues, net income and operating assets of Tampa Electric and of each of the subsidiaries that are allocated costs from TECO Energy that will occur during the 2014 test year and the additional shifting of costs to Tampa Electric from the remaining subsidiaries has not been supported.

Uncollectible Expense

Q. WHAT AMOUNT HAS TAMPA ELECTRIC INCLUDED IN THE TEST YEAR FOR UNCOLLECTIBLE EXPENSE AND HOW WAS THAT AMOUNT DETERMINED?

A. Tampa Electric's 2014 test year expenses include $3,623,000 for uncollectible expense. As shown on MFR Schedule C-4, page 3 of 10 and MFR Schedule C-11, the $3,623,000 projected expense results in a bad debt rate incorporated in the filing of 0.185%. In describing how the amount of test year uncollectible expense included in the filing was determined, in its response to OPC Interrogatory No. 66, Tampa Electric indicated as follows:

> For 2013 and 2014 budget purposes, net write-offs are not broken down between gross write-offs and recoveries. Tampa Electric bases budget calculations first on previous year month-over-month write-off-to-revenue percentages against projected revenues for the budget year. The assumption is that recent write-off-to-revenue performance already reflects some changes to the economic outlook and the revenue forecast reflects best thinking on weather and the economy going forward.
>
> The company has always calculated bad debt expense using the metric of net write-offs as a percentage of total revenues. Trends on performance versus historical data are primarily looked at using net write-offs rather than gross. As a result, Tampa Electric does not have a breakdown of gross write-offs and recoveries for the 2013 projected year and the 2014 test year.

The response did not include further details regarding the projection of the test year bad debt expense.

Q. HOW DOES THE PROJECTED TEST YEAR UNCOLLECTIBLE EXPENSE AND BAD DEBT RATE COMPARE TO HISTORIC AMOUNTS?

A. Tampa Electric's MFR Schedule C-6, page 4, shows that the amount of expense included in Account 904 – Uncollectible Accounts – Customer Accounts Expense was $2,609,000 in 2011 and $2,321,000 in 2012. The amount budgeted in each of those years was $6,465,000 and $6,104,000, respectively. Thus, the amount of uncollectible expense recorded by Tampa Electric in both 2011 and 2012 was significantly less than budgeted. The amounts recorded in 2011 and 2012 were also much lower than the $3,623,000 budgeted in the test year. In fact, the budgeted test year expense is 56% higher than the amount recorded in 2012.

MFR Schedule C-6, page 4, does show that the amount of uncollectible expense recorded in prior years, specifically from 2008 through 2010, was significantly higher than the amounts recorded by Tampa Electric in 2011 and 2012.

Q. HAVE YOU SEEN ANY INFORMATION THAT WOULD SHED LIGHT ON THE CAUSE OF THE SIGNIFICANT REDUCTION IN UNCOLLECTIBLE EXPENSE THAT HAS OCCURRED IN RECENT YEARS?

A. Yes. In addressing 2013 year to date variances in the accumulated provision for uncollectible accounts, the response to OPC Interrogatory No. 41, at page 8, indicates: "The budgeted write-off percentage used to calculate additions to the reserve is higher than the actual write-off percentage that has steadily decreased over time due to the implementation of DebtNext. The budgeted write-off percentage is based off historical trends." Thus, based on the response, Tampa Electric has implemented DebtNext, which has "steadily decreased" the percentage of write-offs it has realized. DebtNext software is used by companies to manage the collection processes and to facilitate various collections reporting.

Additionally, in explaining the actual and projected increases in the Energy Delivery Area for Customer Service – Customer Records & Collection expenses, the response to OPC Interrogatory No. 103, at page 13, indicates that "Beginning late in 2011, the company has focused more efforts on credit-related disconnect/reconnect work endeavoring to reduce its cost of bad debt." These endeavors to reduce the cost of bad debt apparently also positively impacted the level of uncollectible expense.

Q. ARE YOU RECOMMENDING ANY REVISIONS TO THE PROJECTED TEST YEAR UNCOLLECTIBLE EXPENSE?

A. Yes. Despite the economic conditions over the past several years, Tampa Electric has been able to reduce its uncollectible expense, in great part due to its implementation of DebtNext and its increased focus on credit-related disconnect/reconnect work. Further, considering the substantial reductions in uncollectible expense that occurred in 2011 and 2012, coupled with the significant amount by which Tampa Electric's actual uncollectible expenses were below the budgeted amount in both 2011 and 2012 and the significant projected increase in the projected test year expense, I recommend that the projected test year uncollectible expense be reduced by $1,228,000 to $2,395,000.

Q. HOW WAS YOUR RECOMMENDED ADJUSTMENT DETERMINED?

A. As shown on Exhibit DMR-2, Schedule C-4, I first calculated the actual 2012 percentage of net write-offs realized by Tampa Electric to the 2012 Gross Revenues from Sales of Electricity, which resulted in a net write-off to revenues percentage of 0.122%. I then applied the 0.122% percentage of net write-offs to revenues (or the bad debt factor) to the 2014 test year gross revenues from sales of electricity contained in Tampa Electric's filing in determining the adjusted test year uncollectible expense of $2,395,000. This is

$1,228,000 less than the test year uncollectible expense incorporated in Tampa Electric's filing. I also recommend that the resulting bad debt factor of 0.122% be used in determining the revenue expansion factor discussed previously in this testimony.

Q. WHY ARE YOU RECOMMENDING THAT THE BAD DEBT RATE AND THE RESULTING UNCOLLECTIBLE EXPENSE BE BASED ON THE 2012 PERCENTAGE OF NET WRITE-OFFS TO REVENUES INSTEAD OF A BAD DEBT RATE BASED ON A HISTORIC AVERAGE?

A. Since the amount of uncollectible expense and the associated ratio of net write-offs to revenues often varies from year to year, in many situations I would recommend that the projected expense be based on a historic average ratio of net write-offs to revenues. However, if changes have been implemented by a utility that significantly impact the level of uncollectible expense, then an approach that differs from the use of a historic average may be appropriate and more reasonable. This is true for Tampa Electric. As indicated previously, the amount of uncollectible expense has declined substantially for Tampa Electric in 2011 and 2012 when compared to the amounts recorded in 2008 through 2010. The amount of uncollectible expense was also substantially lower than budgeted in both 2011 and 2012. Tampa Electric has also indicated that it implemented DebtNext, which has impacted the actual write-off percentage and continues to impact the level of write-offs, as well as taken other actions to reduce the amount of bad debt. Thus, based on the current facts and circumstances for Tampa Electric, I recommend that the test year uncollectible expense and test year bad debt rate be based on the actual 2012 ratio of net write-offs to revenues.

Income Tax Expense

Q. HAVE YOU ADJUSTED INCOME TAX EXPENSE TO REFLECT THE IMPACT OF THE ADJUSTMENTS SPONSORED BY CITIZENS' WITNESSES TO NET OPERATING INCOME?

A. Yes. On Exhibit DMR-2, Schedule C-5, I calculate the impact of federal and state income tax expenses resulting from the recommended adjustments to operating expenses. The result is carried forward to the Net Operating Income Summary on Exhibit DMR-2, Schedule C-1.

Interest Synchronization

Q. WHAT IS THE PURPOSE OF YOUR INTEREST SYNCHRONIZATION ADJUSTMENT ON EXHIBIT DMR-2, SCHEDULE C-6?

A. The interest synchronization adjustment allows the adjusted rate base and cost of debt to coincide with the income tax calculation. Since interest expense is deductible for income tax purposes, any revisions to the rate base or to the weighted cost of debt will impact the test year income tax expense. OPC's proposed rate base and weighted cost of debt differ from the Company's proposed amounts. Thus, OPC's recommended interest deduction for determining the 2014 test year income tax expense will differ from the interest deduction used by Tampa Electric in its filing. Consequently, OPC's recommended debt ratio increase in this case will lead to a greater interest deduction in the income tax calculation, which will in turn result in a reduction to income tax expense.

OVERALL FINANCIAL SUMMARY – ALTERNATIVE RECOMMENDATION

Q. HAVE YOU CALCULATED AN ALTERNATIVE REVENUE REQUIREMENT IN THE EVENT THE COMMISSION ADOPTS THE DEBT-TO-EQUITY RATIO IN THE CAPITAL STRUCTURE REQUESTED BY TAMPA ELECTRIC?

A. Yes. Exhibit DMR-3, totaling four pages, shows the revisions that need to be made to OPC's primary recommendation presented in Exhibit DMR-2 if the Commission adopts the 2013 test year debt-to-equity ratio used by Tampa Electric for its requested overall rate of return. As shown on page 1 of Exhibit DMR-3, if the Commission adopts Tampa Electric's proposed debt-to-equity ratio, the revenue requirements would result in an increase of $183,000 to Tampa Electric's current base rates.

Q. WHAT IS THE REVISED RATE OF RETURN RECOMMENDED BY OPC UNDER THIS ALTERNATIVE SCENARIO?

A. The overall rate of return would increase from OPC's primary recommendation in this case from 5.66% to 5.67%. Under the alternative scenario, the calculation of OPC's recommended rate of return, as well as the resulting reconciliation of OPC's recommended rate base to the capital structure, is presented on Exhibit DMR-3, page 2 of 4.

OPC witness Woolridge testifies that if the Commission accepts the debt-to-equity ratios presented by Tampa Electric in this case, his original recommended rate of return on equity should be reduced from his primary recommendation of 9.0%, based on OPC's proposed capital structure, to 8.75%. This recommended 8.75% rate of return on equity is included in the calculations presented on Exhibit DMR-3, page 2 of 4.

Q. WHAT ADDITIONAL MODIFICATIONS NEED TO BE MADE TO OPC'S RECOMMENDED REVENUE REQUIREMENT CALCULATIONS UNDER THIS ALTERNATIVE SCENARIO?

A. The weighted cost of debt would change because of Tampa Electric's proposed debt-to-equity ratio. Since OPC has accepted the debt cost rates incorporated in Tampa Electric's capital structure calculations, the weighted cost of debt to be applied to rate base to calculate the tax deductible interest expense would be the same under this scenario. The only difference between Tampa Electric and OPC with regard to the interest synchronization adjustment under this scenario should be because OPC is recommending a lower rate base amount than Tampa Electric. Exhibit DMR-3, page 4 presents the interest synchronization calculation based on OPC's recommended rate base. The result of this calculation is carried forward to page 3 of Exhibit DMR-3 to determine the impact on OPC's recommended net operating income resulting from the modification to the interest synchronization calculation.

Q. DOES THIS COMPLETE YOUR PREFILED TESTIMONY?

A. Yes, it does.

1. INTRODUCTION, QUALIFICATIONS, AND SUMMARY

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A Jeffry Pollock; 12647 Olive Blvd., Suite 585, St. Louis, MO 63141.

Q WHAT IS YOUR OCCUPATION AND BY WHOM ARE YOU EMPLOYED?

A I am an energy advisor and President of J. Pollock, Incorporated.

Q PLEASE STATE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

A I have a Bachelor of Science Degree in Electrical Engineering and a Masters in Business Administration from Washington University. Since graduation in 1975, I have been engaged in a variety of consulting assignments, including energy procurement and regulatory matters in both the United States and several Canadian provinces. My qualifications are documented in **Appendix A.** A partial list of my appearances is provided in **Appendix B** to this testimony.

Q ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS PROCEEDING?

A I am testifying on behalf of the Florida Industrial Power Users Group (FIPUG). The participating FIPUG members are customers of Tampa Electric Company (TECO) who take electricity service on the General Service Demand (GSD), Interruptible Service (IS) and Standby rate classes

Q WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A I am addressing TECO's proposals to:

- Consolidate the GSD and IS rate classes;
- Adopt yet another new production plant cost allocation methodology—Twelve Coincident Peak and 50% Average Demand (12CP-50%AD);
- Classify a portion of the distribution network as customer-

related; and

- Increase its storm reserve.

In addition, I am addressing:

- The design of the GSD rate schedules;
- The design of the IS rate schedules if TECO's proposed GSD-IS class consolidation is rejected; and
- Test year outage expenses.

Q **ARE YOU SPONSORING ANY EXHIBITS?**

A Yes. I am sponsoring **Exhibits ___ (JP-1)** through **___ (JP-10)**.

Q **ARE YOU ADDRESSING EVERY ISSUE THAT MAY BE IN DISPUTE IN THIS CASE?**

A No. However, the fact that I am not addressing a particular issue is not and should not be interpreted as an endorsement of TECO's position.

<u>Summary</u>

Q **PLEASE SUMMARIZE YOUR FINDINGS AND RECOMMENDATIONS.**

A My findings and recommendations are as follows:

<u>GSD-IS Consolidation</u>

- TECO's proposal to consolidate the GSD and IS rate classes (and eliminate the IS rate schedules) should be rejected. A similar proposal by TECO was rejected in TECO's last rate case. TECO has provided no new evidence to support consolidation in this case.
- The GSD and IS rates classes are not homogeneous; that is, they have significantly different load characteristics. This means that GSD and IS should have different rate structures to reflect the corresponding differences in their respective costs to serve.
- Further, contrary to Mr. Ashburn's assertions about inequities under the current class rate structures, consolidating the GSD and IS classes would be grossly inequitable to the IS customers. This is because the IS customers would experience an 11.1% base rate increase under TECO's consolidation proposal but no rate increase (or a decrease) if IS remains a separate stand-alone class. The cost of serving IS does not change just because it is consolidated with

GSD.

- The so-called "transition" referred to by Mr. Ashburn ended when the interruptibility was transferred from the IS rate schedules to the GSLM Riders (which occurred in TECO's last rate case). Under this structure, all non-firm customers are paid the same for their interruptibility, and the interruptible credits remain cost-effective under this Commission's rules. This transition has nothing to do whatsoever with eliminating the IS rate schedules.
- The IS rate schedules should be retained at a minimum; further the Commission should consider re-opening the IS rate schedules to all eligible customers.

GSD/IS Rate Design

- Rate design is a continuation of the cost allocation process. Thus, a proper cost-based rate design should include a Customer charge that recovers customer-related costs, a Demand charge that recovers demand-related costs, and an Energy charge to recover non-fuel energy costs.
- The current GSD Energy charge is already above cost. The proposed charge would be 91% higher than the unit cost. Thus, any increase in Energy charges is unwarranted. This includes TECO's proposal to raise the On-Peak Energy charge by 38%. Not only is this increase contrary to cost-based ratemaking, it would violate gradualism.
- To reflect cost, all of the increase allocated to the GSD class should be collected in the Basic Service and Demand charges.
- If, despite my objections, the GSD and IS classes are consolidated, the Delivery Voltage Adjustment applicable to sub-transmission service should be $0.53 per kW higher than the credit proposed by TECO. Because the IS class takes service primarily at sub-transmission voltage, raising the credit by an additional $0.53 would mitigate the higher rates that would result from the GSD-IS class consolidation.
- No increase should be allocated to the IS class. This class is currently providing a 1.10 parity ratio under TECO's proposed revenue requirements. Thus, IS base rates would have to be reduced to achieve parity, something the Commission may want to consider. However, at a minimum, applying a zero increase is also consistent with Commission practice.
- The current IS Energy charge is more than 166% above cost. The current IS Demand charge is 81% below cost. Consequently, if the IS

class is retained, the Basic Service charge should be set to cost, the Energy charge should be reduced by at least 25%, and the remaining revenue requirement should be collected in the Demand charge.

Production Plant Allocation

- TECO has failed to support changing the production plant allocation method to 12CP-50%AD as it proposes. This method is not supported by:

  (1) How other Florida utilities plan and operate their generation systems because Duke Energy Florida (Duke), Florida Power & Light Company (FPL) and Gulf Power Company (Gulf) continue to use 12CP-1/13thAD, and the Commission has approved 12CP-1/13thAD in their most recent rate cases.

  (2) TECO's investment in base and intermediate load capacity, which has remained relatively unchanged since its last rate case.

  (3) TECO's plan to convert Polk Units 2-5 to combined cycle generation, which won't occur until 2017 (well beyond the test year) because it overlooks the load following and other reliability enhancements provided by CCGTs. TECO's position is not unique for Florida utilities, given that FPL has committed to add over 3,800 MW of new combined cycle gas turbines (CCGTs) to complement its existing nuclear and coal (base load) generation fleet, yet FPL continues to support 12CP-1/13thAD.

  (4) Minimizing the RS and GS revenue requirements, which is contrary to the reasons for selecting a cost allocation method: to reflect cost causation. Rate minimization is appropriately addressed in determining class revenue allocation and rate design and not by selecting a cost allocation methodology.

- 12CP-50%AD represents yet another change in allocation methods. TECO has never proposed the same production plant allocation factor in the four rate cases it has filed since 1985. This constant churn in cost allocation methods creates instability in class cost relationships, which is not a desirable attribute of a good rate design.

- 12CP-50%AD would classify 57% of TECO's net production plant costs to energy. This is comparable to the Equivalent Peaker (EP) method, which classifies between 40% and 75% of production plant costs to energy. Like EP, 12CP-50%AD is based on the erroneous assumption that fuel cost savings drive investment decisions.

- The Commission has previously rejected EP because EP allocates plant costs beyond the economic break-even point. This is also the case with 12CP-50%AD. The only difference between EP and 12CP-

50%AD is the application of judgment in determining the portion of plant costs allocated on energy.

- The Commission should adopt 12CP-1/13thAD for TECO, just as it has adopted this method for Duke, FPL and Gulf. Alternatively, if the Commission determines that no change is appropriate, it should retain 12CP-25%AD, which was approved in TECO's last rate case.
- If, contrary to my recommendation, 12CP-50%AD is adopted, then the 12CP should be replaced with the Summer/Winter CP method because the Summer/Winter CP best reflects TECO's system load characteristics that drive the need for capacity and it would not allocate demand-related costs beyond the economic breakeven point, as is the case with 12CP. Further, the cost study should also recognize that some fuel costs are incurred for reliability (*e.g.,* start-up, stabilization).

Distribution Plant Allocation

- I agree with TECO's proposal to classify a portion of the distribution network investment as customer-related. This is consistent with accepted practice. Further, the results of TECO's minimum distribution system (MDS) method are reasonable relative to other utilities that use MDS or other methods to determine the customer-related portion of distribution network costs.

Planned Outage Expense

- The Commission should disallow $3.7 million of planned outage expenses because TECO's test year expenses are clearly abnormal (26% higher) relative to prior years.

Storm Damage Reserve

- TECO's proposal to increase its storm damage reserve is unwarranted. Not only is the current reserve more than adequate to handle almost three consecutive years of damage (including Category 1 and all but the most severe of Category 2 hurricanes), TECO's analysis fails to recognize the substantial investment in storm hardening, which should lessen future expenses and it ignores the Commission's directives. Specifically, the Commission has stated that the storm reserve should be adequate to accommodate most (but not all) storm years and utilities can seek recovery of all storm damage.
- The target storm reserve should not increase. Accruals to the storm reserve should cease.

2. GSD-IS CLASS CONSOLIDATION

Q IS TECO PROPOSING ANY CHANGES AFFECTING THE CUSTOMERS TAKING SERVICE ON THE INTERRUPTIBLE SERVICE RATE?

A Yes. TECO is proposing to consolidate the GSD and IS rate classes and completely eliminate the IS rate schedules. If approved, IS customers would take service on the various GS and GSD rate schedules.

Q DID TECO PREVIOUSLY PROPOSE ELIMINATING THE INTERRUPTIBLE SERVICE RATE?

A Yes. TECO proposed eliminating the IS rate schedules in its last rate case.

Q WAS TECO'S PROPOSAL TO ELIMINATE THE INTERRUPTIBLE SERVICE RATE APPROVED?

A No. The Commission rejected TECO's proposal.

Q WHY IS TECO ONCE AGAIN PROPOSING TO CONSOLIDATE THE GSD AND INTERRUPTIBLE SERVICE RATE CLASSES AND ELIMINATE THE INTERRUPTIBLE SERVICE RATE SCHEDULES?

A TECO's rate design witness, Mr. Ashburn, cites two reasons in his pre-filed testimony for consolidating the GSD and IS rate classes and eliminating the IS rate schedules. First, he explains that consolidation would allow TECO to "complete the transition of the customers on the IS rate schedules to the GSD rate schedules."[1] Second, he asserts that maintaining the IS rate would preserve "inequitable situations" that exist between the existing IS customers and new interruptible customers.[2]

As explained later, neither reason justifies consolidating the GSD and IS rate classes. Further, TECO's proposed consolidation would be grossly inequitable to the IS customers.

Q **TURNING TO THE FIRST REASON FOR CONSOLIDATION, TO WHAT TRANSITION IS MR. ASHBURN REFERRING?**

A Mr. Ashburn stated that IS customers are fully aware that their "grandfathered" status has been extended for decades.[3] I can only assume from this statement that he is referring to the transition that commenced in 1985, when the Commission closed the IS-1 rate schedules.[4] However, this was not a transition that would ultimately lead to eliminating the IS class. The stated reason for closing the IS-1 rate schedules was that interruptible service was no longer cost-effective.

Q **DID CLOSING THE INTERRUPTIBLE SERVICE RATES PROVIDE A CLEAR INDICATION THAT THEY WOULD EVENTUALLY BE ELIMINATED?**

A No. Closing the IS rate schedules meant that no new interruptible customers could opt for non-firm service under these rates. It did not mean that the IS class would be eliminated. In fact, the IS rate schedules continued to be subject to periodic adjustments in rate cases even though they were closed to new business.

Q **ARE THE CURRENT INTERRUPTIBLE SERVICE RATES THE SAME AS THE RATES THAT WERE CLOSED TO NEW BUSINESS?**

A No. In TECO's last rate case, the "interruptibility" was removed from the IS rate schedules. This transformed IS from an interruptible to a cost-based firm service rate. As such, it marked the end of the transition to ensure that non-firm service remains a viable option for all customers and that the rates for this service remain cost-effective. Thus, it is inaccurate to assert that there was ever a decades-long transition that would ultimately result in eliminating the IS rate schedules.

Q HAVE INTERRUPTIBLE CUSTOMERS KNOWN FOR DECADES THAT THEIR RATE CLASS WAS GOING TO BE ELIMINATED?

A No. The proposal to eliminate the IS class was made for the first time in TECO's last rate case. That case was filed in August, 2008. As previously stated, the Commission rejected TECO's proposal to eliminate IS in that case. Thus, IS customers could not have had any reasonable expectation that the IS rate schedules would be eliminated. Put simply, the IS rate should not be eliminated, and witness Ashburn speculates about the mindset of the IS customers. As discussed later, there is no legitimate reason not to retain and re-open IS allowing the rates to be applicable to all similarly situated customers.

Q DO YOU AGREE WITH MR. ASHBURN'S ASSERTION THAT MAINTAINING THE INTERRUPTIBLE SERVICE RATE WOULD PRESERVE INEQUITABLE SITUATIONS THAT HE SAYS EXIST BETWEEN THE INTERRUPTIBLE SERVICE CUSTOMERS AND GSD CUSTOMERS THAT OPT FOR INTERRUPTIBLE SERVICE?

A No. Mr. Ashburn's assertion is based on an assumption that differences between the GSD and IS rates are inequitable. However, both the GSD and IS rates were set by the Commission in TECO's last rate case using an approved class cost-of-service study and rate design. Thus, his assertion that there are inequities between interruptible customers taking service on the GSD and IS rate schedules misses the mark.

Q **ARE THE DIFFERENCES BETWEEN THE GSD AND INTERRUPTIBLE SERVICE RATES INEQUITABLE?**

A No. It is not uncommon or improper to charge different rates for different customer classes based on differences in the cost of providing service. A class's cost-of-service is highly dependent on its load and usage characteristics. Two classes with different usage characteristics will have different costs to serve. If a cost-of-service study is used to design rates (which is a common practice in Florida), it follows that the rates will be different.

Q. **DO THE GSD AND INTERRUPTIBLE SERVICE CLASSES HAVE DIFFERENT LOAD CHARACTERISTICS?**

A Yes. In fact, Mr. Ashburn concedes that the 42 remaining customers in the IS class have more favorable load characteristics than the 14,000 customers being served on the GSD rate schedules. He even candidly admits that the IS customers have a "cost-supported rate advantage."[5]

I will provide an in-depth comparison between the GSD and IS load characteristics later in my testimony. These differences support retaining both the GSD and IS rate schedules. Thus, there is nothing inequitable about the current GSD and IS rates. They are both cost-based rates for firm service. Contrary to Mr. Ashburn's assertion, eliminating the IS rate schedules would cause an even greater inequity.

Q **PLEASE EXPLAIN.**

A The IS class is providing a 7.43% rate of return at current rates under TECO's preferred class cost-of-service study (CCOSS). TECO is only seeking a 6.74%

rate of return at proposed rates.[6] In other words, the IS class already has a 1.10 parity ratio relative to TECO's *proposed* rate of return. If the Commission approves a lower revenue requirement than TECO has proposed, the IS class's parity ratio could be higher than 1.10. A parity ratio above 1.0 at proposed rates means that *IS customers are currently paying more for their electricity service than is justified by TECO's CCOSS*.

In order to move to parity, base rates for IS customers would have to be reduced. However, the Commission's policy disfavors one customer class receiving a rate decrease when rates are increasing. Under these specific circumstances, the IS class should receive zero increase.

Rather than retaining the IS rate class and maintaining the current base rates, TECO is proposing an 11.1% base rate increase for IS customers.[7] *The 11.1% increase is solely the result of TECO's proposal to consolidate the GSD and IS classes and eliminate the IS rate class.* Forcing the IS customers to absorb a significant base rate increase when TECO's CCOSS supports no increase or even a decrease to the stand-alone IS rate class would be grossly inequitable. TECO's proposal to fold the IS class into the GSD class would also financially penalize many large businesses that employ scores of people and are important participants in the local economy. For this reason alone, TECO's consolidation proposal should be rejected.

Q WOULD THE COST OF SERVICING INTERRUPTIBLE SERVICE CUSTOMERS CHANGE JUST BECAUSE THAT CLASS IS CONSOLIDATED WITH THE GSD CLASS?

A No. Consolidation does not change the level of costs caused by the IS rate class. It would, however, result in charging much higher rates to IS customers because the consolidated GSD-IS class costs would be spread to both GSD and IS customers. In other words, consolidation would simply hide the substantial subsidies that IS customers are currently providing and, with an 11.1% base rate increase that would result if IS were consolidated with GSD, would exacerbate the subsidy being paid by IS customers.

Q WHY ELSE SHOULD TECO'S RATE CONSOLIDATION PROPOSAL BE REJECTED?

A As previously stated, the GSD and IS classes are not homogeneous; that is, they do not have similar load and usage characteristics. Combining dissimilar customer classes is contrary to accepted practice, which is to define customer classes based on homogeneous load and usage characteristics. For example:

> After the costs have been functionalized and classified the next step is to allocate them among the customer classes. ***To accomplish this, the customers served by the utility are separated into several groups based on the nature of the service provided and load characteristics.*** The three principal customer classes are residential, commercial and industrial. ***It may be reasonable to subdivide the three classes based on, characteristics such as size of load the voltage level at which the customer is served and other service characteristics such as whether a residential customer is all-electric or not.*** Additional customer classes that may be established are street lighting, municipal, and agricultural.[8] (emphasis added)

An additional example to further reiterate this mainstream concept and practice:

> A public utility is normally engaged in furnishing service to different classes of customers under varying circumstances of delivery, consumption and/or utilization wherein such variation furnishes a basis for differentials in the pricing of the service rendered. ***These variations in types of utilization and in patterns of consumption may cause differences in the cost of rendering the various classes of service. Such variations are commonly referred to as load characteristics. Foremost among the load characteristics are rates of consumption, the relationship between average and maximum rates of consumption (referred to as load factor) and coincidence of consumption of customers within a particular classification***

as well as among customers served under other classifications. Differences in load characteristics frequently furnish the basis for separate classifications of customers for rate making purposes.[9] (emphasis added)

Q ARE THE GSD AND INTERRUPTIBLE SERVICE CLASSES HOMOGENEOUS?

A No. **Exhibit ___(JP-1)** is an analysis of the characteristics of GSD and IS classes for the Test Year. Page 1 shows the characteristics at the class level. Page 2 shows the characteristics by delivery voltage. The key characteristics include: size, load factor, coincidence factor, and delivery voltage. The analysis is summarized in the table below. As can be seen, there are significant differences in each of the key characteristics.

Test Year Usage, Load, and Service Characteristics
GSD vs. IS Classes

Characteristic	Description	GSD	IS
Size	Avg. kWh Per Month	45,674	1,684,336
	Avg. kW Per Month	119	6,672
Load Factor	12 Coincident Peak	70%	110%
	Non-Coincident Peak	61%	67%
	Billing Demand	52%	35%
Coincidence Factor	12CP to NCP	87%	61%
	12CP to Billing Demand	75%	32%
Delivery Voltage	% at Secondary	84%	0%
	% at Sub-Transmission	0.1%	72%

Further, the differences in load characteristics are not unique to the Test Year, as shown in the table below.

Historical Load Characteristics
GSD Vs. IS Classes

	2010		2011		2012	
Description	**GSD**	**IS**	**GSD**	**IS**	**GSD**	**IS**
Coincident Load Factor	77%	94%	75%	94%	77%	95%
Coincidence Factor	85%	69%	75%	56%	83%	61%

Q WHAT IS COINCIDENT LOAD FACTOR?

A Coincident load factor is the ratio of each class's average demand to its twelve coincident peak (12CP) demand. Thus, it measures how intensively electricity is used during the peak hours of the month.

Q WHAT IS COINCIDENCE FACTOR?

A Coincidence factor is the ratio of 12CP demand to Non-Coincident Peak (NCP) demand. It measures how much of the class's peak demand occurs coincident with the system peak.

Q HOW ARE COINCIDENT LOAD FACTOR AND COINCIDENCE FACTOR RELEVANT IN DETERMINING WHETHER CUSTOMER CLASSES ARE HOMOGENEOUS?

A A class with a high coincident load factor uses electricity more intensively during peak hours. By contrast, a class with a low coincident load factor uses electricity more intensively during non-peak hours. As can be seen, the IS class has a lower coincident load factor than the GSD class.

Differences in coincidence factor have important rate design implications. Specifically, a lower coincidence factor means that it is less costly to serve a customer on a per kilowatt (kW) basis. The higher the coincidence factor, the higher the demand charge when the charge is based on maximum demand. This result is illustrated on below. As can be seen above, the IS class has a lower coincidence factor than the GSD class.

Q HOW DO DIFFERENCES IN COINCIDENCE FACTOR AFFECT THE DESIGN OF A COST-BASED RATE STRUCTURE.

A Coincident demand is the primary basis upon which production, transmission and distribution costs are allocated among the customer classes. Billing or non-coincident demand is the maximum metered demand during the billing month.

Relationship Between Coincidence Factor and Demand Charges					
Customer Class	Coincident Demand (kW)	Billing or Non-Coincident Demand (kW)	Coincidence Factor[a]	Allocated Demand Costs[b]	Demand Charge[c]
	(1)	(2)	(3)	(4)	(5)
1	1,000	2,000	50%	$10,000	$5.00
2	1,000	1,430	70%	$10,000	$6.99
3	1,000	1,175	85%	$10,000	$8.51

(a) Column (1) ÷ Column (2)
(b) Assume that costs are allocated in proportion to Column (1).
(c) Column (4) ÷ Column (2)

As can be seen, the lower the coincidence factor (column 3), the lower per unit demand charge (column 5), all other things being equal. This is because there are more billing units (column 2) over which to spread the allocated demand-related costs (column 4).

Q **WHAT IS THE IMPLICATION OF THE DIFFERENT COINCIDENCE FACTORS IN DETERMINING WHETHER THE GSD AND INTERRUPTIBLE SERVICE CLASSES SHOULD BE COMBINED?**

A As shown previously, the GSD and IS classes have very different coincident load factors and coincidence factors. Thus, they are not homogeneous. Ignoring these differences by consolidating the GSD and IS rate classes would result in inappropriate cross subsidies.

Q **ARE THERE OTHER REASONS THE GSD AND INTERRUPTIBLE SERVICE CLASSES SHOULD NOT BE COMBINED?**

A Yes. Delivery voltage is another characteristic that can be used to define a customer class. For example, FPL has several rate classes that take service solely at transmission voltage. TECO's IS class is similarly situated because a preponderance of service is delivered at sub-transmission voltage. This is in stark contrast to GSD, where almost no electricity is delivered to customers at this high voltage level.

Consolidation would also result in TECO having the fewest rate classes of any investor-owned electric utility in Florida. The number of rate classes by utility is summarized in the table below. Based on my experience, TECO has the fewest rate classes of the vast majority of integrated electric utilities with which I am familiar that serve residential, commercial and industrial customers.

Number of Rate Classes Used in Class Cost-of-Service Studies by Florida Investor-Owned Electric Utilities

Utility	Number of Rate Classes*
FPL	13
Duke	6
Gulf	6
TECO	4

* Lighting is considered as 1 rate class.

The fact that most other utilities have more rate classes than TECO underscores how TECO is at odds with industry practice. Additionally, having too few rate classes means each class cannot be as homogeneous as is required to accurately allocate costs and design rates that reflect the cost of serving each customer. This would be particularly true with respect to TECO's GSD class (both before and after consolidation).

Q **PLEASE SUMMARIZE YOUR RECOMMENDATION ON TECO'S PROPOSAL TO CONSOLIDATE THE GSD AND INTERRUPTIBLE SERVICE CLASSES.**

A The Commission should once again reject TECO's proposal to consolidate the GSD and IS classes. Contrary to Mr. Ashburn's purported "justifications", there has been no decades-long transition to eliminate the IS rate schedules, and there are no inequities in maintaining separate cost-based GSD and IS rate schedules. What Mr. Ashburn characterizes as inequities are in fact legitimate cost-based differences between the GSD and IS rates, as determined by this Commission in TECO's last rate case. Further, Mr. Ashburn concedes that these differences currently exist, and my analysis confirms that the differences in the GSD and IS load, usage and service characteristics support maintaining the status quo. While having homogeneous classes is one of the criteria that Mr. Ashburn references in describing a proper rate design,[10] he has failed to follow his own criterion in this instance. And finally, IS customers do not require a rate increase because the IS class is already above parity relative to TECO's proposed Florida Jurisdictional rate of return. For all of these reasons, the IS class should remain intact.

GSD Rate Design

Q HOW SHOULD THE GSD RATE SCHEDULES BE DESIGNED?

A Rate design is a continuation of the cost allocation process. Thus, a properly designed GSD rate should track cost causation as defined in the class cost-of-service study (CCOSS). This means that Customer (or Basic) charges should reflect customer-related costs, Demand charges should reflect demand-related costs, and Energy charges should reflect energy-related costs. The table below summarizes the unit customer, demand and energy costs of the consolidated GSD-IS rate class with the corresponding proposed rates for service at secondary voltage.

TECO's Proposed Consolidated GSD Rate Design Vs. Unit Cost at Secondary Voltage		
Charge	**Standard Rate**	**Unit Cost**
Basic Charge (per month)	$30.00	$28.31
Demand Charge (per kW-month)	$9.50	$12.60
Energy Charge (per kWh)	1.829¢	0.956¢
Source	E-13c	E-1

Q DOES TECO'S PROPOSED GSD RATE DESIGN FOLLOW THE COSTING PHILOSOPHY DESCRIBED ABOVE?

A No. As can be seen, only the Basic charge reflects unit cost as derived in TECO's preferred CCOSS at proposed rates. The proposed standard Energy charge is nearly double unit cost. In fact, the current GSD Energy charge of 1.583¢ is already above cost. As a consequence of setting Energy charges well above cost, the proposed Demand charges are being set below cost. TECO's workpapers reveal that the proposed $9.50 per kW Demand charge was an input and was not justified by a specific cost support.

Q DO TECO'S PROPOSED GSD STANDARD ENERGY CHARGES AFFECT ANY OTHER CHARGES?

A Yes. The proposed GSD Standard Energy charge is used to derive the On-Peak Energy charge. Specifically, the On-Peak Energy charge is the difference between the proposed Standard and Off-Peak Energy charges weighted for the percent of on and off-peak hours. The proposed Off-Peak Energy charge was set at average unit energy cost. The present and proposed On and Off-Peak Energy charges are summarized in the table below.

TECO's Proposed On and Off-Peak Energy Charges at Secondary Voltage (per kWh)			
Charge	**Present**	**Proposed**	**Percent Increase**
On-Peak	2.898¢	3.999¢	38.5%
Off-Peak	1.046¢	0.946¢	9.6%

The result of this formulation is a 38% increase in the On-Peak Energy charge and a 10% decrease in the Off-Peak Energy charge. These compare to an overall 11.6% base revenue increase for the GSD class. In my opinion, increasing any charge by more than three times the class average increase is both excessive and violates the principle of gradualism.

Q **WHAT DO YOU MEAN BY GRADUALISM?**

A Gradualism is a concept that is applied that limits the movement of rates to cost to prevent "rate shock." Although TECO is not proposing to move the GSD Energy charges to cost, the excessive increases in the On-Peak Energy charge, which exceeds three times the class average increase, would result in rate shock.

Q **SHOULD TECO'S PROPOSED GSD ENERGY CHARGES BE ADOPTED?**

A No. The proposed 1.829¢ Standard Energy charge is 91% above actual cost. The above-cost Standard Energy charge also explains the excessive increase in the On-Peak Energy charge. Thus, TECO's proposed GSD Energy charges not only fail to track actual cost, they are contrary to cost-based ratemaking and the principle of gradualism. For these reasons, TECO's proposed GSD rate design should be rejected.

Q **HOW SHOULD THE GSD ENERGY CHARGES BE DESIGNED?**

A Consistent with the results of TECO's CCOSS and with the objective of aligning rates to reflect actual cost, there should be no increase in the GSD Energy charges. All of the increase should be collected in the Basic Service and Demand charges.

Q SHOULD ANY OTHER CHANGES BE MADE TO THE GSD RATE DESIGN IF THE COMMISSION APPROVES CONSOLIDATING THE GSD AND INTERRUPTIBLE SERVICE RATE SCHEDULES?

A Yes. As previously stated, the IS class is already earning a 1.10 times parity ratio relative to TECO's *proposed* rate of return. Thus, pricing the IS customers on the proposed GSD rate would further exacerbate the subsidy provided by the IS class. For this reason, if the two classes are consolidated, I recommend that the Delivery Voltage Adjustments for sub-transmission service be increased to help mitigate this subsidy. Most of the IS class sales are at sub-transmission voltage. Thus, increasing the applicable Delivery Voltage Adjustment would target most of the relief to the IS customers.

Q BY HOW MUCH SHOULD THE SUB-TRANSMISSION DELIVERY VOLTAGE ADJUSTMENT BE INCREASED?

A The sub-transmission Delivery Voltage Adjustment should provide an additional credit to offset the proposed base revenue increase to the IS class, or $581,000. This would translate into an additional $0.53 credit in the sub-transmission Delivery Voltage Adjustment. Of course, the better solution would be to retain the IS rate schedules.

<u>**Interruptible Service Rate Design**</u>

Q IF TECO'S PROPOSED GSD-IS CLASS CONSOLIDATION IS REJECTED,

HOW SHOULD THE IS RATE BE DESIGNED?

A The same costing philosophy described above for GSD should also apply to the IS rate schedules. Further, because the IS class is presently providing a rate of return higher than TECO's proposed return, the IS rate design should remain revenue neutral. This does not mean that the IS rate design should be unchanged. As can be seen in the table below, the current Demand and Energy charges bear no semblance whatsoever to cost-based rates under TECO's CCOSS.

Current Interruptible Service Rate Design Vs. Unit Cost		
Charge	**Current Rate**	**Unit Cost**
Basic Charge (per month)	$622/$2,372	$1,032
Demand Charge (per kW-month)	$1.45	$7.75
Energy Charge (per kWh)	2.504¢	0.942¢
Source	E-13c	E-1

The Energy charge is 166% above cost, while the Demand charge is 81% below cost.

Q **SHOULD ANY CHANGES BE MADE TO THE IS RATE DESIGN?**

A Yes. If the Commission retains the IS rate schedules, I recommend that the Basic Charge be set to unit cost, the Energy charge should be reduced by 25%, and the remaining revenue requirement be collected in the Demand charge. This would result in the following rates.

Recommended Interruptible Service Rate Design Assuming No Change in IS Base Revenues		
Charge	**Recommended Rate**	**Unit Cost**
Basic Charge (per month)	$520/$2,150	$1.032
Demand Charge (per kW-month)	$5.19	$7.75
Energy Charge (per kWh)	1.878¢	0.942¢

Q **WOULD YOUR RECOMMENDED INTERRUPTIBLE SERVICE RATE DESIGN VIOLATE GRADUALISM?**

A No. Although the recommended changes in the Energy and Demand charges may appear extreme, this is a reflection of how far current rates are from actual cost. Further, it assumes no increase or decrease in the IS class base revenues. Thus, the impact of much higher Demand charges would be offset by the much lower Energy charges. This end result will be a more cost-based rate design than currently exists.

3. CLASS COST-OF-SERVICE STUDY

Q **HAVE YOU REVIEWED THE CLASS COST-OF-SERVICE STUDIES TECO FILED IN THIS PROCEEDING?**

A Yes. TECO filed both the Commission required and preferred CCOSS at present and proposed rates. The Commission required CCOSS is based on the Twelve Coincident Peak (12CP) and 1/13th Average Demand (AD) method, or 12CP-1/13thAD. However, TECO's preferred CCOSS uses 12CP-50%AD to allocate production plant-related costs, and the minimum distribution system (MDS) methodology is used to classify and allocate certain distribution network costs on a customer basis. TECO's preferred CCOSS at proposed rates also assumes consolidation of the GSD and IS classes.

Q **DOES TECO'S PREFERRED CLASS COST-OF-SERVICE STUDY COMPORT WITH ACCEPTED INDUSTRY PRACTICES?**

A With the exceptions I will discuss below, it generally does. TECO's CCOSS recognizes the different types of costs as well as the different ways electricity is used by various customers.

Q **DO YOU AGREE WITH EVERY ASPECT OF TECO'S PREFERRED CLASS COST-OF-SERVICE STUDY?**

A No. As previously explained, the GSD and IS rate classes should not be consolidated. Further, I strongly disagree with TECO's proposed 12CP-50%AD method.

First, it would result in yet another substantial change in production cost allocation methodologies. As explained later, TECO has proposed a different production cost allocation method in every rate case dating back to 1985.

Second, Mr. Ashburn relies on four points in suggesting the Commission adopt the 12CP-50%AD approach:

Reason #1. The manner in which power plants are planned and operated in Florida[11];

Reason #2. TECO has installed a significant amount of base and intermediate load generation which is more expensive to install than alternative peaking generation, but less expensive to operate over time[12];

Reason #3. The proposed conversion of the existing simple cycle peakers at TECO's Polk Power Station to a combined cycle structure[13], which means it is investing in more expensive generating units and associated units to provide more efficient fuel conversion for the generation of electricity; and

Reason #4. To minimize the revenue requirements for the RS and GS rate classes.[14]

None of the four reasons cited by Mr. Ashburn support allocating twice as many production plant costs to energy as under the currently approved methodology: 12CP-25%AD. In fact, Mr. Ashburn's four reasons support adopting the Commission's preferred 12CP-1/13thAD method. 12CP-1/13thAD was also approved by the Commission and used by Duke Energy Florida (Duke), Florida Power & Light Company (FPL) and Gulf Power Company (Gulf) to determine class revenue allocation and rate design in their most recent rate cases.

Third, TECO's proposed 12CP-50%AD would place undue emphasis on year-round energy.[15] In total, 57% of base rate production plant costs would be allocated on an energy basis. By allocating over 57% of TECO's base rate production fixed costs on energy, it gives far less emphasis on peak demand which drives the need for TECO and other utilities to install generation capacity. As explained later, Average Demand is not a cost driver.

Finally, 12CP-50%AD is consistent with the percentage of costs typically allocated on an energy basis under the Equivalent Peaker (EP) Method. EP methods generally result in 40% to 75% of total production plant costs being classified as energy-related.[16] Further, like EP, 12CP-50%AD allocates production plant costs to hours beyond the economic break-even point. This is the reason why the Commission rejected EP in 1990. Thus, given the similarities between EP and 12CP-50%AD, the Commission should also reject 12CP-50%AD and adopt the 12CP-1/13thAD methodology.

Q DO YOU AGREE WITH ANY OF THE CHANGES TO THE CLASS COST-OF-SERVICE STUDY THAT TECO IS PROPOSING?

A Yes. I agree with TECO's proposal to use MDS to classify some portion of network distribution plant-related costs as customer related. TECO's proposal recognizes the reality that the utility is required to invest in a minimal distribution network to attach a customer to the system and provide the voltage support necessary to support reliable electricity service. Stated differently, these costs are incurred regardless of the amount of power and energy usage by customers. Thus, they should be allocated to classes relative to the number of customers served.

Background

Q WHAT IS A CLASS COST-OF-SERVICE STUDY?

A A class cost-of-service study (CCOSS) is an analysis used to determine each class's responsibility for the utility's costs. Thus, it determines whether a class generates sufficient revenues to recover the class's cost of service. A CCOSS separates the utility's total costs into portions incurred on behalf of the various customer groups. Most of a utility's costs are incurred to jointly serve many customers. For purposes of rate design and revenue allocation, customers are grouped into homogeneous classes according to their usage patterns and service characteristics.

Q WHAT PROCEDURES ARE USED TO CONDUCT A CLASS COST-OF-SERVICE STUDY?

A The basic procedure for conducting a CCOSS is fairly simple. First, we identify the different types of costs (*functionalization*), determine their primary causative factors (*classification*), and then apportion each item of cost among the various rate classes (*allocation*). Adding up the individual pieces gives the total cost for each class.

Identifying the utility's different levels of operation is a process referred to as functionalization. The utility's investments and expenses are separated into production, transmission, distribution, and other functions. To a large extent, this is done in accordance with the Uniform System of Accounts (USOA) developed by the Federal Energy Regulatory Commission (FERC).

Once costs have been functionalized, the next step is to identify the primary causative factor (or factors). This step is referred to as *classification*. Costs are classified as demand-related, energy-related or customer-related. Demand (or capacity) related costs vary with peak demand, which is measured in kilowatts (or kW). This includes production, transmission, and some distribution investment and related fixed operation and maintenance (O&M) expenses. As explained later, peak demand determines the amount of capacity needed for reliable service. Energy-related costs vary with the production of energy (or kWh). Energy-related costs include fuel and variable O&M expense. Customer-related costs vary directly with the number of customers, and include expenses such as meters, service drops, billing, and customer service.

Each functionalized and classified cost must then be *allocated* to the various customer classes. This is accomplished by developing allocation factors that reflect the percentage of the total cost that should be paid by each class. The allocation factors should reflect *cost-causation*; that is, the degree to which each class caused the utility to incur the cost.

Q WHAT KEY PRINCIPLES ARE RECOGNIZED IN A CLASS COST-OF-SERVICE STUDY?

A A properly conducted class cost-of-service study recognizes two key cost-causation principles. First, customers are served at different delivery voltages. This affects the amount of investment the utility must make to deliver electricity to the meter. Second, since cost-causation is also related to how electricity is used, both the timing and rate of energy consumption (*i.e.*, demand) are critical. Because electricity cannot be stored for any significant time period, a utility must acquire sufficient generation resources and construct the required transmission facilities to meet the maximum projected demand, including a reserve margin as a contingency against forced and unforced outages, severe weather, and load forecast error. Customers that use electricity during the critical peak hours cause the utility to invest in generation and transmission facilities.

Q WHAT FACTORS CAUSE THE PER-UNIT COSTS TO DIFFER BETWEEN CUSTOMER CLASSES?

A Factors that affect the per-unit cost include whether a customer's usage is constant or fluctuating (load factor), whether the utility must invest in transformers and distribution systems to provide the electricity at lower voltage levels, and the amount of electricity that a customer uses. In general, industrial consumers are less costly to serve on a per unit basis because they:

- (1) Operate at higher load factors;
- (2) Take service at higher delivery voltages; and
- (3) Use more electricity per customer.

These three factors explain why some customers pay higher average rates than others.

For example, the difference in the losses incurred to deliver electricity at the various delivery voltages is a reason why the per-unit energy cost to serve is not the same for all customers. More losses occur to deliver electricity at distribution voltage (either primary or secondary) than at transmission voltage, which is generally the level at which industrial customers take service. This means that the cost per kWh is lower for a transmission customer than a distribution customer. The cost to deliver a kWh at primary distribution, though higher than the per-unit cost at transmission, is also lower than the delivered cost at secondary distribution.

In addition to lower losses, transmission customers do not use the distribution system. Instead, transmission customers construct and own their own distribution systems. Thus, distribution system costs are not allocated to transmission level customers who do not use that system. Distribution customers, by contrast, require substantial investments in these lower voltage facilities to provide service. Secondary distribution customers require more investment than do primary distribution customers. This results in a different cost to serve each type of customer.

Two other cost drivers are efficiency and size. These drivers are important because most fixed costs are allocated on either a demand or customer basis.

Efficiency can be measured in terms of load factor. Load factor is the ratio of average demand (*i.e.*, energy usage divided by the number of hours in the period) to peak demand. A customer that operates at a high load factor is more efficient than a lower load factor customer because it requires less capacity for the same amount of energy. For example, assume that two customers purchase the same amount of energy, but one customer has an 80% load factor and the other has a 40% load factor. The 40% load factor customers would have twice the peak demand of the 80% load factor customers, and the utility would therefore require twice as much capacity to serve the 40% load factor customer as the 80% load factor. Said differently, the fixed costs to serve a high load factor customer are spread over more kWh usage than for a low load factor customer.

Production Plant Allocation

Q WHAT IS THE 12CP-50%AD METHOD?

A The 12CP-50%AD method allocates production plant costs using both 12CP (which is also used to allocation transmission plant related costs) and energy (or average demand). Specifically, the 12CP-50%AD allocation factors are derived as follows:

$$\mathbf{12\mathit{CP} - 50\%\mathit{AD} = 12\mathit{CP}\%\ \mathit{X}\ 50\% + \mathit{Average\ Demand}\%\ \mathit{X}\ 50\%}$$

Q HAS THIS COMMISSION EVER APPROVED THE 12CP-50%AD METHOD?

A No.[17]

Q DID TECO ALSO PROPOSE THE 12CP-50%AD METHOD IN ITS LAST RATE CASE?

A No. TECO proposed and the Commission approved the 12CP-25%AD method in the last rate case. Before TECO's last rate case, it used the 12CP-1/13thAD approach, the same methodology used by Duke, FPL and Gulf today.

Q HAS TECO CONSISTENTLY USED THE SAME PRODUCTION PLANT ALLOCATION METHODOLOGY IN EACH OF ITS PRIOR RATE CASES?

A No. As can be seen in the table below, TECO has proposed a different production plant cost allocation method in each of its last four rate cases, including this case, dating back to 1985.

Summary of Production Plant Cost Allocation Methods Proposed by TECO

Docket No.	Methodology
850050	Equivalent Peaker
920324	12CP-1/13AD
080317	12CP-25%AD
130040	12CP-50%AD

Thus, 12CP-50%AD is another new proposed methodology. Witness Ashburn admitted during his deposition that the approach was proposed in part simply because the Commission accepted the 12CP-25%AD approach during the last rate case, and maybe the Commission would look favorably on yet another change.[18] Under 12CP-50%AD, TECO is now proposing to roughly double the amount of production plant related costs that would be allocated on an energy basis. Coupled with its proposal to directly classify the costs associated with the Big Bend scrubber and Polk Plant gassifier to energy, 12CP-50%AD would result in classifying 57% of net production plants and related fixed costs on an energy basis.

Q **IF THE COMMISSION WERE TO ADOPT 12CP-50%AD WILL THIS ALSO CHANGE HOW CERTAIN NON-BASE RATE COSTS ARE ALLOCATED AND COLLECTED?**

A Yes. TECO currently uses 12CP-25%AD to allocate the demand related portion of purchased power capacity costs in its Capacity Cost Recovery (CCR) rider and certain environmental investment that is being collected in the Environmental Cost Recovery Clause (ECRC). If the Commission were to adopt 12CP-50%AD for allocating base rate costs, this would require a similar change in how costs are allocated and collected in both the CCR and ECRC. Thus, any change in how production plant is allocated in determining base rates will result in corresponding allocation changes in both the CCR and ECRC.

Q **MR. ASHBURN'S REASON #1 IS THAT 12CP-50%AD IS JUSTIFIED BECAUSE IT REFLECTS HOW POWER PLANTS ARE PLANNED AND OPERATED IN FLORIDA. IS THIS AN ACCURATE STATEMENT?**

A No. If 12CP-50%AD reflected how power plants are planned and operated in Florida, one should logically expect that this method would be embraced by all Florida investor-owned electric utilities. However, TECO is the only utility in Florida investor-owned electric utility proposing 12CP-50%AD. Again, Duke, FPL and Gulf currently use 12CP-1/13thAD.

Q **HOW IS THE FACT THAT 12CP-1/13THAD IS USED BY DUKE, FPL AND GULF PERTINENT TO TECO?**

A Duke, FPL and Gulf are among the other Florida utilities that plan and operate generating systems in Florida (*i.e.*, **Reason #1**). Further, these utilities have recently completed rate cases before the Commission. In these cases, with the exception of Duke, who ultimately agreed to continue using the 12CP-13thAD approach, neither FPL nor Gulf proposed changing the 12CP-1/13thAD method. For example, in its most recent rate case, FPL supported 12CP-1/13thAD stating that:

> ***The 12 CP and 1/13th methodology recognizes that the decision to add generating capacity is driven primarily by peak demands on the system.*** This methodology classifies 12/13ths, or approximately 92% of costs on the basis of coincident peak demand and 1/13th, or approximately 8%, of costs on the basis of energy. That portion classified to demand is allocated to the individual rate classes based on their 12 CP contributions, adjusted for losses, while the portion classified to energy is allocated based on their kWh sales, adjusted for losses. ***Under the 12 CP and 1/13th methodology, all generating units are treated consistently based on their function (i.e. production), their classification (12/13th demand and 1/13th energy), and their allocation (contribution to the system peak and kWh of energy).*** The 12 CP and 1/13th methodology has a significant history of regulatory acceptance in Florida. The 12 CP and 1/13th methodology was used in Docket No. 830465-EI and Docket No. 080677-EI. Furthermore, the FPSC has approved the 12 CP and 1/13th methodology in rate cases involving other investor-owned utilities.[19] (emphasis added)

Q IS THERE ANY REASON TO BELIEVE THAT TECO PLANS ITS SYSTEM DIFFERENTLY THAN FPL?

A No.

Q TURNING TO MR. ASHBURN'S REASON #2, DOES THE FACT THAT TECO HAS INSTALLED A SIGNIFICANT AMOUNT OF BASE AND INTERMEDIATE LOAD GENERATION JUSTIFY CHANGING THE CURRENTLY APPROVED PRODUCTION PLANT COST ALLOCATION METHOD?

A No. TECO's capacity mix is relatively unchanged since the addition of the simple cycle peakers that were reflected in the Step 2 rates approved in its last rate case. Thus, TECO's production plant investment reflects the same investment (plus capital additions less depreciation and interim retirements) as was included in base rates in TECO's last rate case.

Q WHAT DOES MR. ASHBURN MEAN BY THE TERM INTERMEDIATE LOAD GENERATION?

A I presume Mr. Ashburn is referring to combined cycle gas turbines (CCGTs) because he specifically referenced TECO's existing generation mix, which includes CCGTs at Bayside Units 1 and 2, and TECO's proposed conversion of Polk Units 2-5.

Q DOES MR. ASHBURN'S REASON #3 (THE PLANNED CONVERSIONS AT POLK) SUPPORT ADOPTING 12CP-50%AD?

A No. First, the planned conversions at Polk Units 2-5 will not be placed into commercial operation until 2017, which is beyond the test year.[20] Thus, any recognition of the conversion would be premature and beyond the scope of this proceeding.

Second, TECO is not the only utility adding CCGTs to its system. FPL, recently installed over 1,295 megawatts (MW) of new CCGTs. It is currently planning to install an additional 2,545 MW of capacity.

Q HAS FPL'S DECISION TO INSTALL SUBSTANTIAL AMOUNTS OF COMBINED CYCLE GENERATION PROMPTED IT TO CHANGE ITS PRODUCTION PLANT ALLOCATION METHODOLOGY?

A No. FPL has supported and continues to support 12CP-1/13thAD despite converting its older steam generation into modern efficient CCGTs. These conversions complement FPL's existing nuclear capacity, which are more capital intensive than CCGTs. Thus, FPL's decision to invest in more capital intensive generation capacity has not prompted it to allocate a much larger percentage of its production plant costs on an energy basis.

Q IS IT ACCURATE TO STATE THAT PRODUCTION PLANT INVESTMENT INCURRED TO PROVIDE MORE EFFICIENT FUEL CONVERSION FOR THE GENERATION OF ELECTRICITY IS CAUSED BY YEAR-ROUND ENERGY USAGE?

A No. Mr. Ashburn's statement is an over-simplification of the system planning process, and it confuses cost causation with benefits.

Q HOW IS MR. ASHBURN'S STATEMENT AN OVERSIMPLIFICATION OF THE SYSTEM PLANNING PROCESS?

A System planners are faced with the dual dimensions of: (1) providing reliable service; and (2) minimizing total cost. Because electric energy cannot be stored in large quantities for any significant length of time, providing reliable service requires construction of sufficient generating capacity to meet the projected system peak demands and to provide an adequate reserve margin. This will ensure that whenever a consumer flips the switch an electric light or other appliance will operate.

Cost minimization is the requirement that the utility provide the service at the lowest overall cost. The utility strives to install the mix of generating capacity (*i.e.*, base, intermediate and peaking) that, along with the existing generation, yields the lowest total cost. In other words, the economic choice between a base load plant and a peaking plant must consider both investment-related costs (*i.e.*, capital costs) and operating costs. Therefore the type of generating unit selected is a function of average *total* costs.

Q ARE THERE OTHER FACTORS, BESIDES THE ECONOMIC TRADE-OFFS, THAT CAN AFFECT UTILITY INVESTMENT DECISIONS?

A Yes. A generating unit represents a 30 to 60-year investment. The long life-cycle makes it difficult for a utility to anticipate every contingency, such as new regulations that require utilities to cease using certain types of fuels, limit operations or install costly equipment to meet prevailing emissions standards or changes in public policy. These contingencies could transform what is otherwise an economical resource under today's circumstances into an uneconomical resource under different circumstances. Thus, it behooves a utility to manage these risks by installing a diversified portfolio of generating resources.

Q WHY DO UTILITIES INSTALL COMBINED CYCLE GENERATION?

A CCGTs provide flexible operating capacity. They can be started up more quickly than older steam units and have considerable load-following capability. Load following means that generator output can be automatically adjusted from moment-to-moment so that the available supply always matches the utility's loads in real time. Flexible capacity is especially important for systems having substantial amounts of intermittent resources (*i.e.,* solar, hydro, wind).

With more flexible capacity, CCGTs can also be used to supply Contingency Reserves, which consist of generation and interruptible loads available within 15 minutes. Contingency Reserves are necessary to assure that sufficient capability exists to meet the NERC Disturbance Control Standard and to reestablish resource and demand balance following a Reportable Disturbance.[21] These functions are clearly necessary to maintain system reliability. As such, it is an oversimplification to claim that any "extra" investment that may be incurred to install CCGTs is driven by fuel savings.

Q **DO PROJECTED FUEL SAVINGS CREATE THE NEED TO ADD GENERATION CAPACITY?**

A No. The primary driver for generation capacity additions is the utility's projected peak demand. According to TECO's 2013 Ten-Year Site Plan:

> To meet the expected system demand and energy requirements over the next ten years, both peaking and intermediate resources are needed. The peaking capacity need will be met by purchased power agreements for peaking capacity secured through 2016. In 2017, Tampa Electric currently expects to meet its intermediate load needs by converting Polk Power Station's simple cycle combustion turbines (Polk Units 2-5) to a natural gas combined cycle (NGCC) unit. The operating and cost parameters associated with the capacity additions resulting from the analysis are shown in Schedule 9. Beyond 2017, the company foresees the future needs being that of additional peaking capacity, which it will meet by combustion turbine additions and/or future purchased power agreements.[22]

Thus, as demonstrated by TECO's own Ten-Year Site Plan, the factor driving the need for new capacity is the growth in projected peak demand. In other words, peak demand is the cost causer, while fuel savings is the outcome of installing more efficient generation capacity. Mr. Ashburn would have us believe that the opposite is true (*i.e.* fuel savings drive plant investment) which is clearly contradicted by the facts.

Q **IF MR. ASHBURN'S THEORY (THAT FUEL SAVINGS ARE THE PRIMARY DRIVER FOR TECO'S INVESTMENT IN BASE AND INTERMEDIATE LOAD CAPACITY) IS VALID, WOULD 12CP-50%AD ACCURATELY REFLECT HIS THEORY?**

A No. Mr. Ashburn's system planning theory is premised on a flawed application of the theory of capacity substitution (CAPSUB). Capital Substitution assumes that utilities invest in more capital-intensive generation (*i.e.* coal and CCGTs) in order to save fuel costs. However, as explained in **Appendix C,** 12CP-50%AD fails to correctly apply capital substitution theory because production plant investment is allocated to the hours beyond the economic break-even point. Further, TECO made no attempt to define that portion of fuel costs that are incurred for reliability and not to provide kWh. Such reliability-driven fuel costs should be allocated on a demand, and not an energy, basis.

Q WHAT IS MEANT BY THE "BREAK-EVEN POINT?"

A The break-even point is the number of operating hours in which the total cost of peaking capacity is the same as a other types of capacity. The illustration in **Appendix C** assumes a break-even point of 1,000 hours. This reflects the fact that peaking units rarely operate more than 1,000 hours per year on a recurring basis.

Q WHAT IS THE SIGNIFICANCE OF THE BREAK-EVEN POINT?

A Once a utility decides that additional production capacity is needed to meet peak demand, if that new capacity is expected to run only a limited number of hours, total costs are minimized by the choice of a peaker. On the other hand, if it is projected that a unit will run for a sufficient number of hours, other types of capacity will be more economical.

Therefore, *annual energy usage* (or Average Demand) does not cause plant investment. However, *load duration up to the break-even point* may influence plant investment decisions. Beyond the break-even point, energy usage is no longer a factor in the decision to select a specific type of generation capacity.

Q HOW DOES 12CP-50%AD RESULT IN ALLOCATING PRODUCTION PLANT COSTS TO HOURS BEYOND THE ECONOMIC BREAK-EVEN POINT?

A This is demonstrated in **Exhibit___ (JP-2),** which shows TECO's load duration curve (in blue) with each of the 12CPs (in green) and average demand (in red) also plotted. A load duration curve is TECO's system demand sorted in descending order with the system peak shown on the left most side of the curve and system minimum demands shown on the right most portion of the curve. In the interest of brevity, only a portion of TECO's load duration curve is shown.

First, 12CP-50%AD assigns 50% of production plant cost to all 8,760 hours in a typical year (the red area under the load duration curve). However, the economic break-even point of peaking capacity occurs around 800 hours per year. Thus, the vast majority of the hours occur beyond the break-even point. Second, three of the 12CPs also occur beyond the economic break-even point.

Q HOW DID YOU DETERMINE THAT THE ECONOMIC BREAK-EVEN POINT OCCURS AT ABOUT 800 HOURS?

A I analyzed the operating hours of TECO's peaker units over the past 3 years. This is shown in **Exhibit___ (JP-3).** As can be seen, TECO typically operates its peakers between 551 and 1,037 hours per year. This translates into 800 hours per year per unit on average.

Q HAS THE COMMISSION PREVIOUSLY REJECTED METHODS THAT ALLOCATE PRODUCTION PLANT COSTS TO ALL 8,760 HOURS?

A Yes. The same issue arose in connection with the Equivalent Peaker (EP) method of allocation. Under EP, 40% to 75% of production plant costs is classified to energy and allocated on Average Demand. The remaining costs are allocated on a CP basis. This is similar to 12CP-50%AD, which allocates 50% of production plant costs on Average Demand and the remaining demand-related costs on 12CP. Both methods allocate significant costs beyond the economic break-even point.

However, in 1990 the Commission rejected the EP method. Specifically, the Commission stated:

> The equivalent peaker methodology implies a refined knowledge of costs which is misleading, ***particularly as to the allocation of plant costs to hours past the break-even point.***[23] *(emphasis added)*

Thus, the Commission has previously determined that methods like EP and 12CP-50%AD, which allocate investment to hours beyond the economic break-even point, are clearly at odds with the utility planning process. This is because all production from a specific plant (*i.e.*, kWh sales) is not the critical factor in deciding what type of capacity to install. Only the production up to the break-even point determines the lowest cost capacity addition.

Q ARE THERE ANY MATERIAL DIFFERENCES BETWEEN 12CP-50%AD AND EQUIVALENT PEAKER METHODS?

A No. The only real difference between EP and 12CP-50% AD is how the percent of energy-related costs is derived. EP methods typically use a more rigorous analysis, while TECO relied on judgment.[24] Given that EP and 12CP-50%AD are for all intents and purposes the same method, the Commission should reject 12CP-50%AD just as it rejected EP.

Q DOES MR. ASHBURN'S REASON #4 JUSTIFY ADOPTING 12CP-50%AD?

A No. Mr. Ashburn's fourth reason (that 12CP-50%AD would minimize the revenue requirements for the RS and GS rate classes) has nothing to do with selecting a class cost-of-service methodology. That selection should be based on the application of the principle of cost causation. Cost causation means allocating costs to those classes that cause the utility to incur the specific costs. It does not mean picking a cost allocation method to minimize the rate impact on certain rate classes (*i.e.*, picking winners and losers while disregarding cost causation). Were it to do so, the Commission would effectively be engaging in "price-based costing" rather than "cost-based pricing." The Commission's long-standing policy has employed "cost-based pricing." In doing so, rate impacts are properly addressed in determining the appropriate allocation of a base rate increase and in the design of the applicable rates, not in the selection of a cost-of-service methodology.

Recommendation

Q SHOULD THE COMMISSION ADOPT 12CP-50%AD?

A No. 12CP-50%AD is not consistent with cost causation and does not accurately reflect the system planning process. Further, 12CP-50%AD is not supported by any changes in TECO's system planning process or its current generation mix relative to the mix that existed in TECO's last rate case. As explained previously, 12CP-50%AD allocates plant costs beyond the economic break-even point and classifies about the same percentage of costs to energy as EP methods, which the Commission long-ago rejected. Finally, 12CP-50%AD is not being used by Duke, FPL or Gulf. This is relevant because these utilities have invested in significant base and intermediate load capacity resources. Mr. Ashburn has failed to demonstrate how TECO is different than Duke, FPL or Gulf.

Q ARE THERE ANY OTHER REASONS FOR REJECTING 12CP-50%AD?

A Yes. Adopting 12CP-50%AD would cause undue instability in both class revenue requirements and rate design. As previously stated, TECO has proposed a new cost allocation methodology in every rate case since 1985. This current change in methodologies is particularly dramatic in light of the fact that it would double the amount of TECO's total production fixed costs (both base rate and cost recovery clauses) allocated in/or collected on an energy basis. Instability is not a desirable attribute of a rate design.

Q **WHAT PRODUCTION PLANT ALLOCATION METHOD SHOULD THE COMMISSION ADOPT FOR TECO?**

A TECO has provided no evidence that it plans its generation system any differently than other Florida electric utility. The Commission has adopted 12CP-1/13thAD for Duke, FPL and Gulf. Unless there are clear differences between TECO and other Florida utilities, 12CP-1/13AD should also be adopted for TECO.

Alternatively, if the Commission does not want to again change its production plant allocation approach, then it should not approve any change in the currently approved cost allocation methodology: 12CP-25%AD. It should not adopt TECO's proposed 12CP-50%AD proposal.

Q **IF THE COMMISSION ACCEPTS TECO'S 12CP-50%AD APPROACH, SHOULD ANY OTHER CHANGES BE MADE?**

A Yes. If the Commission decides that more than 25% of production fixed costs (other than then Big Bend scrubber and Polk gassifier) should be allocated on an energy basis, then it should replace 12CP with an allocator that more closely reflects TECO's actual system load characteristics and does not allocate as many production fixed costs to hours beyond the break-even point as does 12CP-50%AD.

Q **WHAT ALLOCATION METHODOLOGY BEST REFLECTS TECO'S SYSTEM LOAD CHARACTERISTICS?**

A The summer and winter system coincident demand (Summer/Winter CP) method best reflects TECO's load and supply characteristics.

Q **HOW DO TECO'S LOAD CHARACTERISTICS SUPPORT THE USE OF THE SUMMER/WINTER CP METHOD?**

A TECO experiences its maximum annual demand for electricity in either the summer or winter months. This is shown in **Exhibit ____ (JP-4)**, page 1, which is an analysis of TECO's monthly firm peak demands as a percent of the annual system peak for the years 2008 through 2012. TECO routinely peaks in both the summer and winter months. The peak demands in the other months are typically well below the summer and winter peak demands.

These characteristics are further summarized in **Exhibit ____ (JP-4)**, page 2. As can be seen:

- The minimum month peak is generally below 66% of the annual system peak.
- Monthly peak demands are only 85% of the annual system peak.
- Peak demands are 10% (or higher) of the non-peak demands.
- And with one exception, TECO has a 57% average annual load factor.

These ratios confirm that TECO has seasonal load characteristics. Thus, electricity demands in the spring and fall months are not particularly relevant in determining the amount of capacity needed for TECO to provide reliable service.

Q **ARE THE MONTHLY PEAKS IN THE SPRING/FALL MONTHS IMPORTANT BECAUSE TECO HAS TO REMOVE GENERATION FOR SCHEDULED MAINTENANCE?**

A No. Although TECO does schedule most planned outages during the spring and fall months, this does not make these months important from a cost-causation perspective. Specifically, despite planned outages, TECO generally has higher reserve margins during the months when planned outages have occurred than during the peak summer and winter months. This is shown in **Exhibit ___ (JP-5)**.

The reserve margins were calculated as the margin (available capacity less scheduled outages less firm peak demand) divided by firm peak demand. As can be seen, the reserve margins in the summer and winter peak months, adjusted for scheduled outages, have been well below the corresponding non-peak month reserve margins.

Q WHAT DO THE PEAK DEMAND AND RESERVE MARGIN ANALYSES DEMONSTRATE?

A The analyses demonstrate that both summer and winter peak demands determine TECO's capacity requirements. The spring and fall months are irrelevant. Thus, the 12CP method does not reflect cost-causation when measured by TECO's load and supply characteristics. For these reasons, if the Commission allocates an increasing amount of production plant costs to energy, it should also adopt the Summer/Winter CP method.

Q HOW WOULD THE SUMMER/WINTER CP METHOD AVOID ALLOCATING AS MANY COSTS BEYOND THE BREAK-EVEN POINT?

A Both the summer and winter annual peak demands are well within the hours up to the break-even point. As previously explained, this is not the case with 12CP.

Q **WHAT OTHER CHANGES IN THE COST ALLOCATION METHODOLOGY SHOULD BE MADE IF THE COMMISSION DECIDES TO ALLOCATE MORE THAN 25% OF PRODUCTION FIXED COSTS ON AN ENERGY BASIS?**

A The Commission should recognize that not all variable costs are energy related. As explained below, some variable costs are being incurred either for reliability or as a substitute for higher capital costs. Thus, they should be allocated to classes on a peak demand basis.

Q **WHAT ARE VARIABLE COSTS?**

A Variable costs are those that are primarily related to producing energy. The most obvious examples of variable costs are fuel and purchased energy expenses.

Q **HOW ARE FUEL AND PURCHASED ENERGY COSTS ALLOCATED AND COLLECTED?**

A Fuel and purchased energy costs are allocated and collected on an energy basis.

Q **IF SOME PORTION OF PRODUCTION FIXED COSTS IS ASSUMED TO BE ENERGY-RELATED, IS IT REASONABLE TO ASSUME THAT ALL FUEL AND PURCHASED ENERGY COSTS ARE ALSO ENERGY-RELATED?**

A No. TECO's assumption that all fuel and purchased energy costs are energy-related ignores several fundamental principles. First, TECO must commit its generating units in advance of actual demand. This requires fuel to be consumed for unit start-up and stabilization.

Second, certain generating units cannot be cycled completely down once they have been committed to serving load. These units must operate at minimum load levels to provide spinning and supplementary reserves. This is particularly necessary during low load periods.

In both instances (*i.e.* start up and operating units at minimum load), there is no direct link between fuel costs and kWh generated.

Q DOES TECO INCUR FUEL COSTS THAT DO NOT DIRECTLY RESULT IN GENERATING KILOWATT HOURS?

A Yes. As with other utilities, TECO incurs fuel costs both during start-up to commit units to daily operation and to allow units to operate at their economic minimums during low load periods. TECO estimates that about $8.3 million of costs are incurred for start-up. TECO could not quantify the fuel costs incurred to maintain units at minimal operating levels.[25] Arguably, both start-up costs and the fuel costs to maintain a unit in service should be allocated on a demand basis because they are being incurred to maintain system reliability.

<u>**Distribution Cost Classification**</u>

Q HOW HAS TECO CLASSIFIED DISTRIBUTION INVESTMENT?

A TECO has classified a portion of its distribution network investment as customer-related. This is consistent with the purpose of the distribution system, which is to deliver power from the transmission grid to the customer, where it is eventually consumed. Certain investments (*e.g.*, meters, service drops) must be made just to attach a customer to the system. These investments are customer-related.

Q WHAT DO YOU MEAN BY THE DISTRIBUTION NETWORK?

A The distribution "network" consists of TECO's investment in poles, towers, fixtures, overhead lines and line transformers. These investments are booked to FERC Accounts 364, 365, 366, 367, and 368.

Q HOW DID TECO DETERMINE THE CUSTOMER-RELATED PORTION OF THE DISTRIBUTION NETWORK INVESTMENT?

A TECO used a minimum distribution study (MDS). Under MDS, the customer-related portion is representative of the investment in the minimum size equipment required to attach customers to the system and provide the necessary voltage support.

Q WHY IS IT APPROPRIATE TO CLASSIFY A PORTION OF THE DISTRIBUTION NETWORK INVESTMENTS AS A CUSTOMER-RELATED COST?

A Classifying a portion of the distribution network as a customer-related cost recognizes the reality that every utility must provide a path through which electricity can be delivered to each and every customer regardless of the peak demand or energy consumed. Further, that path must be in place if the utility is to meet its obligation to provide service upon demand.

Absent a connection to the system, a customer cannot take power. Further, the connecting facilities must be sized to provide voltage support before any power or energy can be consumed. These prerequisites (*i.e.*, a grid connection with facilities sized to provide voltage support) are clearly related to the existence of the customer.

Q DO ANY OTHER FACTORS JUSTIFY CLASSIFYING A PORTION OF THE DISTRIBUTION NETWORK AS CUSTOMER-RELATED?

A Yes. The distribution network must comply with this Commission's standards of construction. Specifically, Rule 25-6.034 requires that:

> (1) The facilities of each utility shall be constructed, installed, maintained and operated in accordance with generally accepted

> engineering practices to assure, as far as is reasonably possible, continuity of service and uniformity in the quality of service furnished.
>
> (2) Each utility shall, at a minimum, comply with the National Electrical Safety Code [ANSI C-2) [NESC], incorporated by reference in Rule 25-6.0345, F.A.C.

Rule 25-6.0342, Florida Administrative Code, was more recently enacted. It requires utilities to cost-effectively strengthen critical electric infrastructure to increase the ability of transmission and distribution facilities to withstand extreme weather conditions and reduce restoration costs and outage times to end-use customers associated with extreme weather conditions. The costs to comply with these Commission rules are not required because of the amount of electric power and energy demanded. They are required because of the existence of each customer and TECO's obligation to provide a reliable connection to the grid.

Q IS IT A RECOGNIZED PRACTICE TO CLASSIFY A PORTION OF THE DISTRIBUTION NETWORK AS CUSTOMER-RELATED?

A Yes. For example, the NARUC Electric Utility Cost Allocation Manual states that:

> Distribution plant Accounts 364 through 370 involve demand and customer costs. The customer component of distribution facilities is that portion of costs which varies with the number of customers. Thus, the number of poles, conductors, transformers, services, and meters are directly related to the number of customers on the utility's system.[26]

An excerpt from the Manual pertaining to distribution cost classification is provided in **Exhibit___ (JP-6)**.

Q IS THIS PRACTICE FOLLOWED BY OTHER UTILITIES?

A Yes. **Exhibit___ (JP-7)** is a partial list of the utilities that classify some portion of their distribution network investment as customer-related. This is not intended to be an exhaustive survey.

Q **WHAT PORTION OF THE DISTRIBUTION NETWORK IS TECO PROPOSING TO CLASSIFY AS CUSTOMER-RELATED?**

A TECO's MDS study resulted in classifying about 25% of its distribution network investment (FERC Accounts 364 through 368) as customer-related. This is shown in **Exhibit___ (JP-8)**, line 44, column 4.

Q **HOW DOES TECO'S CLASSIFICATION OF DISTRIBUTION NETWORK COSTS COMPARE WITH THE UTILITIES SHOWN IN EXHIBIT___ (JP-8)?**

A As previously stated, TECO classifies about 25% of the investment in FERC Accounts 364 through 368 as customer-related. The corresponding composite percentage for the other listed utilities ranges from 19% to 69%. Some variation is to be expected because of differences between each utility's distribution construction practices and the methodologies used to determine the customer-related component.

Q **PLEASE SUMMARIZE YOUR RECOMMENDATION.**

A TECO's proposed classification of distribution network costs comports with accepted practice and is modest relative to other utilities. Accordingly, TECO's proposed distribution customer classification should be adopted in this case.

4. REVENUE REQUIREMENT

Q WHAT REVENUE REQUIREMENT ISSUES ARE YOU ADDRESSING?

A I am addressing the test year planned outage expense and the storm reserve.

<u>**Planned Outage Expense**</u>

Q WHAT ARE PLANNED OUTAGE EXPENSES?

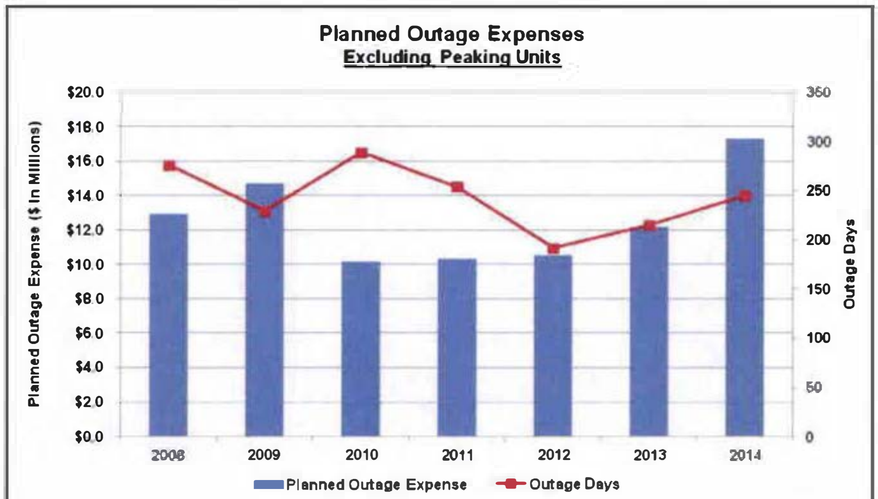
A Planned outage expenses are incurred to conduct major overhauls of generating units. They are a subset of production O&M expense.

Q IS TECO PROPOSING TO INCLUDE PLANNED OUTAGE EXPENSES IN BASE RATE IN THIS CASE?

A Yes. TECO is proposing to include about $17.6 million (Total Company) of planned outage expenses in base rates. This includes all generating units.

Q IS TECO'S PROPOSAL REASONABLE?

A No. As can be seen in the chart below, Test Year planned outage expenses are abnormally high. For my analysis I have included generating units other than peakers that will have been in-service for the entire 2008 – 2014 timeframe.



Source: TECO Response to FIPUG Interrogatory No. 37.

A further analysis of these expenses is provided in **Exhibit___ (JP-9)**. Specifically, I have compared the planned outage expenses during the Test Year (column 1) versus the average outage expenses from the previous six years and Test Year (column 2).

As can be seen, the proposed Test Year expense of $17.3 million is nearly 26% higher than the corresponding average period expense of $12.9 million. Particularly noteworthy is the substantial increase in Test Year overhaul costs incurred at Big Bend Unit 1 (line 1) and Big Bend Unit 4 (line 4) plants. The corresponding Test Year costs are 72% and 66% higher than over the previous six years.

Q **HOW DO TECO'S PROPOSED TEST YEAR PLANNED OUTAGE EXPENSES FOR THE BIG BEND UNITS COMPARE WITH PAST YEARS OUTAGE EXPENSES?**

A In past years major outage expenses have been limited to one unit or no units. The following table lists the Big Bend Units that experienced outage expenses of over $5 million in a year.

Big Bend Units with Yearly Outage Expenses Greater than $5 Million

Unit	Year	Expense
Big Bend 3	2008	$5,219,128
Big Bend 2	2009	$6,105,000
Big Bend 3	2013	$5,300,000

Source: TECO Response to FIPUG Interrogatory No. 37.

The proposed Test Year expenses include major outage expenses of $5.4 million for Big Bend Unit 1 and $5.7 million for Big Bend Unit 4. Therefore, the proposed Test Year planned outage expenses are clearly abnormal. For this reason, TECO's proposal should be rejected.

Q WOULD IT BE APPROPRIATE TO NORMALIZE PLANNED OUTAGE EXPENSES IN SETTING RATES TO BE APPROVED IN THIS CASE?

A Yes. TECO's proposed Test Year planned outage expenses are clearly abnormal and overstated. Thus, it would be appropriate to normalize these expenses so that the base rates approved in this proceeding are more representative of the costs that TECO will actually incur for planned maintenance outages.

Q WHAT IS YOUR RECOMMENDED NORMALIZATION ADJUSTMENT?

A I recommend a $3.7 million reduction in TECO's proposed Test Year expense. The $3.7 million adjustment is shown in column 5. It was derived by reducing Test Year expenses for Big Bend Unit 4 to within 5% of the 2008-2014 average expense (column 7).

Storm Reserve

Q WHAT IS A STORM RESERVE?

A Rule 25-6.0143, Florida Administrative Code, states: "A separate subaccount shall be established for that portion of Account No. 228.1 which is designated to cover storm-related damages to the utility's own property or property leased from others that is not covered by insurance."

Q WHAT IS TECO'S CURRENT STORM RESERVE LEVEL?

A The balance in TECO's storm reserve as of December 31, 2012 was $50.2 million. Considering the current annual storm damage accrual of $8 million, the balance will grow to $57.3 million assuming no further property damage is charged to the reserve in 2013.[27] If TECO experiences low storm activity similar to the 2005 – 2012 period, the reserve level could reach the target level of $64 million in 2014.

Q **HOW IS THE STORM RESERVE FUNDED?**

A The storm reserve is funded through customer contributions that the Commission authorizes when it sets base rates. Customers currently contribute $8 million per year to the storm reserve.

Q **DOES THE COMMISSION HAVE A FRAMEWORK FOR STORM RESTORATION COST RECOVERY?**

A Yes. According to the order in the last Tampa Electric Company rate case, the Commission addresses the storm restoration cost issue in the following manner:

> We have established a regulatory framework consisting of three major components: (1) an annual storm accrual, adjusted over time as circumstances change; (2) a storm reserve adequate to accommodate most, but not all storm years; and, (3) a provision for utilities to seek recovery of costs that go beyond the storm reserve.[28]

Q **WHO ULTIMATELY ASSUMES THE RISK OF LOSS FROM STORM DAMAGE UNDER THE EXISTING COMMISSION FRAMEWORK?**

A As the Commission stated, TECO's customers ultimately bear all of the risk of losses due to hurricanes and other storms:

> . . . under the current approach to the recovery of storm restoration costs, the risk associated with a lower reserve level (i.e., the possibility of storm restoration costs exceeding the Reserve, leading to subsequent customer charges) and the risk associated with a higher reserve level (i.e., paying charges now for storm restoration costs that do not materialize) is completely borne by FPL's customers. The customers represented in this proceeding have made clear that they would rather pay to fund the Reserve to a lower level now and risk future rate volatility than pay to fund the Reserve to a higher level before future storm restoration costs have been incurred.[29]

As such, TECO is at little or no risk that it will not recover its legitimate storm restoration costs regardless of the amount in the storm reserve. Put simply, from a customer perspective, the question is when to pay for the cost of restoration – before or after the damage occurs. It is clear that customers prefer to pay when the damage occurs, rather than have the utility hold their money for them. And, the Commission has made it clear through its past actions that when a documented case for such recovery is made, it will permit the utility to recover these costs.

Q IS TECO PROPOSING AN INCREASE IN THE ANNUAL ACCRUALS FOR ITS STORM RESERVE?

A No. TECO proposes to continue the $8 annual accrual it collects for storm reserve.

Q HAS TECO PROPOSED CHANGES TO THE TARGET STORM RESERVE BALANCE?

A Yes. The current target level is $64 million, approved by the Commission in Docket No. 080317-EI, Order No. PSC-09-0283-FOF-EI. In this case, TECO is proposing the targeted reserve balance to increase from $64 to $100 million.[30]

Q SHOULD TECO'S PROPOSED $36 MILLION INCREASE TO THE TARGETED STORM RESERVE BE APPROVED?

A No. TECO has not supported the need for a $36 million increase. Further, since the $50.2 million storm reserve balance as of 12/31/12 is sufficient to cover all but the severest storms, accruals should cease. Put simply, this increase is not warranted. As explained below, funds in the storm reserve are sufficient even if the accrual is stopped altogether. Therefore, I recommend that the Commission maintain the targeted reserve at its current level of $64 million.

Q WHAT IS THE BASIS FOR YOUR RECOMMENDATION?

A Under the Commission's framework described above, the storm reserve accrual and reserve balance are designed to provide coverage for some, but not all, storms. However, the Expected Annual Damage (EAD) presented by TECO witness, Steven Harris, takes into account all manner and strength of storms.[31] In other words, it assumes that the storm reserve should be adequate to cover damage from hurricanes up to Category 4. The current $50.2 million reserve balance covers all Category 1 hurricanes.[32] Considering $17.6 expected annual charges to the storm reserve, it is sufficient to cover almost three consecutive years.[33]

Q WHY IS TECO SEEKING A $36 MILLION INCREASE IN STORM DAMAGE RESERVE?

A The proposed increase is based on an increase in asset value from the previous study and to cover the expected average annual storm loss to be charged to the reserve derived in the TECO Storm Loss and Reserve Performance Analysis.

Q DOES THE EAD PRESENTED IN THE STUDY PROPERLY REFLECT THE ANNUAL COSTS THAT ARE COVERED WITH THE STORM RESERVE?

A No. I believe the EAD is overstated because it ignores the Commission's directive that the storm reserve should be adequate to accommodate most, but not all storm years.

Q WHAT TYPE OF STORMS ARE INCLUDED IN THE STUDY PRESENTED BY MR. HARRIS?

A The EAD is the average damage of thousands of simulated hurricane seasons in the EQECAT model. The EAD of $21.9 million presented by TECO represents the average of all these simulations. The analysis includes all storm categories in the EAD. The EAD for all levels of storms is $21.9 million per year, with a $17.6 million average expected charge to the reserve. Over the 2000-2012 time frame, TECO has charged $79 million (in total) to the reserve, as shown in **Exhibit___ (JP-10)**. This equates to an annual average charge to the reserve of less than $6.1 million. The 2004 Hurricanes (Charley, Francis, and Jeanne) account for $74 million of this total. The average annual charges to the storm reserve excluding the 2004 hurricanes have been $0.4 million. The 2000 – 2012 period falls in a timeframe with increased hurricane activity as recognized by the National Oceanic and Atmospheric Administration (NOAA).[34]

Q IS THERE ANY OTHER ISSUE WITH HOW THE EAD WAS CALCULATED?

A Yes. TECO has indicated that the EAD calculation did not include consideration for storm hardening since no major storm has occurred since the storm hardening program was implemented in 2004.[35] One would expect the expenditures dedicated to this program to reduce storm damage. However, the EAD calculation omits these benefits and made no assumptions that the result of TECO's storm hardening efforts should result in less damage when a major storm strikes TECO's service territory, all things being equal, as compared to the damage that could be expected before the storm hardening efforts were undertaken. This is an assumption that I believe is a reasonable one to make, and is supported by a factual predicate as described below.

Q WHAT IS THE SOURCE OF THE EXPECTATIONS THAT THE STORM HARDENING PROGRAM WOULD REDUCE STORM DAMAGE?

A The Direct Testimony of Beth Young (page 27) includes the following:

> Q You have discussed the reliability of the T&D system and steps you have taken to improve reliability and strengthen the system. What impact do these steps have on restoration after a major storm event?
>
> A These steps reduce the amount of damage, reduce the number of outages and reduce the overall restoration time for Tampa Electric's system for a major storm event.

TECO has projected spending $54 million in 2014 on storm hardening initiatives so one would expect reduced storm damages as a benefit of these initiatives.[36]

Q WHAT IS THE LIKELIHOOD THAT TECO WOULD INCUR DAMAGE IN EXCESS OF THE CURRENT $64 MILLION TARGET RESERVE?

A TECO analyzed the Aggregate Damage Exceedance Probabilities for various damage levels up to and in excess of $360 million.[37] According to TECO's study, there is an 8.68% probability that there will be damage in any one year that exceeds $60 million. In other words, a storm inflicting damage in an amount of approximately $60 million is likely to occur only once every 11.5 years.

Q WHAT RESULTS DOES THE STUDY SHOW FOR CATEGORY 1 AND 2 HURRICANES?

A On average, the most destructive Category 1 storm would cause mean damage of slightly less than $45 million.[38] The damage from the most severe Category 2 storm would cause mean damage of less than $120 million.[39]

Q **IS IT NECESSARY TO SET THE STORM RESERVE TO COVER THE COSTS OF ALL TROPICAL STORMS OR HURRICANES REGARDLESS OF THE LEVEL OF SUCH STORMS?**

A No. The storm reserve and associated accrual are only part of the framework for recovering storm restoration costs. The Commission has demonstrated its ability and willingness to promptly consider and act upon a utility's request to recover storm costs. As such, the storm reserve need not cover all storms. To do so would impose an unnecessary added burden on customers.

Rather, what is needed is a reasonable accrual and a reasonable reserve designed to cover the expected damage from the more common (but not all) storm events. In this instance, TECO is seeking to establish the reserve at a level designed to provide for coverage for all storm damage. Such a "worst case" approach is only necessary if the storm reserve and associated accrual are the only means by which a utility is able to obtain coverage for damages from storms.

Q **DO TECO'S CUSTOMERS BENEFIT FROM A HIGHER RESERVE TARGET?**

A No. As explained above, the current $8 million contribution and the current storm reserve target of $64 million are more than sufficient to cover all but the most severe storms. Finally, the risk of non-recovery for storm damage restoration costs will remain with customers because if a catastrophic storm or storms strike TECO's service territory, customers will be surcharged to allow TECO to recover restoration in excess of the storm reserve balance.

Q **IS AN INCREASE IN THE RESERVE NECESSARY TO MAINTAIN THE STATUS QUO?**

A No. The current reserve balance is sufficient to cover all Category 1 hurricanes, as well as all but the most severe Category 2 hurricanes. In fact, at the EAD chargeable to the reserve each year, the reserve balance is sufficient to provide coverage for almost three years. Thus, it is not necessary to increase the current target level, and in fact, it would be sufficient for some years even if the accruals were stopped.

Q WHAT WOULD BE THE IMPACT ON THE STORM RESERVE IF ACCRUALS WERE STOPPED ENTIRELY?

A Over time, the level of the reserve will decline. However, absent a direct strike in the most populated portion of TECO's service territory, the current reserve balance may be sufficient to cover the EAD funded from the reserve for a number of years. If losses remain at the levels experienced over the 2005-2012 period, the current reserve is more than capable of supporting storm recovery for several years, without any further customer contributions.

Q SHOULD THE COMPANY REVISE ITS STORM RESERVE ANALYSIS IN THE NEXT RATE CASE?

A Yes. Since the present analysis addresses all manner and strength of storms up to and including the most severe and damaging storms and excludes any benefits of the storm hardening program, the Commission should require that any subsequent study consider alternative levels of storm damage. Any subsequent study should evaluate the reserve performance taking into account only Category 1 (and potentially Category 2) storms. This approach gives recognition to the framework for addressing storm restoration costs – which recognizes that the annual accrual and reserve balance are not intended to cover the most destructive storms. A future analysis should also expressly consider in detail how storm hardening efforts have reduced the risk of damage from hurricane or tropical storm events and the need to accrue monies for storm reserves.

Q PLEASE SUMMARIZE YOUR RECOMMENDATION.

A The storm reserve target should not be increased. The current reserve balance is sufficient to provide for coverage of the EAD funding from the reserve and also provides coverage for all Category 1 storms. Thus, TECO should stop accruing to the storm reserve. A revised study should be submitted when TECO next files a rate case or seeks to re-institute the storm reserve accrual and collection that shows what an appropriate reserve target is assuming coverage of *most* (Category 1 and 2) storms instead of *all* levels of storms.

Q DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A Yes.

Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS, AND OCCUPATION.

A. My name is Steve W. Chriss. My business address is 2001 SE 10th St., Bentonville, AR 72716-0550. I am employed by Wal-Mart Stores, Inc. ("Walmart") as Senior Manager, Energy Regulatory Analysis.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS DOCKET?

A. I am testifying on behalf of the Florida Retail Federation ("FRF"), a statewide trade association of more than 8,000 of Florida's retailers, many of whom are retail customers of Tampa Electric Company ("TECO").

Q. PLEASE DESCRIBE YOUR EDUCATION AND EXPERIENCE.

A. In 2001, I completed a Masters of Science degree in Agricultural Economics at Louisiana State University. From 2001 to 2003, I was an Analyst and later a Senior Analyst at the Houston office of Econ One Research, Inc., a Los Angeles-based consulting firm. My duties included research and analysis on domestic and international energy and regulatory issues. From 2003 to 2007, I was an Economist and later a Senior Utility Analyst at the Public Utility Commission of Oregon in Salem, Oregon. My duties included appearing as a witness for PUC Staff in electric, natural gas, and telecommunications dockets. I joined the energy department at Walmart in July 2007 as Manager, State Rate Proceedings, and was promoted to my current position in June 2011. My Witness Qualifications Statement is included herein as Exhibit SWC-1.

Q. HAVE YOU PREVIOUSLY SUBMITTED TESTIMONY BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION ("COMMISSION")?

A. Yes. I submitted testimony in Docket Nos. 110138-EI, the 2011 Gulf Power Company ("Gulf") general rate case, and 120015-EI, the 2012 Florida Power & Light Company ("FP&L") general rate case.

Q. HAVE YOU PREVIOUSLY SUBMITTED TESTIMONY BEFORE OTHER STATE REGULATORY COMMISSIONS?

A. Yes. I have submitted testimony in over 75 proceedings before 31 other utility regulatory commissions and before the Missouri House Committee on Utilities and the Missouri Senate Committee on Veterans' Affairs, Emerging Issues, Pensions, and Urban Affairs. My testimony has addressed many subjects, including cost of service and rate design, ratemaking policy, qualifying facility rates, telecommunications deregulation, resource certification, energy efficiency, conservation, and demand side management, fuel cost adjustment mechanisms, decoupling, and the collection of cash earnings on construction work in progress.

Q. ARE YOU SPONSORING ANY EXHIBITS WITH YOUR TESTIMONY?

A. Yes. I am sponsoring the following exhibits to my testimony:

Exhibit SWC-1: Witness Qualifications Statement of Steve W. Chriss

Exhibit SWC-2: Calculation of Test Year Jurisdictional Revenues Collected through Base Rates

Exhibit SWC-3: Reported Authorized Returns on Equity, Electric Utility Rates Cases Completed in 2012 and 2013

Q. **WHAT IS THE PURPOSE OF YOUR TESTIMONY?**

A. The purpose of my testimony is to provide a customer perspective on TECO's proposed rate increase and to explain the FRF's concerns regarding the Company's return on equity ("ROE") and rate base proposals.

Q. **PLEASE SUMMARIZE YOUR RECOMMENDATIONS TO THE COMMISSION.**

A. My recommendations to the Commission are as follows:

1) The Commission should reject TECO's request to include $174.1 Million of CWIP in rate base. If, however, the Commission determines it necessary to include any CWIP in rate base, it should ensure that the shift of risk from the Company to ratepayers through the inclusion of CWIP in rate base is reflected in the ROE approved in this docket, such that as the level of CWIP is increased from zero, ROE is accordingly reduced.

2) In setting the ROE for TECO, the Commission should closely examine the Company's proposed revenue increase in light of what appears to be an excessive proposed return on equity and the risk reduction due to the collection of over half of the Company's jurisdictional revenues outside of base rates, the Company's use of a projected test year, and the Company's proposal to include CWIP in rate base.

3) The Commission should carefully consider the impacts of any increase on customers.

The fact that an issue is not addressed should not be construed as an endorsement of any filed position.

Q. GENERALLY, WHY ARE UTILITY CUSTOMERS, INCLUDING RETAILERS AND OTHER COMMERCIAL CUSTOMERS, CONCERNED ABOUT TECO'S PROPOSED RATE INCREASE?

A. Electricity represents a significant portion of retailers' operating costs. When rates increase, that increase in cost to retailers puts pressure on consumer prices and on the other expenses required by a business to operate, which impacts retailers' customers and employees. Rate increases also directly impact retailers' customers, who are also TECO's residential and small business customers. FRF recognizes TECO's duty to provide reliable and adequate service to its customers and that there are costs required to do so, including a reasonable return on the Company's used and useful capital investments. However, given current economic conditions, a rate increase is a serious concern for retailers and their customers and the Commission should consider these impacts thoroughly and carefully in ensuring that any increase in TECO's rates is only the minimum amount necessary to provide adequate and reliable service at the lowest possible cost.

Q. WHAT REVENUE REQUIREMENT INCREASE HAS THE COMPANY PROPOSED IN ITS FILING?

A. The Company has proposed a total base rate revenue requirement increase of approximately $134.8 million. *See* MFR Schedule A-1. The Company's proposed increase includes base rate increases of approximately $133.6 million per year and increases in service charges and fees of approximately $1.2 million per year. *See* Tampa Electric's Petition at page 6.

Q. WHAT IS THE COMPANY'S PROPOSED ROE IN THIS DOCKET?

A. The Company is proposing an after-tax ROE of 11.25 percent and a range of 10.5 percent to 11.5 percent. *See* Direct Testimony of Robert B. Hevert, page 3, line 17 to line 21. Applying the Company's proposed Net Operating Income multiplier (1.6322, from MFR A-1) to this return indicates that TECO is requesting a before-tax ROE of 18.36 percent.

Q. IS FRF CONCERNED THAT THE PROPOSED ROE IS EXCESSIVE?

A. Yes. FRF is concerned that the Company's proposed ROE is excessive, especially given the current economic conditions faced by the utility's customers, as well as when viewed in light of (1) the percentage of jurisdictional revenues collected through base rates relative to the percentage of the Company's costs that are recovered through cost recovery rider charges, such as Fuel and Purchased Power Cost Recovery, Environmental Cost Recovery, and Energy Conservation Cost Recovery, (2) the use of a projected test year, and (3) the Company's proposal to include $174.1 million of CWIP in rate base. Finally, the proposed ROE is significantly higher than ROEs recently approved by the Commission and by other commissions nationwide.

Q. FOR THE COMPANY'S PROPOSED 2014 TEST YEAR, WHAT PERCENT OF JURISDICTIONAL REVENUES ARE PROPOSED TO BE COLLECTED THROUGH BASE RATES?

A. Only 48.8 percent, or less than half of TECO's jurisdictional revenues for the proposed 2014 test year, would be collected through base rates and would be essentially at risk due to forecast error or regulatory lag. *See* Exhibit SWC-2. As such, over half of the Company's revenues would be collected outside of base rates through cost recovery rider charges that are reset annually.

Q. ARE THERE ANY OTHER FACETS OF THE COMPANY'S PROPOSAL IN THIS DOCKET THAT COULD REDUCE TECO'S EXPOSURE TO REGULATORY LAG?

A. Yes. The use of a projected test year reduces the risk due to regulatory lag because, as the Commission has previously stated, "the main advantage of a projected test year is that it includes all information related to rate base, NOI, and capital structure for the time new rates will be in effect." *See* Order No. PSC-02-0787-FOF-EI, page 9. As such, the Commission should carefully consider the level of ROE justified by the Company's reduced exposure to regulatory lag.

Q. DOES THE COMPANY PROPOSE TO INCLUDE CONSTRUCTION WORK IN PROGRESS ("CWIP") IN ITS RATE BASE?

A. Yes. The Company has proposed to include approximately $174.1 million of CWIP in rate base. *See* MFR Schedule B-1, page 1. This is an increase of approximately $53 million from the CWIP included in rate base for projected prior year 2013. *See* MFR Schedule B-1, page 2.

Q. IS THE INCLUSION OF CWIP IN RATE BASE OF CONCERN TO FRF?

A. Yes. The inclusion of CWIP in rate base charges ratepayers for assets that are not used and useful in the provision of electric service. Under the Company's proposal ratepayers would pay for the assets during a period when they are not receiving any benefits from those assets, so the matching principle (*i.e.* customers bearing costs only when they are receiving a benefit) is not satisfied. In this case, TECO's customers in 2014, the test year that the Company chose for its rate increase request, would pay for assets that do not provide service yet – i.e., assets that are not used and useful – during that test year. The problem is compounded by changes in the number of customers during the construction process. For example, customers may pay for the assets during construction but leave the system before they are operational, receiving no benefit from the assets for which they helped pay.

Q. IS THERE ANOTHER CONCERN WITH THE INCLUSION OF CWIP IN RATE BASE THAT THE COMMISSION SHOULD CONSIDER?

A. Yes. Including CWIP in rate base shifts the risks traditionally assumed by investors, for which they are compensated through the rate of return elements once the plant is in service, and instead places the risks squarely on the shoulders of ratepayers with no offer of compensation. Additionally, should the Company encounter problems during construction of the plant resulting in stoppage of the construction, non-completion of the project and/or substantial delay in the completion of the project, consumers have no recourse for recovering the money they have paid for the inclusion of CWIP in rate base.

Q. WHAT IS YOUR UNDERSTANDING OF HOW, UNDER TRADITIONAL REGULATORY PRACTICES, TECO WOULD RECOVER THE COSTS OF THE ASSETS THAT WILL, ACCORDING TO TECO, BE UNDER CONSTRUCTION BUT NOT COMPLETED DURING THE COMPANY'S CHOSEN TEST YEAR?

A. Under traditional regulatory practices, TECO would add the assets to its rate base accounts if and when they were completed. They would then be reflected in the rate base and depreciation accounts in TECO's earnings surveillance reports and would, other things equal, lower TECO's achieved ROE. If and when TECO's earnings (i.e., its ROE) were to fall to a level that TECO believed was insufficient to enable it to provide adequate and reliable service, TECO would ask for a rate increase that would include the value of the assets in some future test year.

Q. WHAT IS FRF'S RECOMMENDATION TO THE COMMISSION REGARDING THE INCLUSION OF CWIP IN RATE BASE?

A. The Commission should reject TECO's request to include $174.1 Million of CWIP in rate base. If, however, the Commission determines it necessary to include any CWIP in rate base, it should ensure that the shift of risk from the Company to ratepayers through the inclusion of CWIP is reflected in the ROE approved in this docket, such that as the level of CWIP is increased from zero, ROE is accordingly reduced.

Q. WHAT IS YOUR UNDERSTANDING OF THE RETURNS ON EQUITY RECENTLY APPROVED BY THE COMMISSION?

A. My understanding is that the Commission approved a ROE of 10.25 percent for Gulf in Docket No. 110138-EI and a ROE of 10.5 percent for FP&L in Docket No. 120015-EI. *See* Order No. PSC-12-0179-FOF-EI, April 12, 2012, page 52 and Order No. PSC-13-0023-S-EI, page 5. Both of these are significantly lower than TECO's proposed ROE of 11.25 and, as I will discuss in more detail below, the FP&L ROE was the highest ROE awarded nationwide after January, 2012. *See* Exhibit SWC-3.

Q. WHAT IS YOUR UNDERSTANDING OF THE RETURNS ON EQUITY APPROVED BY COMMISSIONS NATIONWIDE IN 2012 AND IN 2013 THUS FAR?

A. According to data from SNL Financial, a financial news and reporting company, the average of the 65 reported electric utility rate case ROEs authorized by commissions to investor-owned electric utilities in 2012 and so far in 2013 is 9.97 percent. The range of reported authorized ROEs for the period is 9.00 percent to 10.5 percent, and the median authorized ROE is 10 percent. *Id.*, page 2. Both the average and median values are significantly below the Company's proposed ROE of 11.25 percent and even below 10.5 percent, the low end of the Company's proposed range. *See* Direct Testimony of Robert B. Hevert, page 3, line 17 to line 21.

Q. SEVERAL OF THE REPORTED AUTHORIZED ROES ARE FOR DISTRIBUTION-ONLY UTILITIES OR FOR ONLY THE UTILITY'S DISTRIBUTION SERVICE RATES. WHAT IS THE AVERAGE AUTHORIZED ROE IN THE REPORTED GROUP FOR THE VERTICALLY INTEGRATED UTILITIES?

A. In the group reported by SNL Financial, the average authorized ROE for vertically integrated utilities is 10.05 percent. *See* Exhibit SWC-3, page 2. This is essentially equal to the 9.97 percent value for the total group, and still significantly below TECO's request.

Q. HAS THE COMMISSION FOUND THAT AUTHORIZED ROES FROM COMMISSIONS IN OTHER JURISDICTIONS SERVE AS A GAUGE TO TEST THE REASONABLENESS OF A UTILITY'S ROE?

A. Yes. *See* Order No. PSC-12-0179-FOF-EI, April 12, 2012, page 52. As such, while FRF recognizes that the ROE approved for TECO in this docket will be based on an independent assessment of the testimony and evidence in the record, FRF supports the use of ROE decisions from other jurisdictions as a gauge to test the reasonableness of the ROE to be used in setting TECO's retail rates.

Q. WHAT IS YOUR RECOMMENDATION TO THE COMMISSION REGARDING RETURN ON EQUITY?

A. In setting the ROE for TECO, the Commission should closely examine the Company's proposed revenue increase in light of what appears – specifically in light of recent decisions by this Commission and by many other state regulatory commissions – to be an excessive proposed return on equity and the risk reduction due to the collection of over half of the Company's jurisdictional revenues outside of base rates, the Company's use of a projected test year, and the Company's proposal to include CWIP in rate base. The Commission should also carefully consider the impacts of any increase on all customers.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

In Re: Petition for Rate Increase by Tampa Electric Company	**Docket No. 130040-EI**

Direct Testimony of Michael P. Gorman

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A Michael P. Gorman. My business address is 16690 Swingley Ridge Road, Suite 140, Chesterfield, MO 63017.

Q WHAT IS YOUR OCCUPATION?

A I am a consultant in the field of public utility regulation and a Managing Principal of Brubaker & Associates, Inc., energy, economic and regulatory consultants.

Q PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

A This information is included in Appendix A to my testimony.

Q ON WHOSE BEHALF ARE YOU APPEARING IN THIS PROCEEDING?

A I am appearing in this proceeding on behalf of the Federal Executive Agencies ("FEA").

Q ARE YOU SPONSORING ANY EXHIBITS IN CONNECTION WITH THIS TESTIMONY?

A Yes. I am sponsoring Exhibit MPG-2 through Exhibit MPG-22.

Q WHAT IS THE SUBJECT OF YOUR DIRECT TESTIMONY?

A In my testimony I make several recommendations concerning Tampa Electric Company's ("Tampa Electric" or "Company") rate filing in this proceeding. These recommendations include the following:

1. I recommend a fair overall rate of return and return on common equity used to set Tampa Electric's revenue requirement in this proceeding.
2. I recommend an adjustment to the residential sales revenue at current rates.

SUMMARY

Q PLEASE SUMMARIZE YOUR RATE OF RETURN RECOMMENDATIONS.

A I recommend the Florida Public Service Commission (the "Commission") award Tampa Electric a return on common equity of 9.25%, and an overall rate of return of 5.66~~5~~%. Exhibit MPG-1.

My recommended overall rate of return also reflects a revised synchronization of rate base and capital structure used to develop the overall rate of return. The Company's proposed capital structure allocates rate base pro forma additions across all capital components, both investor capital and ratepayer-supplied capital, in proportion to their mix of the overall capital. In my proposed capital structure, I allocate all customer-supplied capital to the capital structure used to develop rates and allocate the pro forma rate base adjustments across only investor capital components. This revised allocation provides a direct allocation of customer-supplied capital to the development of Tampa Electric's cost of providing utility service to those same customers. In significant contrast, the Company's proposal retains a portion of customer-supplied zero-cost capital components for benefit of its investors, rather than passing the full benefits of zero-cost customer-supplied capital to development of the overall rate of return in this proceeding.

Q WILL YOUR OVERALL RATE OF RETURN SUPPORT TAMPA ELECTRIC'S CURRENT FINANCIAL INTEGRITY AND INVESTMENT GRADE BOND RATING?

A Yes. My recommended return on equity and proposed capital structure will provide Tampa Electric with an opportunity to realize cash flow financial coverages and balance sheet strength that conservatively support Tampa Electric's current bond rating. Consequently, my recommended return on equity represents fair compensation for Tampa Electric's investment risk, and it will preserve the Company's financial integrity and credit standing.

Q WILL YOU RESPOND TO TAMPA ELECTRIC WITNESS MR. ROBERT HEVERT'S RECOMMENDED OVERALL RATE OF RETURN IN THIS PROCEEDING?

A Yes. I will also respond to Mr. Hevert's proposed return on equity of 11.25%. For the reasons discussed below, Mr. Hevert's recommended return on equity is excessive and should be rejected.

Q **HOW DID YOU ESTIMATE TAMPA ELECTRIC'S CURRENT MARKET COST OF EQUITY?**

A I performed analyses using three Discounted Cash Flow ("DCF") models, a Risk Premium study, and a Capital Asset Pricing Model ("CAPM"). These analyses used a proxy group of publicly traded companies that have investment risk similar to Tampa Electric. Based on the results from these assessments, I estimate Tampa Electric's current market cost of equity to be 9.25%.

Q **WHAT IS THE IMPACT ON TAMPA ELECTRIC'S REVENUE REQUIREMENT BASED ON YOUR RECOMMENDED RETURN ON EQUITY AND CAPITAL STRUCTURE ADJUSTMENT?**

A The Florida revenue requirement impact of my recommended 9.25% return on equity and revised capital structure is $73.6~~75.5~~ million.

Q **PLEASE SUMMARIZE YOUR PROPOSED ADJUSTMENT TO RESIDENTIAL SALES REVENUE AT CURRENT RATES.**

A I am proposing an increase in residential sales revenue at current rates of $12.5 million. This adjustment reflects my assessment that Tampa Electric has understated the amount of sales for the 2014 test year for an increased number of residential customers.

RATE OF RETURN

Q HOW DOES YOUR RECOMMENDED RETURN ON EQUITY COMPARE TO TAMPA ELECTRIC'S LAST AUTHORIZED RETURN ON EQUITY?

A On April 30, 2009, the Commission issued its final order in Docket No. 080317-EI general rate case, which included a return on equity of 11.25%.[1]

My recommended return on equity is lower in this case than the return on equity authorized in Tampa Electric's last rate case in April 2009. My recommended return on equity is lower in this case because capital market costs today are much lower than they were in 2009 when Tampa Electric's last rate of return was approved.

Q PLEASE DESCRIBE THE DECLINE IN CAPITAL MARKET COSTS SINCE TAMPA ELECTRIC'S LAST RATE CASE.

A The decline in capital market costs is illustrated by a comparison of bond yields in this case and the last case, and is evident from cost of capital estimates in this case versus the last case. In Table 1, I show the change in utility bond yields.

[1]Docket No. 080317-EI, Order No. PSC-09-0283-FOF-EL, April 30, 2009 at 48.

TABLE 1

Capital Costs – Tampa Electric Rate Cases

Description	Current Case*	Docket No. 080317-EI	Yield Change
"A" Rated Utility Bond Yields	4.19%	6.44%	(2.25%)
"Baa" Rated Utility Bond Yields	4.69%	7.97%	(3.28%)
13-Week Period Ending	06/21/2013	04/30/2009	

Source:

*Exhibit MPG-14, page 1.

Tampa Electric's current Standard & Poor's ("S&P") and Moody's bond ratings are "BBB+" and "A3," respectively. As shown in the table above, the current market cost of debt for "A" (by S&P) and "Baa" (by Moody's) rated utility bond yields has significantly decreased in this case relative to Tampa Electric's last rate case. The current "A" and "Baa" rated utility bond yields are approximately 200 and 300 percentage points lower, respectively, now than they were in Tampa Electric's last rate case.

The material decline in utility bond yields is observable market evidence that capital market costs today are significantly lower than they were during the time of Tampa Electric's last rate case. My recommended return on equity reflects this material decline to capital market costs for relatively low risk regulated electric utility companies like Tampa Electric.

Electric Utility Industry Market Outlook

Q PLEASE DESCRIBE THIS SECTION OF YOUR TESTIMONY.

A I begin my estimate of a fair return on equity for Tampa Electric by reviewing the market's assessment of electric utility industry investment risk, credit standing, and stock price performance in general. I used this information to get a sense of the market's perception of the risk characteristics of electric utility investments in general, which is then used to produce a refined estimate of the market's return requirement for assuming investment risk similar to Tampa Electric's utility operations.

Based on the assessments described below, I find the credit rating outlook of the industry to be strong and supportive of the industry's financial integrity, and electric utilities' stocks have exhibited strong price performance over the last several years.

Further, the electric utility industry in general is in a large capital expenditure portion of its cycle, which is creating significant demands for external capital in order to support large capital improvement programs. Credit rating agencies and market participants have embraced the utilities' need for significant amounts of external capital by meeting the capital market demands of electric utilities at near historical low capital market costs. All of this supports my belief that Tampa Electric should have sufficient access to capital to support its major capital program, and relatively moderate capital costs are currently available and expected to be available for the next several years.

Based on this review of credit outlooks and stock price performance, I conclude that the market continues to embrace the electric utility industry as a safe-haven investment, and views utility equity and debt investments as low-risk securities.

Q PLEASE DESCRIBE ELECTRIC UTILITIES' CREDIT RATING OUTLOOK.

A Electric utilities' credit rating outlook has improved over the recent past and is stable. S&P recently provided an assessment of the credit rating of U.S. electric utilities. S&P's commentary included the following:

> **Effect on ratings**
>
> Notwithstanding the slow economic recovery, credit quality in the domestic utility industry has continued a long shift to greater stability, and even modest improvement in some cases, especially as many companies re-emphasize their core competencies.
>
> * * *
>
> **Industry Ratings Outlook**
>
> **Good access to funding expected to continue**
>
> Liquidity is adequate for most utilities and investor appetite for utility debt remains healthy, with deals continuing to be oversubscribed at very attractive rates. The amount of medium- to long-term debt and hybrid securities issued through the three months ended March 31, 2013 was about $8.7 billion. <u>Credit fundamentals indicate that most, if not all, utilities should continue to have ample access to funding sources and credit</u>. The relative certainty of financial performance provided by the regulatory framework under which utilities operate, their effective monopoly position, long-lived assets, and the financing necessary to fund

these assets are all factors that make the utility sector attractive to investors. These elements have also helped utilities more effectively manage their rate-relief needs and mitigate the effect of sizable rate increases on customers.[2]

Similarly, Fitch states:

Rating Outlook

Flat Growth Base Case: Fitch Ratings expects overall <u>stable</u> ratings for issuers within the U.S. Power and Gas Utility sector in 2013 despite modest deterioration in operating environment.

* * *

Stable Regulation but Authorized ROEs Trending Down

<u>Fitch expects the downward pressure on authorized ROEs for regulated utilities to persist in tandem with falling interest rates in the economy.</u> Lower ROEs are also associated with features increasingly common in tariff structures that minimize cash flow volatility. Many state regulators are awarding lower ROEs as an offset to awarding special tariff mechanisms such as revenue decoupling, forward test year, rate-adjustment trackers[,] etc.

* * *

Strong Liquidity Conditions to Prevail

Fitch expects the power and gas utility sectors to continue to enjoy <u>strong capital market access</u>. Low interest rates due to

---

[2] *Standard & Poor's Ratings Direct*: "Industry Report Card: Stable-To-Modestly Improved Industry Outlook Supports Ratings For U.S. Regulated Electric, Gas, And Water Utilities," April 19, 2013 at 3-4 and 6-7, emphasis added.

accommodative monetary policies by the Fed continue to bring down the cost of debt for companies, which represents a significant expense item for the capital-intensive utility sector. Since 2006, interest expense has declined almost 150 bps for the typical utility holding company as financing costs for new debt issuance is at historic lows and these companies have unprecedented access to the capital and bank markets.[3]

The Edison Electric Institute ("EEI") also opined as follows:

Steady Industry Fundamentals

Indeed, broad global macroeconomic forces have been the principle [sic] driver of utility stock returns in recent years, relative to other market sectors. Investors now take mostly as a given the industry's reasonably strong business fundamentals. Utilities are undertaking sizeable and wide-ranging capital investment programs that include distribution network upgrades, Smart Grid investments, a significant boost in the pace of transmission investment, rising emissions-related capex driven by the need to comply with EPA regulations, and generation investments in select power markets.

* * *

Credit analysts are generally positive on the industry's ability to finance an aggressive pace of investment, noting that while it is now cash flow negative on an annual operating basis, its balance

[3] *FitchRatings*: "2013 Outlook: Utilities, Power, and Gas," December 7, 2012 at 1, 6-7 and 10, emphasis added.

sheets are generally strong and utilities have access to a diverse range of funding sources. The industry weathered the storm of the 2008/2009 financial crisis by postponing optional capex projects and finding cost savings where possible without jeopardizing service quality. Today's economic backdrop is much improved from that period, and with interest rates at multi-decade lows and investors of all types hungry for yield, the capital markets are wide open for most economic sectors, including utilities. The execution risk inherent in managing large, complex construction projects in a way that addresses the interests of both shareholders and regulators seems far more pronounced than financing risk.[4]

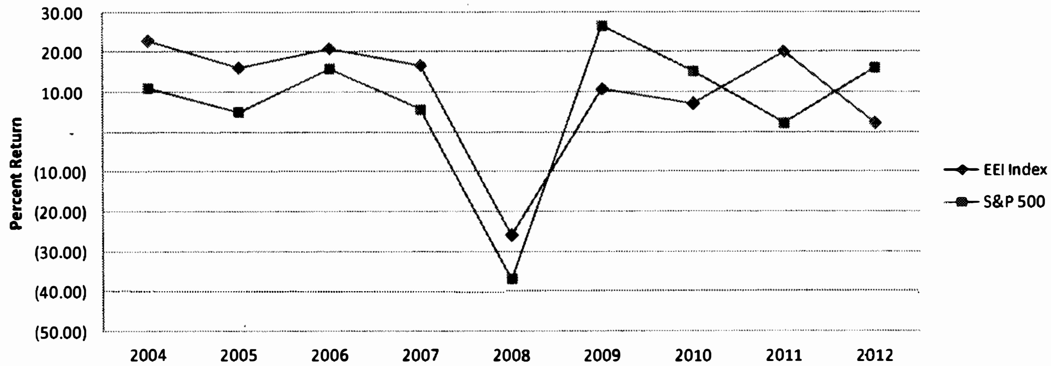
Q PLEASE DESCRIBE ELECTRIC UTILITY STOCK PRICE PERFORMANCE OVER THE LAST SEVERAL YEARS.

A As shown in the graph below, the EEI has recorded electric utility stock price performance compared to the market. The EEI data shows that its Electric Utility Index has outperformed the market in downturns and trailed the market during recovery. This supports my conclusion that utility stock investments are regarded by market participants as a moderate to low-risk investment.

[4] *EEI Q3 2012 Financial Update* "Stock Performance" at 5, emphasis added.

FIGURE 1

Index Comparison



Source: EEI Q4 2012 Stock Performance Financial Update, at Page 1.

EEI describes electric utility stock price/valuation as sustainable:

> **Mixed Valuation Signals**
>
> The broad market's gains during Q3 along with the EEI Index's flat performance removed some of the richness to utility share valuations that several analysts noted at the end of Q2. Indeed, the magnitude of underperformance for the first nine months of 2012 is similar to that which occurred during the same period of 2009, after markets bottomed and then recovered from the losses produced by the financial crisis. As the market recovery continued in 2010, with 14% to 17% gains, the staid utility sector's 7% return could not keep pace. Yet when 2011 produced worries of economic slowdown, the worsening of the European debt crisis and the summer's woefully memorable deficit gridlock and S&P downgrade of U.S. Treasury debt in August — along with sharply falling

> interest rates — the EEI Index powered forward with a 20% return against single-digit gains across the broader markets.
>
> With the industry business models now set on regulated or mostly regulated structures, and with slow growth in earnings and dividends as the main appeal for investors, such periodic reversals of fortune, driven by changing economic prospects and investor sentiments, seem likely to continue. Interest rates are now at multi-decade lows and while analysts still cite utility price/earnings ratios as above average, 4% dividend yields give utility shares considerable price support relative to the lower yields available from bonds.[5]

Q WHAT ARE THE IMPORTANT TAKEAWAY POINTS FROM THIS ASSESSMENT OF ELECTRIC UTILITY INDUSTRY CREDIT AND INVESTMENT RISK OUTLOOKS?

A Credit rating agencies consider the electric utility industry to be stable and believe investors will continue to provide an abundance of capital to support utilities' large capital programs and at moderate capital costs. All of this supports the continued belief that electric utility investments are generally regarded as safe-haven or low-risk investments, and the market embraces low-risk investments – like utility investments. The demand for low-risk investments will provide funding for electric utilities in general.

[5] *Id.* at 6, emphasis added.

Tampa Electric Investment Risk

Q PLEASE DESCRIBE THE MARKET'S ASSESSMENT OF THE INVESTMENT RISK OF TAMPA ELECTRIC.

A The market assessment of Tampa Electric's investment risk is best described by credit rating analysts' reports. Tampa Electric's current corporate bond ratings from S&P and Moody's are "BBB+" and "A3," respectively. Both rating agencies have a Stable outlook for Tampa Electric.[6]

Specifically, S&P states the following:

> **Rationale**
>
> Standard & Poor's Ratings Services bases its ratings on Tampa Electric Co. on the consolidated credit profile of parent company TECO Energy Inc. The ratings reflect the company's commitment to its credit quality after shedding some of its unregulated businesses, restoring its balance sheet, and focusing on better financial performance through regulatory initiatives and cost controls amid a difficult economy. The company's business profile is "excellent" and its financial risk profile is "significant". (See "Criteria Methodology: Business Risk/Financial Risk Matrix Expanded," published on May 27, 2009, on RatingsDirect.) TECO's business strategy centers on the operations of its high-quality electric and gas utilities in historically high-growth areas of Florida. The utilities effectively manage regulatory risk. Continued exposure to elevated business

[6]Callahan Direct at 15.

> risk in ventures outside of Florida, including coal-mining operations in Appalachia and electric generation overseas, detracts from credit quality. The utilities exhibit excellent credit characteristics: relatively healthy service territories, supportive regulation, and stable cash flow and earnings.
>
> * * *
>
> We view the company's regulatory risk as low. The electric utility supplies a large proportion of energy from its own portfolio of power plants, which is evenly divided between coal and gas-fired.[7]

Similarly, Moody's states:

> SUMMARY RATING RATIONALE
>
> TEC's A3 unsecured rating reflects its <u>stable</u> and <u>supportive regulatory</u> framework and strong financial credit metrics. The rating incorporates a view that the financial credit metrics will soften in 2013, before rate relief expected in early 2014.[8]

---

[7] *Standard & Poor's RatingsDirect*: "Summary: Tampa Electric Co.," December 13, 2012 at 1-2, provided by Tampa Electric in response to OPC's Fourth Request for PODs, POD No. 26, Bates Nos. 294-295.

[8] *Moody's Investors Service Credit Opinion*: "Tampa Electric Company," May 6, 2013, provided by Tampa Electric in response to OPC's Fourth Request for PODs, POD No. 26, Bates Nos. 303-304, emphasis added.

Fitch states:

> Key Rating Drivers
>
> Ratings Affirmed and Stable: Fitch Ratings affirmed the ratings of Tampa Electric Company (Tampa Electric) and its parent, TECO Energy, Inc. (TECO, issuer default rating [IDR] 'BBB') on March 23, 2012.
>
> * * *
>
> Strong Utility Operations: Tampa Electric's stand-alone financial and operational performance has been strong and supports the ratings. The utility has effectively managed operations and maintenance costs throughout the recession while continuing to safely operate the system. Financial results have been consistent, and benefited from both the cost savings efforts and the recent base rate increases.
>
> * * *
>
> Parent Ratings Linkage: Tampa Electric's ratings are linked to that of its parent, TECO, whose credit profile includes greater leverage and higher business risk.[9]

[9] *FitchRatings Corporates*: "Tampa Electric Company," April 16, 2012, provided by Tampa Electric in response to OPC's Fourth Request for PODs, POD No. 26, Bates No. 255.

Tampa Electric's Proposed Capital Structure

Q WHAT CAPITAL STRUCTURE IS THE COMPANY REQUESTING TO USE TO DEVELOP ITS OVERALL RATE OF RETURN FOR ELECTRIC OPERATIONS IN THIS PROCEEDING?

A Tampa Electric's December 2014 forecasted regulatory capital structure, as supported by Tampa Electric witness Ms. Sandra W. Callahan, is shown below in Table 2.

TABLE 2

Tampa Electric's Proposed Capital Structure

Description	Regulatory Capital Structure (1)	Investors' Capital Structure (2)
Long-Term Debt	35.15%	45.08%
Customer Deposits	2.60%	—
Common Equity	42.26%	54.19%
Short-Term Debt	0.57%	0.73%
Deferred Income Tax	19.24%	—
Investment Tax Credit	0.18%	—
Total Capital Structure	100.00%	100.00%

Source: MFR Schedule D-1a.

Q IS TAMPA ELECTRIC'S PROPOSED CAPITAL STRUCTURE REASONABLE?

A No. Tampa Electric's proposed capital structure misallocates customer-supplied capital in the development of the overall rate of return for jurisdictional operations. In reconciling its jurisdictional rate base with its jurisdictional capital structure, Tampa Electric allocates pro forma rate base adjustments to the capital structure by spreading these adjustments equally over both investor-supplied capital and customer-supplied capital.

Customer-supplied capital includes deferred taxes and customer deposits. Deferred taxes are a zero-cost capital component, and customer deposits have a relatively low interest rate as prescribed by the Commission. These low-cost customer-supplied capital components should be used exclusively to fund jurisdictional rate base. If they are not, then a portion of the customer-supplied low-cost capital components will be used to benefit investors rather than exclusively jurisdictional customers.

Q HOW DO YOU PROPOSE TO ADJUST THE COMPANY'S PROPOSED CAPITAL STRUCTURE?

A The Company develops its proposed capital structure on its Schedule D-1a, page 1. On that schedule under column 6, the Company proposes to spread its pro rata adjustments equally over investor capital and customer-supplied capital. I recommend to modify this spread of pro rata adjustments to only investor-supplied capital. All customer-supplied capital should be fully allocated to jurisdictional cost of service to ensure customers get full benefit of the low-cost capital they provide the Company.

I developed this revised capital structure on my Exhibit MPG-1. As shown on this exhibit, this revised capital structure mix produces a common equity ratio of total capital of 40.51~~35~~%. In comparison, the Company's proposed capital structure produces a common equity ratio of 42.26%. Again, the difference in capital structures reflects my recommendation to allocate 100% of the customer-supplied low-cost capital to jurisdictional cost of service.

Q **WHY SHOULD CUSTOMERS RECEIVE THE FULL BENEFIT OF CUSTOMER-SUPPLIED CAPITAL?**

A Customers should receive the full benefit of customer-supplied capital because this is actual cash proceeds provided to the Company from customers that have been retained by the Company to fund its invested cost of utility operations.

Accumulated deferred income taxes reflect the Company's collection of income tax expense, from customers that temporarily exceeds its current income tax liability.

As the Company's income tax liability comes due over time, the deferred tax collections will ultimately be paid to government taxing authorities. In the interim, the Company is permitted to retain the prepaid tax accruals as zero-cost capital which is used to fund plant and equipment.

Since customers provide the deferred tax proceeds, customers should receive a full benefit of the cost savings.

Customer deposits are also funds available to the Company to support its investment in utility plant and equipment. These funds do have a prescribed interest rate which is included in Tampa Electric's cost of service. Since customers provide this capital, and actually provide a return on the capital by recovery of customer deposit expense in Tampa Electric's cost of service, these funds should be fully reflected as a source of capital available to support Tampa Electric's invested capital cost.

Q **WHAT IS YOUR PROPOSED CAPITAL STRUCTURE IN THIS PROCEEDING?**

A My proposed capital structure is shown below in Table 3.

TABLE 3

Proposed Capital Structure

Description	Percent of Total Capital
Long-Term Debt	33.70~~8~~%
Customer Deposits	2.98~~9~~%
Common Equity	40.51~~35~~%
Short-Term Debt	0.545%
Deferred Income Tax	22.06~~12~~%
Investment Tax Credit	0.21%
Total Capital Structure	100.00%

Source: Exhibit MPG-1, page 1.

Q WILL YOUR PROPOSED CAPITAL STRUCTURE SUPPORT TAMPA ELECTRIC'S FINANCIAL INTEGRITY AND CREDIT RATING?

A Yes. As I will discuss later in my testimony, my proposed capital structure is consistent with Tampa Electric's current credit rating and will support Tampa Electric's financial integrity.

RETURN ON EQUITY

Q PLEASE DESCRIBE WHAT IS MEANT BY A "UTILITY'S COST OF COMMON EQUITY."

A A utility's cost of common equity is the return investors require on an investment in the utility. Investors expect to achieve their return requirement from receiving dividends and stock price appreciation.

Q PLEASE DESCRIBE THE FRAMEWORK FOR DETERMINING A REGULATED UTILITY'S COST OF COMMON EQUITY.

A In general, determining a fair cost of common equity for a regulated utility has been framed by two hallmark decisions of the U.S. Supreme Court: Bluefield Water Works & Improvement Co. v. Pub. Serv. Comm'n of W. Va., 262 U.S. 679 (1923) and Fed. Power Comm'n v. Hope Natural Gas Co., 320 U.S. 591 (1944).

These decisions identify the general standards to be considered in establishing the cost of common equity for a public utility. Those general standards provide that the authorized return should: (1) be sufficient to maintain financial integrity; (2) attract capital under reasonable terms; and (3) be commensurate with returns investors could earn by investing in other enterprises of comparable risk.

Q PLEASE DESCRIBE THE METHODS YOU HAVE USED TO ESTIMATE TAMPA ELECTRIC'S COST OF COMMON EQUITY.

A I have used several models based on financial theory to estimate Tampa Electric's cost of common equity. These models are: (1) a constant growth Discounted Cash Flow ("DCF") model using consensus analysts' growth rate projections; (2) a constant growth DCF using sustainable growth rate estimates; (3) a multi-stage growth DCF model; (4) a Risk Premium model; and (5) a Capital Asset Pricing Model ("CAPM"). I have applied these models to a group of publicly traded utilities that I have determined share investment risk similar to Tampa Electric's.

Risk Proxy Group

Q **HOW DID YOU SELECT A UTILITY PROXY GROUP SIMILAR IN INVESTMENT RISK TO TAMPA ELECTRIC TO ESTIMATE ITS CURRENT MARKET COST OF EQUITY?**

A I relied on the same utility proxy group used by Tampa Electric's witness Mr. Hevert to estimate Tampa Electric's return on equity.

Q **PLEASE DESCRIBE WHY YOU BELIEVE YOUR PROXY GROUP IS REASONABLY COMPARABLE IN INVESTMENT RISK TO TAMPA ELECTRIC.**

A The proxy group is shown in Exhibit MPG-2. This proxy group has an average corporate credit rating from S&P of "BBB," which is similar to S&P's corporate credit rating for Tampa Electric of "BBB+." The proxy group's corporate credit rating from Moody's of "Baa2" is also comparable to Tampa Electric's corporate credit rating from Moody's of "A3." The comparable bond rating indicates that the proxy group has reasonably comparable investment risk to Tampa Electric.

The proxy group has an average common equity ratio of 49.0% (including short-term debt) from SNL Financial ("SNL") and 51.9% (excluding short-term debt) from *The Value Line Investment Survey* ("*Value Line*") in 2012. The proxy group's common equity ratio is significantly lower than the 54.2% common equity ratio proposed by the Company.

I also compared Tampa Electric's business risk to the business risk of the proxy group based on S&P's ranking methodology. Tampa Electric has an S&P business risk profile of "Excellent," which is identical to the S&P business risk profile of the proxy group. The S&P business risk profile score indicates that

Tampa Electric's business risk is comparable to that of the proxy group.[10]

Based on these proxy group selection criteria, I believe that my proxy group reasonably approximates the investment risk of Tampa Electric, and can be used to estimate a fair return on equity for Tampa Electric.

Discounted Cash Flow Model

Q PLEASE DESCRIBE THE DCF MODEL.

A The DCF model posits that a stock price is valued by summing the present value of expected future cash flows discounted at the investor's required rate of return or cost of capital. This model is expressed mathematically as follows:

$$P_0 = \frac{D_1}{(1+K)^1} + \frac{D_2}{(1+K)^2} \; .... \; \frac{D_\infty}{(1+K)^\infty} \quad \text{where} \qquad \text{(Equation 1)}$$

P_0 = Current stock price

D = Dividends in periods 1 - ∞

K = Investor's required return

This model can be rearranged in order to estimate the discount rate or investor-required return, "K." If it is reasonable to assume that earnings and dividends will grow at a constant rate, then Equation 1 can be rearranged as follows:

[13] S&P ranks the business risk of a utility company as part of its corporate credit rating review. S&P considers total investment risk in assigning bond ratings to issuers, including utility companies. In analyzing total investment risk, S&P considers both the business risk and the financial risk of a corporate entity, including a utility company. S&P's business risk profile score is based on a six-notch credit rating starting with "Vulnerable" (highest risk) to "Excellent" (lowest risk). The business risk of most utility companies falls within the lowest risk category, "Excellent," or the category one notch lower (more risk), "Strong." *Standard & Poor's RatingsDirect:* "Criteria Methodology: Business Risk/Financial Risk Matrix Expanded," May 27, 2009.

$K = D_1/P_0 + G$ (Equation 2)

K = Investor's required return

D_1 = Dividend in first year

P_0 = Current stock price

G = Expected constant dividend growth rate

Equation 2 is referred to as the annual "constant growth" DCF model.

Q PLEASE DESCRIBE THE INPUTS TO YOUR CONSTANT GROWTH DCF MODEL.

A As shown in Equation 2 above, the DCF model requires a current stock price, expected dividend, and expected growth rate in dividends.

Q WHAT STOCK PRICE HAVE YOU RELIED ON IN YOUR CONSTANT GROWTH DCF MODEL?

A I relied on the average of the weekly high and low stock prices of the utilities in the proxy group over a 13-week period ending on June 21, 2013. An average stock price is less susceptible to market price variations than a spot price. Therefore, an average stock price is less susceptible to aberrant market price movements, which may not be reflective of the stock's long-term value.

A 13-week average stock price reflects a period that is still short enough to contain data that reasonably reflect current market expectations, but the period is not so short as to be susceptible to market price variations that may not reflect the stock's long-term value. In my judgment, a 13-week average stock price is a reasonable balance between the need to reflect current market expectations and the need to capture sufficient data to smooth out aberrant market movements.

Q WHAT DIVIDEND DID YOU USE IN YOUR CONSTANT GROWTH DCF MODEL?

A I used the most recently paid quarterly dividend, as reported in *Value Line*.[11] This dividend was annualized (multiplied by 4) and adjusted for next year's growth to produce the D_1 factor for use in Equation 2 above.

Q WHAT DIVIDEND GROWTH RATES HAVE YOU USED IN YOUR CONSTANT GROWTH DCF MODEL?

A There are several methods that can be used to estimate the expected growth in dividends. However, regardless of the method, for purposes of determining the market-required return on common equity, one must attempt to estimate investors' consensus about what the dividend or earnings growth rate will be, and not what an individual investor or analyst may use to make individual investment decisions.

As predictors of future returns, security analysts' growth estimates have been shown to be more accurate than growth rates derived from historical data.[12] That is, assuming the market generally makes rational investment decisions, analysts' growth projections are more likely to influence observable stock prices than growth rates derived only from historical data.

For my constant growth DCF analysis, I have relied on a consensus, or mean, of professional security analysts' earnings growth estimates as a proxy for investor consensus dividend growth rate expectations. I used the average of analysts' growth rate estimates from three sources: Zacks, SNL, and Reuters.

[11] *The Value Line Investment Survey*, May 3, May 24, and June 21, 2013.
[12] *See, e.g.,* David Gordon, Myron Gordon, and Lawrence Gould, "Choice Among Methods of Estimating Share Yield," *The Journal of Portfolio Management*, Spring 1989.

All such projections were available on June 24, 2013, and all were reported online.

Each consensus growth rate projection is based on a survey of security analysts. There is no clear evidence whether a particular analyst is most influential on general market investors. Therefore, a single analyst's projection does not as reliably predict consensus investor outlooks as does a consensus of market analysts' projections. The consensus estimate is a simple arithmetic average, or mean, of surveyed analysts' earnings growth forecasts. A simple average of the growth forecasts gives equal weight to all surveyed analysts' projections. Therefore, a simple average, or arithmetic mean, of analyst forecasts is a good proxy for market consensus expectations.

Q WHAT ARE THE GROWTH RATES YOU USED IN YOUR CONSTANT GROWTH DCF MODEL?

A The growth rates I used in my DCF analysis are shown in Exhibit MPG-3. The average growth rate for my proxy group is 5.22%.

Q WHAT ARE THE RESULTS OF YOUR CONSTANT GROWTH DCF MODEL?

A As shown in Exhibit MPG-4, the average and median constant growth DCF returns for my proxy group are 9.16% and 9.40%, respectively.

Q DO YOU HAVE ANY COMMENTS ON THE RESULTS OF YOUR CONSTANT GROWTH DCF ANALYSIS?

A Yes. The constant growth DCF analysis was based on a proxy group average growth rate of 5.22%. This growth rate is higher than the projected long-term

GDP growth rate of 4.9% as reflected in *The Blue Chip Financial Forecasts*. Because this short-term growth rate exceeds the long-term growth outlook for the U.S. economy, I believe the growth rate of the constant growth DCF analysis is not sustainable over the long term.

Therefore, I believe my constant growth DCF analysis, using consensus analysts' growth projections produces overstated results. Therefore, I have developed additional DCF studies to enhance the information available to accurately estimate Tampa Electric's current market cost of common equity.

Sustainable Growth DCF

Q. PLEASE DESCRIBE HOW YOU ESTIMATED A SUSTAINABLE LONG-TERM GROWTH RATE FOR YOUR SUSTAINABLE GROWTH DCF MODEL.

A. A sustainable growth rate is based on the percentage of the utility's earnings that is retained and reinvested in utility plant and equipment. These reinvested earnings increase the earnings base (rate base). Earnings grow when plant funded by reinvested earnings is put into service, and the utility is allowed to earn its authorized return on such additional rate base investment.

The internal growth methodology is tied to the percentage of earnings retained in the company and not paid out as dividends. The earnings retention ratio is 1 minus the dividend payout ratio. As the payout ratio declines, the earnings retention ratio increases. An increased earnings retention ratio will fuel stronger growth because the business funds more investments with retained earnings. The payout ratios of the proxy group are shown in my Exhibit MPG-5. These dividend payout ratios and earnings retention ratios then can be used to develop a sustainable long-term earnings retention growth rate. A sustainable long-term earnings retention ratio will help gauge whether analysts' current three- to five-year growth rate projections can be sustained over an indefinite period of time.

The data used to estimate the long-term sustainable growth rate is based on the Company's current market to book ratio and on *Value Line's* three- to five-year projections of earnings, dividends, earned returns on book equity, and stock issuances.

As shown in Exhibit MPG-6, page 1, the average sustainable growth rate for the proxy group using this internal growth rate model is 4.39%.

Q WHAT IS THE DCF ESTIMATE USING THESE SUSTAINABLE LONG-TERM GROWTH RATES?

A A DCF estimate based on these sustainable growth rates is developed in Exhibit MPG-7. As shown there, a sustainable growth DCF analysis produces proxy group average and median DCF results of 8.30 and 8.14%, respectively.

Multi-Stage Growth DCF Model

Q HAVE YOU CONDUCTED ANY OTHER DCF STUDIES?

A Yes. My first constant growth DCF is based on consensus analysts' growth rate projections, so it is a reasonable reflection of rational investment expectations over the next three to five years. The limitation on the constant growth DCF model is that it cannot reflect a rational expectation that a period of high/low short-term growth can be followed by a change in growth to a rate that is more reflective of long-term sustainable growth. Hence, I performed a multi-stage growth DCF analysis to reflect this outlook of changing growth expectations.

Q WHEN DO YOU BELIEVE SHORT-TERM GROWTH RATES CHANGE OVER TIME?

A Analyst projected growth rates over the next three to five years will change as utility earnings growth outlooks change. Utility companies typically go through cycles in making investments in their systems. When utility companies are making large investments, their rate base grows rapidly, which accelerates their earnings growth. Once a major construction cycle is completed or levels off, growth in the utility rate base slows, and its earnings slow from an abnormally high three- to five-year growth rate period to a lower sustainable growth rate.

As major construction cycles extend over longer periods of time, even with an accelerated construction program, the growth rate of the utility will slow simply because it is adding to a larger rate base, and the utility has limited human and capital resources available to expand its construction program. Hence, the three- to five-year growth rate projection should be used as a long-term sustainable growth rate but not without making a reasonable informed judgment to determine whether it considers the current market environment, the industry, and whether the three- to five-year growth outlook is sustainable.

Q IS THE USE OF A MULTI-STAGE DCF MODEL SUPPORTED IN ACADEMIC AND INDUSTRY LITERATURE?

A Yes. In his book *New Regulatory Finance*, Dr. Roger Morin states the following:

> Dividends need not be, and probably are not, constant from period to period. Moreover, there are circumstances where the standard DCF model cannot be used to assess investor return requirements. For example, if a utility company is in the process

> of altering its dividend payout policy and dividends are not expected to grow at the same rate as earnings during the transition period, the standard DCF model is inapplicable. This is because the expected growth in stock price has to be different from that of dividends, earnings, and book value if the market price is to converge toward book value.
>
> * * *
>
> A Non-Constant Growth DCF model is appropriate whenever the growth rate is expected to change, and the only way to produce a change in the forecast payout ratio is by introducing an intermediate growth rate that is different from the long-term growth rate, as in the previous example.[13]

Q PLEASE DESCRIBE YOUR MULTI-STAGE GROWTH DCF MODEL.

A The multi-stage growth DCF model reflects the possibility of non-constant growth for a company over time. The multi-stage growth DCF model reflects three growth periods: (1) a short-term growth period, which consists of the first five years; (2) a transition period, which consists of the next five years (6 through 10); and (3) a long-term growth period, starting in year 11 through perpetuity.

For the short-term growth period, I relied on the consensus analysts' growth projections described above in relationship to my constant growth DCF model. For the transition period, the growth rates were reduced or increased by an equal factor, which reflects the difference between the analysts' growth rates and the United States Gross Domestic Product ("U.S. GDP") growth rate. For

[13] *New Regulatory Finance*, Roger A. Morin, PhD, 2006 Public Utilities Reports, Inc., Vienna, Virginia, pp. 264 and 267.

the long-term growth period, I assumed each company's growth would converge to the maximum sustainable growth rate for a utility company as proxied by the consensus analysts' projected growth for the U.S. GDP of 4.9%.

Q WHY IS THE GDP GROWTH PROJECTION A REASONABLE PROXY FOR THE MAXIMUM SUSTAINABLE GROWTH RATE FOR A UTILITY?

A Utilities cannot indefinitely sustain a growth rate that exceeds the growth rate of the overall economy. Utilities' earnings/dividend growth is created by increased utility investment or rate base. Such investment, in turn, is driven by service area economic growth and demand for utility service. In other words, utilities invest in plant to meet sales demand growth, and sales growth, in turn, is tied to economic growth in their service areas. The Energy Information Administration ("EIA") has observed that utility sales growth is less than U.S. GDP growth, as shown in Exhibit MPG-8. Utility sales growth has lagged behind GDP growth for more than a decade. As a result, nominal GDP growth is a very conservative, albeit overstated, proxy for electric utility sales growth, rate base growth, and earnings growth. Therefore, GDP growth is a conservative proxy for the highest sustainable long-term growth rate of a utility.

Q IS THERE RESEARCH THAT SUPPORTS YOUR POSITION THAT, OVER THE LONG TERM, A COMPANY'S EARNINGS AND DIVIDENDS CANNOT GROW AT A RATE GREATER THAN THE GROWTH OF THE U.S. GDP?

A Yes. This concept is supported in both published analyst literature and academic work. Specifically, in a textbook entitled "Fundamentals of Financial Management," published by Eugene Brigham and Joel F. Houston, the authors state as follows:

> The constant growth model is most appropriate for mature companies with a stable history of growth and stable future expectations. Expected growth rates vary somewhat among companies, but dividends for mature firms are often expected to grow in the future at about the same rate as nominal gross domestic product (real GDP plus inflation).[14]

Q HOW DID YOU DETERMINE A SUSTAINABLE LONG-TERM GROWTH RATE THAT REFLECTS THE CONSENSUS OF THE MARKET?

A I relied on the consensus analysts' projections of long-term GDP growth. *The Blue Chip Financial Forecasts* publishes consensus economists' GDP growth projections twice a year. These consensus analysts' GDP growth outlooks are the best available measure of the market's assessment of long-term GDP growth. These analyst projections reflect all current outlooks for GDP, as reflected in analyst projections, and are likely the most influential on investors' expectations of future growth outlooks. The consensus economists' published GDP growth rate outlook is 5.0% to 4.8% over the next 10 years.[15]

Therefore, I propose to use the consensus economists' projected 5- and 10-year average GDP consensus growth rates of 5.0% and 4.8%, respectively, as published by *Blue Chip Financial Forecasts,* as an estimate of long-term sustainable growth. *Blue Chip Financial Forecasts'* projections provide real GDP

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[14] Fundamentals of Financial Management, Eugene F. Brigham and Joel F. Houston, Eleventh Edition 2007, Thomson South-Western, a Division of Thomson Corporation at 298.
[15] *Blue Chip Financial Forecasts*, June 1, 2013 at 14.

growth projections of 2.8% and 2.5%, and GDP inflation of 2.1% and 2.2%[16] over the 5-year and 10-year projection periods, respectively. This consensus GDP growth forecast represents the most likely views of market participants because it is based on published consensus economist projections.

Q DO YOU CONSIDER OTHER SOURCES OF PROJECTED LONG-TERM GDP GROWTH?

A Yes, and these sources corroborate my consensus analysts' projections. The U.S. EIA in its *Annual Energy Outlook* projects real GDP out until 2040. In its *2013 Annual Report*, the EIA projects real GDP through 2040 to be in the range of 2.0% to 2.9%, with a midpoint or reference case of 2.5%.[17]

Also, the Congressional Budget Office ("CBO") makes long-term economic projections. The CBO is projecting real GDP growth of 2.6% to 2.2% during the next 5 and 10 years, respectively, with GDP price inflation of 2.0%.[18] The CBO's real GDP projections are higher than the consensus, but its GDP inflation is lower than the consensus economists.

The real GDP and nominal GDP growth projections made by the U.S. EIA and those made by the CBO support the use of the consensus analyst 5-year and 10-year projected GDP growth outlooks as a reasonable market assessment of long-term prospective GDP growth.

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[16]GDP growth is the product of real and inflation GDP growth.
[17]*DOE/EIA Annual Energy Outlook 2013 With Projections to 2040*, April 2013 at 56.
[18]*CBO: The Budget and Economic Outlook: Fiscal Years 2013 to 2023*, February 2013 at 64.

Q **WHAT STOCK PRICE, DIVIDEND, AND GROWTH RATES DID YOU USE IN YOUR MULTI-STAGE GROWTH DCF ANALYSIS?**

A I relied on the same 13-week stock price and the most recent quarterly dividend payment data discussed above. For stage one growth, I used the consensus analysts' growth rate projections discussed above in my constant growth DCF model. The transition period begins in year 6 and ends in year 10. For the long-term sustainable growth rate starting in year 11, I used 4.9%, the average of the consensus economists' 5-year and 10-year projected nominal GDP growth rates.

Q **WHAT ARE THE RESULTS OF YOUR MULTI-STAGE GROWTH DCF MODEL?**

A As shown in Exhibit MPG-9, the average and median DCF returns on equity for my proxy group are both 8.89%.

Q **PLEASE SUMMARIZE THE RESULTS FROM YOUR DCF ANALYSES.**

A The results from my DCF analyses are summarized in Table 4 below:

TABLE 4

Summary of DCF Results

Description	Proxy Average/Median
Constant Growth DCF Model (Analysts' Growth)	9.16%/9.40%
Constant Growth DCF Model (Sustainable Growth)	8.30%/8.14%
Multi-Stage Growth DCF Model	8.89%/8.89%

I conclude that a reasonable DCF return for Tampa Electric in this case is conservatively 9.15%. I primarily relied on my constant growth DCF model and multi-stage growth DCF model in this case because I believe these models reflect the expectation of accelerated growth in the near term, followed by the contraction of growth to a long-term sustainable level. My constant growth study based on analysts' growth rate estimates suggests a return on equity in the range of 9.16% to 9.40%. For my multi-stage growth model, a return of approximately 8.89% or 8.90% rounded, is appropriate. The range for these two models is 8.90% to 9.40%, with a midpoint of 9.15%. This return estimate largely reflects my constant growth and multi-stage DCF analyses.

Risk Premium Model

Q PLEASE DESCRIBE YOUR BOND YIELD PLUS RISK PREMIUM MODEL.

A This model is based on the principle that investors require a higher return to assume greater risk. Common equity investments have greater risk than bonds because bonds have more security of payment in bankruptcy proceedings than common equity and the coupon payments on bonds represent contractual obligations. In contrast, companies are not required to pay dividends or guarantee returns on common equity investments. Therefore, common equity securities are considered to be more risky than bond securities.

This risk premium model is based on two estimates of an equity risk premium. First, I estimated the difference between the required return on utility common equity investments and U.S. Treasury bonds. The difference between the required return on common equity and the Treasury bond yield is the risk premium. I estimated the risk premium on an annual basis for each year over the period 1986 through 2012. The common equity required returns were based on regulatory commission-authorized returns for electric utility companies. Authorized returns are typically based on expert witnesses' estimates of the contemporary investor-required return.

The second equity risk premium estimate is based on the difference between regulatory commission-authorized returns on common equity and contemporary "A" rated utility bond yields. I selected the period 1986 through 2012 because public utility stocks consistently traded at a premium to book value during that period. This is illustrated in Exhibit MPG-10, which shows that the market to book ratio since 1986 for the electric utility industry was consistently above 1.0. Over this period, regulatory authorized returns were sufficient to support market prices that at least exceeded book value. This is an indication that regulatory authorized returns on common equity supported a utility's ability to issue additional common stock without diluting existing shares. It further demonstrates that utilities were able to access equity markets without a detrimental impact on current shareholders.

Based on this analysis, as shown in Exhibit MPG-11, the average indicated equity risk premium over U.S. Treasury bond yields has been 5.30%. Of the 27 observations, 21 indicated risk premiums fall in the range of 4.41% to 6.18%. Since the risk premium can vary depending upon market conditions and changing investor risk perceptions, I believe using an estimated range of risk premiums provides the best method to measure the current return on common equity using this methodology.

As shown in Exhibit MPG-12, the average indicated equity risk premium over contemporary Moody's utility bond yields was 3.89% over the period 1986 through 2012. The indicated equity risk premium estimates based on this analysis primarily fall in the range of 3.03% to 4.88% over this time period.

Q DO YOU BELIEVE THAT THESE EQUITY RISK PREMIUM ESTIMATES ARE BASED ON A TIME PERIOD THAT IS TOO LONG OR TOO SHORT TO DRAW ACCURATE CONCLUSIONS CONCERNING CONTEMPORARY MARKET CONDITIONS?

A No. Contemporary market conditions can change dramatically during the period that rates determined in this proceeding will be in effect. A relatively long period of time where stock valuations reflect premiums to book value is an indication that the authorized returns on equity and the corresponding equity risk premiums were supportive of investors' return expectations and provided utilities access to the equity markets under reasonable terms and conditions. Further, this time period is long enough to smooth abnormal market movement that might distort equity risk premiums. While market conditions and risk premiums do vary over time, this historical time period is a reasonable period to estimate contemporary risk premiums.

The time period I use in this risk premium study is a generally accepted period to develop a risk premium study using "expectational" data. Conversely, studies have recommended that use of "actual achieved return data" should be based on very long historical time periods. The studies find that achieved returns over short time periods may not reflect investors' expected returns due to unexpected and abnormal stock price performance. However, these short-term abnormal actual returns would be smoothed over time and the achieved actual returns over long time periods would approximate investors' expected returns.

Therefore, it is reasonable to assume that averages of annual achieved returns over long time periods will generally converge on the investors' expected returns.

My risk premium study is based on expectational data, not actual returns, and, thus, need not encompass very long time periods.

Q BASED ON HISTORICAL DATA, WHAT RISK PREMIUM HAVE YOU USED TO ESTIMATE TAMPA ELECTRIC'S COST OF COMMON EQUITY IN THIS PROCEEDING?

A The equity risk premium should reflect the relative market perception of risk in the utility industry today. I have gauged investor perceptions in utility risk today in Exhibit MPG-13. On that schedule, I show the yield spread between utility bonds and Treasury bonds over the last 33 years. As shown in this schedule, the 2011 utility bond yield spreads over Treasury bonds for "A" rated and "Baa" rated utility bonds are 1.13% and 1.65%, respectively. The utility bond yield spreads over Treasury bonds for "A" and "Baa" rated utility bonds for 2012 are 1.21% and 1.91%, respectively. The current average "A" and "Baa" rated utility bond yield spreads over Treasury bond yields are now lower than the 33-year average spreads of 1.56% and 1.98%, respectively.

A current 13-week average "A" rated utility bond yield of 4.19%, when compared to the current Treasury bond yield of 3.12% as shown in Exhibit MPG-14, page 1 implies a yield spread of around 1.00%. This current utility bond yield spread is lower than the 33-year average spread for "A" utility bonds of 1.56%. Similarly, the current spread for the "Baa" utility yields of 1.57% is lower than the 33-year average spread of 1.98%.

These utility bond yield spreads are clear evidence that the market considers the utility industry to be a relatively low-risk investment and demonstrates that utilities continue to have strong access to capital.

Q HOW DID YOU ESTIMATE TAMPA ELECTRIC'S COST OF COMMON EQUITY WITH THIS RISK PREMIUM MODEL?

A I added a projected long-term Treasury bond yield to my estimated equity risk premium over Treasury yields. The 13-week average 30-year Treasury bond yield, ending June 21, 2013 was 3.12%, as shown in Exhibit MPG-14, page 1. *Blue Chip Financial Forecasts* projects the 30-year Treasury bond yield to be 3.70%, and a 10-year Treasury bond yield to be 2.50%.[19] Using the projected 30-year bond yield of 3.70%, and a Treasury bond risk premium of 4.41% to 6.18%, as developed above, produces an estimated common equity return in the range of 8.11% (3.70% + 4.41%) to 9.88% (3.70% + 6.18%). Based on the large risk premium in the market yield spreads, I recommend giving 75% weight to my high-end risk premium and 25% weight to my low risk premium estimate. This produces an equity risk premium estimate of 9.44%.[20] I believe this is appropriate given the unusually large yield spreads between Treasury bond and utility bond yields.

I next added my equity risk premium over utility bond yields to a current 13-week average yield on "Baa" rated utility bonds for the period ending June 21, 2013 of 4.69%. Adding the utility equity risk premium of 3.03% to 4.88%, as developed above, to a "Baa" rated bond yield of 4.69%, produces a cost of equity in the range of 7.72% (4.69% + 3.03%) to 9.57% (4.69% + 4.88%). Again,

[19] *Blue Chip Financial Forecasts*, June 1, 2013 at 2.
[20] 75% x 9.88% + 25% x 8.11% = 9.44%.

recognizing the unusually wide Treasury to utility bond yield spreads, I recommend a risk premium return on equity of 9.11%.[21]

My risk premium analyses produce a return estimate in the range of 9.11% to 9.44%, with a midpoint of 9.28%, rounded to 9.30%.

Capital Asset Pricing Model ("CAPM")

Q PLEASE DESCRIBE THE CAPM.

A The CAPM method of analysis is based upon the theory that the market-required rate of return for a security is equal to the risk-free rate, plus a risk premium associated with the specific security. This relationship between risk and return can be expressed mathematically as follows:

$R_i = R_f + B_i \times (R_m - R_f)$ where:

R_i = Required return for stock i

R_f = Risk-free rate

R_m = Expected return for the market portfolio

B_i = Beta - Measure of the risk for stock

The stock-specific risk term in the above equation is beta. Beta represents the investment risk that cannot be diversified away when the security is held in a diversified portfolio. When stocks are held in a diversified portfolio, firm-specific risks can be eliminated by balancing the portfolio with securities that react in the opposite direction to firm-specific risk factors (e.g., business cycle, competition, product mix, and production limitations).

The risks that cannot be eliminated when held in a diversified portfolio are non-diversifiable risks. Non-diversifiable risks are related to the market in

[21] 75% x 9.57% + 25% x 7.72% = 9.11%.

general and are referred to as systematic risks. Risks that can be eliminated by diversification are regarded as non-systematic risks. In a broad sense, systematic risks are market risks, and non-systematic risks are business risks. The CAPM theory suggests that the market will not compensate investors for assuming risks that can be diversified away. Therefore, the only risk that investors will be compensated for are systematic or non-diversifiable risks. The beta is a measure of the systematic or non-diversifiable risks.

Q PLEASE DESCRIBE THE INPUTS TO YOUR CAPM.

A The CAPM requires an estimate of the market risk-free rate, the company's beta, and the market risk premium.

Q WHAT DID YOU USE AS AN ESTIMATE OF THE MARKET RISK-FREE RATE?

A As previously noted, *Blue Chip Financial Forecasts*' projected 30-year Treasury bond yield is 3.70%.[22] The current 30-year Treasury bond yield is 3.12%, as shown in Exhibit MPG-14, page 1. I used *Blue Chip Financial Forecasts*' projected 30-year Treasury bond yield of 3.70% for my CAPM analysis.

Q WHY DID YOU USE LONG-TERM TREASURY BOND YIELDS AS AN ESTIMATE OF THE RISK-FREE RATE?

A Treasury securities are backed by the full faith and credit of the United States government, so long-term Treasury bonds are considered to have negligible credit risk. Also, long-term Treasury bonds have an investment horizon similar to

[22] *Blue Chip Financial Forecasts*, June 1, 2013 at 2.

that of common stock. As a result, investor-anticipated long-run inflation expectations are reflected in both common-stock required returns and long-term bond yields. Therefore, the nominal risk-free rate (or expected inflation rate and real risk-free rate) included in a long-term bond yield is a reasonable estimate of the nominal risk-free rate included in common stock returns.

Treasury bond yields, however, do include risk premiums related to unanticipated future inflation and interest rates. A Treasury bond yield is not a risk-free rate. Risk premiums related to unanticipated inflation and interest rates are systematic or market risks. Consequently, for companies with betas less than 1.0, using the Treasury bond yield as a proxy for the risk-free rate in the CAPM analysis can produce an overstated estimate of the CAPM return.

Q WHAT BETA DID YOU USE IN YOUR ANALYSIS?

A As shown in Exhibit MPG-15, the proxy group average *Value Line* beta estimate is 0.73.

Q HOW DID YOU DERIVE YOUR MARKET RISK PREMIUM ESTIMATE?

A I derived two market risk premium estimates, a forward-looking estimate and one based on a long-term historical average.

The forward-looking estimate was derived by estimating the expected return on the market (as represented by the S&P 500) and subtracting the risk-free rate from this estimate. I estimated the expected return on the S&P 500 by adding an expected inflation rate to the long-term historical arithmetic average real return on the market. The real return on the market represents the achieved return above the rate of inflation.

Morningstar's *Stocks, Bonds, Bills and Inflation 2013 Classic Yearbook* estimates the historical arithmetic average real market return over the period 1926 to 2012 as 8.7%.[23] A current consensus analysts' inflation projection, as measured by the Consumer Price Index, is 2.3%.[24] Using these estimates, the expected market return is 11.20%.[25] The market risk premium then is the difference between the 11.20% expected market return, and my 3.70% risk-free rate estimate, or approximately 7.50%.

The historical estimate of the market risk premium was also estimated by Morningstar in *Stocks, Bonds, Bills and Inflation 2013 Classic Yearbook*. Over the period 1926 through 2012, Morningstar's study estimated that the arithmetic average of the achieved total return on the S&P 500 was 11.8%,[26] and the total return on long-term Treasury bonds was 6.1%.[27] The indicated market risk premium is 5.7% (11.8% - 6.1% = 5.7%). The average of my market risk premium estimates is 6.6% (7.5% to 5.7%).

Q HOW DOES YOUR ESTIMATED MARKET RISK PREMIUM RANGE COMPARE TO THAT ESTIMATED BY MORNINGSTAR?

A Morningstar's analysis indicates that a market risk premium falls somewhere in the range of 6.0% to 6.7%. My market risk premium falls in the range of 5.7% to 7.5%. My average market risk premium of 6.6% is at the high end of Morningstar's range.

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[23] *Morningstar, Inc., Ibbotson SBBI 2013 Classic Yearbook*; Market Results for Stocks, Bonds, Bills, and Inflation 1926-2012 at 88.

[24] *Blue Chip Financial Forecasts*, June 1, 2013 at 2.

[25] $\{ [(1 + 0.087) * (1 + 0.023)] - 1 \} * 100$.

[26] *Morningstar, Inc. Ibbotson SBBI 2013 Classic Yearbook* at 87.

[27] *Id.*

Morningstar estimates a forward-looking market risk premium based on actual achieved data from the historical period of 1926 through 2012. Using this data, Morningstar estimates a market risk premium derived from the total return on large company stocks (S&P 500), less the income return on Treasury bonds. The total return includes capital appreciation, dividend or coupon reinvestment returns, and annual yields received from coupons and/or dividend payments. The income return, in contrast, only reflects the income return received from dividend payments or coupon yields. Morningstar argues that the income return is the only true risk-free rate associated with Treasury bonds and is the best approximation of a truly risk-free rate.[28] I disagree with this assessment from Morningstar, because it does not reflect a true investment option available to the marketplace and therefore does not produce a legitimate estimate of the expected premium of investing in the stock market versus that of Treasury bonds. Nevertheless, I will use Morningstar's conclusion to show the reasonableness of my market risk premium estimates.

Morningstar's range is based on several methodologies. First, Morningstar estimates a market risk premium of 6.7% based on the difference between the total market return on common stocks (S&P 500) less the income return on Treasury bond investments. Second, Morningstar found that if the New York Stock Exchange (the "NYSE") was used as the market index rather than the S&P 500, that the market risk premium would be 6.5%, not 6.7%. Third, if only the two deciles of the largest companies included in the NYSE were considered,

[28]*Morningstar, Inc., Ibbotson SBBI 2013 Valuation Yearbook: Market Results for Stocks, Bonds, Bills, and Inflation 1926-2012* at 55.

the market risk premium would be 6.0%.[29]

Finally, Morningstar found that the 6.7% market risk premium based on the S&P 500 was influenced by an abnormal expansion of price-to-earnings ("P/E") ratios relative to earnings and dividend growth during the period 1980 through 2001. Morningstar believes this abnormal P/E expansion is not sustainable.[30] Therefore, Morningstar adjusted this market risk premium estimate to normalize the growth in the P/E ratio to be more in line with the growth in dividends and earnings. Based on this alternative methodology, Morningstar published a long-horizon supply-side market risk premium of 6.0%.[31]

Q WHAT ARE THE RESULTS OF YOUR CAPM ANALYSIS?

A As shown in Exhibit MPG-16, based on Morningstar's market risk premium of 6.7%, a risk-free rate of 3.70%, and a beta of 0.73, my CAPM analysis produces a return of 8.60%.

<u>Return on Equity Summary</u>

Q BASED ON THE RESULTS OF YOUR RETURN ON COMMON EQUITY ANALYSES DESCRIBED ABOVE, WHAT RETURN ON COMMON EQUITY DO YOU RECOMMEND FOR TAMPA ELECTRIC?

A Based on my analyses, I estimate Tampa Electric's current market cost of equity to be 9.25%.

[29] Morningstar observes that the S&P 500 and the NYSE Decile 1-2 are both large capitalization benchmarks. *Id.* at 54.

[30] *Morningstar, Inc., Ibbotson SBBI 2013 Valuation Yearbook: Market Results for Stocks, Bonds, Bills, and Inflation 1926-2012* at 54.

[31] *Id.*

TABLE 5

Return on Common Equity Summary

Description	Results
DCF	9.15%
Risk Premium	9.30%
CAPM	8.60%

My recommended return on common equity is 9.25%. My recommended return on equity is in the range of 9.15% to 9.30% and is supported by the results of my DCF studies and my risk premium studies. My recommended return of 9.25% is based on the approximate midpoint of my DCF return estimate, 9.15%, and risk premium result, 9.30%.

I am placing minimal weight on the results of my CAPM study because of my concerns about the risk-free rate and market risk premium outlined in this study.

Financial Integrity

Q WILL YOUR RECOMMENDED OVERALL RATE OF RETURN SUPPORT AN INVESTMENT GRADE BOND RATING FOR TAMPA ELECTRIC?

A Yes. I have reached this conclusion by comparing the key credit rating financial ratios for Tampa Electric, at my proposed return on equity and capital structure, to S&P's benchmark financial ratios using S&P's new credit metric ranges.

Q PLEASE DESCRIBE THE MOST RECENT S&P FINANCIAL RATIO CREDIT METRIC METHODOLOGY.

A S&P publishes a matrix of financial ratios that correspond to its assessment of the business risk of the utility company and related bond rating. On May 27, 2009, S&P expanded its matrix criteria[32] by including additional business and financial risk categories. Based on S&P's most recent credit matrix, the business risk profile categories are "Excellent," "Strong," "Satisfactory," "Fair," "Weak," and "Vulnerable." Most electric utilities have a business risk profile of "Excellent" or "Strong." The financial risk profile categories are "Minimal," "Modest," "Intermediate," "Significant," "Aggressive," and "Highly Leveraged." Most of the electric utilities have a financial risk profile of "Aggressive." Tampa Electric has an "Excellent" business risk profile and a "Significant" financial risk profile.

Q PLEASE DESCRIBE S&P'S USE OF THE FINANCIAL BENCHMARK RATIOS IN ITS CREDIT RATING REVIEW.

A S&P evaluates a utility's credit rating based on an assessment of its financial and business risks. A combination of financial and business risks equates to the overall assessment of Tampa Electric's total credit risk exposure. S&P publishes a matrix of financial ratios that defines the level of financial risk as a function of the level of business risk.

S&P publishes ranges for three primary financial ratios that it uses as guidance in its credit review for utility companies. The three primary financial ratio benchmarks it relies on in its credit rating process include: (1) Total Debt to

[32]S&P updated its 2008 credit metric guidelines in 2009, and incorporated utility metric benchmarks with the general corporate rating metrics. *Standard & Poor's RatingsDirect*: "Criteria Methodology: Business Risk/Financial Risk Matrix Expanded," May 27, 2009.

Total Capital; (2) Debt to Earnings Before Interest, Taxes, Depreciation and Amortization ("EBITDA"); and (3) Funds From Operations ("FFO") to Total Debt.[33]

Q HOW DID YOU APPLY S&P'S FINANCIAL RATIOS TO TEST THE REASONABLENESS OF YOUR RATE OF RETURN RECOMMENDATIONS?

A I calculated each of S&P's financial ratios based on Tampa Electric's cost of service for its Florida jurisdictional electric operations. While S&P would normally look at total consolidated Tampa Electric financial ratios in its credit review process, my investigation in this proceeding is not the same as S&P's. I am attempting to judge the reasonableness of my proposed cost of capital for rate-setting in Tampa Electric's Florida regulated utility operations. Hence, I am attempting to determine whether my proposed rate of return will in turn support cash flow metrics, balance sheet strength, and earnings that will support an investment grade bond rating and Tampa Electric's financial integrity.

Q DID YOU INCLUDE ANY OFF-BALANCE SHEET DEBT ("OBSD")?

A Yes. As shown in Exhibit MPG-17, page 3, I estimated OBSD equivalents of $56.10 million attributed to Tampa Electric's operating leases and purchased power agreements ("PPA") as provided by the Company in response to FEA's First Set of IRRs, IRR No. 3. S&P includes other off-balance sheet debt adjustments which I did not include in my analysis. S&P's inclusion of intermediate hybrids, post-retirement benefits, and accrued interest not reported on the Company's debt and asset retirement obligations, were not included in my analysis. Each of these factors are either reflected in Tampa Electric's cost of

[33] *Standard & Poor's RatingsDirect*: "Criteria Methodology: Business Risk/Financial Risk Matrix Expanded," May 27, 2009.

service, or I could not find evidence that they relate to regulated utility operations. As such, I did not include them in the metrics to judge the reasonableness of my rate of return for retail operations in Florida in this proceeding.

Q PLEASE DESCRIBE THE RESULTS OF THIS CREDIT METRIC ANALYSIS FOR TAMPA ELECTRIC.

A The S&P financial metric calculations for Tampa Electric at a 9.25% return are developed on Exhibit MPG-17, page 1.

Tampa Electric's adjusted total debt ratio is approximately 47%. This is within the "Significant" utility guideline range of 45% to 50%. This total debt ratio will support an investment grade bond rating.

As shown in Exhibit MPG-17, page 1, column 1, based on an equity return of 9.25%, Tampa Electric will be provided an opportunity to produce a debt to EBITDA ratio of 2.9x. This is at the high end of S&P's "Intermediate" guideline range of 2.0x to 3.0x.[34] This ratio also supports an investment grade credit rating.

Finally, Tampa Electric's retail operations FFO to total debt coverage at a 9.25% equity return would be 24%, which is within the "Significant" metric guideline range of 20% to 30%. The FFO/total debt ratio will support an investment grade bond rating.

At my recommended return on equity of 9.25% and proposed capital structure, Tampa Electric's financial credit metrics are supportive of its current "BBB+" utility bond rating.

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[34]*Standard & Poor's RatingsDirect*: "Criteria Methodology: Business Risk/Financial Risk Matrix Expanded," May 27, 2009 at 4.

RESPONSE TO TAMPA ELECTRIC WITNESS MR. ROBERT HEVERT

Q WHAT RETURN ON COMMON EQUITY IS TAMPA ELECTRIC PROPOSING FOR THIS PROCEEDING?

A Mr. Hevert is sponsoring Tampa Electric's return on equity recommendation. He is proposing a return on equity of 11.25%[35] based on a recommended range of 10.50% to 11.50%. Mr. Hevert relied on a constant growth DCF analysis, CAPM studies, and a Bond Yield Plus Risk Premium approach to support his recommended return for Tampa Electric.

Q ARE MR. HEVERT'S RETURN ON EQUITY ESTIMATES REASONABLE?

A No. Mr. Hevert's estimated costs ranging from 10.50% to 11.50% are overstated and should be rejected. Mr. Hevert's analyses produce excessive results for various reasons: (1) his constant growth DCF results are based on excessive, unsustainable growth rates, (2) his CAPM is based on inflated market risk premiums, and (3) his Bond Yield Plus Risk Premium is based on inflated utility equity risk premiums.

Q PLEASE SUMMARIZE TAMPA ELECTRIC WITNESS MR. HEVERT'S RETURN ON EQUITY ESTIMATES.

A Mr. Hevert's return on equity estimates are summarized below in Table 6. In Column 2, I show the results with prudent and sound adjustments to Mr. Hevert's common equity return estimates. With reasonable adjustments to his proxy group's DCF, CAPM and Risk Premium return estimates, Mr. Hevert's own

[35]Hevert Direct at 3.

studies show my recommended return on equity of 9.25% is reasonable for Tampa Electric.

TABLE 6

Hevert's Return on Equity Estimates

Description	Mean[1] (1)	Adjusted[2] (2)
Constant Growth DCF (Mean/Median)		
30-Day Average Stock Price	10.60%/10.84%	9.57%/9.54%
90-Day Average Stock Price	10.69%/10.86%	9.64%/9.51%
180-Day Average Stock Price	10.70%/10.81%	9.62%/9.38%
CAPM Results (Bloomberg Beta)		
Current Treasury Yield (Sharpe Ratio – 3.12%)	7.42%	7.90%
Current Treasury Yield (Bloomberg DCF – 3.12%)	10.18%	7.90%
Current Treasury Yield (Capital IQ DCF – 3.12%)	10.13%	7.90%
Near-Term Projected (Sharpe Ratio – 3.25%)	7.56%	8.00%
Near-Term Projected (Bloomberg DCF – 3.25%)	10.31%	8.00%
Near-Term Projected (Capital IQ DCF – 3.25%)	10.26%	8.00%
Long-Term Projected (Sharpe Ratio – 5.10%)	9.41%	9.90%
Long-Term Projected (Bloomberg DCF – 5.10%)	12.16%	9.90%
Long-Term Projected (Capital IQ DCF – 5.10%)	12.11%	9.90%
Average	**9.95%**	**8.60%**
CAPM Results (*Value Line* Beta)		
Current Treasury Yield (Sharpe Ratio – 3.12%)	7.45%	7.90%
Current Treasury Yield (Bloomberg DCF – 3.12%)	10.22%	7.90%
Current Treasury Yield (Capital IQ DCF – 3.12%)	10.16%	7.90%
Near-Term Projected (Sharpe Ratio – 3.25%)	7.58%	8.00%
Near-Term Projected (Bloomberg DCF – 3.25%)	10.35%	8.00%
Near-Term Projected (Capital IQ DCF – 3.25%)	10.30%	8.00%
Long-Term Projected (Sharpe Ratio – 5.10%)	9.43%	9.90%
Long-Term Projected (Bloomberg DCF – 5.10%)	12.20%	9.90%
Long-Term Projected (Capital IQ DCF – 5.10%)	12.15%	9.90%
Average	**9.98%**	**8.60%**
Risk Premium		
Current	10.23%	7.51%
Near-Term Projected	10.24%	7.64%
Long-Term Projected	10.76%	9.50%
Average	**10.41%**	**8.22%**
Range	**10.50%-11.50%**	**8.60%-9.70%**
Recommended/Midpoint Return on Equity	**11.25%**	**9.30%**

Sources:
[1]Exhibit No. ___ (RBH-1), Document No. 1.
[2]Exhibit MPG-18.

Q PLEASE DESCRIBE MR. HEVERT'S CONSTANT GROWTH DCF RETURN ESTIMATES.

A His constant growth DCF returns are developed in his Exhibit No. ___ (RBH-1), Document No. 2, pages 1-3. Mr. Hevert's constant growth DCF models are based on consensus growth rates published by Zacks and First Call, and individual growth rate projections made by *Value Line*. He relied on dividend yield calculations based on average stock prices over three different periods – 30-day, 90-day and 180-day.

Q DO YOU BELIEVE THAT MR. HEVERT'S CONSTANT GROWTH DCF RETURN MODELS PRODUCE A REASONABLE RETURN ESTIMATE FOR TAMPA ELECTRIC?

A No. Mr. Hevert relied on growth rate estimates which are far too high to be reasonable estimates of long-term sustainable growth. Also, Mr. Hevert's results are subject to certain outliers. For example, Otter Tail Corporation and PNM Resources have *Value Line* growth rates of 24.0% and 16.0%, respectively, which is significantly above the sustainable long-term growth rate of 4.9% as discussed above. Eliminating these clearly outlier growth rate estimates would reduce Mr. Hevert's average DCF studies to 9.57% to 9.64% as shown on my Exhibit MPG-18. However, Mr. Hevert's DCF results are still overstated because of his development of his DCF input estimates.

Q PLEASE DESCRIBE THE GROWTH RATES INCLUDED IN MR. HEVERT'S CONSTANT GROWTH DCF RETURN ESTIMATES.

A The growth rate estimates, dividend yields and corresponding DCF return estimates for Mr. Hevert's constant growth DCF studies are illustrated on my Exhibit MPG-19. Mr. Hevert's schedules do not show the details of the DCF estimate.

As shown on that schedule, his DCF return estimates for his proxy group are based on a range of growth rate estimates from a low of 4.73%, to a mean growth rate estimate of 6.50%, and a high DCF growth rate of 8.94%. These growth rate estimates were used in all of his constant growth DCF study 30-, 90- and 180-day average stock prices.

Q WHY DO YOU BELIEVE THAT MR. HEVERT'S MEAN AND HIGH-END GROWTH RATE ESTIMATES OF 6.50% AND 8.94%, RESPECTIVELY, ARE TOO HIGH TO BE REASONABLE ESTIMATES OF LONG-TERM SUSTAINABLE GROWTH?

A These growth rates cannot be sustained indefinitely for various reasons. First, the consensus of economists is that GDP growth of the U.S. general economy, which is a proxy for the growth rate of the economies in which these utilities operate, is between 4.7% and 5.1% indefinitely.[36] Hence, the growth rates of 6.50% and 8.94% are substantially higher than the growth outlooks of the economies in which these utilities operate. It is simply not rational to expect that these companies can grow faster than the economies in which they provide

[36]*Blue Chip Financial Forecasts*, June 1, 2013, page 14.

service, because utilities provide service to meet the demand of the economies they serve.

Second, growth rates in the range of 6.50% and 8.94% could not be sustained by the current earnings retention rate of utility companies. Indeed, the *Value Line* long-term payout ratio for the utility industry will be about 60.12% (Exhibit MPG-5). In order to sustain growth rates of 6.50% and 8.94%, utilities would have to achieve returns on book equity of 16.30% and 22.42%, respectively, indefinitely.[37] Hence, it is simply not a rational outlook to expect that utilities will be able to produce earnings that could sustain this level of growth indefinitely.

Q **CAN YOU DESCRIBE AGAIN WHY A THREE- TO FIVE-YEAR GROWTH RATE CAN EXCEED A LONG-TERM SUSTAINABLE GROWTH RATE?**

A Yes. A three- to five-year growth rate can exceed a long-term sustainable growth rate for several reasons including: (1) the utility's capital program and rate base are growing at an abnormally high level; (2) a company's growth in earnings is above a depressed level of earnings; and/or (3) altering dividend payout ratio targets can create temporary acceleration or decline to short-term growth.

As discussed above, while short-term accelerated earnings growth rates may be a reasonable expectation for relatively short periods of time, it is not reasonable to expect that accelerated short-term growth can be sustained indefinitely. That is the flaw of Mr. Hevert's DCF studies. He is deriving DCF estimates based on accelerated short-term growth rates that he assumes can be sustained over an indefinite period of time. This is simply not a rational outlook,

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[37] 6.50% ÷ (1 – 60.12%) = 16.30% and 8.94% ÷ (1 – 60.12%) = 22.42%.

and produces an excessive DCF return estimate.

Q CAN MR. HEVERT'S DCF ANALYSES BE REVISED TO REFLECT A REASONABLE LONG-TERM SUSTAINABLE GROWTH RATE?

A Yes. Mr. Hevert's DCF studies can be revised to reflect the short-term growth rate estimates that will be realized over the period they were designed to reflect, five years, and the growth rate after that would eventually converge down to a lower sustainable long-term rate of growth. This can be accomplished by using a multi-stage growth DCF analysis. The multi-stage growth DCF model can reflect abnormally high short-term growth, followed by a decline to a lower growth rate that can be sustained over a long-term period.

Q HOW WOULD MR. HEVERT'S CONSTANT GROWTH DCF MODEL CHANGE IF A MULTI-STAGE DCF MODEL IS PERFORMED?

A As shown on my Exhibit MPG-19, using *The Blue Chip Financial Forecasts'* GDP growth forecast of 4.9% (average of 5.1% and 4.7%) and Mr. Hevert's inputs as developed on his Exhibit No. ___ (RBH-1), will reduce his DCF return estimate for his proxy group from 10.69% (mean) and 10.84% (median) to 9.61% (mean) and 9.55% (median). The results are summarized in Table 7 below.

TABLE 7

Hevert Multi-Stage DCF Analysis

Description	Hevert Mean[1] (1)	Revised Estimate[2] (2)
Mean		
30-Day Average Stock Price	10.60%	9.54%
90-Day Average Stock Price	10.69%	9.64%
180-Day Average Stock Price	10.79%	9.66%
Average	10.69%	9.61%
Median		
30-Day Average Stock Price	10.84%	9.61%
90-Day Average Stock Price	10.86%	9.59%
180-Day Average Stock Price	10.81%	9.45%
Average	10.84%	9.55%

Sources:
[1]Exhibit No. ___ (RBH-1), Document No. 2.
[2]Exhibit MPG-20.

Q PLEASE DESCRIBE THE ISSUES YOU TAKE WITH MR. HEVERT'S CAPM ANALYSES.

A My major concern with Mr. Hevert's CAPM analysis is his inflated market risk premium estimates.

Q PLEASE DESCRIBE MR. HEVERT'S MARKET RISK PREMIUMS.

A Mr. Hevert developed three market risk premium estimates. The first two are DCF-derived market risk premiums of 9.88% (Bloomberg) and 9.81% (Capital IQ), which are based on market DCF returns of 13.00% and 12.93%, respectively, less the current 30-year Treasury bond yield of 3.12%. (Exhibit No.

___ (RBH-2), Document No. 5, pages 2 and 15). The second market risk premium (referred as the Sharpe market risk premium) of 6.03% is based on one historical market risk premium estimate of 6.60%, adjusted for the difference in long-term historical and current market volatility. (*Id.*, page 1).

Q WHAT ISSUES DO YOU HAVE WITH MR. HEVERT'S DCF-DERIVED MARKET RISK PREMIUM ESTIMATES?

A Mr. Hevert's DCF-derived market risk premiums are based on market returns of approximately 13.00% and 12.93%, which consist of a growth rate component of approximately 11.00% and a dividend yield of approximately 2.00%. As discussed above, the DCF model requires a long-term sustainable growth rate. Mr. Hevert's sustainable market growth rate of approximately 11.00% is far too high to be a rational outlook for sustainable long-term market growth. This growth rate is more than two times the growth rate of the U.S. GDP long-term growth outlook of 4.9%. Indeed, it is even about twice Mr. Hevert's flawed and overstated GDP growth projection.

As a result of this unreasonable long-term market growth rate estimate, Mr. Hevert's market DCF returns are inflated and not reliable. Consequently, Mr. Hevert's 9.88% (Bloomberg) and 9.81% (Capital IQ) market risk premiums are inflated and not reliable.

Q **IS THERE INFORMATION ON ACTUAL ACHIEVED CAPITAL APPRECIATION FOR THE MARKET INDEX USED BY MR. HEVERT?**

A Yes. Morningstar estimates the actual capital appreciation for the S&P 500 over the period 1926 through 2012 to have been 7.5%.[38] Using this gauge of actual capital appreciation in the market in the past as an estimate of future expected growth of the market index going forward, along with Mr. Hevert's estimated dividend yield of approximately 2.0%, would imply a total expected return on the market going forward of approximately 9.5%. This 9.5% less the risk-free estimates used by Mr. Hevert of 3.1% would imply a going-forward expected market risk premium of 6.4%.

This expected return on the market is very consistent with Morningstar's data which estimates market risk premiums in the range of 6.0% to 6.7% based on its historical market and Treasury bond investment data that I discussed above.

Q **PLEASE DESCRIBE MR. HEVERT'S SHARPE MARKET RISK PREMIUM.**

A Mr. Hevert's Sharpe market risk premium is 6.03%. Mr. Hevert maintains that his Sharpe market risk premium adjusts the historical market risk premium to reflect the difference between historic and expected market volatility. He adjusts the historical market risk premium of 6.6% by the expected market volatility of 18.54%, relative to historical market volatility of 20.30%.[39] He measures expected market volatility using the Chicago Board Options Exchange's ("CBOE") three-month volatility index of settlement prices of futures on the CBOE's one-month volatility index (July 2013 through Sept 2013).

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[38] 2013 Ibbotson *SBBI Valuation Yearbook* at 23.
[39] Exhibit No. ___ (RBH-1), Document No. 3, page 1 of 27.

As shown on his Exhibit No. ___ (RBH-1), Document No. 3, page 1, using this relative comparison of market volatility, he adjusts the historical market risk premium of 6.60% down to 8.35%, by the ratio of expected market volatility of 18.54%, to historical market volatility of 20.30% (6.60% x (18.54% ÷ 20.30%)).

Q DO YOU BELIEVE THAT MR. HEVERT'S SHARPE RATIO EXPECTED MARKET RISK PREMIUM PRODUCES RELIABLE RESULTS?

A No. The period rates determined in this proceeding will be in effect is several years into the future. In significant contrast, Mr. Hevert is measuring expected market volatility for a relatively short six-week time period in 2012. This relatively short period of time does not prove that market volatility in the long term will be different from volatility in the past. Mr. Hevert's short-term based analysis is not useful in estimating a fair return for Tampa Electric in this case. It simply is not designed to estimate long-term investors' cost of capital requirements.

Q WHY IS MR. HEVERT'S PROPOSAL TO MEASURE MARKET RISK PREMIUM BASED ON A SIX-WEEK MARKET VOLATILITY NOT USEFUL IN ESTIMATING A FAIR RETURN ON EQUITY FOR TAMPA ELECTRIC IN THIS PROCEEDING?

A Mr. Hevert's Sharpe ratio market risk premium does not capture the return expectations of long-term utility investors. Rather, it reflects the short-term investment outlooks of short-term trading investors or speculators looking to react to misvaluations in the marketplace. Indeed, the entire analysis is based on derivative future valuation data rather than directly on stock price data. As such, the Sharpe market risk premium does not measure long-term stock investment outlooks and requirements, and does not produce a fair return on equity estimate for Tampa Electric.

Q CAN MR. HEVERT'S CAPM ANALYSIS BE REVISED TO REFLECT A MORE REASONABLE MARKET RISK PREMIUM?

A Yes. Using Mr. Hevert's risk-free rates of 3.12%, 3.25% and 5.10% (Exhibit No. ___ (RBH-4), published Bloomberg beta estimate of 0.71,[40] and the 6.70% Morningstar market risk premium described above, Mr. Hevert's CAPM would be in the range of 7.90% to 9.90%. Using the same risk-free rates and market risk premium, and the *Value Line* beta of 0.72,[41] will produce a CAPM return in the range of 7.90% to 9.90%[42] for Mr. Hevert's proxy group.

Q PLEASE DESCRIBE MR. HEVERT'S BOND YIELD PLUS RISK PREMIUM.

A As shown on Exhibit No. ___ (RBH-5), Mr. Hevert constructs a risk premium return on equity estimate based on the premise that equity risk premiums are inversely related to the interest rates. He estimates an average electric risk premium of 4.39% current, near-term and long-term over Treasury bond yields of 3.12%, 3.25% and 5.10% over the period January 1980 to February 2013, respectively. Then he applies a regression analysis to the current, near-term and long-term projected Treasury bond yields of 3.12%, 3.25% and 5.10% to produce an average electric risk premium of 7.11%, 6.99% and 5.66%, respectively. This in turn yields a return on equity estimate of 10.23%, 10.24% and 10.76%, respectively.

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[40]Exhibit No. ___ (RBH-1), Document No. 5.
[41]*Id.*
[42]3.12% + 0.71 (or 0.72) x 6.70% = 7.90%; 3.25% + 0.71 (or 0.72) x 6.70% = 8.00%; 5.10% + 0.71 (or 0.72) x 6.70% = 9.90%.

Q IS MR. HEVERT'S BOND YIELD PLUS RISK PREMIUM METHODOLOGY REASONABLE?

A No. Mr. Hevert's contention that there is a simplistic inverse relationship between equity risk premiums and interest rates is not supported by academic research. While academic studies have shown that, in the past, there has been an inverse relationship with these variables, researchers have found that the relationship changes over time and is influenced by changes in perception of the risk of bond investments relative to equity investments, and not simply changes to interest rates.[43]

In the 1980s, equity risk premiums were inversely related to interest rates, but that was likely attributable to the interest rate volatility that existed at that time. As such, when interest rates were more volatile, the relative perception of bond investment risk increased relative to the investment risk of equities. This changing investment risk perception caused changes in equity risk premiums.

In today's marketplace, interest rate volatility is not as extreme as it was during the 1980s.[44] Nevertheless, changes in the perceived risk of bond investments relative to equity investments still drive changes in equity premiums. However, a relative investment risk differential cannot be measured simply by observing nominal interest rates. Changes in nominal interest rates are highly influenced by changes to inflation outlooks, which also change equity return expectations. As such, the relevant factor needed to explain changes in equity

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[43]"The Market Risk Premium: Expectational Estimates Using Analysts' Forecasts," Robert S. Harris and Felicia C. Marston, *Journal of Applied Finance*, Volume 11, No. 1, 2001 and "The Risk Premium Approach to Measuring a Utility's Cost of Equity," Eugene F. Brigham, Dilip K. Shome, and Steve R. Vinson, *Financial Management*, Spring 1985.

[44]"The Risk Premium Approach to Measuring a Utility's Cost of Equity," Eugene F. Brigham, Dilip K. Shome, and Steve R. Vinson, *Financial Management*, Spring 1985, at 44.

risk premiums is the relative changes to the risk of equity versus debt securities investments, and not simply changes in interest rates.

Importantly, Mr. Hevert's analysis simply ignores investment risk differentials. He bases his adjustment to the equity risk premium exclusively on changes in nominal interest rates. This is a flawed methodology and does not produce accurate or reliable risk premium estimates. As such, his argument should be rejected by the Commission.

Q DO YOU HAVE ANY OTHER COMMENTS CONCERNING MR. HEVERT'S RISK PREMIUM ANALYSES?

A Yes. Mr. Hevert's use of projected long-term Treasury yields is not appropriate because the accuracy of those projections could be highly problematic. However, to limit the issues with Mr. Hevert's studies and considering the low interest rate environment today, I will not take issue with his use of long-term projected Treasury bond yields.

Q CAN MR. HEVERT'S BOND YIELD PLUS RISK PREMIUM STUDY BE USED TO PRODUCE A MORE REASONABLE RETURN ON EQUITY ESTIMATE FOR TAMPA ELECTRIC?

A Yes. Mr. Hevert's equity risk premium average of 4.39% applied to the Treasury bond yields of 3.12%, 3.25% and 5.10%, will produce a risk premium return estimate in the range of 7.51% to 9.50%. While I agree with Mr. Hevert that his estimate is significantly low because it is influenced by the current low-cost interest environment, I find his attempt to increase the average equity risk premium by applying the notion of an inverse relationship inappropriate.

Q DO YOU HAVE ANY COMMENTS CONCERNING MR. HEVERT'S FLOTATION COST ADJUSTMENT?

A Yes. Even though Mr. Hevert did not propose a specific flotation cost adjustment, he estimated that a 14 basis point adder represents a reasonable adjustment to account for flotation costs. He also took flotation costs along with other factors into consideration when determining where the Company's return on equity falls within the range of his results.[45]

Q DO YOU AGREE WITH MR. HEVERT'S FLOTATION COST ESTIMATE OF 0.14%?

A No. Mr. Hevert's flotation cost estimate is flawed and it should not be taken into consideration when determining a fair return for Tampa Electric.

Flotation costs are a legitimate cost of doing business. However, flotation costs should only be included in the development of cost of service under two conditions. First, the Company has to demonstrate what its actual flotation costs are, and prove they are reasonable. It is not appropriate to approximate flotation cost for utility companies and build that approximated cost into a utility's cost of service. Costs should be known and measurable and should be verifiable and most importantly should be shown to be reasonable before they are included in cost of service. This is not possible if a utility's flotation costs are approximated, as Mr. Hevert has done.

Second, and more important, Tampa Electric is not a publicly traded company. Rather, it is a wholly-owned subsidiary of TECO Energy. Hence, Tampa Electric does not incur costs related to selling common stock to the

[45] Hevert Direct at 4 and 52.

market. Tampa Electric's common equity capital comes from two sources: (1) retained earnings, which incur no flotation cost, and (2) equity infusion from its parent company.

Therefore, Mr. Hevert's estimate of 14 basis points to account for flotation costs should be disregarded and not considered in determining the Company's return on equity.

Q **DID MR. HEVERT ALSO OFFER AN ANALYSIS TO ASSESS CURRENT MARKET CONDITIONS IN SUPPORT OF HIS RECOMMENDED RETURN ON EQUITY?**

A Yes. At pages 52 through 65 of his direct testimony, Mr. Hevert describes several factors which he suggests gauge investor sentiment including incremental credit spreads, market volatility, and the relationship between the dividend yield of proxy group companies and Treasury yields. He concludes that these metrics indicate that current levels of instability and risk aversion are significantly higher than the levels observed prior to the recent recession.

Q **DO YOU BELIEVE THAT MR. HEVERT'S USE OF THESE MARKET SENTIMENTS SUPPORTS HIS FINDINGS THAT TAMPA ELECTRIC'S MARKET COST OF EQUITY IS CURRENTLY 11.25%?**

A No. Indeed, in many instances Mr. Hevert's analysis simply ignores market sentiments toward utility companies, and instead lumps utility investments in with general corporate investments. A broader analysis of utility securities shows that the market generally regards utility securities as low-risk investment instruments, and helps support the reasonable findings that utilities' cost of capital is very low in today's marketplace.

RESIDENTIAL SALES REVENUE

Q DID TAMPA ELECTRIC FORECAST RESIDENTIAL SALES REVENUE FOR THE 2014 TEST YEAR?

A Yes. Tampa Electric witnesses Lorraine C. Cifuentes and William R. Ashburn prepared direct testimony which addressed the projected 2014 residential sales revenue. Based on Ms. Cifuentes' forecast, Mr. Ashburn presents the customer and sales data used by Tampa Electric to calculate the residential sales revenue at existing rates.

Q WHAT IS THE RESIDENTIAL SALES REVENUE AT PRESENT RATES PROPOSED BY TAMPA ELECTRIC?

A Tampa Electric has proposed a level of residential sales revenue of $489.6 million based on 619,152 customers and total residential sales of 8,563,003 MWh.

Q IS THE RESIDENTIAL REVENUE AT PRESENT RATES PROJECTED BY TAMPA ELECTRIC REASONABLE?

A No. I believe Tampa Electric has substantially understated the annualized level of residential sales revenue at present rates.

Ms. Cifuentes' projection reflects a decline in average residential sales per customer usage relative to that actually experienced by Tampa Electric over the period 2005 through 2012. This level of sales per customer is shown below in Table 8.

TABLE 8

Residential Sales/Customer

Year	MWh Sales[1]	Number of Customers[1]	Sales per Customer (MWh/Customer)
2005	8,558,461	558,728	15.32
2006	8,720,867	575,111	15.16
2007	8,871,217	586,776	15.12
2008	8,546,468	587,602	14.54
2009	8,666,471	587,396	14.75
2010	9,184,729	591,554	15.53
2011	8,717,962	595,914	14.63
2012	8,395,166	603,594	13.91
Average			14.87
Tampa Electric Proposed 2014	8,563,003[2]	619,152[2]	13.83

Sources/Notes:

[1]2005-2012 data from Tampa Electric FERC Form 1 Annual Reports.
[2]Tampa Electric's Minimum Filing Requirements, Schedule E-13c, page 2 of 19 (Customers = Bills ÷ 12).

As shown above in Table 8, the projected 2014 test year sales per customer declines to 13.83 MWh per year. However, the actual usage/customer over the 2005-2012 ranges from 15.53 to 13.91 MWh per year and averages 14.87 MWh per year.

As shown in the table above, the Company's projected sales significantly understate Tampa Electric's actual residential sales revenue per customer experienced over the last eight years.

Q **WHY DO YOU BELIEVE THAT TAMPA ELECTRIC'S ESTIMATED RESIDENTIAL REVENUE IS UNREASONABLE BASED ON THE DATA ABOVE IN TABLE 8?**

A Tampa Electric's use per residential customer projected for the 2014 test year is lower than the actual sales use per customer in any year during the period 2005-2012. I believe this projection is inconsistent with the data outlined in Ms. Cifuentes' testimony. Specifically, she describes an economic forecast used to derive the Company's projected peak demand and customer load energy sales. As shown on Ms. Cifuentes' Document No. 3, the projected economic activity for the Tampa Electric service territory is quite robust for the 2014 test year relative to the historical period 2009-2012. For example, commercial real gross output is projected to grow by 8.6% in 2014 over 2012, compared to only 4.4% growth from 2010 to 2012. This would indicate strong economic growth for a commercial business in the Tampa Electric area.

This is a strong indication that residential customers would be spending more of their disposable income, which is also projected to grow by 5.6% in 2012-2014, compared to only 2% growth from 2010-2012. This strong increase in real household income is supporting strong commercial real estate gross output, and would also suggest customers are spending more on discretionary items which would include electricity consumption.

Further, construction employment in the service territory actually declined from 2010-2012 but is projected to increase by 5.5% for 2012-2014. Industrial employment is projected to stay relatively flat through the period 2010-2014.

Further, the Company's actual load characteristics appear to be rather pessimistic. For example, the actual heating and cooling degree days projections as outlined on Ms. Cifuentes' Document No. 4, suggests that there will be fewer heating degree days and cooling degree days in the projected period relative to the actual experienced on average through the period 1992-2011. Specifically, Ms. Cifuentes states that the heating degree days and cooling degree days over 1992-2011 were 515 and 3,667, respectively. However, for the forecast, she is expecting considerably milder heating and cooling weather reflecting only 512 heating degree days and 3,655 cooling degree days over the projected period 2013-2022. This change in heating and cooling degree days impacts residential consumptions during the heating and cooling seasons, respectively, and likely explains why she is projecting a decline in average use per residential customer. I believe Ms. Cifuentes has not adequately justified this expectation of lower heating and cooling weather events, driving down Tampa Electric's sales for heating and cooling residential load.

Q WOULD IT BE APPROPRIATE TO USE THE ACTUAL SALES IN CALENDAR YEAR 2012 AS A PROJECTION FOR ACTUAL SALES IN THE 2014 TEST YEAR?

A No. Actual weather-related sales data included in Ms. Cifuentes' testimony demonstrates that calendar year 2012 did not reflect normal residential heating loads.

Q DO YOU BELIEVE THE ANNUAL AVERAGE USAGE PER RESIDENTIAL CUSTOMER AS PROPOSED BY TAMPA ELECTRIC IS REASONABLE?

A No. Tampa Electric is proposing a usage per residential customer that is below any level previously experienced by the Company. Referring to Table 8, the annual average usage per residential customer has historically been in the 14-15 MWh range. The only time usage per residential customer has been below 14.5 in the last eight years was 2012 and as I have previously stated, the low annual usage experienced that year was due to an unusually warm winter. Yet Tampa Electric has proposed a level even lower than the abnormal results experienced in 2012. Proposing an annual usage level less than the 2012 level highlights the unreasonableness of Tampa Electric's proposal.

Q DO YOU TAKE ISSUE WITH THE COMPANY'S PROJECTED NUMBER OF CUSTOMERS IN THE 2014 TEST YEAR?

A No. I believe the Company's projected increase in customers of 1.5% appears to be reasonably consistent with its historical data. However, the use per customer appears to be understated.

Q WHAT LEVEL OF SALES DO YOU RECOMMEND BE USED TO ESTIMATE RESIDENTIAL SALES REVENUE IN THE FORECASTED TEST YEAR IN ORDER TO ESTIMATE TAMPA ELECTRIC'S CLAIMED REVENUE DEFICIENCY IN THIS PROCEEDING?

A I recommend the use of average residential sales of 14.25 MWh/customer. This level exceeds the projection for 2014, but reflects a decline in annual usage the Company has actually experienced over the period 2005-2011. However, this decline I believe is skewed by 2012 data, which reflects weak economic activity, and abnormally low heating degree days for the period around 2012. Ms. Cifuentes' projections reflect a return to stronger economic activity, which should encourage residential customers to return to more normal consumption levels.

Q WHAT IS THE IMPACT ON TAMPA ELECTRIC'S ANNUALIZED RESIDENTIAL SALES REVENUE USING YOUR PROPOSED 14.25 MWH LEVEL OF USAGE?

A As shown on my Exhibit MPG-22, by using a 14.25 MWh level of usage per customer, Tampa Electric's annualized residential revenues would be increased by $12.5 million.

Q DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A Yes, it does.

STATE OF FLORIDA)
: CERTIFICATE OF REPORTER
COUNTY OF LEON)

I, LINDA BOLES, CRR, RPR, Official Commission Reporter, do hereby certify that the foregoing proceeding was heard at the time and place herein stated.

IT IS FURTHER CERTIFIED that I stenographically reported the said proceedings; that the same has been transcribed under my direct supervision; and that this transcript constitutes a true transcription of my notes of said proceedings.

I FURTHER CERTIFY that I am not a relative, employee, attorney or counsel of any of the parties, nor am I a relative or employee of any of the parties' attorney or counsel connected with the action, nor am I financially interested in the action.

DATED THIS 10th day of September 2013.

Linda Boles

LINDA BOLES, CRR, RPR
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