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BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

IN RE: PETITION FOR RATE INCREASE BY TAMPA ELECTRIC COMPANY) DOCKET NO. 130040-EI

DIRECT TESTIMONY

AND EXHIBITS

OF

LANE KOLLEN

ON BEHALF OF

THE WCF HOSPITAL UTILITY ALLIANCE

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

JULY 15, 2013

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I. QUALIFICATIONS AND SUMMARY

A. Qualifications

Q. Please state your name and business address.

A. My name is Lane Kollen. My business address is J. Kennedy and Associates, Inc. ("Kennedy and Associates"), 570 Colonial Park Drive, Suite 305, Roswell, Georgia 30075.

Q. What is your occupation and by whom are you employed?

A. I am a utility rate and planning consultant holding the position of Vice President and Principal with Kennedy and Associates.

Q. Please describe your education and professional experience.

A. I earned a Bachelor of Business Administration in Accounting degree and a Master of Business Administration degree, both from the University of Toledo. I also earned a Master of Arts degree from Luther Rice University. I am a Certified Public Accountant, with a practice license, and a Certified Management Accountant.

I have been an active participant in the utility industry for more than thirty years, both as a consultant and as an employee. Since 1986, I have been a consultant with Kennedy and Associates, providing services to consumers of utility services and state and local government agencies in the areas of utility planning, ratemaking, accounting, taxes, financial reporting, financing and management decision-making. From 1983 to 1986, I was a consultant with

Energy Management Associates, providing services to investor and consumer owned utility companies in the areas of planning, financial reporting, financing, ratemaking and management decision-making. From 1976 to 1983, I was employed by The Toledo Edison Company in a series of positions providing services in the areas of planning, accounting, financial and statistical reporting and taxes.

I have appeared as an expert witness on utility planning, ratemaking, accounting, reporting, financing, and tax issues before state and federal regulatory commissions and courts on nearly two hundred occasions. In many of those proceedings, I have represented state and local ratemaking agencies or their Staffs, including the Louisiana Public Service Commission, Georgia Public Service Commission and various groups of Cities with original rate jurisdiction in Texas. I also have appeared before the Florida Public Service Commission ("Commission") in numerous proceedings, including the four most recent Florida Power & Light Company base rate proceedings in Docket Nos. 120015-EI (2012), 080677-EI (2009), 050045-EI (2005), and 001148-EI (2002). I have developed and presented papers at various industry conferences on ratemaking, accounting, and tax issues. My qualifications and regulatory appearances are further detailed in my Exhibit___(LK-1).

Q. **On whose behalf are your testifying?**

A. I am providing testimony on behalf of the WCF Hospital Utility Alliance ("HUA"), a group of hospitals and healthcare facilities that take electric utility service from Tampa Electric Company (the "Company").

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to: 1) address and make recommendations regarding the operation and maintenance ("O&M") expense included in the Company's claimed revenue requirement, 2) quantify the effect of an adjustment to the other revenue included in the Company's claimed revenue requirement, and 3) quantify the effect of HUA witness Mr. Richard Baudino's return on equity recommendation on the Company's claimed revenue requirement.

Q. Please summarize your testimony.

A. I recommend that the Commission reduce the Company's claimed revenue requirement by $40.898 million to reflect a reduction in O&M expense to a just and reasonable amount. From a "top-down" perspective, the Company's request is excessive and represents an 18.4% increase over 2012, the most recent year for which actual amounts are available. The Company's request reflects a wish list of increased spending and is not justified by the present economic realities or by the expansion of service or work-scope activities. After its last base rate case in 2009, the Company initially reduced its O&M expense in 2010 and then carefully and successfully managed it through 2012 so that there essentially was no growth over that sustained period. The Company did so by implementing more efficient processes and investing in new systems to offset the effects of inflation and other growth drivers.[1] The Commission should direct the Company to continue this approach and limit any increase in O&M expense since 2012 to 4.7%, or a 2.3% annual growth rate to reflect the net effects of inflation, offset by the Company's

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1 The costs of these investments and the investments that will be incurred in 2013 and 2014 are included in the Company's rate base in this proceeding and should continue to reap savings as well as allow the Company to achieve additional savings.

continuing and additional efficiency improvements, and to reflect limited growth in the expansion of work-scope requirements due primarily to government regulations.

I also address specific "bottoms-up" adjustments to the Company's proposed O&M expense in further support of my recommendation to limit the increase in O&M expense from a top-down perspective. More specifically, the following adjustments would be appropriate under a "bottoms-up" approach:

Summary of HUA Issue-Specific O&M Expense Reductions
($ Million)

Reduce Big Bend Planned Maintenance Outage Expense to Reflect Historic Levels	$7.145
Reduce Distribution Operation and Maintenance Expense to Reflect Historic Levels	5.317
Reject Increase in Performance Sharing Plan Incentive Compensation	5.304
Reject Stock Compensation Expense	5.084
Normalize Injuries and Damages Expense to Reflect Recent Historic Levels	1.728
Reduce Affiliate Charges in to Reflect TECO Energy Acq of New Mexico Gas Co.	2.900
Reduce Proposed Increase in Call Center Expense	1.575
Eliminate Proposed Increase in Uncollectible Accounts Expense	1.302
Reduce Proposed Increase in Legal Expenses	1.521
Sum of HUA Issue-Specific Recommendations	$31.876

In addition to my recommended reduction in O&M expense, I recommend that the Commission increase other revenues by $4.920 million to reflect the fact that Calpine recently notified the Company of its intent to rollover a portion of its transmission load under the Company's Open Access Transmission Tariff ("OATT"). The Company incorrectly assumed that the Calpine load would be terminated in its filing.

Finally, I quantify the effect of Mr. Baudino's 9.3% return on equity recommendation compared to the Company's request for an 11.25% return on equity. The effect is a reduction in the Company's claimed revenue deficiency of

$58.375 million, assuming no adjustments to rate base or adjustments to the Company's proposed capital structure. Each 1.0% return on equity is equivalent to $29.936 million in the base revenue requirement, again, assuming no adjustments to rate base or capital structure. I also describe the additional effects of the return on equity on various clause revenue recoveries and on the cost of plant included in rate base and the related depreciation expense.

I address each of these issues in more detail in the same sequence that I summarized my recommendations.

II. O&M EXPENSE IS EXCESSIVE FROM BOTH A "TOP-DOWN" PERSPECTIVE AND BASED ON SPECIFIC "BOTTOMS-UP" ADJUSTMENTS

A. O&M Expense is Excessive from a "Top-Down" Perspective

Q. Please describe the O&M expense included in the Company's proposed revenue requirement.

A. The Company proposes $354.531 million in O&M expense for the test year (on a jurisdictional basis), excluding amounts recovered outside of the base revenue requirement through the Fuel Adjustment Clause ("FAC"), Environmental Cost Recovery Clause ("ECRC"), and the Energy Conservation Cost Recovery Clause ("ECCR"). The Company's O&M expense request is summarized on Schedule C-2 and is detailed on various schedules included in its filing.

Q. How does the Company's test year request for O&M expense compare to 2012, the historical prior year?

A. The Company's test year request for O&M expense reflects significant proposed growth compared to the actual historical prior year 2012. The Company proposes an increase of $51.164 million on a total Company basis, or 16.3%, over the amount it actually incurred in 2012 ($364.126 million less $312.962 million). The Company provided its requested test year (2014), projected prior year (2013), and historical prior year (2012) O&M expense on a total Company basis, adjusted for proformas, and adjusted to exclude the O&M expense recovered through the various clauses on Schedule C-36 in its filing.

On a jurisdictional basis, the increase is even greater than on a total Company basis. The Company proposes an increase of $54.985 million, or 18.4%, in the test year compared to 2012. On a jurisdictional and adjusted proforma basis, the Company's projected test year O&M expense is $354.531 million compared to the actual $299.546 million incurred in 2012. The Company provided the adjusted proforma O&M expense information by year on a jurisdictional basis in Document 16, an attachment to Mr. Chronister's Direct Testimony.

Q. How does the Company's test year request for O&M expense compare to the pattern of actual O&M expense since 2009, the year of the Order in its last base revenue proceeding, through 2012?

A. Since the Order in early 2009, the Company (through its parent company, TECO Energy, Inc.) restructured its operations in the second half of 2009, successfully reduced its O&M expense in 2010 compared to 2009, and then managed and controlled its O&M expense so that it remained essentially flat through 2012. TECO Energy, Inc.'s 2009 SEC Form 10-K stated that mid-year it "announced organizational changes and a new senior executive team structure as part of its response to industry changes, economic uncertainties and its commitment to maintain a lean and efficient organization." [TECO Energy, Inc. 2009 10-K at 164]. In his testimony in this proceeding, Company witness Mr. Brad Register describes the 2009 restructuring and the Company's "continuing desire to maintain a lean and efficient operation." [Register Direct Testimony at 7]. Mr. Register states:

> the Florida operations were streamlined and integrated to capture efficiencies and synergies throughout the entire organization. This integration led to a net reduction of 169 positions at Tampa Electric without adversely affecting service to our customers. All areas and levels of the organization were affected, excluding front line personnel.

[Register Direct Testimony at 7].

With respect to the Company's operating expenses, TECO Energy, Inc.'s 2010 10-K stated:

> [e]xcluding all FPSC-approved cost recovery clause-related expenses, the 2009 restructuring charges and the write-off of project development costs, operations and maintenance expense increased $5.1 million in 2010, due to the accrual of performance-based incentive compensation for all employees partially offset by lower spending on generating unit maintenance and other savings as a result of the 2009 restructuring actions. Tampa Electric expects operation and maintenance expense, excluding fuel and purchased power, to decrease in 2011, assuming normal levels of employee incentive compensation accruals.

[TECO Energy, Inc. 2010 10-K at 46-47].

TECO Energy, Inc.'s 2011 10-K stated:

> [e]xcluding all FPSC-approved cost recovery clause-related expenses, operations and maintenance expense decreased $23.6 million driven primarily by lower accruals for performance-based incentive compensation for all employees and other benefit costs, lower power plant maintenance costs, and lower costs to operate and maintain the transmission and distribution system. Tampa Electric expects operations and maintenance expense to increase in 2012 driven primarily by higher employee-related expenses, and higher costs to operate the transmission, distribution and power generating systems.

[TECO Energy, Inc. 2011 10-K at 48].

In its 2012 10-K, TECO Energy, Inc. stated that with respect to the Company's electric operation results:

> O&M expense, excluding all FPSC-approved cost-recovery clauses, increased $11.8 million reflecting higher generating system maintenance expenses, higher costs to operate and maintain the distribution system and higher pension and other employee benefit expenses, partially offset by lower bad-debt expense.

[TECO Energy, Inc. 2012 10-K at 40]. I have included these referenced excerpts from TECO Energy, Inc.'s 2009, 2010, 2011 and 2012 10-K filings as my Exhibit___(LK-21).

In summary, there actually was a net decrease in O&M expense over the 2010-2012 period compared to 2009, excluding the effects in 2009 of the restructuring charges and project development write-off costs. The Company's ability to achieve essentially flat O&M expenses since the last Order through 2012 stands in stark contrast to its request for an increase of $54.985 million, or 18.4%, from 2012 to the 2014 test year.

Q. Why is this history relevant to the Company's request in this proceeding?

A. It is relevant because the Commission must judge whether the Company's request is just and reasonable. The starting point for that judgment is to make a "top-down" assessment by comparing the total requested O&M expense in the test year to the total actual O&M expense incurred in prior years. This judgment is particularly important because the test year is projected and reflects the Company's wish list for O&M expense for a period that is two years beyond the most recent calendar year for which actual results are available.

The Company claims that its request reflects the return to a "normal" level of operations after several years of reduced and deferred activities. The question the Commission must answer is whether, and, if so, to what extent, this assertion is correct given the Company's self-interest in this proceeding to project significant increases in the test year. The best evidence in support of or against the necessity of such significant increases is the Company's own experience and statements over the last several years in response to the minimal sales growth and the "industry changes, economic uncertainties and its commitment to maintain a lean and efficient organization" cited in its 2010 10-K.

The compelling actual evidence is that the Company can successfully manage and control its O&M expense if it has the real-world incentive to do so. The Commission found in the 2009 rate case that the Company's O&M expense request was excessive and reduced it by $23.977 million from the amount requested by the Company. Company witness Chronister states that in response to this reduction, the Company took "proactive steps to reduce O&M expense from budgeted amounts." [Chronister Direct Testimony at 31]. I have attached a copy of the Schedule included in the Commission's Order in the 2009 proceeding summarizing the Company's request and the Commission's adjustments as my Exhibit___(LK-2).

Q. How does the Company's request for an increase of 18.4% in jurisdictional O&M expense in the test year over the 2012 prior year actual compare to an increase that reflects only the Company's projection of inflation over the two year period, assuming no improvement in efficiencies and no changes in work-scope?

A. The increase in jurisdictional O&M expense over the two year period would be \$14.087 million, a mere fraction of the jurisdictional \$54.985 million increase proposed by the Company in this proceeding. I used the Company's projections of inflation to quantify this increase. The Company projects increases in inflation as measured by the CPI of 1.99% in 2013 and 2.66% in 2014, as shown on Schedule C-36 in its filing, an average of 2.3% annually, or 4.7% over the two year period. I computed the portion of the requested increase due to inflation alone by applying the Company's inflation rates as shown on Schedule C-36 to the \$299.546 million (jurisdictional) actually incurred in 2012 as shown on Document 16 attached to Mr. Chronister's Direct Testimony. The application of these inflation rates to the 2012 jurisdictional amounts results in an inflation adjusted amount of \$313.633 million (jurisdictional) for the test year.

Q. Is a jurisdictional O&M expense of \$313.633 million just and reasonable considering the effects of inflation, improvements in efficiencies, additional investment in systems and other plant to achieve those efficiencies, and limited increases in work-scope activities, assuming that the Company continues its three year history of cost control as a "lean and efficient organization" and that the additional investments in systems and other plant

to achieve those efficiencies are included in rate base?

A. Yes. Consequently, I recommend a reduction in the Company's requested O&M expense of $40.898 million to $313.633 million on a jurisdictional basis. The Company has not justified an increase in O&M expense in the test year compared to 2012 of more than $14.087 million. The Commission should hold the line against unbridled projected O&M expense increases. This recommendation is consistent with the Mr. Hornick's Direct Testimony wherein he states that:

> there has been a focus on controlling O&M expenses, particularly since 2009. Expense spending budgets have been held essentially flat, which has required the company to offset increases in labor, materials and other costs with reduced spending and efficiency measures across the company.

[Hornick Direct Testimony at 11].

Q. **Have you compared the Company's proposed 2014 O&M expenses to the most recent year for which actual information is available on an account level basis to determine where the Company proposes to increase its O&M expense?**

A. Yes. The Commission must determine the just and reasonable level of O&M expense. Although I recommend that it do so through a "top-down" approach, I also provide a supplemental "bottoms-up" analysis of specific issues in further support of my recommendation to disallow a portion of the Company's requested increase. This approach was necessary due to the lack of testimony addressing the reasonableness of the increase beyond general descriptions of a "return" to "normal" spend rates, whatever that abstract description means and however the Company may define "normal." The Company should not be allowed to define "normal" as the level it spent prior to its response to the last Order in 2009. The pre-2009 levels no longer are relevant or applicable due to the systemic organizational and process changes implemented by the Company in 2009 and thereafter. A more relevant and correct definition of "normal" should be 2012 because it reflects the changes implemented in 2009 and thereafter. The 2012 prior historical year represents the most recent year for which actual amounts are available and the most recent year in which the Company had a direct self-interest in controlling and minimizing increases in its O&M expenses. The Company provided its actual O&M expenses and projected test year expenses by Federal Energy Regulatory Commission ("FERC") O&M expense account on Schedule C-6 in its filing.

HUA, the Florida Office of Public Counsel ("OPC"), and the Commission Staff ("Staff") served numerous interrogatories addressing the significant increases in many of these accounts in the test year compared to 2012. This comparison on an account by account basis was hindered in part by the fact that the Company reviewed its accounting in early 2012 in conjunction with the implementation of a new accounting system and changed the accounts it used for recording the costs of numerous activities as a result of that review. In many of the Company's responses to this discovery, this change in accounting was cited as a reason for the significant increases in certain accounts. However, there should have been a concomitant reduction in the other accounts if the changes in accounting were the sole driver; generally, there were no such reductions, with only a few exceptions.

The resulting difficulty in performing an account by account comparison to determine the reasonableness of the Company's proposed O&M expense spend rate leads to the necessity, and reinforces the reasonableness, of the "top-down" approach that I recommend the Commission employ in this proceeding. Nevertheless, I also have reviewed specific O&M expense areas and specific O&M expense accounts to assess the reasonableness of the Company's requested increases under a "bottoms-up" analysis. I address these specific issues and set forth specific adjustments in the following sections of my testimony based upon a "bottoms-up" approach that, in the aggregate, support my recommendation to set the allowed O&M expense using a "top-down" approach.

B. Energy Supply Maintenance Outage Expenses Should Be Normalized to Reflect Recent Actual Experience

Q. Please describe the Company's request to increase the Energy Supply O&M expenses in the test year compared to 2012.

A. The Company proposes to increase the Energy Supply O&M expense by $21.566 million (*i.e.*, from $117.274 million in 2012 to $138.840 million in 2014), as shown on the revised version of Mr. Hornick's Exhibit No. ___ (MJH-1) Document 4.

Q. What has been the Company's recent history of Energy Supply O&M expense?

A. Since the restructuring in 2009, the Company reduced its Energy Supply O&M expense and kept it essentially flat. The Company actually incurred $120.325 million in 2010, $115.366 million in 2011, and $117.274 million in 2012, according to the revised version of Mr. Hornick's Exhibit No. ___ (MJH-1) Document 4.

Q. How much of the proposed increase in the test year is for planned maintenance outage expense?

A. The Company seeks an increase of $6.830 million for planned maintenance outage expense, to $17.585 million in 2014 from $10.755 million in 2012, which is an increase of 64%. The Company provided the historical O&M expense by unit in response to OPC's Interrogatory No. 75 ("OPC-I-75") and the test year O&M expense by unit in response to OPC's Interrogatory No. 77 ("OPC-I-77"). The increase is primarily related to planned outages for the Big Bend units that exceed the average O&M expense for these units over the most recent 10 years, according to the Company's response to OPC-I-75. I have attached a copy of the response to OPC-I-75 as my Exhibit___(LK-3) and the response to OPC-I-77 as my Exhibit___(LK-4).

Q. Should the Commission normalize the planned maintenance outage expense so that it is consistent with historic amounts?

A. Yes. The Company's proposed expense is wildly in excess of the amounts that it incurred historically. Since 2009, the Company's planned maintenance outage expense has not exceeded $2.5 million on any one of its four Big Bend units. In stark contrast to its actual recent experience, the Company proposes planned maintenance outage expense of $5.4 million on Big Bend 1 and $5.7 million on Big Bend 4 in the test year. These stark differences and the magnitude of the increase in spending should weigh strongly in favor of normalizing the expense based on historic spending levels instead of blindly adopting the Company's proposed increase.

Q. What is the effect of normalizing planned maintenance outage expense?

A. The effect, under a "bottoms-up" approach, would be a reduction of $7.145 million in planned outage expense based on the average of the three most recent years for which actual information is available. The average for the years 2010-2012 is $10.440 million, based on the simple average of the actual annual expense amounts provided in the Company's response to OPC-I-75.

<u>C. Distribution Operation and Maintenance Expense Increase is Excessive and Has Not Been Justified</u>

Q. Please describe the increase in projected test year O&M expense compared to the actual O&M expense for the distribution operation and maintenance expense accounts.

A. The test year distribution operation expense is $3.939 million, or 21.0%, more in the test year than the Company actually incurred in 2012, according to Schedule C-6. Schedule C-6 provides a comparison of prior year expenses compared to the Company's request in this proceeding by FERC O&M expense account. On Schedule C-6, the Company reflected $22.715 million in the test year and $18.776 million in 2012.

The test year distribution maintenance expense is $3.443 million, or 13.7%, more in the test year than the Company actually incurred in 2012, also according to Schedule C-6. On Schedule C-6, the Company reflected $28.570 million in the test year and $25.127 million in 2012.

Q. Did the Company justify these significant increases through the testimony of its witnesses, or more specifically, through Ms. Young's testimony?

A. No. Consequently, HUA served a series of Interrogatories and Requests for Production of Documents ("PODs") addressing the specific accounts where the Company proposes significant increases. For example, the Company proposes $0.439 million for account 581 *load dispatching distribution* in the test year compared to the actual $0.059 incurred in 2012, an increase of 744.1%. The Company explained in response to HUA's Interrogatory No. 76 ("HUA-I-76") that $0.439 million of this increase was due to a shift in accounting in mid-2012 where expenses previously recorded in account 593 were shifted to account 581. However, when reviewing account 593, the expense in that account increased by $1.584 million in the test year compared to 2012. Thus, this explanation does not justify the increase in account 581 that is requested. I have attached a copy of the Company's response to HUA-I-76 as my Exhibit___(LK-5).

As another example, the Company proposes $5.533 million for account 583 *overhead line expenses distribution* in the test year compared to the actual $0.750 incurred in 2012, an increase of 637.7%. The Company explained in response to HUA's Interrogatory No. 61 ("HUA-I-61") that $4.579 million of this increase was due to shifts in accounting in mid-2012 where expenses previously recorded in accounts 580, 588, and 593 were shifted to account 583. However, there was no net reduction in these three accounts to offset the increase in account

583 due to these "accounting" changes. Instead, these three other accounts increased in the test year by a net $2.210 million (account 580 went down by $0.147 million; account 588 increased by $0.773 million; and account 593 increased by $1.584 million). I have attached a copy of the Company's response to HUA-I-61 as my Exhibit___(LK-6).

In short, the Company's explanation of "accounting" changes does not justify the increase in account 583 that was requested and does not explain the net increases in all four of the affected accounts.

Q. **Aside from the Company's description of accounting changes, do these responses otherwise justify the increases in distribution operation and maintenance expenses reflected in the Company's projected test year revenue requirement?**

A. No. They merely provide a narrative description of the increases the Company included in the test year, but do not justify those increases. These narrative descriptions are inherently circular, *i.e.*, the amount increased because it includes additional amounts. Further, the accounting changes obscure the details of the increases on an account by account basis, but when considered together with the other distribution accounts, do not justify the overall increases on an account by account basis.

Q. **What is the effect of your recommendation on distribution operation and maintenance expense under a "bottoms-up" approach based on these facts?**

A. The effect, under a "bottoms-up" approach, would be a reduction of $5.317

million of the Company's request by reducing the distribution O&M expense to the average inflation growth since 2012 projected by the Company and shown on Schedule C-36. This assumes that any increases due to program or work-scope expansion are funded through efficiency improvements. This is a reasonable result given the Company's failure to provide substantive and rational justifications for the proposed huge increases in these expenses.

Q. One of the drivers of the distribution O&M expense increases is the addition of 40 positions. Please address the addition of these positions.

A. The Company asserts that these positions are necessary based on "workload projections and apprentices required to replace future front line retirements" and to "respond to an aging infrastructure," according to its response to Staff's Interrogatory No. 48 ("Staff-I-48"). However, the Company provided no evidence that the work-scope will be any greater in the test year than it was in 2012 or that the so-called "aging infrastructure" requires more operation or maintenance expense than it did in 2012 or that the replacement of retiring workers will be any greater in 2014 than it was in 2012. I have attached a copy of the Company's response to Staff-I-48 as my Exhibit___(LK-7).

Q. Do you have any further comments on the Company proposed increase in distribution O&M expense in the test year compared 2012?

A. Yes. The Company has invested heavily in new infrastructure, which is included in the test year rate base through the end of 2014. The Company has implemented an extensive storm hardening program, including maintenance programs, vegetation management, distribution maintenance, pole replacements, and other initiatives and actions, according to the Storm Hardening Plan addressed by Ms. Young. [Young Direct Testimony at 26-27]. The Company provided a copy of the Storm Hardening Plan in response to OPC's POD No. 76. In addition, the Company now is on a cycle-based vegetation management program, which ostensibly is lower cost than a reliability-based program.

These investments and programs, which are paid for by customers, should result in continuing and growing savings through the test year. In fact, it is these very investments and programs that have enabled the Company actually to achieve savings in O&M expense in recent years. These investments and programs should operate to continue to restrain growth in the distribution O&M expenses in future years. Thus, the Commission should view the Company's request for significant increases in these expenses with extreme skepticism and instead allow only a reasonable increase consistent with my analysis. The Commission, and more importantly, the Company's customers, who have paid and continue to pay the costs of these investments and initiatives, should see the benefits of these investments and programs in the form of savings. The test year expense should reflect the savings in lower O&M expense from reduced work-scope, not increased O&M expense.

<u>D. Incentive Compensation Expense Increase is Excessive and Has Not Been Justified</u>

Q. Please describe the Company's requested increase in Performance Sharing Plan ("PSP") incentive compensation expense.

A. The Company proposes to increase the PSP incentive compensation expense by $5.956 million, from $6.427 million in 2012 to $12.383 million in 2014, according to the Company's response to OPC's Interrogatory No. 8 ("OPC-I-8"). The expense in 2012 was based on 2.0% of payroll, according to the Company's response to OPC's Interrogatory No. 60 ("OPC-I-60"), and the proposed expense in 2014 is based on 5.0% of payroll, according to Company witness Mr. Brad Register. [Register Direct Testimony at 18]. The Company has not yet determined the PSP goals for 2014, but they are expected to be "consistent" with the goals for 2013, according to Mr. Register. [*Id.* at 17]. The Company claims that there is another 7.0% available based on financial performance, but that it did not include this amount in its revenue requirement, also according to Mr. Register. [*Id.* at 18]. I have attached a copy of the Company's responses to OPC-I-8 and OPC-I-60 as my Exhibit___(LK-8) and Exhibit___(LK-9), respectively.

Q. Is the PSP incentive compensation expense discretionary and does the Company change the goals and percentages from year to year?

A. Yes. The Company reassesses the PSP incentive compensation expense goals and percentages each year. For example, in 2008, the potential payout was 4.0%, consisting of 2.25% for various safety and operational goals and 1.75% for financial goals. However, in 2012, the potential payout was only 2.0%, consisting only of safety goals due to the failure to achieve the Company's financial goals.

Q. Why is it relevant whether the PSP incentive compensation expense is discretionary?

A. It is relevant because the Company is under no obligation to continue the PSP or to set goals that benefit customers or challenge the organization to achieve metrics that directly benefit customers. In other words, even if the expense is allowed, the Company is under no obligation to pay these amounts. It may pay less or it may pay more, depending on the annual targets that it sets and its financial performance.

Q. What is the effect of your recommendation to reject the proposed increase in PSP incentive compensation expense under a "bottoms-up" approach?

A. The effect, under a "bottoms-up" approach, would be a reduction of $5.304 million to eliminate the Company's proposed increase. This reduction would allow recovery of no more than $7.079 million, using the 2.0% payout rate from 2012. This amount reflects the increase in payroll in the test year compared to 2012. To quantify the amount that should be allowed, I used the ratio of the $6.427 million in PSP incentive expense to the $194.408 million in payroll dollars in 2012 from the Company's response to OPC's Interrogatory No. 57 ("OPC-I-57") and applied this ratio to the $214.139 million in proposed payroll dollars in 2014, also from the Company's response to OPC-I-57. I have attached a copy of the Company's response to OPC-I-57 as my Exhibit___(LK-10).

Q. HUA witness Mr. Baudino notes in his testimony that the Company's common equity ratio is greater than the comparative group's. What is the significance of the common equity ratio on the revenue requirement?

A. Common equity is the most expensive source of financing for two reasons. First, the return on equity generally is much greater than the cost of debt. In this case, the Company seeks an 11.25% return on equity, a 5.40% cost of long-term debt, and a 1.47% cost of short-term debt. The weighted average cost of the long-term debt and short-term debt is 5.34%.

Second, the return on equity must be grossed-up for income taxes. The cost of debt is not grossed-up for income taxes. The gross-up factor for the return on equity is 1.6322. Thus, the return on equity sought by the Company is equivalent to a before tax cost of 18.36%.

Q. What is the effect of reducing the common equity ratio by 1.0% and increasing the long-term debt ratio by 1.0%?

A. The effect is a reduction in the revenue requirement of $5.6 million.

Q. Regardless of whether the Commission employs a "top-down" approach or a "bottoms-up" approach to the Company's requested O&M expense, should the Commission consider options to incentivize the Company to maximize actual PSP incentive compensation tied to a reduction in its common equity ratio and an increase in its long-term debt ratio?

A. Yes. I recommend that the Commission consider two options to incentivize the Company to reduce its common equity ratio. The first option would be to reduce the common equity ratio in the rate of return in this case and then allow the Company to retain 25% of the revenue requirement reduction as an increase to the PSP incentive compensation expense. In that manner, for each reduction of 1% in the common equity ratio, the Commission would reduce the revenue requirement by $5.6 million through a lower rate of return, but then increase it by $1.4 million through an increase to the PSP incentive compensation expense.

The second option would be for the Commission to establish an incentive for the Company to reduce its common equity ratio in the next rate case compared to the common equity ratio allowed in this case. The Commission could state its intent to allow a proforma adjustment to increase the PSP incentive compensation expense in the next rate case for 25% of the savings in the revenue requirement due to the lower return in the next case.

E. Stock Compensation Expense

Q. Please describe the Company's request for stock compensation expense.

A. The Company included stock compensation expense of $5.084 million in the revenue requirement for the test year, according to the Company's response to OPC-I-57. The Company incurred $2.703 million for this expense in 2010, $3.006 million in 2011, and $3.679 million in 2012, according to the response to OPC-I-57. Unlike its other benefit costs, the Company expensed the entire cost each year and did not capitalize any amount.

The Company's stock compensation expense is based on the grant and payout of performance shares and time-vested restricted stock pursuant to the Company's long-term incentive awards, according to TECO Energy, Inc.'s 2013 Proxy Statement. The payout of these awards is based on the Company's total shareholder return compared to the companies in the Dow Jones Conventional Electricity and Multiutility subsectors of its utility index, also according to the 2013 Proxy Statement. I have attached excerpts of the TECO Energy, Inc. 2013

Proxy Statement as my Exhibit___(LK-22).

Q. Should the Commission include stock compensation expense in the revenue requirement?

A. No. This expense is incurred to incentivize the financial performance of the Company, not to achieve operational or customer service goals that may directly benefit the customers. As such, the expense should be borne by the Company's shareholder, TECO Energy, Inc. In addition, the Commission should not provide financial incentives to seek and obtain rate increases and higher authorized returns on equity, particularly when such increases are paid by the same customers who are asked to pay for this incentive against their interests. Again, the expense should be borne by the Company's shareholder, TECO Energy, Inc.

F. Injuries and Damages Expense Should Be Normalized to Reflect Recent Actual Experience

Q. Please describe the Company's requested injuries and damages expense.

A. The Company proposes injuries and damages expense of $6.806 million according to its response to OPC's Interrogatory No. 12 ("OPC-I-12"). I have attached a copy of this response as my Exhibit___(LK-11). No witness explicitly addresses this expense in his or her Direct Testimony.

Q. How does the Company's request compare to its actual expense in prior years?

A. The Company's request is $1.728 million greater than the $5.078 million average of the injuries and damages expense actually incurred in the years 2010 through

2012. The Company incurred \$3.663 million in 2010, \$5.018 million in 2011, and \$6.552 million in 2012, according to its response to OPC-I-12.

Q. Under a "bottoms-up" approach, should the Commission consider the Company's historical experience and normalize this expense for the test year based on that experience?

A. Yes. Under the "bottoms-up" approach, the Commission should normalize this expense based on the Company's actual experience and reduce the amount included in the revenue requirement by \$1.728 million to reflect its most recent three years of experience. The Company uses reserve accounting and presently has a liability reserve balance, meaning that the Company has accrued and customers have contributed more to the reserve than the Company has paid out for such damages. Unlike the storm damage expense accrual, the Company does not accrue the same amount authorized by the Commission each year and retains discretion to accrue an amount each year based on experience and its determination of an appropriate reserve.

G. <u>Miscellaneous General Expense Is Excessive because It Does Not Reflect TECO Energy, Inc.'s Acquisition of New Mexico Gas Company and the Lower Allocation of Affiliate Costs to the Company</u>

Q. How does the Company account for affiliate charges from TECO Energy, Inc. in the test year?

A. The Company includes these amounts in account 930, Miscellaneous General Expense, although it recorded such charges in a variety of accounts in prior years.

Q. Did the Company reflect the lower affiliate charges from TECO Energy, Inc. that will result from TECO Energy, Inc.'s acquisition of New Mexico Gas Company?

A. No, according to the Company's response to OPC's Interrogatory No. 131 ("OPC-I-131"). The Company claims that it presently does not know whether TECO Energy, Inc. will direct charge any of its expenses to New Mexico Gas Company, according to its response to OPC's Interrogatory No. 133 ("OPC-I-133"), but it does agree that it will allocate a portion of the expenses that are not direct charged to the Company or other affiliates to New Mexico Gas Company starting in March 2014 when it closes on the acquisition, according to its responses to OPC-I-131 and OPC's Interrogatory No. 138 ("OPC-I-138"). I have attached a copy of the response to OPC-I-131 as my Exhibit___(LK-12), a copy of the response to OPC-I-133 as my Exhibit___(LK-13) and a copy of the response to OPC-I-138 as my Exhibit___(LK-14).

Q. Has the Company estimated what the reduction in allocated expenses will be?

A. Yes. The Company estimates that the reduction in allocated expenses will be $2.1 million in 2014, according to the Company's response to OPC-I-131, and $2.9 million in 2015 and 2016, according to its response to OPC-I-138. If some of the allocated expenses instead are direct charged to New Mexico Gas Company, then the reduction in the allocated charges to the Company will be greater than the Company quantified.

Q. Do you recommend that this reduction in af liate expense be reflected in the revenue requirement under a "bottoms-up" approach?

A. Yes. The effect, under a "bottoms-up" approach, would be a reduction in the Company's O&M expense of $2.9 million. The Commission should use the larger amount, rather than the $2.1 million amount estimated by the Company specifically for the test year. This is appropriate in order to reflect the annualized amount, rather than the savings for a portion of the year, and also to reflect the full impact of the acquisition on the Company, including the effect of a reduction in the allocated charges due to the fact that TECO Energy, Inc. likely will direct charge certain of its costs to New Mexico Gas Company, which should result in a reduction in the residual amounts that are allocated to the various affiliates using the modified Massachusetts methodology cited in the response to OPC-I-131.

H. Call Center Expense Increase Is Excessive and Has Not Been Justified

Q. Please describe the Company's requested increase in Call Center expenses.

A. The Company proposes to increase Call Center expense by $1.967 million in the test year compared to 2012, from $8.566 million to $10.533 million, according to its response to OPC's Interrogatory No. 49 ("OPC-I-49"). This is an increase of 23.0% over two years. The Company attributes part of this increase to additional staffing in order to improve Call Center metrics, according to its response to OPC-I-49. I have attached a copy of the response to OPC-I-49 as my Exhibit___(LK-15).

Q. Should the Commission authorize an increase of this magnitude in Call Center expenses?

A. No. First, the Company has provided no evidence that the 2012 performance was not acceptable. Second, the Company has provided no evidence that the 2012 performance was worse than its historical average. Third, the Company has provided no evidence that the 2012 performance was due to a lack of staffing. Fourth, the Company has provided no evidence why its other communication tools, including customer service interaction through its internet portal, either has been insufficient or cannot be improved in order to relieve any pressure on the Call Center.

Q. What is your recommendation with respect to the Call Center expenses under a "bottoms-up" approach?

A. I would recommend that the Commission reject an increase of this magnitude and instead increase the 2012 actual expense by the average inflation growth since 2012 projected by the Company and shown on Schedule C-36 to reflect inflation net of efficiency improvements and incremental expenses. This would result in an increase of $0.402 million, from $8.556 million to $8.958 million. I would recommend that the Commission reduce the Company's requested O&M expense by $1.575 million.

I. Uncollectible Accounts Expense Increase Is Excessive and Has Not Been Justified

Q. Please describe the Company's request for uncollectible accounts expense.

A. The Company proposes to increase the uncollectible accounts expense by $1.302 million in the test year compared to 2012. The Company implemented a new credit and collections system in 2011 along with other initiatives that reduced this expense compared to prior years, according to its response to HUA's Interrogatory No. 81 ("HUA-I-81"). However, the Company now believes that the uncollectible accounts expense "will trend toward the higher historical levels through 2014," according to its response to HUA-I-81. I have attached a copy of the response to HUA-I-81 as my Exhibit___(LK-16).

Q. Should the Commission approve this increase for recovery in the revenue requirement?

A. No. The Company has offered no empirical evidence that this expense will revert to historical levels. The Company's claim is particularly disturbing because of the investment in and implementation of technology in the form of the new credit and collections system along with the other "successful initiatives," such as the outbound dialer and better targeted and more aggressive collection policies, cited in the response to OPC-I-81. These costs also are included in the Company's revenue requirement. The savings from these initiatives also should be reflected.

<u>J. Legal Expense Increase Is Excessive and Has Not Been Justified</u>

Q. Please describe the Company's request for legal expense included in outside professional services in account 923.

A. The Company proposes to increase the legal expense by $2.254 million to $4.115

million in the test year, compared to $1.861 million 2012, as shown on the Company's corrected Schedule C-16 in its filing. The Company claims that the increase consists of $0.733 million for the amortization of rate case expenses, $0.520 million for pending litigation with Verizon, and $0.560 million associated with fuel contracts that are expiring, and other miscellaneous legal expenses, according to its response to OPC's Interrogatory No. 119 ("OPC-I-119"). I have attached a copy of the response to OPC-I-119 as my Exhibit___(LK-17).

Q. Should the Commission approve this increase for recovery in the revenue requirement?

A. No, except for the rate case amortization expense. The Commission should disallow the remaining $1.521 million. The Company has offered no evidence that it did not incur similar expenses in 2012, albeit for different contracts and other litigation. The Company does not propose a reduction in legal expenses for those similar expenses incurred in 2012 that will not recur in 2014. However, if, in fact, similar expenses were not incurred in 2012 and these expenses in the test year are nonrecurring, then the expenses should be deferred and recovery sought in the Company's next base rate case when they are known and measurable.

III. OTHER REVENUES SHOULD BE INCREASED TO REFLECT ONGOING OATT REVENUES FROM CALPINE

Q. In its filing, the Company assumed that it no longer would receive revenues or provide transmission service to Auburndale Power Partners ("APP") or Calpine under its OATT in the test year even though it had not received

official notice of termination from either of these entities. Has there been an update since the Company made its filing?

A. Yes. The Company recently received a notification from Calpine that it will roll-over 249 MW effective June 1, 2014 and ending May 31, 2019, according to its responses to HUA's Interrogatory No. 125 ("HUA-I-125") and Interrogatory No. 131 ("HUA-I-131"). This will result in an additional $4.92 million in revenues in the test year that were not reflected in the Company's revenue requirement, according to its response to HUA-I-131. I have attached a copy of the responses to HUA-I-125 and HUA-I-131 as my Exhibit___(LK-18) and Exhibit___(LK-19), respectively.

Q. **Should these additional revenues be reflected in the Company's revenue requirement?**

A. Yes. Consequently, the Company's revenue deficiency should be reduced by $4.92 million.

IV. RETURN ON EQUITY IS EXCESSIVE

Q. **If the Commission approves a reduction in the return on equity, as proposed by HUA witness Mr. Baudino, what effects will that have on the revenue requirement in this proceeding and in the various clause recoveries?**

A. In this proceeding, it will result in a reduction to the Company's claimed revenue deficiency and a reduction in the base revenue increase. It also will result in a reduction to the Company's clause revenue recoveries that include a return on rate base, such as the Environmental Cost Recovery Clause. The reductions in the clause revenue recoveries will partially offset any base revenue increase in this proceeding.

Q. Are there other effects resulting from a reduction in the return on equity?

A. Yes. A reduction in the return on equity also will reduce the rate of return used to capitalize financing costs during construction in the form of Allowance for Funds Used During Construction ("AFUDC"). The AFUDC is added to Construction Work in Progress ("CWIP") during construction and is included along with the direct costs of construction in Plant in Service when the CWIP is completed and placed in service. Due to the lower rate of return for AFUDC, the Company's rate base and depreciation expense will be less than if there had been an excessive return on equity during the construction period. Thus, a reduction in the AFUDC rate from the effective date of the Order in this proceeding until the next order in a subsequent proceeding resetting the return on equity will result in ongoing lower revenue requirements for decades over the service lives of the assets constructed during the period in which the lower AFUDC rate was in effect.

Q. Have you quantified the effect of the HUA return on equity recommendation in this proceeding?

A. Yes. The effect is to reduce the Company's revenue requirement by $58.375 million on a jurisdictional basis to reflect the reduction to the 9.3% return recommended by Mr. Baudino from the 11.25% return sought by the Company. The effect is to reduce the Company's revenue requirement by $29.936 million for each 1.0% change in the return on equity. I relied on the Company's rate base, capital structure, and cost of all capital components, except for the return on equity, to quantify the effects of modifying the return on equity; however, the effects will vary depending on the adjustments to rate base and capital structure that are adopted by the Commission in its Order. I provide my computations, including the reduction in the grossed-up rate of return, in my Exhibit___(LK-20).

Q. Does this complete your testimony?

A. Yes.

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

IN RE: PETITION FOR RATE INCREASE BY	)	DOCKET NO. 130040-EI
TAMPA ELECTRIC COMPANY	)	

EXHIBIT___(LK-1)

OF

LANE KOLLEN

ON BEHALF OF

THE WCF HOSPITAL UTILITY ALLIANCE

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

RESUME OF LANE KOLLEN, VICE PRESIDENT

EDUCATION

University of Toledo, BBA
Accounting

University of Toledo, MBA

Luther Rice University, MA

PROFESSIONAL CERTIFICATIONS

Certified Public Accountant (CPA)

Certified Management Accountant (CMA)

PROFESSIONAL AFFILIATIONS

American Institute of Certified Public Accountants

Georgia Society of Certified Public Accountants

Institute of Management Accountants

Mr. Kollen has more than thirty years of utility industry experience in the financial, rate, tax, and planning areas. He specializes in revenue requirements analyses, taxes, evaluation of rate and financial impacts of traditional and nontraditional ratemaking, utility mergers/acquisition and diversification. Mr. Kollen has expertise in proprietary and nonproprietary software systems used by utilities for budgeting, rate case support and strategic and financial planning.

RESUME OF LANE KOLLEN, VICE PRESIDENT

EXPERIENCE

1986 to Present:

J. Kennedy and Associates, Inc.: Vice President and Principal. Responsible for utility stranded cost analysis, revenue requirements analysis, cash flow projections and solvency, financial and cash effects of traditional and nontraditional ratemaking, and research, speaking and writing on the effects of tax law changes. Testimony before Connecticut, Florida, Georgia, Indiana, Louisiana, Kentucky, Maine, Maryland, Minnesota, New York, North Carolina, Ohio, Pennsylvania, Tennessee, Texas, West Virginia and Wisconsin state regulatory commissions and the Federal Energy Regulatory Commission.

1983 to 1986:

Energy Management Associates: Lead Consultant.
Consulting in the areas of strategic and financial planning, traditional and nontraditional ratemaking, rate case support and testimony, diversification and generation expansion planning. Directed consulting and software development projects utilizing PROSCREEN II and ACUMEN proprietary software products. Utilized ACUMEN detailed corporate simulation system, PROSCREEN II strategic planning system and other custom developed software to support utility rate case filings including test year revenue requirements, rate base, operating income and pro-forma adjustments. Also utilized these software products for revenue simulation, budget preparation and cost-of-service analyses.

1976 to 1983:

The Toledo Edison Company: Planning Supervisor.
Responsible for financial planning activities including generation expansion planning, capital and expense budgeting, evaluation of tax law changes, rate case strategy and support and computerized financial modeling using proprietary and nonproprietary software products. Directed the modeling and evaluation of planning alternatives including:

Rate phase-ins.
Construction project cancellations and write-offs.
Construction project delays.
Capacity swaps.
Financing alternatives.
Competitive pricing for off-system sales.
Sale/leasebacks.

RESUME OF LANE KOLLEN, VICE PRESIDENT

CLIENTS SERVED

Industrial Companies and Groups

Air Products and Chemicals, Inc.
Airco Industrial Gases
Alcan Aluminum
Armco Advanced Materials Co.
Armco Steel
Bethlehem Steel
Connecticut Industrial Energy Consumers
ELCON
Enron Gas Pipeline Company
Florida Industrial Power Users Group
Gallatin Steel
General Electric Company
GPU Industrial Intervenors
Indiana Industrial Group
Industrial Consumers for Fair Utility Rates - Indiana
Industrial Energy Consumers - Ohio
Kentucky Industrial Utility Customers, Inc.
Kimberly-Clark Company
Lehigh Valley Power Committee
Maryland Industrial Group
Multiple Intervenors (New York)
National Southwire
North Carolina Industrial Energy Consumers
Occidental Chemical Corporation
Ohio Energy Group
Ohio Industrial Energy Consumers
Ohio Manufacturers Association
Philadelphia Area Industrial Energy Users Group
PSI Industrial Group
Smith Cogeneration
Taconite Intervenors (Minnesota)
West Penn Power Industrial Intervenors
West Virginia Energy Users Group
Westvaco Corporation

Regulatory Commissions and Government Agencies

Cities in Texas-New Mexico Power Company's Service Territory
Cities in AEP Texas Central Company's Service Territory
Cities in AEP Texas North Company's Service Territory
Georgia Public Service Commission Staff
Kentucky Attorney General's Office, Division of Consumer Protection
Louisiana Public Service Commission Staff
Maine Office of Public Advocate
New York State Energy Office
Office of Public Utility Counsel (Texas)

RESUME OF LANE KOLLEN, VICE PRESIDENT

Utilities

Allegheny Power System
Atlantic City Electric Company
Carolina Power & Light Company
Cleveland Electric Illuminating Company
Delmarva Power & Light Company
Duquesne Light Company
General Public Utilities
Georgia Power Company
Middle South Services
Nevada Power Company
Niagara Mohawk Power Corporation
Otter Tail Power Company
Pacific Gas & Electric Company
Public Service Electric & Gas
Public Service of Oklahoma
Rochester Gas and Electric
Savannah Electric & Power Company
Seminole Electric Cooperative
Southern California Edison
Talquin Electric Cooperative
Tampa Electric
Texas Utilities
Toledo Edison Company

**Expert Testimony Appearances
of
Lane Kollen
as of July 2013**

Date	Case	Jurisdict.	Party	Utility	Subject
10/86	U-17282 Interim	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Cash revenue requirements financial solvency.
11/86	U-17282 Interim Rebuttal	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Cash revenue requirements financial solvency.
12/86	9613	KY	Attorney General Div. of Consumer Protection	Big Rivers Electric Corp.	Revenue requirements accounting adjustments financial workout plan.
1/87	U-17282 Interim	LA 19th Judicial District Ct.	Louisiana Public Service Commission Staff	Gulf States Utilities	Cash revenue requirements, financial solvency.
3/87	General Order 236	WV	West Virginia Energy Users' Group	Monongahela Power Co.	Tax Reform Act of 1986.
4/87	U-17282 Prudence	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Prudence of River Bend 1, economic analyses, cancellation studies.
4/87	M-100 Sub 113	NC	North Carolina Industrial Energy Consumers	Duke Power Co.	Tax Reform Act of 1986.
5/87	86-524-E-SC	WV	West Virginia Energy Users' Group	Monongahela Power Co.	Revenue requirements, Tax Reform Act of 1986.
5/87	U-17282 Case In Chief	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Revenue requirements, River Bend 1 phase-in plan, financial solvency.
7/87	U-17282 Case In Chief Surrebuttal	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Revenue requirements, River Bend 1 phase-in plan, financial solvency.
7/87	U-17282 Prudence Surrebuttal	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Prudence of River Bend 1, economic analyses, cancellation studies.
7/87	86-524 E-SC Rebuttal	WV	West Virginia Energy Users' Group	Monongahela Power Co.	Revenue requirements, Tax Reform Act of 1986.
8/87	9885	KY	Attorney General Div. of Consumer Protection	Big Rivers Electric Corp.	Financial workout plan.
8/87	E-015/GR-87-223	MN	Taconite Intervenors	Minnesota Power & Light Co.	Revenue requirements, O&M expense, Tax Reform Act of 1986.
10/87	870220-EI	FL	Occidental Chemical Corp.	Florida Power Corp.	Revenue requirements, O&M expense, Tax Reform Act of 1986.
11/87	87-07-01	CT	Connecticut Industrial Energy Consumers	Connecticut Light & Power Co.	Tax Reform Act of 1986.
1/88	U-17282	LA 19th Judicial District Ct.	Louisiana Public Service Commission	Gulf States Utilities	Revenue requirements, River Bend 1 phase-in plan, rate of return.
2/88	9934	KY	Kentucky Industrial Utility Customers	Louisville Gas & Electric Co.	Economics of Trimble County, completion.
2/88	10064	KY	Kentucky Industrial Utility Customers	Louisville Gas & Electric Co.	Revenue requirements, O&M expense, capital structure, excess deferred income taxes.

**Expert Testimony Appearances
of
Lane Kollen
as of July 2013**

Date	Case	Jurisdict.	Party	Utility	Subject
5/88	10217	KY	Alcan Aluminum National Southwire	Big Rivers Electric Corp.	Financial workout plan.
5/88	M-87017-1C001	PA	GPU Industrial Intervenors	Metropolitan Edison Co.	Nonutility generator deferred cost recovery.
5/88	M-87017-2C005	PA	GPU Industrial Intervenors	Pennsylvania Electric Co.	Nonutility generator deferred cost recovery.
6/88	U-17282	LA 19th Judicial District Ct.	Louisiana Public Service Commission	Gulf States Utilities	Prudence of River Bend 1 economic analyses, cancellation studies, financial modeling.
7/88	M-87017-1C001 Rebuttal	PA	GPU Industrial Intervenors	Metropolitan Edison Co.	Nonutility generator deferred cost recovery, SFAS No. 92.
7/88	M-87017-2C005 Rebuttal	PA	GPU Industrial Intervenors	Pennsylvania Electric Co.	Nonutility generator deferred cost recovery, SFAS No. 92.
9/88	88-05-25	CT	Connecticut Industrial Energy Consumers	Connecticut Light & Power Co.	Excess deferred taxes, O&M expenses.
9/88	10064 Rehearing	KY	Kentucky Industrial Utility Customers	Louisville Gas & Electric Co.	Premature retirements, interest expense.
10/88	88-170-EL-AIR	OH	Ohio Industrial Energy Consumers	Cleveland Electric Illuminating Co.	Revenue requirements, phase-in, excess deferred taxes, O&M expenses, financial considerations, working capital.
10/88	88-171-EL-AIR	OH	Ohio Industrial Energy Consumers	Toledo Edison Co.	Revenue requirements, phase-in, excess deferred taxes, O&M expenses, financial considerations, working capital.
10/88	8800-355-EI	FL	Florida Industrial Power Users' Group	Florida Power & Light Co.	Tax Reform Act of 1986, tax expenses, O&M expenses, pension expense (SFAS No. 87).
10/88	3780-U	GA	Georgia Public Service Commission Staff	Atlanta Gas Light Co.	Pension expense (SFAS No. 87).
11/88	U-17282 Remand	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Rate base exclusion plan (SFAS No. 71).
12/88	U-17970	LA	Louisiana Public Service Commission Staff	AT&T Communications of South Central States	Pension expense (SFAS No. 87).
12/88	U-17949 Rebuttal	LA	Louisiana Public Service Commission Staff	South Central Bell	Compensated absences (SFAS No. 43), pension expense (SFAS No. 87), Part 32, income tax normalization.
2/89	U-17282 Phase II	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Revenue requirements, phase-in of River Bend 1, recovery of canceled plant.
6/89	881602-EU 890326-EU	FL	Talquin Electric Cooperative	Talquin/City of Tallahassee	Economic analyses, incremental cost-of-service, average customer rates.
7/89	U-17970	LA	Louisiana Public Service Commission Staff	AT&T Communications of South Central States	Pension expense (SFAS No. 87), compensated absences (SFAS No. 43), Part 32.

**Expert Testimony Appearances
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Date	Case	Jurisdict.	Party	Utility	Subject
8/89	8555	TX	Occidental Chemical Corp.	Houston Lighting & Power Co.	Cancellation cost recovery, tax expense, revenue requirements.
8/89	3840-U	GA	Georgia Public Service Commission Staff	Georgia Power Co.	Promotional practices, advertising, economic development.
9/89	U-17282 Phase II Detailed	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Revenue requirements, detailed investigation.
10/89	8880	TX	Enron Gas Pipeline	Texas-New Mexico Power Co.	Deferred accounting treatment, sale/leaseback.
10/89	8928	TX	Enron Gas Pipeline	Texas-New Mexico Power Co.	Revenue requirements, imputed capital structure, cash working capital.
10/89	R-891364	PA	Philadelphia Area Industrial Energy Users Group	Philadelphia Electric Co.	Revenue requirements.
11/89 12/89	R-891364 Surrebuttal (2 Filings)	PA	Philadelphia Area Industrial Energy Users Group	Philadelphia Electric Co.	Revenue requirements, sale/leaseback.
1/90	U-17282 Phase II Detailed Rebuttal	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Revenue requirements, detailed investigation.
1/90	U-17282 Phase III	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Phase-in of River Bend 1, deregulated asset plan.
3/90	890319-EI	FL	Florida Industrial Power Users Group	Florida Power & Light Co.	O&M expenses, Tax Reform Act of 1986.
4/90	890319-EI Rebuttal	FL	Florida Industrial Power Users Group	Florida Power & Light Co.	O&M expenses, Tax Reform Act of 1986.
4/90	U-17282	LA 19th Judicial District Ct.	Louisiana Public Service Commission	Gulf States Utilities	Fuel clause, gain on sale of utility assets.
9/90	90-158	KY	Kentucky Industrial Utility Customers	Louisville Gas & Electric Co.	Revenue requirements, post-test year additions, forecasted test year.
12/90	U-17282 Phase IV	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Revenue requirements.
3/91	29327, et. al.	NY	Multiple Intervenors	Niagara Mohawk Power Corp.	Incentive regulation.
5/91	9945	TX	Office of Public Utility Counsel of Texas	El Paso Electric Co.	Financial modeling, economic analyses, prudence of Palo Verde 3.
9/91	P-910511 P-910512	PA	Allegheny Ludlum Corp., Armco Advanced Materials Co., The West Penn Power Industrial Users' Group	West Penn Power Co.	Recovery of CAAA costs, least cost financing.
9/91	91-231-E-NC	WV	West Virginia Energy Users Group	Monongahela Power Co.	Recovery of CAAA costs, least cost financing.

**Expert Testimony Appearances
of
Lane Kollen
as of July 2013**

Date	Case	Jurisdict.	Party	Utility	Subject
11/91	U-17282	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Asset impairment, deregulated asset plan, revenue requirements.
12/91	91-410-EL-AIR	OH	Air Products and Chemicals, Inc., Armco Steel Co., General Electric Co., Industrial Energy Consumers	Cincinnati Gas & Electric Co.	Revenue requirements, phase-in plan.
12/91	PUC Docket 10200	TX	Office of Public Utility Counsel of Texas	Texas-New Mexico Power Co.	Financial integrity, strategic planning, declined business affiliations.
5/92	910890-EI	FL	Occidental Chemical Corp.	Florida Power Corp.	Revenue requirements, O&M expense, pension expense, OPEB expense, fossil dismantling, nuclear decommissioning.
8/92	R-00922314	PA	GPU Industrial Intervenors	Metropolitan Edison Co.	Incentive regulation, performance rewards, purchased power risk, OPEB expense.
9/92	92-043	KY	Kentucky Industrial Utility Consumers	Generic Proceeding	OPEB expense.
9/92	920324-EI	FL	Florida Industrial Power Users' Group	Tampa Electric Co.	OPEB expense.
9/92	39348	IN	Indiana Industrial Group	Generic Proceeding	OPEB expense.
9/92	910840-PU	FL	Florida Industrial Power Users' Group	Generic Proceeding	OPEB expense.
9/92	39314	IN	Industrial Consumers for Fair Utility Rates	Indiana Michigan Power Co.	OPEB expense.
11/92	U-19904	LA	Louisiana Public Service Commission Staff	Gulf States Utilities /Entergy Corp.	Merger.
11/92	8649	MD	Westvaco Corp., Eastalco Aluminum Co.	Potomac Edison Co.	OPEB expense.
11/92	92-1715-AU-COI	OH	Ohio Manufacturers Association	Generic Proceeding	OPEB expense.
12/92	R-00922378	PA	Armco Advanced Materials Co., The WPP Industrial Intervenors	West Penn Power Co.	Incentive regulation, performance rewards, purchased power risk, OPEB expense.
12/92	U-19949	LA	Louisiana Public Service Commission Staff	South Central Bell	Affiliate transactions, cost allocations, merger.
12/92	R-00922479	PA	Philadelphia Area Industrial Energy Users' Group	Philadelphia Electric Co.	OPEB expense.
1/93	8487	MD	Maryland Industrial Group	Baltimore Gas & Electric Co., Bethlehem Steel Corp.	OPEB expense, deferred fuel, CWIP in rate base.
1/93	39498	IN	PSI Industrial Group	PSI Energy, Inc.	Refunds due to over-collection of taxes on Marble Hill cancellation.

**Expert Testimony Appearances
of
Lane Kollen
as of July 2013**

Date	Case	Jurisdict.	Party	Utility	Subject
3/93	92-11-11	CT	Connecticut Industrial Energy Consumers	Connecticut Light & Power Co	OPEB expense.
3/93	U-19904 (Surrebuttal)	LA	Louisiana Public Service Commission Staff	Gulf States Utilities /Entergy Corp.	Merger.
3/93	93-01-EL-EFC	OH	Ohio Industrial Energy Consumers	Ohio Power Co.	Affiliate transactions, fuel.
3/93	EC92-21000 ER92-806-000	FERC	Louisiana Public Service Commission Staff	Gulf States Utilities /Entergy Corp.	Merger.
4/93	92-1464-EL-AIR	OH	Air Products Armco Steel Industrial Energy Consumers	Cincinnati Gas & Electric Co.	Revenue requirements, phase-in plan.
4/93	EC92-21000 ER92-806-000 (Rebuttal)	FERC	Louisiana Public Service Commission	Gulf States Utilities /Entergy Corp.	Merger.
9/93	93-113	KY	Kentucky Industrial Utility Customers	Kentucky Utilities	Fuel clause and coal contract refund.
9/93	92-490, 92-490A, 90-360-C	KY	Kentucky Industrial Utility Customers and Kentucky Attorney General	Big Rivers Electric Corp.	Disallowances and restitution for excessive fuel costs, illegal and improper payments, recovery of mine closure costs.
10/93	U-17735	LA	Louisiana Public Service Commission Staff	Cajun Electric Power Cooperative	Revenue requirements, debt restructuring agreement, River Bend cost recovery.
1/94	U-20647	LA	Louisiana Public Service Commission Staff	Gulf States Utilities Co.	Audit and investigation into fuel clause costs.
4/94	U-20647 (Surrebuttal)	LA	Louisiana Public Service Commission Staff	Gulf States Utilities Co.	Nuclear and fossil unit performance, fuel costs, fuel clause principles and guidelines.
5/94	U-20178	LA	Louisiana Public Service Commission Staff	Louisiana Power & Light Co.	Planning and quantification issues of least cost integrated resource plan.
9/94	U-19904 Initial Post-Merger Earnings Review	LA	Louisiana Public Service Commission Staff	Gulf States Utilities Co.	River Bend phase-in plan, deregulated asset plan, capital structure, other revenue requirement issues.
9/94	U-17735	LA	Louisiana Public Service Commission Staff	Cajun Electric Power Cooperative	G&T cooperative ratemaking policies, exclusion of River Bend, other revenue requirement issues.
10/94	3905-U	GA	Georgia Public Service Commission Staff	Southern Bell Telephone Co.	Incentive rate plan, earnings review.
10/94	5258-U	GA	Georgia Public Service Commission Staff	Southern Bell Telephone Co.	Alternative regulation, cost allocation.
11/94	U-19904 Initial Post-Merger Earnings Review (Rebuttal)	LA	Louisiana Public Service Commission Staff	Gulf States Utilities Co.	River Bend phase-in plan, deregulated asset plan, capital structure, other revenue requirement issues.
11/94	U-17735 (Rebuttal)	LA	Louisiana Public Service Commission Staff	Cajun Electric Power Cooperative	G&T cooperative ratemaking policy, exclusion of River Bend, other revenue requirement issues.

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Date	Case	Jurisdict.	Party	Utility	Subject
4/95	R-00943271	PA	PP&L Industrial Customer Alliance	Pennsylvania Power & Light Co.	Revenue requirements. Fossil dismantling, nuclear decommissioning.
6/95	3905-U Rebuttal	GA	Georgia Public Service Commission	Southern Bell Telephone Co.	Incentive regulation, affiliate transactions, revenue requirements, rate refund.
6/95	U-19904 (Direct)	LA	Louisiana Public Service Commission Staff	Gulf States Utilities Co.	Gas, coal, nuclear fuel costs, contract prudence, base/fuel realignment.
10/95	95-02614	TN	Tennessee Office of the Attorney General Consumer Advocate	BellSouth Telecommunications, Inc.	Affiliate transactions.
10/95	U-21485 (Direct)	LA	Louisiana Public Service Commission Staff	Gulf States Utilities Co.	Nuclear O&M, River Bend phase-in plan, base/fuel realignment, NOL and AltMin asset deferred taxes, other revenue requirement issues.
11/95	U-19904 (Surrebuttal)	LA	Louisiana Public Service Commission Staff	Gulf States Utilities Co. Division	Gas, coal, nuclear fuel costs, contract prudence, base/fuel realignment.
11/95 12/95	U-21485 (Supplemental Direct) U-21485 (Surrebuttal)	LA	Louisiana Public Service Commission Staff	Gulf States Utilities Co.	Nuclear O&M, River Bend phase-in plan, base/fuel realignment, NOL and AltMin asset deferred taxes, other revenue requirement issues.
1/96	95-299-EL-AIR 95-300-EL-AIR	OH	Industrial Energy Consumers	The Toledo Edison Co., The Cleveland Electric Illuminating Co.	Competition, asset write-offs and revaluation, O&M expense, other revenue requirement issues.
2/96	PUC Docket 14965	TX	Office of Public Utility Counsel	Central Power & Light	Nuclear decommissioning.
5/96	95-485-LCS	NM	City of Las Cruces	El Paso Electric Co.	Stranded cost recovery, municipalization.
7/96	8725	MD	The Maryland Industrial Group and Redland Genstar, Inc.	Baltimore Gas & Electric Co., Potomac Electric Power Co., and Constellation Energy Corp.	Merger savings, tracking mechanism, earnings sharing plan, revenue requirement issues.
9/96 11/96	U-22092 U-22092 (Surrebuttal)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	River Bend phase-in plan, base/fuel realignment, NOL and AltMin asset deferred taxes, other revenue requirement issues, allocation of regulated/nonregulated costs.
10/96	96-327	KY	Kentucky Industrial Utility Customers, Inc.	Big Rivers Electric Corp.	Environmental surcharge recoverable costs.
2/97	R-00973877	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy Co.	Stranded cost recovery, regulatory assets and liabilities, intangible transition charge, revenue requirements.
3/97	96-489	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Co.	Environmental surcharge recoverable costs, system agreements, allowance inventory, jurisdictional allocation.

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Date	Case	Jurisdict.	Party	Utility	Subject
6/97	TO-97-397	MO	MCI Telecommunications Corp., Inc., MCImetro Access Transmission Services, Inc.	Southwestern Bell Telephone Co.	Price cap regulation, revenue requirements, rate of return.
6/97	R-00973953	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, nuclear and fossil decommissioning.
7/97	R-00973954	PA	PP&L Industrial Customer Alliance	Pennsylvania Power & Light Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, nuclear and fossil decommissioning.
7/97	U-22092	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Depreciation rates and methodologies, River Bend phase-in plan.
8/97	97-300	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas & Electric Co., Kentucky Utilities Co.	Merger policy, cost savings, surcredit sharing mechanism, revenue requirements, rate of return.
8/97	R-00973954 (Surrebuttal)	PA	PP&L Industrial Customer Alliance	Pennsylvania Power & Light Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, nuclear and fossil decommissioning.
10/97	97-204	KY	Alcan Aluminum Corp. Southwire Co.	Big Rivers Electric Corp.	Restructuring, revenue requirements, reasonableness.
10/97	R-974008	PA	Metropolitan Edison Industrial Users Group	Metropolitan Edison Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, nuclear and fossil decommissioning, revenue requirements.
10/97	R-974009	PA	Penelec Industrial Customer Alliance	Pennsylvania Electric Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, nuclear and fossil decommissioning, revenue requirements.
11/97	97-204 (Rebuttal)	KY	Alcan Aluminum Corp. Southwire Co.	Big Rivers Electric Corp.	Restructuring, revenue requirements, reasonableness of rates, cost allocation.
11/97	U-22491	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Allocation of regulated and nonregulated costs, other revenue requirement issues.
11/97	R-00973953 (Surrebuttal)	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, nuclear and fossil decommissioning.
11/97	R-973981	PA	West Penn Power Industrial Intervenors	West Penn Power Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, fossil decommissioning, revenue requirements, securitization.
11/97	R-974104	PA	Duquesne Industrial Intervenors	Duquesne Light Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, nuclear and fossil decommissioning, revenue requirements, securitization.
12/97	R-973981 (Surrebuttal)	PA	West Penn Power Industrial Intervenors	West Penn Power Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, fossil decommissioning, revenue requirements.

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12/97	R-974104 (Surrebuttal)	PA	Duquesne Industrial Intervenors	Duquesne Light Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, nuclear and fossil decommissioning, revenue requirements, securitization.
1/98	U-22491 (Surrebuttal)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Allocation of regulated and nonregulated costs, other revenue requirement issues.
2/98	8774	MD	Westvaco	Potomac Edison Co.	Merger of Duquesne, AE, customer safeguards, savings sharing.
3/98	U-22092 (Allocated Stranded Cost Issues)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Restructuring, stranded costs, regulatory assets, securitization, regulatory mitigation.
3/98	8390-U	GA	Georgia Natural Gas Group, Georgia Textile Manufacturers Assoc.	Atlanta Gas Light Co.	Restructuring, unbundling, stranded costs, incentive regulation, revenue requirements.
3/98	U-22092 (Allocated Stranded Cost Issues) (Surrebuttal)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Restructuring, stranded costs, regulatory assets, securitization, regulatory mitigation.
10/98	97-596	ME	Maine Office of the Public Advocate	Bangor Hydro-Electric Co.	Restructuring, unbundling, stranded costs, T&D revenue requirements.
10/98	9355-U	GA	Georgia Public Service Commission Adversary Staff	Georgia Power Co.	Affiliate transactions.
10/98	U-17735	LA	Louisiana Public Service Commission Staff	Cajun Electric Power Cooperative	G&T cooperative ratemaking policy, other revenue requirement issues.
11/98	U-23327	LA	Louisiana Public Service Commission Staff	SWEPCO, CSW and AEP	Merger policy, savings sharing mechanism, affiliate transaction conditions.
12/98	U-23358 (Direct)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Allocation of regulated and nonregulated costs, tax issues, and other revenue requirement issues.
12/98	98-577	ME	Maine Office of Public Advocate	Maine Public Service Co.	Restructuring, unbundling, stranded cost, T&D revenue requirements.
1/99	98-10-07	CT	Connecticut Industrial Energy Consumers	United Illuminating Co.	Stranded costs, investment tax credits, accumulated deferred income taxes, excess deferred income taxes.
3/99	U-23358 (Surrebuttal)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Allocation of regulated and nonregulated costs, tax issues, and other revenue requirement issues.
3/99	98-474	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas and Electric Co.	Revenue requirements, alternative forms of regulation.
3/99	98-426	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co.	Revenue requirements, alternative forms of regulation.
3/99	99-082	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas and Electric Co.	Revenue requirements.

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Date	Case	Jurisdict.	Party	Utility	Subject
3/99	99-083	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co.	Revenue requirements.
4/99	U-23358 (Supplemental Surrebuttal)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Allocation of regulated and nonregulated costs, tax issues, and other revenue requirement issues.
4/99	99-03-04	CT	Connecticut Industrial Energy Consumers	United Illuminating Co.	Regulatory assets and liabilities, stranded costs, recovery mechanisms.
4/99	99-02-05	Ct	Connecticut Industrial Utility Customers	Connecticut Light and Power Co.	Regulatory assets and liabilities, stranded costs, recovery mechanisms.
5/99	98-426 99-082 (Additional Direct)	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas and Electric Co.	Revenue requirements.
5/99	98-474 99-083 (Additional Direct)	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co.	Revenue requirements.
5/99	98-426 98-474 (Response to Amended Applications)	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas and Electric Co., Kentucky Utilities Co.	Alternative regulation.
6/99	97-596	ME	Maine Office of Public Advocate	Bangor Hydro-Electric Co.	Request for accounting order regarding electric industry restructuring costs.
6/99	U-23358	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Affiliate transactions, cost allocations.
7/99	99-03-35	CT	Connecticut Industrial Energy Consumers	United Illuminating Co.	Stranded costs, regulatory assets, tax effects of asset divestiture.
7/99	U-23327	LA	Louisiana Public Service Commission Staff	Southwestern Electric Power Co., Central and South West Corp, American Electric Power Co.	Merger Settlement and Stipulation.
7/99	97-596 Surrebuttal	ME	Maine Office of Public Advocate	Bangor Hydro-Electric Co.	Restructuring, unbundling, stranded cost, T&D revenue requirements.
7/99	98-0452-E-GI	WV	West Virginia Energy Users Group	Monongahela Power, Potomac Edison, Appalachian Power, Wheeling Power	Regulatory assets and liabilities.
8/99	98-577 Surrebuttal	ME	Maine Office of Public Advocate	Maine Public Service Co.	Restructuring, unbundling, stranded costs, T&D revenue requirements.
8/99	98-426 99-082 Rebuttal	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas and Electric Co.	Revenue requirements.
8/99	98-474 98-083 Rebuttal	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co.	Revenue requirements.

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8/99	98-0452-E-GI Rebuttal	WV	West Virginia Energy Users Group	Monongahela Power, Potomac Edison, Appalachian Power, Wheeling Power	Regulatory assets and liabilities.
10/99	U-24182 Direct	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Allocation of regulated and nonregulated costs, affiliate transactions, tax issues, and other revenue requirement issues.
11/99	PUC Docket 21527	TX	The Dallas-Fort Worth Hospital Council and Coalition of Independent Colleges and Universities	TXU Electric	Restructuring, stranded costs, taxes, securitization.
11/99	U-23358 Surrebuttal Affiliate Transactions Review	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Service company affiliate transaction costs.
01/00	U-24182 Surrebuttal	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Allocation of regulated and nonregulated costs, affiliate transactions, tax issues, and other revenue requirement issues.
04/00	99-1212-EL-ETP 99-1213-EL-ATA 99-1214-EL-AAM	OH	Greater Cleveland Growth Association	First Energy (Cleveland Electric Illuminating, Toledo Edison)	Historical review, stranded costs, regulatory assets, liabilities.
05/00	2000-107	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Co.	ECR surcharge roll-in to base rates.
05/00	U-24182 Supplemental Direct	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Affiliate expense proforma adjustments.
05/00	A-110550F0147	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy	Merger between PECO and Unicom.
05/00	99-1658-EL-ETP	OH	AK Steel Corp.	Cincinnati Gas & Electric Co.	Regulatory transition costs, including regulatory assets and liabilities, SFAS 109, ADIT, EDIT, ITC.
07/00	PUC Docket 22344	TX	The Dallas-Fort Worth Hospital Council and The Coalition of Independent Colleges and Universities	Statewide Generic Proceeding	Escalation of O&M expenses for unbundled T&D revenue requirements in projected test year.
07/00	U-21453	LA	Louisiana Public Service Commission	SWEPCO	Stranded costs, regulatory assets and liabilities.
08/00	U-24064	LA	Louisiana Public Service Commission Staff	CLECO	Affiliate transaction pricing ratemaking principles, subsidization of nonregulated affiliates, ratemaking adjustments.
10/00	SOAH Docket 473-00-1015 PUC Docket 22350	TX	The Dallas-Fort Worth Hospital Council and The Coalition of Independent Colleges and Universities	TXU Electric Co.	Restructuring, T&D revenue requirements, mitigation, regulatory assets and liabilities.

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Date	Case	Jurisdict.	Party	Utility	Subject
10/00	R-00974104 Affidavit	PA	Duquesne Industrial Intervenors	Duquesne Light Co.	Final accounting for stranded costs, including treatment of auction proceeds, taxes, capital costs, switchback costs, and excess pension funding.
11/00	P-00001837 R-00974008 P-00001838 R-00974009	PA	Metropolitan Edison Industrial Users Group Penelec Industrial Customer Alliance	Metropolitan Edison Co., Pennsylvania Electric Co.	Final accounting for stranded costs, including treatment of auction proceeds, taxes, regulatory assets and liabilities, transaction costs.
12/00	U-21453, U-20925, U-22092 (Subdocket C) Surrebuttal	LA	Louisiana Public Service Commission Staff	SWEPCO	Stranded costs, regulatory assets.
01/01	U-24993 Direct	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Allocation of regulated and nonregulated costs, tax issues, and other revenue requirement issues.
01/01	U-21453, U-20925, U-22092 (Subdocket B) Surrebuttal	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Industry restructuring, business separation plan, organization structure, hold harmless conditions, financing.
01/01	Case No. 2000-386	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas & Electric Co.	Recovery of environmental costs, surcharge mechanism.
01/01	Case No. 2000-439	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co.	Recovery of environmental costs, surcharge mechanism.
02/01	A-110300F0095 A-110400F0040	PA	Met-Ed Industrial Users Group, Penelec Industrial Customer Alliance	GPU, Inc. FirstEnergy Corp.	Merger, savings, reliability.
03/01	P-00001860 P-00001861	PA	Met-Ed Industrial Users Group, Penelec Industrial Customer Alliance	Metropolitan Edison Co., Pennsylvania Electric Co.	Recovery of costs due to provider of last resort obligation.
04/01	U-21453, U-20925, U-22092 (Subdocket B) Settlement Term Sheet	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Business separation plan: settlement agreement on overall plan structure.
04/01	U-21453, U-20925, U-22092 (Subdocket B) Contested Issues	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Business separation plan: agreements, hold harmless conditions, separations methodology.
05/01	U-21453, U-20925, U-22092 (Subdocket B) Contested Issues Transmission and Distribution Rebuttal	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Business separation plan: agreements, hold harmless conditions, separations methodology.

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Date	Case	Jurisdict.	Party	Utility	Subject
07/01	U-21453, U-20925, U-22092 (Subdocket B) Transmission and Distribution Term Sheet	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Business separation plan: settlement agreement on T&D issues, agreements necessary to implement T&D separations, hold harmless conditions, separations methodology.
10/01	14000-U	GA	Georgia Public Service Commission Adversary Staff	Georgia Power Company	Revenue requirements, Rate Plan, fuel clause recovery.
11/01	14311-U Direct Panel with Bolin Killings	GA	Georgia Public Service Commission Adversary Staff	Atlanta Gas Light Co	Revenue requirements, revenue forecast, O&M expense, depreciation, plant additions, cash working capital.
11/01	U-25687 Direct	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Revenue requirements, capital structure, allocation of regulated and nonregulated costs, River Bend uprate.
02/02	PUC Docket 25230	TX	The Dallas-Fort Worth Hospital Council and the Coalition of Independent Colleges and Universities	TXU Electric	Stipulation. Regulatory assets, securitization financing.
02/02	U-25687 Surrebuttal	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Revenue requirements, corporate franchise tax, conversion to LLC, River Bend uprate.
03/02	14311-U Rebuttal Panel with Bolin Killings	GA	Georgia Public Service Commission Adversary Staff	Atlanta Gas Light Co.	Revenue requirements, earnings sharing plan, service quality standards.
03/02	14311-U Rebuttal Panel with Michelle L. Thebert	GA	Georgia Public Service Commission Adversary Staff	Atlanta Gas Light Co.	Revenue requirements, revenue forecast, O&M expense, depreciation, plant additions, cash working capital.
03/02	001148-EI	FL	South Florida Hospital and Healthcare Assoc.	Florida Power & Light Co.	Revenue requirements. Nuclear life extension, storm damage accruals and reserve, capital structure, O&M expense.
04/02	U-25687 (Suppl. Surrebuttal)	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Revenue requirements, corporate franchise tax, conversion to LLC, River Bend uprate.
04/02	U-21453, U-20925 U-22092 (Subdocket C)	LA	Louisiana Public Service Commission	SWEPCO	Business separation plan, T&D Term Sheet, separations methodologies, hold harmless conditions.
08/02	EL01-88-000	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	System Agreement, production cost equalization, tariffs.
08/02	U-25888	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc. and Entergy Louisiana, Inc.	System Agreement, production cost disparities, prudence.
09/02	2002-00224 2002-00225	KY	Kentucky Industrial Utilities Customers, Inc.	Kentucky Utilities Co., Louisville Gas & Electric Co.	Line losses and fuel clause recovery associated with off-system sales.

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Date	Case	Jurisdict.	Party	Utility	Subject
11/02	2002-00146 2002-00147	KY	Kentucky Industrial Utilities Customers, Inc.	Kentucky Utilities Co., Louisville Gas & Electric Co.	Environmental compliance costs and surcharge recovery.
01/03	2002-00169	KY	Kentucky Industrial Utilities Customers, Inc.	Kentucky Power Co.	Environmental compliance costs and surcharge recovery.
04/03	2002-00429 2002-00430	KY	Kentucky Industrial Utilities Customers, Inc.	Kentucky Utilities Co., Louisville Gas & Electric Co.	Extension of merger surcredit, flaws in Companies' studies.
04/03	U-26527	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Revenue requirements, corporate franchise tax, conversion to LLC, capital structure, post-test year adjustments.
06/03	EL01-88-000 Rebuttal	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	System Agreement, production cost equalization, tariffs.
06/03	2003-00068	KY	Kentucky Industrial Utility Customers	Kentucky Utilities Co.	Environmental cost recovery, correction of base rate error.
11/03	ER03-753-000	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	Unit power purchases and sale cost-based tariff pursuant to System Agreement.
11/03	ER03-583-000, ER03-583-001, ER03-583-002 ER03-681-000, ER03-681-001 ER03-682-000, ER03-682-001, ER03-682-002 ER03-744-000, ER03-744-001 (Consolidated)	FERC	Louisiana Public Service Commission	Entergy Services, Inc., the Entergy Operating Companies, EWO Marketing, LP, and Entergy Power, Inc.	Unit power purchases and sale agreements, contractual provisions, projected costs, levelized rates, and formula rates.
12/03	U-26527 Surrebuttal	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Revenue requirements, corporate franchise tax, conversion to LLC, capital structure, post-test year adjustments.
12/03	2003-0334 2003-0335	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co., Louisville Gas & Electric Co.	Earnings Sharing Mechanism.
12/03	U-27136	LA	Louisiana Public Service Commission Staff	Entergy Louisiana, Inc.	Purchased power contracts between affiliates, terms and conditions.
03/04	U-26527 Supplemental Surrebuttal	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Revenue requirements, corporate franchise tax, conversion to LLC, capital structure, post-test year adjustments.
03/04	2003-00433	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas & Electric Co.	Revenue requirements, depreciation rates, O&M expense, deferrals and amortization, earnings sharing mechanism, merger surcredit, VDT surcredit.

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03/04	2003-00434	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co.	Revenue requirements, depreciation rates, O&M expense, deferrals and amortization, earnings sharing mechanism, merger surcredit, VDT surcredit.
03/04	SOAH Docket 473-04-2459 PUC Docket 29206	TX	Cities Served by Texas-New Mexico Power Co.	Texas-New Mexico Power Co.	Stranded costs true-up, including valuation issues, ITC, ADIT, excess earnings.
05/04	04-169-EL-UNC	OH	Ohio Energy Group, Inc.	Columbus Southern Power Co. & Ohio Power Co.	Rate stabilization plan, deferrals, T&D rate increases, earnings.
06/04	SOAH Docket 473-04-4555 PUC Docket 29526	TX	Houston Council for Health and Education	CenterPoint Energy Houston Electric	Stranded costs true-up, including valuation issues, ITC, EDIT, excess mitigation credits, capacity auction true-up revenues, interest.
08/04	SOAH Docket 473-04-4555 PUC Docket 29526 (Suppl Direct)	TX	Houston Council for Health and Education	CenterPoint Energy Houston Electric	Interest on stranded cost pursuant to Texas Supreme Court remand.
09/04	U-23327 Subdocket B	LA	Louisiana Public Service Commission Staff	SWEPCO	Fuel and purchased power expenses recoverable through fuel adjustment clause, trading activities, compliance with terms of various LPSC Orders.
10/04	U-23327 Subdocket A	LA	Louisiana Public Service Commission Staff	SWEPCO	Revenue requirements.
12/04	Case Nos. 2004-00321, 2004-00372	KY	Gallatin Steel Co.	East Kentucky Power Cooperative, Inc., Big Sandy Recc, et al.	Environmental cost recovery, qualified costs, TIER requirements, cost allocation.
01/05	30485	TX	Houston Council for Health and Education	CenterPoint Energy Houston Electric, LLC	Stranded cost true-up including regulatory Central Co. assets and liabilities, ITC, EDIT, capacity auction, proceeds, excess mitigation credits, retrospective and prospective ADIT.
02/05	18638-U	GA	Georgia Public Service Commission Adversary Staff	Atlanta Gas Light Co.	Revenue requirements.
02/05	18638-U Panel with Tony Wackerly	GA	Georgia Public Service Commission Adversary Staff	Atlanta Gas Light Co.	Comprehensive rate plan, pipeline replacement program surcharge, performance based rate plan.
02/05	18638-U Panel with Michelle Thebert	GA	Georgia Public Service Commission Adversary Staff	Atlanta Gas Light Co.	Energy conservation, economic development, and tariff issues.
03/05	Case Nos. 2004-00426, 2004-00421	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co., Louisville Gas & Electric	Environmental cost recovery, Jobs Creation Act of 2004 and §199 deduction, excess common equity ratio, deferral and amortization of nonrecurring O&M expense.
06/05	2005-00068	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Co.	Environmental cost recovery, Jobs Creation Act of 2004 and §199 deduction, margins on allowances used for AEP system sales.

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Date	Case	Jurisdict.	Party	Utility	Subject
06/05	050045-EI	FL	South Florida Hospital and Healthcare Assoc.	Florida Power & Light Co.	Storm damage expense and reserve, RTO costs, O&M expense projections, return on equity performance incentive, capital structure, selective second phase post-test year rate increase.
08/05	31056	TX	Alliance for Valley Healthcare	AEP Texas Central Co.	Stranded cost true-up including regulatory assets and liabilities, ITC, EDIT, capacity auction, proceeds, excess mitigation credits, retrospective and prospective ADIT.
09/05	20298-U	GA	Georgia Public Service Commission Adversary Staff	Atmos Energy Corp.	Revenue requirements, roll-in of surcharges, cost recovery through surcharge, reporting requirements.
09/05	20298-U Panel with Victoria Taylor	GA	Georgia Public Service Commission Adversary Staff	Atmos Energy Corp.	Affiliate transactions, cost allocations, capitalization, cost of debt.
10/05	04-42	DE	Delaware Public Service Commission Staff	Artesian Water Co.	Allocation of tax net operating losses between regulated and unregulated.
11/05	2005-00351 2005-00352	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co., Louisville Gas & Electric	Workforce Separation Program cost recovery and shared savings through VDT surcredit.
01/06	2005-00341	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Co.	System Sales Clause Rider, Environmental Cost Recovery Rider. Net Congestion Rider, Storm damage, vegetation management program, depreciation, off-system sales, maintenance normalization, pension and OPEB.
03/06	PUC Docket 31994	TX	Cities	Texas-New Mexico Power Co.	Stranded cost recovery through competition transition or change.
05/06	31994 Supplemental	TX	Cities	Texas-New Mexico Power Co.	Retrospective ADFIT, prospective ADFIT.
03/06	U-21453, U-20925, U-22092	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Jurisdictional separation plan.
03/06	NOPR Reg 104385-OR	IRS	Alliance for Valley Health Care and Houston Council for Health Education	AEP Texas Central Company and CenterPoint Energy Houston Electric	Proposed Regulations affecting flow- through to ratepayers of excess deferred income taxes and investment tax credits on generation plant that is sold or deregulated.
04/06	U-25116	LA	Louisiana Public Service Commission Staff	Entergy Louisiana, Inc.	2002-2004 Audit of Fuel Adjustment Clause Filings. Affiliate transactions.
07/06	R-00061366, Et. al.	PA	Met-Ed Ind. Users Group Pennsylvania Ind. Customer Alliance	Metropolitan Edison Co., Pennsylvania Electric Co.	Recovery of NUG-related stranded costs, government mandated programs costs, storm damage costs.
07/06	U-23327	LA	Louisiana Public Service Commission Staff	Southwestern Electric Power Co.	Revenue requirements, formula rate plan, banking proposal.
08/06	U-21453, U-20925, U-22092 (Subdocket J)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Jurisdictional separation plan.

**Expert Testimony Appearances
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Date	Case	Jurisdict.	Party	Utility	Subject
11/06	05CVH03-3375 Franklin County Court Affidavit	OH	Various Taxing Authorities (Non-Utility Proceeding)	State of Ohio Department of Revenue	Accounting for nuclear fuel assemblies as manufactured equipment and capitalized plant.
12/06	U-23327 Subdocket A Reply Testimony	LA	Louisiana Public Service Commission Staff	Southwestern Electric Power Co.	Revenue requirements, formula rate plan, banking proposal.
03/07	U-29764	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc., Entergy Louisiana, LLC	Jurisdictional allocation of Entergy System Agreement equalization remedy receipts.
03/07	PUC Docket 33309	TX	Cities	AEP Texas Central Co.	Revenue requirements, including functionalization of transmission and distribution costs.
03/07	PUC Docket 33310	TX	Cities	AEP Texas North Co.	Revenue requirements, including functionalization of transmission and distribution costs.
03/07	2006-00472	KY	Kentucky Industrial Utility Customers, Inc.	East Kentucky Power Cooperative	Interim rate increase, RUS loan covenants, credit facility requirements, financial condition.
03/07	U-29157	LA	Louisiana Public Service Commission Staff	Cleco Power, LLC	Permanent (Phase II) storm damage cost recovery.
04/07	U-29764 Supplemental and Rebuttal	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc., Entergy Louisiana, LLC	Jurisdictional allocation of Entergy System Agreement equalization remedy receipts.
04/07	ER07-682-000 Affidavit	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	Allocation of intangible and general plant and A&G expenses to production and state income tax effects on equalization remedy receipts.
04/07	ER07-684-000 Affidavit	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	Fuel hedging costs and compliance with FERC USOA.
05/07	ER07-682-000 Affidavit	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	Allocation of intangible and general plant and A&G expenses to production and account 924 effects on MSS-3 equalization remedy payments and receipts.
06/07	U-29764	LA	Louisiana Public Service Commission Staff	Entergy Louisiana, LLC, Entergy Gulf States, Inc.	Show cause for violating LPSC Order on fuel hedging costs.
07/07	2006-00472	KY	Kentucky Industrial Utility Customers, Inc.	East Kentucky Power Cooperative	Revenue requirements, post-test year adjustments, TIER, surcharge revenues and costs, financial need.
07/07	ER07-956-000 Affidavit	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Storm damage costs related to Hurricanes Katrina and Rita and effects of MSS-3 equalization payments and receipts.
10/07	05-UR-103 Direct	WI	Wisconsin Industrial Energy Group	Wisconsin Electric Power Company, Wisconsin Gas, LLC	Revenue requirements, carrying charges on CWIP, amortization and return on regulatory assets, working capital, incentive compensation, use of rate base in lieu of capitalization, quantification and use of Point Beach sale proceeds.

**Expert Testimony Appearances
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Date	Case	Jurisdict.	Party	Utility	Subject
10/07	05-UR-103 Surrebuttal	WI	Wisconsin Industrial Energy Group	Wisconsin Electric Power Company, Wisconsin Gas, LLC	Revenue requirements, carrying charges on CWIP, amortization and return on regulatory assets, working capital, incentive compensation, use of rate base in lieu of capitalization, quantification and use of Point Beach sale proceeds.
10/07	25060-U Direct	GA	Georgia Public Service Commission Public Interest Adversary Staff	Georgia Power Company	Affiliate costs, incentive compensation, consolidated income taxes, §199 deduction.
11/07	06-0033-E-CN Direct	WV	West Virginia Energy Users Group	Appalachian Power Company	IGCC surcharge during construction period and post-in-service date.
11/07	ER07-682-000 Direct	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	Functionalization and allocation of intangible and general plant and A&G expenses.
01/08	ER07-682-000 Cross-Answering	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	Functionalization and allocation of intangible and general plant and A&G expenses.
01/08	07-551-EL-AIR Direct	OH	Ohio Energy Group, Inc.	Ohio Edison Company, Cleveland Electric Illuminating Company, Toledo Edison Company	Revenue requirements.
02/08	ER07-956-000 Direct	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	Functionalization of expenses in account 923; storm damage expense and accounts 924, 228.1, 182.3, 254 and 407.3; tax NOL carrybacks in accounts 165 and 236; ADIT; nuclear service lives and effect on depreciation and decommissioning.
03/08	ER07-956-000 Cross-Answering	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	Functionalization of expenses in account 923; storm damage expense and accounts 924, 228.1, 182.3, 254 and 407.3; tax NOL carrybacks in accounts 165 and 236; ADIT; nuclear service lives and effect on depreciation and decommissioning.
04/08	2007-00562, 2007-00563	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co., Louisville Gas and Electric Co.	Merger surcredit.
04/08	26837 Direct Panel with Thomas K. Bond, Cynthia Johnson, and Michelle Thebart	GA	Georgia Public Service Commission Staff	SCANA Energy Marketing, Inc.	Rule Nisi complaint.

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Date	Case	Jurisdict.	Party	Utility	Subject
05/08	26837 Rebuttal Panel with Thomas K. Bond, Cynthia Johnson, and Michelle Thebert	GA	Georgia Public Service Commission Staff	SCANA Energy Marketing, Inc.	Rule Nisi complaint.
05/08	26837 Supplemental Rebuttal Panel with Thomas K. Bond, Cynthia Johnson, and Michelle Thebert	GA	Georgia Public Service Commission Staff	SCANA Energy Marketing, Inc.	Rule Nisi complaint.
06/08	2008-00115	KY	Kentucky Industrial Utility Customers, Inc.	East Kentucky Power Cooperative, Inc.	Environmental surcharge recoveries, including costs recovered in existing rates, TIER.
07/08	27163 Direct	GA	Georgia Public Service Commission Public Interest Advocacy Staff	Atmos Energy Corp.	Revenue requirements, including projected test year rate base and expenses.
07/08	27163 Panel with Victoria Taylor	GA	Georgia Public Service Commission Public Interest Advocacy Staff	Atmos Energy Corp.	Affiliate transactions and division cost allocations, capital structure, cost of debt.
08/08	6680-CE-170 Direct	WI	Wisconsin Industrial Energy Group, Inc.	Wisconsin Power and Light Company	Nelson Dewey 3 or Colombia 3 fixed financial parameters.
08/08	6680-UR-116 Direct	WI	Wisconsin Industrial Energy Group, Inc.	Wisconsin Power and Light Company	CWIP in rate base, labor expenses, pension expense, financing, capital structure, decoupling.
08/08	6680-UR-116 Rebuttal	WI	Wisconsin Industrial Energy Group, Inc.	Wisconsin Power and Light Company	Capital structure.
08/08	6690-UR-119 Direct	WI	Wisconsin Industrial Energy Group, Inc.	Wisconsin Public Service Corp.	Prudence of Weston 3 outage, incentive compensation, Crane Creek Wind Farm incremental revenue requirement, capital structure.
09/08	6690-UR-119 Surrebuttal	WI	Wisconsin Industrial Energy Group, Inc.	Wisconsin Public Service Corp.	Prudence of Weston 3 outage, Section 199 deduction.
09/08	08-935-EL-SSO, 08-918-EL-SSO	OH	Ohio Energy Group, Inc.	First Energy	Standard service offer rates pursuant to electric security plan, significantly excessive earnings test.
10/08	08-917-EL-SSO	OH	Ohio Energy Group, Inc.	AEP	Standard service offer rates pursuant to electric security plan, significantly excessive earnings test.
10/08	2007-564, 2007-565, 2008-251 2008-252	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas and Electric Co., Kentucky Utilities Company	Revenue forecast, affiliate costs, depreciation expenses, federal and state income tax expense, capitalization, cost of debt.
11/08	EL08-51	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Spindletop gas storage facilities, regulatory asset and bandwidth remedy.

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Date	Case	Jurisdict.	Party	Utility	Subject
11/08	35717	TX	Cities Served by Oncor Delivery Company	Oncor Delivery Company	Recovery of old meter costs, asset ADFIT, cash working capital, recovery of prior year restructuring costs, levelized recovery of storm damage costs, prospective storm damage accrual, consolidated tax savings adjustment.
12/08	27800	GA	Georgia Public Service Commission	Georgia Power Company	AFUDC versus CWIP in rate base, mirror CWIP, certification cost, use of short term debt and trust preferred financing, CWIP recovery, regulatory incentive.
01/09	ER08-1056	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Entergy System Agreement bandwidth remedy calculations, including depreciation expense, ADIT, capital structure.
01/09	ER08-1056 Supplemental Direct	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Blytheville leased turbines; accumulated depreciation.
02/09	EL08-51 Rebuttal	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Spindletop gas storage facilities regulatory asset and bandwidth remedy.
02/09	2008-00409 Direct	KY	Kentucky Industrial Utility Customers, Inc.	East Kentucky Power Cooperative, Inc.	Revenue requirements.
03/09	ER08-1056 Answering	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Entergy System Agreement bandwidth remedy calculations, including depreciation expense, ADIT, capital structure.
03/09	U-21453, U-20925 U-22092 (Subdocket J)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States Louisiana, LLC	Violation of EGSI separation order, ETI and EGSL separation accounting, Spindletop regulatory asset.
04/09	U-21453, U-20925 U-22092 (Subdocket J) Rebuttal	LA	Louisiana Public Service Commission Staff	Entergy Gulf States Louisiana, LLC	Violation of EGSI separation order, ETI and EGSL separation accounting, Spindletop regulatory asset.
04/09	2009-00040 Direct-Interim (Oral)	KY	Kentucky Industrial Utility Customers, Inc.	Big Rivers Electric Corp.	Emergency interim rate increase; cash requirements.
04/09	PUC Docket 36530	TX	State Office of Administrative Hearings	Oncor Electric Delivery Company, LLC	Rate case expenses.
05/09	ER08-1056 Rebuttal	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Entergy System Agreement bandwidth remedy calculations, including depreciation expense, ADIT, capital structure.
06/09	2009-00040 Direct-Permanent	KY	Kentucky Industrial Utility Customers, Inc.	Big Rivers Electric Corp.	Revenue requirements, TIER, cash flow.

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Date	Case	Jurisdict.	Party	Utility	Subject
07/09	080677-EI	FL	South Florida Hospital and Healthcare Association	Florida Power & Light Company	Multiple test years, GBRA rider, forecast assumptions, revenue requirement, O&M expense, depreciation expense, Economic Stimulus Bill, capital structure.
08/09	U-21453, U-20925, U-22092 (Subdocket J) Supplemental Rebuttal	LA	Louisiana Public Service Commission	Entergy Gulf States Louisiana, LLC	Violation of EGSI separation order, ETI and EGSL separation accounting, Spindletop regulatory asset.
08/09	8516 and 29950	GA	Georgia Public Service Commission Staff	Atlanta Gas Light Company	Modification of PRP surcharge to include infrastructure costs.
09/09	05-UR-104 Direct and Surrebuttal	WI	Wisconsin Industrial Energy Group	Wisconsin Electric Power Company	Revenue requirements, incentive compensation, depreciation, deferral mitigation, capital structure, cost of debt.
09/09	09AL-299E	CO	CF&I Steel, Rocky Mountain Steel Mills LP, Climax Molybdenum Company	Public Service Company of Colorado	Forecasted test year, historic test year, proforma adjustments for major plant additions, tax depreciation.
09/09	6680-UR-117 Direct and Surrebuttal	WI	Wisconsin Industrial Energy Group	Wisconsin Power and Light Company	Revenue requirements, CWIP in rate base, deferral mitigation, payroll, capacity shutdowns, regulatory assets, rate of return.
10/09	09A-415E	CO	Cripple Creek & Victor Gold Mining Company, et al.	Black Hills/CO Electric Utility Company	Cost prudence, cost sharing mechanism.
10/09	EL09-50 Direct	LA	Louisiana Public Service Commission	Entergy Services, Inc.	Waterford 3 sale/leaseback accumulated deferred income taxes, Entergy System Agreement bandwidth remedy calculations.
10/09	2009-00329	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas and Electric Company, Kentucky Utilities Company	Trimble County 2 depreciation rates.
12/09	PUE-2009-00030	VA	Old Dominion Committee for Fair Utility Rates	Appalachian Power Company	Return on equity incentive.
12/09	ER09-1224 Direct	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Hypothetical versus actual costs, out of period costs, Spindletop deferred capital costs, Waterford 3 sale/leaseback ADIT.
01/10	ER09-1224 Cross-Answering	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Hypothetical versus actual costs, out of period costs, Spindletop deferred capital costs, Waterford 3 sale/leaseback ADIT.
01/10	EL09-50 Rebuttal	LA	Louisiana Public Service Commission	Entergy Services, Inc.	Waterford 3 sale/leaseback accumulated deferred income taxes, Entergy System Agreement bandwidth remedy calculations.
02/10	ER09-1224 Final	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Hypothetical versus actual costs, out of period costs, Spindletop deferred capital costs, Waterford 3 sale/leaseback ADIT.

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Date	Case	Jurisdict.	Party	Utility	Subject
02/10	30442 Wackerly-Kollen Panel	GA	Georgia Public Service Commission Staff	Atmos Energy Corporation	Revenue requirement issues.
02/10	30442 McBride-Kollen Panel	GA	Georgia Public Service Commission Staff	Atmos Energy Corporation	Affiliate/division transactions, cost allocation, capital structure.
02/10	2009-00353	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas and Electric Company, Kentucky Utilities Company	Ratemaking recovery of wind power purchased power agreements.
03/10	2009-00545	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Company	Ratemaking recovery of wind power purchased power agreement.
03/10	E015/GR-09-1151	MN	Large Power Interveners	Minnesota Power	Revenue requirement issues, cost overruns on environmental retrofit project.
03/10	EL10-55	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	Depreciation expense and effects on System Agreement tariffs.
04/10	2009-00459	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Company	Revenue requirement issues.
04/10	2009-00458, 2009-00459	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Company, Louisville Gas and Electric Company	Revenue requirement issues.
08/10	31647	GA	Georgia Public Service Commission Staff	Atlanta Gas Light Company	Revenue requirement and synergy savings issues.
08/10	31647 Wackerly-Kollen Panel	GA	Georgia Public Service Commission Staff	Atlanta Gas Light Company	Affiliate transaction and Customer First program issues.
08/10	2010-00204	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas and Electric Company, Kentucky Utilities Company	PPL acquisition of E.ON U.S. (LG&E and KU) conditions, acquisition savings, sharing deferral mechanism.
09/10	38339 Direct and Cross-Rebuttal	TX	Gulf Coast Coalition of Cities	CenterPoint Energy Houston Electric	Revenue requirement issues, including consolidated tax savings adjustment, incentive compensation FIN 48; AMS surcharge including roll-in to base rates; rate case expenses.
09/10	EL10-55	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	Depreciation rates and expense input effects on System Agreement tariffs.
09/10	2010-00167	KY	Gallatin Steel	East Kentucky Power Cooperative, Inc.	Revenue requirements.

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Date	Case	Jurisdict.	Party	Utility	Subject
09/10	U-23327 Subdocket E Direct	LA	Louisiana Public Service Commission	SWEPCO	Fuel audit: S02 allowance expense, variable O&M expense, off-system sales margin sharing.
11/10	U-23327 Rebuttal	LA	Louisiana Public Service Commission	SWEPCO	Fuel audit: S02 allowance expense, variable O&M expense, off-system sales margin sharing.
09/10	U-31351	LA	Louisiana Public Service Commission Staff	SWEPCO and Valley Electric Membership Cooperative	Sale of Valley assets to SWEPCO and dissolution of Valley.
10/10	10-1261-EL-UNC	OH	Ohio OCC, Ohio Manufacturers Association, Ohio Energy Group, Ohio Hospital Association, Appalachian Peace and Justice Network	Columbus Southern Power Company	Significantly excessive earnings test.
10/10	10-0713-E-PC	WV	West Virginia Energy Users Group	Monongahela Power Company, the Potomac Edison Power Company	Merger of First Energy and Allegheny Energy.
10/10	U-23327 Subdocket F Direct	LA	Louisiana Public Service Commission Staff	SWEPCO	AFUDC adjustments in Formula Rate Plan.
11/10	EL10-55 Rebuttal	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	Depreciation rates and expense input effects on System Agreement tariffs.
12/10	ER10-1350 Direct	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	Waterford 3 lease amortization, ADIT, and fuel inventory effects on System Agreement tariffs.
01/11	ER10-1350 Cross-Answering	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	Waterford 3 lease amortization, ADIT, and fuel inventory effects on System Agreement tariffs.
03/11 04/11	ER10-2001 Direct Cross-Answering	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and Entergy Arkansas, Inc.	EAI depreciation rates.
04/11	U-23327 Subdocket E	LA	Louisiana Public Service Commission Staff	SWEPCO	Settlement, including resolution of S02 allowance expense, variable O&M expense, and tiered sharing of off-system sales margins.
04/11 05/11	38306 Direct Supplemental Direct	TX	Cities Served by Texas-New Mexico Power Company	Texas-New Mexico Power Company	AMS deployment plan, AMS Surcharge, rate case expenses.
05/11	11-0274-E-GI	WV	West Virginia Energy Users Group	Appalachian Power Company and Wheeling Power Company	Deferral recovery phase-in, construction surcharge.

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Date	Case	Jurisdict.	Party	Utility	Subject
05/11	2011-00036	KY	Kentucky Industrial Utility Customers, Inc.	Big Rivers Electric Corp.	Revenue requirements.
06/11	29849	GA	Georgia Public Service Commission Staff	Georgia Power Company	Accounting issues related to Vogtle risk-sharing mechanism.
07/11	ER11-2161 Direct and Answering	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and Entergy Texas, Inc.	ETI depreciation rates; accounting issues.
07/11	PUE-2011-00027	VA	Virginia Committee for Fair Utility Rates	Virginia Electric and Power Company	Return on equity performance incentive.
07/11	11-346-EL-SSO 11-348-EL-SSO 11-349-EL-AAM 11-350-EL-AAM	OH	Ohio Energy Group	AEP-OH	Equity Stabilization Incentive Plan; actual earned returns; ADIT offsets in riders.
08/11	ER-11-2161 Cross-Answering	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and Entergy Texas, Inc.	ETI depreciation rates; accounting issues.
08/11	U-23327 Subdocket F Rebuttal	LA	Louisiana Public Service Commission Staff	SWEPCO	Depreciation rates and service lives; AFUDC adjustments.
08/11	05-UR-105	WI	Wisconsin Industrial Energy Group	WE Energies, Inc.	Suspended amortization expenses; revenue requirements.
08/11	ER11-2161 Cross-Answering	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and Entergy Texas, Inc.	ETI depreciation rates; accounting issues.
09/11	PUC Docket 39504	TX	Gulf Coast Coalition of Cities	CenterPoint Energy Houston Electric	Investment tax credit, excess deferred income taxes; normalization.
09/11	2011-00161 2011-00162	KY	Kentucky Industrial Utility Consumers, Inc.	Louisville Gas & Electric Company, Kentucky Utilities Company	Environmental requirements and financing.
10/11	11-4571-EL-UNC 11-4572-EL-UNC	OH	Ohio Energy Group	Columbus Southern Power Company, Ohio Power Company	Significantly excessive earnings.
10/11	4220-UR-117 Direct	WI	Wisconsin Industrial Energy Group	Northern States Power-Wisconsin	Nuclear O&M, depreciation.
11/11	4220-UR-117 Surrebuttal	WI	Wisconsin Industrial Energy Group	Northern States Power-Wisconsin	Nuclear O&M, depreciation.
11/11	PUC Docket 39722	TX	Cities Served by AEP Texas Central Company	AEP Texas Central Company	Investment tax credit, excess deferred income taxes; normalization.
02/12	PUC Docket 40020	TX	Cities Served by Oncor	Lone Star Transmission, LLC	Temporary rates.
03/12	2011-00401	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Company	Big Sandy 2 environmental retrofits and environmental surcharge recovery.

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Date	Case	Jurisdict.	Party	Utility	Subject
4/12	2011-00036 Direct Rehearing Supplemental Direct Rehearing	KY	Kentucky Industrial Utility Customers, Inc.	Big Rivers Electric Corp.	Rate case expenses, depreciation rates and expense.
04/12	10-2929-EL-UNC	OH	Ohio Energy Group	AEP Ohio Power	State compensation mechanism, CRES capacity charges, Equity Stabilization Mechanism
05/12	11-346-EL-SSO 11-348-EL-SSO	OH	Ohio Energy Group	AEP Ohio Power	State compensation mechanism, Equity Stabilization Mechanism, Retail Stability Rider.
05/12	11-4393-EL-RDR	OH	Ohio Energy Group	Duke Energy Ohio, Inc.	Incentives for over-compliance on EE/PDR mandates.
06/12	40020	TX	Cities Served by Oncor	Lone Star Transmission, LLC	Revenue requirements, including ADIT, bonus depreciation and NOL, working capital, self insurance, depreciation rates, federal income tax expense.
07/12	120015-EI	FL	South Florida Hospital and Healthcare Association	Florida Power & Light Company	Revenue requirements, including vegetation management, nuclear outage expense, cash working capital, CWIP in rate base.
07/12	2012-00063	KY	Kentucky Industrial Utility Customers, Inc.	Big Rivers Electric Corp.	Environmental retrofits, including environmental surcharge recovery.
09/12	05-UR-106	WI	Wisconsin Industrial Energy Group, Inc.	Wisconsin Electric Power Company	Section 1603 grants, new solar facility, payroll expenses, cost of debt.
10/12	2012-00221 2012-00222	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas and Electric Company, Kentucky Utilities Company	Revenue requirements, including off-system sales, outage maintenance, storm damage, injuries and damages, depreciation rates and expense.
10/12	120015-EI Direct Rebuttal	FL	South Florida Hospital and Healthcare Association	Florida Power & Light Company	Settlement issues.
10/12	40604	TX	Steering Committee of Cities Served by Oncor	Cross Texas Transmission, LLC	Policy and procedural issues, revenue requirements, including AFUDC, ADIT – bonus depreciation & NOL, incentive compensation, staffing, self-insurance, net salvage, depreciation rates and expense, income tax expense.
11/12	40627 Direct	TX	City of Austin d/b/a Austin Energy	City of Austin d/b/a Austin Energy	Rate case expenses.
12/12	40443	TX	Cities Served by SWEPCO	Southwestern Electric Power Company	Revenue requirements, including depreciation rates and service lives, O&M expenses, consolidated tax savings, CWIP in rate base, Turk plant costs.
12/12	U-29764	LA	Louisiana Public Service Commission Staff	Entergy Gulf States Louisiana, LLC and Entergy Louisiana, LLC	Termination of purchased power contracts between EGSL and ETI, Spindletop regulatory asset.

Expert Testimony Appearances
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Date	Case	Jurisdict.	Party	Utility	Subject
01/13	ER12-1384	FERC	Louisiana Public Service Commission	Entergy Gulf States Louisiana, LLC and Entergy Louisiana, LLC	Little Gypsy 3 cancellation costs.
02/13	40627 Rebuttal	TX	City of Austin d/b/a Austin Energy	City of Austin d/b/a Austin Energy	Rate case expenses.
03/13	12-426-EL-SSO	OH	The Ohio Energy Group	The Dayton Power and Light Company	Capacity charges under state compensation mechanism, Service Stability Rider, Switching Tracker.
04/13	12-2400-EL-UNC	OH	The Ohio Energy Group	Duke Energy Ohio, Inc.	Capacity charges under state compensation mechanism, deferrals, rider to recover deferrals.
04/13	2012-00578	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Company	Resource plan, including acquisition of interest in Mitchell plant.
05/13	2012-00535	KY	Kentucky Industrial Utility Customers, Inc.	Big Rivers Electric Corporation	Revenue requirements, excess capacity, restructuring.
06/13	12-3254-EL-UNC	OH	The Ohio Energy Group, Inc.	Ohio Power Company	Energy auctions under CBP, including reserve prices.
07/13	2013-00144	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Company	Biomass renewable energy purchase agreement.

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

IN RE: PETITION FOR RATE INCREASE BY TAMPA ELECTRIC COMPANY	))	DOCKET NO. 130040-EI

EXHIBIT___(LK-2)

OF

LANE KOLLEN

ON BEHALF OF

THE WCF HOSPITAL UTILITY ALLIANCE

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

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

SCHEDULE 3

		Operating Revenues	O&M - Fuel & Purchased Power	O&M Other	Depreciation and Amortization	Taxes Other Than Income	Total Income Taxes	(Gain)/Loss on Disposal of Plant	Total Operating Expenses	Net Operating Income
	Adjusted per Company	865,359,000	7,614,000	370,934,000	194,608,000	62,275,000	48,492,000	(1,534,000)	682,389,000	182,970,000
	Commission Adjustments:									
2	Revenue Forecast	0	0	0	0	0	0	0	0	0
8	Plant in Service Amount	0	0	0	(1,248,485)	0	481,603	0	(766,882)	766,882
39	Total Operating Revenues	0	0	0	0	0	0	0	0	0
40-S	Inflation Factors	0	0	0	0	0	0	0	0	0
41	Total O&M Expense	0	0	0	0	0	0	0	0	0
42-S	FAC Revenues and Expenses	0	0	0	0	0	0	0	0	0
43-S	ECCR Revenues and Expenses	0	0	0	0	0	0	0	0	0
44-S	CCRC Revenues and Expenses	0	0	0	0	0	0	0	0	0
45-S	ECRC Revenues and Expenses	0	0	0	0	0	0	0	0	0
46	Advertising Expenses	0	0	0	0	0	0	0	0	0
47	Lobbying Expenses	0	0	0	0	0	0	0	0	0
48	Salaries and Employee Benefits	0	0	(5,195,129)	0	0	2,004,021	0	(3,191,108)	3,191,108
49	OPEB Expenses	0	0	0	0	0	0	0	0	0
50	Vacant Positions	0	0	0	0	0	0	0	0	0
51	Service reliability initiatives	0	0	0	0	0	0	0	0	0
52	Incentive Compensation Plan	0	0	(540,000)	0	0	208,305	0	(331,695)	331,695
53	Generating Units - CSAs	0	0	0	0	0	0	0	0	0
54	Generation Maintenance Expense	0	0	(2,850,000)	0	0	1,099,388	0	(1,750,612)	1,750,612
55	Preventive Maintenance Expense	0	0	0	0	0	0	0	0	0
56	Dredging Expense	0	0	(650,056)	0	0	250,759	0	(399,297)	399,297
57	Economic Development Expense	0	0	0	0	0	0	0	0	0
58	Pension Expense	0	0	0	0	0	0	0	0	0
59	Storm Damage Accrual	0	0	(12,000,000)	0	0	4,629,000	0	(7,371,000)	7,371,000
60	Injuries & Damages Accrual	0	0	0	0	0	0	0	0	0
61	Executives' Liability Insurance	0	0	0	0	0	0	0	0	0
62	Meter & Meter Reading Expenses	0	0	0	0	0	0	0	0	0
63	Rate Case Expense Amortization	0	0	(557,750)	0	0	215,152	0	(342,598)	342,598
64	Bad Debt Expense	0	0	0	0	0	0	0	0	0
65	Office Supplies	0	0	0	0	0	0	0	0	0
66	Tree Trimming Expense	0	0	(1,314,000)	0	0	506,876	0	(807,125)	807,125
67	Pole Inspections	0	0	0	0	0	0	0	0	0
68	Transmission Inspection Expense	0	0	0	0	0	0	0	0	0
69	Outage Normalization	0	0	0	0	0	0	0	0	0
70	CIS Expenses	0	0	0	0	0	0	0	0	0
71	Combustion Turbine Annualization	0	0	(870,000)	(5,425,000)	(5,453,000)	4,531,791	0	(7,216,209)	7,216,209
72	Big Bend Rail Project Annualization	0	0	0	(906,000)	(1,039,000)	750,284	0	(1,194,716)	1,194,716
73	Depreciation Study	0	0	0	0	0	0	0	0	0
74	Total Depreciation Expense	0	0	0	0	0	0	0	0	0
75	Taxes Other Than Income	0	0	0	0	0	0	0	0	0
76	Parent Debt Adjustment	0	0	0	0	0	(9,657,000)	0	(9,657,000)	9,657,000
77	Income Tax Expense	0	0	0	0	0	0	0	0	0
	Interest Synchronization	0	0	0	0	0	984,709	0	984,709	(984,709)
	Total Commission Adjustments	0	0	(23,976,935)	(7,579,485)	(6,492,000)	6,004,887	0	(32,043,533)	32,043,533
78	Commission Adjusted NOI	865,359,000	7,614,000	346,957,065	187,028,515	55,783,000	54,496,887	(1,534,000)	650,345,467	215,013,533

Docket No. 130040-EI
Sched. of Adj. - 2009 Rate Case
Exhibit LK-2, Page 1 of 1

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

IN RE: PETITION FOR RATE INCREASE BY TAMPA ELECTRIC COMPANY	**))**	**DOCKET NO. 130040-EI**

EXHIBIT___(LK-3)

OF

LANE KOLLEN

ON BEHALF OF

THE WCF HOSPITAL UTILITY ALLIANCE

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

**TAMPA ELECTRIC COMPANY
DOCKET NO. 130040-EI
OPC'S FIFTH SET OF
INTERROGATORIES
INTERROGATORY NO. 75
PAGE 1 OF 2
FILED: MAY 24, 2013**

75. Maintenance Outages. For each year during the period 2003 through 2012, please provide the amount of expense recorded on the Company's books associated with maintenance outages at the generation plants. The amounts should be broken down by year and by generation plant unit.

A. See the attached table.

Planned Maintenance Outage Expense By Unit & Year

Unit	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
BB1	$0	$881,993	$1,520,388	$4,016,826	$0	$0	$1,131,000	$1,920,000	$645,199	$652,357
BB2	$0	$1,053,242	$3,407,331	$0	$219,594	$620,154	$6,105,000	$451,000	$1,734,997	$685,472
BB3	$0	$1,091,632	$1,014,921	$1,775,289	$979,543	$5,219,128	$448,000	$1,495,000	$791,323	$385,765
BB4	$2,945,746	$0	$1,205,664	$2,323,420	$6,378,696	$134,063	$0	$2,474,000	$949,192	$1,470,302
BBCT1	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
BBCT2	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
BBCT3	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
BBCT4	$0	$0	$0	$0	$0	$0	$0	$0	$20,427	$31,160
GN1	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
GN2	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
GN3	$577,356	$0	$0	$0	$0	$0	$0	$0	$0	$0
GN4	$583,406	$0	$0	$0	$0	$0	$0	$0	$0	$0
GN5	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
GN6	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
GNCT1	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
BS1	$3,272	$448,981	$427,682	$537,842	$2,045,565	$417,860	$404,499	$316,000	$2,953,811	$321,000
BS2	$0	$273,862	$208,578	$1,355,994	$239,175	$3,951,000	$473,219	$509,000	$287,000	$2,941,000
BS3	$0	$0	$0	$0	$0	$0	$0	$0	$31,250	$50,000
BS4	$0	$0	$0	$0	$0	$0	$0	$0	$31,250	$50,000
BS5	$0	$0	$0	$0	$0	$0	$0	$0	$31,250	$50,000
BS6	$0	$0	$0	$0	$0	$0	$0	$0	$31,250	$50,000
PK1	$4,050,000	$1,126,000	$1,483,000	$4,557,000	$1,532,000	$2,578,000	$6,107,000	$2,962,000	$2,930,000	$4,068,000
PK2	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
PK3	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
PK4	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
PK5	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
PH1 PH2	$246,000	$279,000	$197,000	$290,000	$40,000	$75,000	$75,000	$0	$0	$0
Total	$8,405,780	$5,104,710	$9,464,564	$14,856,371	$11,434,573	$12,995,205	$14,743,718	$10,127,000	$10,436,949	$10,755,056

Note: Combustion turbine maintenance and capital replacements (on units BS 1A, B, C, BS 2A, B, C, and PK 2, 3, 4, 5) are performed under contractual services agreements (CSAs). Costs for these units are based on usage (starts/hours) and not tied to a particular planned maintenance outage.

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

IN RE:	**PETITION FOR RATE INCREASE BY TAMPA ELECTRIC COMPANY**	**))**	**DOCKET NO. 130040-EI**

EXHIBIT___(LK-4)

OF

LANE KOLLEN

ON BEHALF OF

THE WCF HOSPITAL UTILITY ALLIANCE

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

TAMPA ELECTRIC COMPANY
DOCKET NO. 130040-EI
OPC'S FIFTH SET OF INTERROGATORIES
INTERROGATORY NO. 77
PAGE 1 OF 1
FILED: MAY 24, 2013

77. Maintenance Outages. For each of the years 2013 and 2014, please provide the projected amount of expense incorporated in the Company's filing associated with overhauls at the production plants, as well as the projected expense for 2015 and 2016. Provide the amounts in total and broken down by generation plant unit.

A. The requested information is provided in the following table.

Projected Planned Maintenance Expense By Unit & Year

Unit	2013	2014	2015	2016
BB1	$900,000	$5,400,000	$840,000	$840,000
BB2	$900,000	$950,000	$5,490,000	$840,000
BB3	$5,300,000	$950,000	$840,000	$5,600,000
BB4	$900,000	$5,700,000	$840,000	$840,000
BBCT4	$25,000	$25,000	$0	$0
BS1	$500,000	$600,000	$5,050,000	$600,000
BS2	$500,000	$600,000	$600,000	$5,150,000
BS3	$62,500	$65,000	$67,500	$70,000
BS4	$62,500	$65,000	$67,500	$70,000
BS5	$62,500	$65,000	$67,500	$70,000
BS6	$62,500	$65,000	$67,500	$70,000
PK1	$3,200,000	$3,100,000	$4,100,000	$3,300,000
PK2	$0	$0	$0	$0
PK3	$0	$0	$0	$0
PK4	$0	$0	$0	$0
PK5	$0	$0	$0	$0
Total	$12,475,000	$17,585,000	$18,030,000	$17,450,000

Note: Combustion turbine maintenance and capital replacements (on units BS 1A, B, C, BS 2A, B, C, and PK 2, 3, 4, 5) are performed under contractual services agreements (CSAs). Costs for these units are based on usage (starts/hours) and not tied to a particular planned maintenance outage.

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

IN RE: PETITION FOR RATE INCREASE BY TAMPA ELECTRIC COMPANY	))	DOCKET NO. 130040-EI

EXHIBIT___(LK-5)

OF

LANE KOLLEN

ON BEHALF OF

THE WCF HOSPITAL UTILITY ALLIANCE

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

TAMPA ELECTRIC COMPANY
DOCKET NO. 130040-EI
HUA'S FIRST SET OF INTERROGATORIES
INTERROGATORY NO. 76
PAGE 1 OF 1
FILED: JULY 5, 2013

76. Regarding Chronister at MFR Schedule C-6. Please refer to the actual 2012 and budgeted 2014 amounts of $0.059 million and $0.498 million, respectively, total company depicted on Schedule C-6 for Account 581, "Load Dispatching Distribution" in your filing. Please explain in detail why the expense in this account increases by $0.439 million, or 744.1%, for the projected twelve months ending December 31, 2014 compared to the actual twelve months ending December 31, 2012. Your answer should identify any deferral or delay in work from prior periods or acceleration in work from later periods or any other change in scheduling such work from a previous schedule, provide a complete explanation in each instance for each change in schedule, and provide a reconciliation of the expense amounts reflected for this account between the two periods and explain in detail all known differences.

A. In late 2012, the company determined that the FERC CFR requires time spent switching and arranging clearance by system dispatchers/operators for capital work to be charged as an O&M expense rather than to the associated capital project. In addition, O&M-related switching shifted from 593 FERC in mid-2012 - $439,000.

The 2014 spending does not reflect a deferral or delay in work from prior periods or acceleration in work from later periods or any other change in scheduling such work from a previous schedule.

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

IN RE: PETITION FOR RATE INCREASE BY TAMPA ELECTRIC COMPANY	**))**	**DOCKET NO. 130040-EI**

EXHIBIT___(LK-6)

OF

LANE KOLLEN

ON BEHALF OF

THE WCF HOSPITAL UTILITY ALLIANCE

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

TAMPA ELECTRIC COMPANY
DOCKET NO. 130040-EI
HUA'S FIRST SET OF INTERROGATORIES
INTERROGATORY NO. 61
PAGE 1 OF 1
FILED: JULY 5, 2013

61. Regarding Chronister at MFR Schedule C-6. Please refer to the actual 2012 and budgeted 2014 amounts of $0.750 million and $5.533 million, respectively, total company depicted on Schedule C-6 for Account 583, "Overhead Line Expenses Distribution" in your filing. Please explain in detail why the expense in this account increases by $4.783 million, or 637.7%, for the projected twelve months ending December 31, 2014 compared to the actual twelve months ending December 31, 2012. Your answer should identify any deferral or delay in work from prior periods or acceleration in work from later periods or any other change in scheduling such work from a previous schedule, provide a complete explanation in each instance for each change in schedule, and provide a reconciliation of the expense amounts reflected for this account between the two periods and explain in detail all known differences.

A. The requested information is provided below.

- Inflationary increases - $45,000
- Shift in pole inspections from 593 FERC – $1.6 million
- Shift in distribution line support from 580 & 588 FERCs – $2.3 million
- Shift in distribution environmental expenses from 588 FERC – $162,000
- Shift in joint use related expenses from 588 FERC and inclusion of legal expenses based on actual historical average – $879,000

The 2014 spending does not reflect a deferral or delay in work from prior periods or acceleration in work from later periods or any other change in scheduling such work from a previous schedule.

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

IN RE: PETITION FOR RATE INCREASE BY TAMPA ELECTRIC COMPANY	))	DOCKET NO. 130040-EI

EXHIBIT___(LK-7)

OF

LANE KOLLEN

ON BEHALF OF

THE WCF HOSPITAL UTILITY ALLIANCE

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

TAMPA ELECTRIC COMPANY
DOCKET NO. 130040-EI
STAFF'S FOURTH SET OF INTERROGATORIES
INTERROGATORY NO. 48
PAGE 1 OF 1
FILED: JUNE 10, 2013

Please refer to the direct testimony of Witness S. Beth Young for the following questions:

48. Refer to page 7, lines 4-15. How did Tampa Electric Company determine the number of additional positions to be hired for 2013 and 2014? For purposes of this response, please identify how many apprentice linemen and apprentice substation journeymen positions will be hired to meet the NERC requirements?

A. There are 26 new positions in the 2013 plan, and 20 new positions in the 2014 plan. The positions were added based on workload projections and apprentices required to replace future front line retirements. This was reviewed by management with overall approval from the Vice President.

The particular sentence on lines 6-9 of page 7 of witness Young's testimony is actually referencing just the relay tester as a position to meet NERC requirements. The other new positions referenced are being added to ensure that there is an adequate front line workforce to maintain existing service levels, and respond to an aging infrastructure.

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

IN RE: PETITION FOR RATE INCREASE BY TAMPA ELECTRIC COMPANY	))	DOCKET NO. 130040-EI

EXHIBIT___(LK-8)

OF

LANE KOLLEN

ON BEHALF OF

THE WCF HOSPITAL UTILITY ALLIANCE

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

TAMPA ELECTRIC COMPANY
DOCKET NO. 130040-EI
OPC'S FIRST SET OF INTERROGATORIES
INTERROGATORY NO. 8
PAGE 1 OF 1
FILED: MAY 6, 2013

8. Incentive Compensation. Please provide the budgeted and the actual amount of incentive compensation expense, by plan (i.e., short term incentive plan, long term incentive plan, etc.) and bonus expense for each year, 2010 through 2012 and the budgeted amounts incorporated in the filing for the test year.

A. The requested information is provided in the following table.

Tampa Electric
Performance Sharing Program (PSP)
($)

	Actual	Budget
2010		
PSP	20,078,475	5,721,706
Prev Year (True-down)	(567,821)	-
	19,510,654	5,721,706
2011		
PSP	6,506,499	6,240,000
Prev Year (True-down)	(445,931)	-
	6,060,568	6,240,000
2012		
PSP	6,631,770	6,427,200
Prev Year True-up	395,132	-
	7,026,902	6,427,200
2013		
PSP	N/A	7,168,000
2014		
PSP	N/A	12,383,000

TECO Energy A&G Allocable to Tampa Electric
Performance Sharing Program (PSP)
($)

	Actual	Budget
2010		
PSP	2,396,567	1,717,753
2011		
PSP	1,665,027	1,651,538
2012		
PSP	1,932,335	1,769,624
2013		
PSP	N/A	1,826,926
2014		
PSP	N/A	1,836,882

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

IN RE: PETITION FOR RATE INCREASE BY TAMPA ELECTRIC COMPANY	**))**	**DOCKET NO. 130040-EI**

EXHIBIT___(LK-9)

OF

LANE KOLLEN

ON BEHALF OF

THE WCF HOSPITAL UTILITY ALLIANCE

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

TAMPA ELECTRIC COMPANY
DOCKET NO. 130040-EI
OPC'S FOURTH SET OF INTERROGATORIES
INTERROGATORY NO. 60
PAGE 1 OF 7
FILED: MAY 20, 2013

60. Payroll – PSP plan. Please refer to the testimony of Brad Register, page 18, lines 22 through 25. According to the testimony, the average actual PSP payout for the period 2008 to 2012 was 4.54%. Please provide the actual PSP payout, by year, for 2008 through 2012. Please also provide the actual payouts for each year broken down between financial performance related goals and non-financial goals.

A. The requested information is attached.

TECO
TAMPA ELECTRIC

the TECO edge

TAMPA ELECTRIC COMPANY
SUCCESS SHARING & SAVINGS PLAN GOALS
2008 UPDATE

Goal	Year-to-Date Actuals	Projected Payout
Safety[1] – Limit companywide OSHA recordable incidence rate to 1.61 and business unit incidence rates to: Energy Delivery, 2.6; Energy Supply, 1.32; and Support Services, .47. (Success Sharing weight 2% - Company 1%, Business Unit 1%)	Company: 1.37 ED: 2.36 ES: 0.90 SS: 0.44	2%
Environmental – Limit preventable environmental events to four. (Success Sharing weight .5%)	2	.5%
Customer Favorability – Achieve a yearly average favorability rating of 95 percent or better. (Success Sharing weight .5%; updated quarterly)	95%	.5%
Reliability[2] – Limit average annual outage time to no more than 89 minutes, and the average annual number of momentary interruptions to no more than 14 occurrences. (Success Sharing weight .5%)	SAIDI – 83:20 mins. MAIFIe – 13:98 events	.5%
Cost Recovery Clauses – Achieve total recovery clauses costs of $57.92/MWh or less. (Success Sharing weight .5%)	$63.66	-
Capital Expenditures – Limit annual capital expenditures to $536.9 million. (Success Sharing weight 1%)	$488.5	1%
Net Income[3] – Achieve annual net income of:		
Tampa Electric $151.8 million – $162.4 million (Success Sharing weight up to 3%; updated quarterly)	$135.6	-
TECO Energy $217.7 million – $230.3 million (Success Sharing weight up to 2%, updated quarterly)	$183.3	-
Projected Payout		4.5%

1. Payout is based 50% on business unit goal and 50% on companywide goal.
2. Payout is based 50% on outage time and 50% on number of interruptions.
3. Savings Plan Performance Match and Success Sharing Net Income payout are directly tied to the achievement of the Net Income targets and will be prorated accordingly.

TECO
TAMPA ELECTRIC

the TECO edge

TAMPA ELECTRIC COMPANY
2009 SUCCESS SHARING UPDATE

GOAL	Year End Targets	Year End Actuals	Achieved Success Sharing
Safety[1] - Limit companywide OSHA recordable incidence rate to 1.20 and business unit incidence rates to: Energy Delivery, 1.90; Energy Supply, .98; and Support Services, .35. *(Success Sharing weight: 2% - Company 1%, Business Unit 1%)*	Company: 1.20 ED: 1.90 ES: 0.98 SS: 0.35	Company: 1.47 ED: 2.40 ES: 1.19 SS: 0.45	-
Environmental - Limit preventable environmental events to three. *(Success Sharing weight .5%)*	3	2	.5 %
Customer Favorability - Achieve a yearly average favorability rating of 95 percent or better. *(Success Sharing weight .5%; updated quarterly)*	95%	93%	-
Reliability[2] - Limit average annual outage time to no more than 91 minutes, and the average annual number of momentary interruptions to no more than 14 occurrences. *(Success Sharing weight .5%)*	SAIDI – 91.00 MAIFIe – 14.00	SAIDI – 99.17 MAIFIe – 11.39	.25%
Cost Recovery Clauses - Achieve total recovery clauses costs of $68.84/MWh or less. *(Success Sharing weight .5%)*	$68.84	$57.46	.5%
NERC Compliance – Limit violations of the mandatory reliability standards to eight. *(Success Sharing weight .5%)*	8	5	.5%
Capital Expenditures – Limit annual capital expenditures, net of asset sales, to $500.0 million. *(Success Sharing weight .5%)*	$500.0	$506.0	.5%*
Net Income[3] - Achieve annual net income of:			
Tampa Electric: $174.7 million – $186.9 million *(Success Sharing weight up to 2%; updated quarterly)*	$174.7	$176.7	1.75%
TECO Energy: $239.7 million – $244.5 million *(Success Sharing weight up to 2%; updated quarterly)*	$239.7	$230.0	-
Total Payout			4.0%

1. Payout is based 50% on business unit goal and 50% on companywide goal.
2. Payout is based 50% on outage time and 50% on number of interruptions.
3. Saving Plan Performance Match and Success Sharing Net Income Payout are directly tied to the achievement of the Net Income Targets and will be prorated accordingly.

* Although year-end management decisions were made to spend additional capital, this goal was deemed to be met for Success Sharing purposes.

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TECO TAMPA ELECTRIC | TECO PEOPLES GAS

Performance Sharing Program (PSP) Goal	[illegible] Target	[illegible] Actual	[illegible]	[illegible]
Safety – Limit companywide OSHA recordable incidence rate to 1.40 (1.00%). Achieve Near Miss reports by business unit. Energy Supply 1,000; Electric and Gas Delivery, 1,300; Support Services, 800: (1.00%).	Companywide Incidence Rate: 1.40 Near Misses: ES: 1,000 E&G Delivery: 1,300 SS: 800	Companywide Incidence Rate: 1.23 Near Misses: ES: 2,333 E&G Delivery: 2,350 SS: 2,186	Yes Yes Yes Yes	2.00%
Reliability – Achieve a gas emergency response rate of 96 percent or better (0.33%). Achieve a generation EAF (Equivalent Availability Factor) of 79.3 percent or better (0.33%). Achieve an electric SAIDI (System Average Interruption Duration Index) of 108 minutes or less (0.33%).	Emergency Response Rate: 96.00% EAF: 79.30% SAIDI: 108.00 min.	Emergency Response Rate: 97.05% EAF: 80.80% SAIDI: 96.39 min.	Yes Yes Yes	1.00%
Customer Favorability – Achieve a yearly average favorability rating of 93 percent.	93.00%	95.00%	Yes	1.00%
Compliance – Limit internally assessed FERC compliance events to 12 (0.50%). Limit preventable environmental events to three (0.50%).	FERC: 12 Environmental: 3	FERC: 8 Environmental: 2	Yes Yes	1.00%
Net Income** **Tampa Electric/Peoples Gas** **TECO Energy**	$230.6 million $265.2 million	$256.7 million*** $275.6 million	Yes Partial	5.00% 0.16%
Payout Percentage				[illegible]

*Notes: *Operational goal payouts (other than Safety) are tied to exceeding a combined Tampa Electric and Peoples Gas Net Income target and will be funded on a $1.00 for $1.00 basis to the extent there remains a surplus above the Net Income target.*

*** By achieving better than target and covering all operational goal payouts, any upside in Net Income will be funded $0.50 on the $1.00.*

****Actual year to date Net Income before accruals for additional PSP payout over budget*

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TECO TAMPA ELECTRIC | TECO PEOPLES GAS

Performance Sharing Program (PSP) Goal	[illegible] Target	Potential [illegible]
Safety – Limit companywide OSHA recordable incidence rate to 1.10 (1.00%). Achieve Near Miss reports by business unit. Energy Supply 1,800; Electric and Gas Delivery, 1,800; Support Services, 1,000. (1.00%).	Companywide Incidence Rate: 1.10 Near Misses: ES: 1,800 E&G Delivery. 1,800 SS: 1,000	Up to 2.00%
Reliability – Achieve a gas emergency response rate of 96 percent or better (0.33%). Achieve a generation EAF (Equivalent Availability Factor) of 81.50 percent or better (0.33%). Achieve an electric SAIDI (System Average Interruption Duration Index) of 105 minutes or less (0.33%).	Emergency Response Rate: 96.00% EAF: 81.50% SAIDI: 105 min.	Up to 1.00%*
Customer Favorability – Achieve a yearly average favorability rating of 93 percent.	93.00%	1.00%*
Compliance – Limit internally assessed FERC compliance events to 12 (0.50%). Limit preventable environmental events to three (0.50%). Achieve companywide near miss reports for environmental of 165 (0.00%, tracking and reporting only).	FERC: 12 Environmental: 3 Near Misses: 165	Up to 1.00%*
Net Income** **Tampa Electric/Peoples Gas** **TECO Energy**	$235.3 million*** $TBD million	Up to 5.00% Up to 2.00%
Maximum Payout Percentage		Up to 12.00%

*Notes: *Operational goal payouts (other than Safety) are tied to exceeding a combined Tampa Electric and Peoples Gas Net Income target and will be funded on a $1.00 for $1.00 basis to the extent there remains a surplus above the Net Income target.*

*** By achieving better than target and covering all operational goal payouts, any upside in Net Income will be funded $0.50 on the $1.00.*

****Actual year to date Net Income before accruals for additional PSP payout over budget*

TAMPA ELECTRIC COMPANY
DOCKET NO. 130040-EI
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Exhibit LK-9, Page 5 of 7

TECOedge

TECO TAMPA ELECTRIC | TECO PEOPLES GAS

Performance Sharing Program (PSP) Goal	December 2011 YTD Target	December 2011 YTD Actual	Achieved?	Payout
Safety – Limit companywide OSHA recordable incidence rate to 1.10 (1.00%). Achieve Near Miss reports by business unit. Energy Supply 1,800; Electric and Gas Delivery, 1,800; Support Services, 1,000: (1.00%).	Companywide Incidence Rate: 1.10 Near Misses: ES: 1,800 E&G Delivery: 1,800 SS: 1,000	Companywide Incidence Rate: 1.02 Near Misses: ES: 3,935 E&G Delivery: 3,458 SS: 2,344	Yes Yes Yes Yes	2.00%
Reliability – Achieve a gas emergency response rate of 96 percent or better (0.33%). Achieve a generation EAF (Equivalent Availability Factor) of 81.50 percent or better (0.33%). Achieve an electric SAIDI (System Average Interruption Duration Index) of 105 minutes or less (0.33%).	Emergency Response Rate: 96.00% EAF: 81.50% SAIDI: 105.00min.	Emergency Response Rate: 97.86% EAF: 79.00% SAIDI: 99.21 min.	Yes No Yes	-*
Customer Favorability – Achieve a yearly average favorability rating of 93 percent.	93.00%	96.00%	Yes	-*
Compliance – Limit internally assessed FERC compliance events to 12 (0.50%). Limit preventable environmental events to three (0.50%). Achieve companywide near miss reports for environmental of 185 (0.00%, tracking and reporting only).	FERC: 12 Environmental: 3 Near Misses: 185	FERC: 20 Environmental: 2 Near Misses: 174	No Yes Yes	-*
Net Income** **Tampa Electric/Peoples Gas** **TECO Energy**	 $235.3 million $286.2 million	 $235.3 million*** $272.6 million	 Yes No	 - -
Maximum Payout Percentage				2.00%

*Notes: *Operational goal payouts (other than Safety) are tied to exceeding a combined Tampa Electric and Peoples Gas Net Income target and will be funded on a $1.00 for $1.00 basis to the extent there remains a surplus above the Net Income target.*

*** By achieving better than target and covering all operational goal payouts, any upside in Net Income will be funded $0.50 on the $1.00.*

****Actual year to date Net Income before accruals for additional PSP payout over budget.*

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TAMPA ELECTRIC COMPANY
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INTERROGATORY NO. 60
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TECO**edge**

TECO TAMPA ELECTRIC | TECO PEOPLES GAS

[illegible] Sharing Program (PSP) Goal	YTD December 20[illegible]	YTD December [illegible]	[illegible] Goal	Payout [illegible]
Safety – 1) Limit companywide OSHA recordable Incidence Rate to 1.00. 2) Achieve Near Miss reports by business unit. Energy Supply 1,800; Electric and Gas Delivery, 1,800; Support Services, 1,000.	Incidence Rate: 1.00 Near Misses: ES: 1,800 E&G Delivery: 1,800 SS: 1,000	Incidence Rate: 0.53 Near Misses: ES: 3,637 E&G Delivery: 5,139 SS: 2,259	Yes Yes	1.00% 1.00%
FOCUS Priority Business Challenges* – 1) In support of meeting future years earnings growth challenges, complete at least six Lean Projects. 2) Based on completed Customer and Constituent Survey results, develop and implement three cost effective solutions to either: (a) improve existing customer experience, (b) provide new valued products and services, or (c) improve customer communications. 3) Successfully execute SAP Enterprise Resource Planning release two go-live in July 2012 and ensure impacted team members attend appropriate training.	At least 6 3 solutions On time, on budget with expected quality and appropriate training	Completed 9 projects More than 3 solutions completed On time, on budget with expected quality and appropriate training	Yes Yes Yes	None – due to NI None – due to NI None – due to NI
Florida Operations Net Income – By achieving better than target Net Income and covering all FOCUS Priority Business Challenges goal payouts, the remaining upside in Net Income will be funded \$0.60 on the \$1.00.	\$246.3 million	\$231.1 million**	No	None
TECO Energy Net Income – Achieve TECO Energy consolidated results from continuing operations before charges and gains.	\$301.0 million	\$248.0 million**	No	None
				2.00%

*Notes: *FOCUS Priority Business Challenges goal payout is tied to exceeding a combined Florida Operations Net Income target and will be funded on a \$1.00 for \$1.00 basis to the extent there is a surplus above the Net Income target. The payout can be achieved on a graduating scale.*

***Reflects year to date Net Income before accruals for additional PSP payout over budget*

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TAMPA ELECTRIC COMPANY
DOCKET NO. 130040-EI
OPC'S FOURTH SET OF
INTERROGATORIES
INTERROGATORY NO. 60
PAGE 7 OF 7
FILED: MAY 20, 2013

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

IN RE:	**PETITION FOR RATE INCREASE BY TAMPA ELECTRIC COMPANY**	**)** **)**	**DOCKET NO. 130040-EI**

EXHIBIT___(LK-10)

OF

LANE KOLLEN

ON BEHALF OF

THE WCF HOSPITAL UTILITY ALLIANCE

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

TAMPA ELECTRIC COMPANY
DOCKET NO. 130040-EI
OPC'S FOURTH SET OF INTERROGATORIES
INTERROGATORY NO. 57
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57. Payroll and Benefits. Please refer to MFR Schedule C-35:

a. Please explain, in detail, what factors cause the projected gross average salary to increase by 7.12% between 2013 and 2014.

b. Please provide a revised version of this schedule breaking down each of the amounts between the amount expensed and the amount charged to capital and other.

A. a. The 2014 average salary includes a 3 percent merit increase, 2.5 percent additional PSP payout, and approximately 1 percent of additional overtime compared to 2013. For 2013, only the 2 percent PSP payout attributable to safety is included in the budget. However for 2014, a 5 percent PSP payout (2 percent for safety goals and 3 percent for operational goals) has been included in the rate request. This additional 3 percent compared to 2013 equates to $5 million in expenses.

b. The requested information is attached.

TAMPA ELECTRIC COMPANY
DOCKET NO. 130040-EI
OPC'S FOURTH SET OF INTERROGATORIES
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FILED: MAY 20, 2013

PAYROLL AND FRINGE BENEFIT INCREASES COMPARED TO CPI

Page 1 of 1

FLORIDA PUBLIC SERVICE COMMISSION

EXPLANATION: Provide the following Payroll and Fringe Benefits data for the historical test year and two prior years. If a projected test year is used, provide the same data for the projected test year and for prior years to include two historical years.

Type of data shown:
XX Projected Test Year Ended 12/31/2014
XX Projected Prior Year Ended 12/31/2013
XX Historical Prior Year Ended 12/31/2012
Witness: J. S. Chronister / [illegible]
L. L. Cifuentes

COMPANY: TAMPA ELECTRIC COMPANY

DOCKET No. 130040-EI

Total - (Dollars in 000's)

Line No.	(1)	(2) 2014 Amount	(3) 2014 % Increase	(4) 2014 % CPI	(5) 2013 Amount	(6) 2013 % Increase	(7) 2013 % CPI	(8) 2012 Amount	(9) 2012 % Increase	(10) 2012 % CPI	(11) 2011 Amount	(12) 2011 % Increase	(13) 2011 % CPI	(14) 2010 Amount
1	Total Company Basis													
2														
3	Gross Payroll (A)	$ 214,139	7.86	2.7	$ 198,5[illegible]	2.00	2.8	$ 194,4[illegible]	5.46	3.3	$ 184,353	(0.1[illegible])	3.2	$ 184,322
4														
5														
6	Fringe Benefits													
7														
8	Medical & Dental Insurance	20,072	7.84		18,640	(6.80)		20,000	10.67		18,070	10.38		16,343
9	Federal Insurance Contributions Act	15,303	3.02		14,850	1.26		13,872	5.71		11,9[illegible]	(4.8[illegible])		13,086
10	Postretirement Medical	8,413	(1.00)		8,665	(14.08)		11,174	(8.26)		12,178	(0.80)		12,286
11	Pension Plan	14,481	(22.93)		18,[illegible]	22.20		15,301	41.45		10,8[illegible]	(31.60)		14,778
12	Long Term Disability	4,799	13.72		4,144	20.99		3,425	46.26		2,342	(42.40)		4,708
13	Retirement Savings Plan	5,672	5.27		5,296	0.53		6,374	3.67		5,882	(35.96)		7,714
14	Workers Compensation Insurance	3,208	5.32		3,039	30.54		2,328	(46.83)		4,383	260.78		1,209
15	Stock Compensation	4,084	3.82		4,008	34.17		3,078	22.39		3,020	11.31		2,780
16	Other Benefits	1,245	12.35		1,108	8.82		1,020	(3.03)		1,138	3.64		1,098
17	Vacation Carryover	746	2.92		720	(16.48)		862	4.67		814	27.69		638
18	Group Life Insurance	489	3.26		475	1.53		468	(36.52)		736	(4.05)		768
19	Federal & State Unemployment Taxes	831	1.71		817	(16.62)		980	30.46		757	100.20		378
20														
21	Subtotal Fringe Benefits	$ 81,242	(0.45)		$ 81,634	3.96		$ 78,530	8.25		$ 72,542	(6.69)		$ 77,716
22														
23	Total Payroll and Fringes	$ 295,381	5.52		$ 279,930	2.50		$ 272,934	6.29		$ 256,894	(5.17)		$ 272,038
24														
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31														
32														
33														
34														
35														
36														
37	(A) Gross Payroll includes all wages and salaries, overtime, premiums, and Performance Sharing Program pay													
38	* Figures not shown in 000's													
39	Totals may be affected due to rounding													

TAMPA ELECTRIC COMPANY
DOCKET NO. 130040-EI
OPC'S FOURTH SET OF INTERROGATORIES
INTERROGATORY NO. 57
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PAYROLL AND FRINGE BENEFIT INCREASES COMPARED TO CPI — Page 2 of 4

FLORIDA PUBLIC SERVICE COMMISSION

EXPLANATION: Provide the following Payroll and Fringe Benefits data for the historical test year and two prior years. If a projected test year is used, provide the same data for the projected test year and for prior years to include two historical years.

COMPANY: TAMPA ELECTRIC COMPANY

DOCKET No. 130040-EI

Type of data shown:
XX Projected Test Year Ended 12/31/2014
XX Projected Prior Year Ended 12/31/2013
XX Historical Prior Year Ended 12/31/2012
Witness: J. S. Chronister/S. Register
L. L. Cifuentes

O&M Expense - (Dollars in 000's)

Line No.	(1)	(2) 2014 Amount	(3) 2014 % Increase	(4) 2014 % CPI	(5) 2013 Amount	(6) 2013 % Increase	(7) 2013 % CPI	(8) 2012 Amount	(9) 2012 % Increase	(10) 2012 % CPI	(11) 2011 Amount	(12) 2011 % Increase	(13) 2011 % CPI	(14) 2010 Amount
1	Total Company Basis													
2														
3	Gross Payroll (A)	$ 142,954	6.91	2.7	$ 133,710	4.60	2.6	$ 127,834	5.40	2.3	$ 121,284	(8.38)	3.2	$ 132,380
4														
5														
6	Fringe Benefits													
7														
8	Medical & Dental Insurance	12,644	1.81		12,419	(3.38)		12,853	13.36		11,338	4.51		10,875
9	Federal Insurance Contributions Act	8,640	2.78		8,391	6.09		8,916	7.51		8,308	(1.02)		8,223
10	Postretirement Medical	7,770	(3.90)		8,087	(12.01)		9,207	(7.63)		10,358	(2.83)		10,357
11	Pension Plan	8,131	(27.13)		12,101	28.77		9,484	44.25		6,552	(34.74)		10,500
12	Long Term Disability	3,021	9.42		2,761	26.44		2,251	45.16		1,476	(55.05)		3,279
13	Retirement Savings Plan	3,511	(8.47)		3,837	4.07		3,338	5.04		3,228	(37.00)		5,130
14	Worker's Compensation Insurance	2,078	(5.45)		2,198	38.35		1,496	(45.57)		2,748	241.60		805
15	Stock Compensation	5,024	3.00		4,608	24.17		3,679	22.39		3,008	11.31		2,702
16	Other Benefits	784	6.31		738	4.52		706	(1.37)		714	(1.66)		726
17	Vacation Carryover	467	2.60		480	(12.39)		548	6.76		513	21.18		423
18	Group Life Insurance	300	(2.67)		315	5.67		299	(37.32)		475	(8.16)		526
19	Federal & State Unemployment Taxes	320	(3.53)		344	(13.67)		430	32.34		417	80.81		232
20														
21	Subtotal Fringe Benefits	$ 54,9[illegible]	[illegible]		$ 57,730	7.0[illegible]		$ 53,689	5.69		$ 49,227	(10.23)		$ 54,801
22														
23	Total Payroll and Fringes	$ 197,820	3.16		$ 191,444	5.34		$ 181,723	6.69		$ 170,430	(8.92)		$ 187,181
24														
25														
26														
27														
28														
29														
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32														
33														
34														
35														
36														
37	(A) Gross Payroll excludes all wages and salaries, overtime, premium, and Performance Sharing Program pay.													
38	* Figures not shown in 000's													
39	Totals may be affected due to rounding													

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Response to OPC-I-57
Exhibit LK-10, Page 4 of 5

TAMPA ELECTRIC COMPANY
DOCKET NO. 130040-EI
OPC'S FOURTH SET OF INTERROGATORIES
INTERROGATORY NO. 57
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PAYROLL AND FRINGE BENEFIT INCREASES COMPARED TO CPI

Page 3 of 4

FLORIDA PUBLIC SERVICE COMMISSION

EXPLANATION: Provide the following Payroll and Fringe Benefits data for the historical test year and two prior years. If a projected test year is used, provide the same data for the projected test year and for prior years to include two historical years.

COMPANY: TAMPA ELECTRIC COMPANY

DOCKET No. 130040-EI

Type of data shown:
XX Projected Test Year Ended 12/31/2014
XX Projected Prior Year Ended 12/31/2013
XX Historical Prior Year Ended 12/31/2012
Witness: J. S. Chronister / Register
L. L. Cifuentes

Capital Expense - (Dollars in 000's)

Line No.	(1)	(2) 2014 Amount	(3) 2014 % Increase	(4) 2014 % CPI	(5) 2013 Amount	(6) 2013 % Increase	(7) 2013 % CPI	(8) 2012 Amount	(9) 2012 % Increase	(10) 2012 % CPI	(11) 2011 Amount	(12) 2011 % Increase	(13) 2011 % CPI	(14) 2010 Amount
1	Total Company Basis													
2														
3	Gross Payroll (A)	$ 84,378	13.24	1.7	$ 46,365	(11.03)	2.0	$ 84,918	3.70	2.2	$ 82,811	4.44	3.2	$ 80,884
4														
5														
6	Fringe Benefits													
7														
8	Medical & Dental Insurance	5,804	21.81		4,967	(21.61)		6,334	5.31		5,995	25.18		4,472
9	Federal Insurance Contributions Act	4,350	27.81		3,563	(14.16)		4,060	(0.08)		4,087	7.83		3,794
10	Postretirement Medical	1,340	10.71		1,126	(27.17)		1,546	(12.84)		1,778	12.28		1,584
11	Pension Plan	4,080	(12.90)		4,686	3.64		4,334	34.34		3,575	(21.83)		4,360
12	Long Term Disability	1,383	30.71		1,000	2.50		1,010	38.81		727	(46.10)		1,349
13	Retirement Savings Plan	1,572	18.80		1,323	(14.92)		1,568	(1.82)		1,580	(26.19)		2,111
14	Workers Compensation Insurance	809	10.92		730	10.84		668	(49.24)		1,304	305.11		334
15	Stock Compensation	-	-		-	-		-	-		-	-		-
16	Other Benefits	361	30.00		277	(14.55)		324	(7.86)		352	17.86		298
17	Vacation Carryover	200	10.85		180	(23.24)		231	(0.57)		233	46.28		174
18	Group Life Insurance	132	10.27		119	(13.86)		137	(41.52)		234	8.12		218
19	Federal & State Unemployment Taxes	234	14.81		204	(30.34)		300	72.67		325	127.13		103
20														
21	Subtotal Fringe Benefits	$ 20,000	12.24		$ 17,871	(11.66)		$ 20,230	3.70		$ 19,677	4.44		$ 19,746
22														
23	Total Payroll and Fringes	$ 78,334	12.24		$ 69,349	(11.82)		$ 78,229	3.70		$ 77,498	4.44		$ 69,428

37 (A) Gross Payroll includes all wages and salaries, overtime, premiums, and Performance Sharing Program pay
38 * Figures not shown in 000's
39 Totals may be affected due to rounding

TAMPA ELECTRIC COMPANY
DOCKET NO. 130040-EI
OPC'S FOURTH SET OF INTERROGATORIES
INTERROGATORY NO. 57
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PAYROLL AND FRINGE BENEFIT INCREASES COMPARED TO CPI

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FLORIDA PUBLIC SERVICE COMMISSION

EXPLANATION: Provide the following Payroll and Fringe Benefits data for the [illegible] year and [illegible] prior years. If a projected test year is used, provide the same data for the projected test year and for prior years to include two historical years.

Type of data shown:
XX Projected Test Year Ended 12/31/2014
XX Projected Prior Year Ended 12/31/2013
XX Historical Prior Year Ended 12/31/2012
Witness: J. S. Chronister/ [illegible]
L. L. Cifuentes

COMPANY: TAMPA ELECTRIC COMPANY

DOCKET No. 130040-EI

Other Expense - (Dollars in 000's)

Line No.	(1)	(2) 2014 Amount	(3) 2014 % Increase	(4) 2014 % CPI	(5) 2013 Amount	(6) 2013 % Increase	(7) 2013 % CPI	(8) 2012 Amount	(9) 2013 % Increase	(10) 2012 % CPI	(11) 2011 Amount	(12) 2011 % Increase	(13) 2011 % CPI	(14) 2010 Amount
1	Total Company Basis													
2														
3	Gross Payroll (A)	$ 18,909	4.13	2.7	$ 16,239	30.32	2.0	$ 11,650	14.76	2.3	$ 10,157	(0.20)	3.2	$ 11,271
4														
6														
8	Fringe Benefits													
7														
8	Medical & Dental Insurance	1,704	12.83		1,604	24.80		1,231	18.44		1,025	8.83		965
9	Federal Insurance Contributions Act	1,349	14.11		1,179	28.80		915	15.43		786	(6.95)		844
10	Postretirement Medical	386	2.18		378	18.24		320	(3.94)		341	(3.02)		352
11	Pension Plan	1,274	(16.20)		1,045	63.88		922	46.34		648	(32.39)		961
12	Long Term Disability	422	21.25		346	62.28		214	50.92		143	(41.42)		300
13	Retirement Savings Plan	488	10.28		444	34.81		330	8.78		303	(38.40)		476
14	Worker's Compensation Insurance	233	10.33		200	70.08		140	(43.05)		250	253.07		74
15	Stock Compensation	-	-		-	-		-	-		-	-		-
16	Other Benefits	100	17.72		83	38.00		60	1.67		57	1.72		66
17	Vacation Carryover	65	7.62		60	13.33		53	9.62		60	39.29		38
18	Group Life Insurance	43	7.86		40	38.70		29	(38.43)		46	(8.11)		49
19	Federal & State Unemployment Taxes	71	6.06		88	16.80		61	32.86		45	88.04		23
20														
21	Subtotal Fringe Benefits	$ 6,276	4.13		$ 5,008	38.22		$ 4,313	14.10		$ 3,758	(8.80)		$ 4,170
22														
23	Total Payroll and Fringes	$ 25,185	4.13		$ 22,247	30.22		$ 15,960	14.76		$ 13,910	(0.30)		$ 15,441
24														
25														
26														
27														
28														
29														
30														
31														
32														
33														
34														
35														
36														
37	(A) Gross Payroll includes all wages and salaries, overtime, premiums, and Performance Sharing Program pay													
38	* Figures not shown in 000's													
39	Totals may be affected due to rounding.													

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

IN RE: PETITION FOR RATE INCREASE BY TAMPA ELECTRIC COMPANY	))	DOCKET NO. 130040-EI

EXHIBIT___(LK-11)

OF

LANE KOLLEN

ON BEHALF OF

THE WCF HOSPITAL UTILITY ALLIANCE

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

TAMPA ELECTRIC COMPANY
DOCKET NO. 130040-EI
OPC'S FIRST SET OF INTERROGATORIES
INTERROGATORY NO. 12
PAGE 1 OF 1
FILED: MAY 6, 2013

12. Injuries and Damages. Please provide the amount of injuries and damages expense for each year, 2010 through 2013, year to date and the projected amount of injuries and damages expense included in the test year.

A. The requested information is provided below.

	Injuries and Damages
2010	$3,662,511
2011	$5,017,699
2012	$6,551,971
YTD March 2013	$1,201,417
2013 Budget	$6,563,000
2014 Budget	$6,806,000

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

IN RE:	**PETITION FOR RATE INCREASE BY TAMPA ELECTRIC COMPANY**	**))**	**DOCKET NO. 130040-EI**

EXHIBIT___(LK-12)

OF

LANE KOLLEN

ON BEHALF OF

THE WCF HOSPITAL UTILITY ALLIANCE

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

TAMPA ELECTRIC COMPANY
DOCKET NO. 130040-EI
OPC'S TENTH SET OF INTERROGATORIES
INTERROGATORY NO. 131
PAGE 1 OF 1
FILED: JUNE 28, 2013

131. Allocations. Was the impact of the recently announced agreement for TECO Energy to acquire New Mexico Gas Company, expected to close by March 2014 and will add 50% to the customer base, factored into the 2014 budget upon which the filing is based? If yes, please explain, in detail, how it was reflected and include all assumptions. If not, please provide the current best estimate of the impacts of the acquisition on the filing. Include all assumptions used in deriving the estimates and identify the amounts and the MFR schedules impacted.

A. No. At the time of the filing on April 5, 2013 TECO Energy had not made a binding offer to purchase New Mexico Gas Company ("NMGC") and had no certainty that such an offer would ultimately be accepted and result in an agreement to purchase. Hence, the 2014 test year budget as filed does not reflect any impacts related to the future acquisition of NMGC by TECO Energy. TECO Energy expects the acquisition of NMGC to close by March of 2014, dependent upon various regulatory approvals. 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.

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

IN RE:	**PETITION FOR RATE INCREASE BY TAMPA ELECTRIC COMPANY**	**))**	**DOCKET NO. 130040-EI**

EXHIBIT___(LK-13)

OF

LANE KOLLEN

ON BEHALF OF

THE WCF HOSPITAL UTILITY ALLIANCE

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

TAMPA ELECTRIC COMPANY
DOCKET NO. 130040-EI
OPC'S TENTH SET OF INTERROGATORIES
INTERROGATORY NO. 133
PAGE 1 OF 1
FILED: JUNE 28, 2013

133. Allocations. Please identify the currently projected month and year that TECO Energy, Inc. will begin to direct charge and allocate costs to New Mexico Gas Company and provide the current best estimate of the amount that will be direct charged and, separately, the amount that will be allocated from TECO Energy, Inc. to New Mexico Gas Company in the first twelve month period after the charges begin and for the subsequent twelve month period.

A. Please refer to OPC's Tenth Set of Interrogatories, No. 131 for the estimated impacts of the TECO Energy allocation assuming a successful closing in March 2014. It is premature at this time to estimate how much, if any, direct charges from TECO Energy would go to New Mexico Gas Company ("NMGC") during the specified time period. Additionally, direct charges to Tampa Electric are based solely on the work provided to the Company and would not be subject to change as a result of direct charges to NMGC.

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

IN RE: PETITION FOR RATE INCREASE BY TAMPA ELECTRIC COMPANY	))	DOCKET NO. 130040-EI

EXHIBIT___(LK-14)

OF

LANE KOLLEN

ON BEHALF OF

THE WCF HOSPITAL UTILITY ALLIANCE

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

TAMPA ELECTRIC COMPANY
DOCKET NO. 130040-EI
OPC'S TENTH SET OF INTERROGATORIES
INTERROGATORY NO. 138
PAGE 1 OF 1
FILED: JUNE 28, 2013

138. Allocations. Please provide the current best projection of the impacts of TECO Energy's acquisition of New Mexico Gas Company on costs direct charged and cost allocated to the Company for each year, 2014 through 2016. This should include both a description of the impacts as well as the quantification of the impacts.

A. Please see Tampa Electric's response to OPC's Tenth Set of Interrogatories, Nos. 131 and 133. 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.

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

IN RE:	**PETITION FOR RATE INCREASE BY TAMPA ELECTRIC COMPANY**	**))**	**DOCKET NO. 130040-EI**

EXHIBIT___(LK-15)

OF

LANE KOLLEN

ON BEHALF OF

THE WCF HOSPITAL UTILITY ALLIANCE

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

TAMPA ELECTRIC COMPANY
DOCKET NO. 130040-EI
OPC'S FOURTH SET OF INTERROGATORIES
INTERROGATORY NO. 49
PAGE 1 OF 4
FILED: MAY 20, 2013

49. Expenses. Please refer to MFR Schedule C-6, page 4 of 6. With regards to Records and Collection Expense- Customer Accounts (Account 903):

a. Please explain, in detail, why the amount of actual expense has been so much below the annual budgeted expense in this account for each year of the period 2008 through 2012. (For example, the 2012 actual expense is approximately $3.1M below the budgeted amount).

b. Please explain, in detail, why the cost is projected to increase by $6.5 million or 38% between 2012 actual and 2014 budgeted.

A. a. For the period 2008 through 2012, the primary area that experienced below budget favorable variances in Account 903 was the call center operations. The most significant driver of the Call Center Account 903 favorable variance was the department consistently budgeting all of its non-recoverable O&M labor to Account 903 when a portion of actual non-recoverable O&M labor costs were charged to Account 587 and Account 920. As a result, the variance for Account 903 alone was significant; however, the overall total non-recoverable O&M labor variance for the call center was far less. The attached document details the call center operations non-recoverable O&M labor related variances for Account 903 and in total.

As shown in the attached document, the total non-recoverable O&M call center labor budget favorable variance for years 2008 through 2012 is related to efforts to offset base revenue shortfalls with cost reductions. These labor cost reductions were achieved through eliminating Customer Service Professional ("CSP") additions and temporarily holding jobs vacant.

b. In addition to customer growth and cost inflation, the significant increase from the 2012 actual to 2014 budgeted amount in Account 903 is primarily resulting from the call center area consistently budgeting all of its labor in Account 903. As illustrated in the attached document, if the call center area had budgeted its 2014 labor using the same percentage allocation as 2012 actual labor charges, the Call Center Account 903 budgeted labor for 2014 would have been approximately $2.9 million less, and the total of Accounts 587 and 903 would have been higher by $2.9 million.

TAMPA ELECTRIC COMPANY
DOCKET NO. 130040-EI
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FILED: MAY 20, 2013

In addition to the account budgeting difference and general cost inflation, the remainder of the 2012 actual to 2014 budget increase is primarily being driven by the desire to improve the call center customer service metrics by increasing labor resources. In 2012, the call center average headcount was approximately 98 team members. Due to significant shortfall in base revenues, cost reductions were put in place and CSP positions were not filled in 2012. Call volume increased nearly 15 percent in 2012, and service levels for calls answered within 60 seconds declined approximately 12 percent. Other call center metrics including Average Speed of Answers and Calls Abandoned were also reduced. The 2014 budget includes restoring the CSP headcount to an average of 109 Call Center team members and improving the customer service metrics. Along with adding CSPs, two additional call center supervisors are included in the 2014 budget. The increases in headcount are budgeted to be achieved over the two year period of 2013 and 2014. To achieve this increase in CSPs, three new hire classes will be required to offset projected attrition. Therefore, the additional Call Center headcount plus two years of general inflation on Account 903 resources are the main drivers for the true increase in costs from the 2012 actual to 2014 budget.

Call Center[1] Operations Labor Variances By FERC
(Dollars in 000s)

	Budget			Actual					Fav/(Unfav) Variance	
Year	FERC 903	Other O&M	Total	FERC 903	FERC 587	FERC 920	Other	Total	FERC 903	Total
2008	8,689	-	8,689	6,197	1,380	721	25	8,323	2,492	366
2009	8,861	172	9,034	6,566	1,400	702	23	8,691	2,296	343
2010	9,117	-	9,117	6,608	1,415	734	-	8,757	2,508	360
2011	8,854	-	8,854	6,505	1,401	701	-	8,606	2,349	247
2012	8,930	-	8,930	6,233	758	1,575	-	8,566	2,697	364

[1] Includes departments Call Center (orig loc 599), Customer Care and Advisory (orig loc 428) and Business & Industry Team (orig loc 420)

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TAMPA ELECTRIC COMPANY
DOCKET NO. 130040-EI
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INTERROGATORIES
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FILED: MAY 20, 2013

Call Center[1] Operations Labor By FERC
(Dollars in 000s)

FERC	Actual $ 2012	Actual % 2012	Budget $ 2014	Budget % 2014	Pro Forma $ 2014	Pro Forma % 2014*	2014 Variance
903	6,233	73%	10,533	100%	7,665	73%	2,868
587	758	9%		0%	932	9%	(932)
920	1,575	18%		0%	1,937	18%	(1,937)
Total	8,566	1	10,533	100%	10,533	100%	-

* Pro forma % equal to 2012 Actual %

[1] Includes departments Call Center and Development Services Cost Centers (formerly Customer Care and Advisory and Business & Industry Team)

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TAMPA ELECTRIC COMPANY
DOCKET NO. 130040-EI
OPC'S FOURTH SET OF
INTERROGATORIES
INTERROGATORY NO. 49
PAGE 4 OF 4
FILED: MAY 20, 2013

Docket No. 130040-EI
Response to OPC-I-49
Exhibit LK-15, Page 4 of 4

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

IN RE:	**PETITION FOR RATE INCREASE BY TAMPA ELECTRIC COMPANY**	**))**	**DOCKET NO. 130040-EI**

EXHIBIT___(LK-16)

OF

LANE KOLLEN

ON BEHALF OF

THE WCF HOSPITAL UTILITY ALLIANCE

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

TAMPA ELECTRIC COMPANY
DOCKET NO. 130040-EI
HUA'S FIRST SET OF
INTERROGATORIES
INTERROGATORY NO. 81
PAGE 1 OF 1
FILED: JULY 5, 2013

81. Regarding Chronister at MFR Schedule C-6. Please refer to the actual 2012 and budgeted 2014 amounts of $2.321 million and $3.623 million, respectively, total company depicted on Schedule C-6 for Account 904, "Uncollectible Accounts-Cust Accounts" in your filing. Please explain in detail why the expense in this account increases by $1.302 million, or 56.1%, for the projected twelve months ending December 31, 2014 compared to the actual twelve months ending December 31, 2012. Please identify and fully explain each additional step you are taking to improve collections in 2014 in light of your projections. Your answer should also provide a reconciliation of the expense amounts reflected for this account between the two periods and explain in detail all known differences.

A. As shown on MFR C-11, Tampa Electric's Bad Debt Factor reflected significant improvement. This improvement began in 2011 due to the implementation of a new credit and collections system that was implemented in 2011. One of the efficiencies that came with implementing the technology was a significant improvement in the ability to identify active accounts to transfer previously written off accounts. This activity will continue along with other successful initiatives, including outbound dialer, aggressive recovery of old write-offs, better targeted collection activities, Red Flag rules requiring positive customer identification, and the culmination of aggressive efforts to secure accounts, are projected to keep the net write-off percentage well below Tampa Electric's historical average and the industry average. However, the level of account transfers to previously written off accounts will slow and be exhausted in time. In addition, reductions in LIHEAP and other public assistance programs and Preference awards in bankruptcies are expected to have a negative impact on write-offs in the future. Therefore, the budgeted amount of Bad Debt Expense and associated Bad Debt Factor is projected to trend toward the higher historical levels through 2014.

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

IN RE: PETITION FOR RATE INCREASE BY TAMPA ELECTRIC COMPANY	**))**	**DOCKET NO. 130040-EI**

EXHIBIT___(LK-17)

OF

LANE KOLLEN

ON BEHALF OF

THE WCF HOSPITAL UTILITY ALLIANCE

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

TAMPA ELECTRIC COMPANY
DOCKET NO. 130040-EI
OPC'S NINTH SET OF INTERROGATORIES
INTERROGATORY NO. 119
PAGE 1 OF 102
FILED: JUNE 24, 2013

119. Outside Services Expense. Please refer to the Original MFR Schedule C-16 and revised MFR Schedule C-16. The May 17, 2013 letter provided with the revised MFR Schedule C-16 indicates that the "...revised MFR correctly reflects only the O&M (excluding clause) components of those consultants." The amount for Legal outside consulting costs for 2012 declined from $4,775,000 in the original MFR Sch. C-16 to $1,861,000 to the revised version.

a. Please provide a description of the legal costs that were removed in the revised version and identify why they were removed (i.e., capital costs, clause, etc.). If any were removed as clause related, identify which clause. If any were removed as capital, identify what project(s) these legal costs were capitalized to.

b. Please explain, in detail, why the Company projects the legal outside services expense (non-clause) will increase from $1,861,000 in 2012 to $4,116,000 in the 2014 test year.

c. Please provide the total outside consultant legal expense for each year, 2008 through 2012, broke down between capital, expenses (non-clause) and clause related by clause.

A. a. The original amount included approximately $1.6 million of legal costs capitalized to FERC Account 228 associated with Accumulated Provision for Injuries and Damages. Additionally, approximately $0.6 million of legal costs associated with capital projects were included. Of that amount, $372,535 was associated with the Polk 2-5 Combined Cycle Conversion. Other capital projects included an easement for IMC Phosphates, the gypsum storage addition, Polk water project conveyance, Polk 1 CSA and Lee Roy Selmon Viaduct widening. No clause-related O&M expenses were removed.

b. The company budgeted an increase in legal costs of $2,255,000 between 2012 to 2014. Of that amount, $733,333 represents one-third of the anticipated rate case expense that the company is amortizing over three years. The remaining $1,521,667 consists of $520,000 incremental Energy Delivery costs associated with pending litigation with Verizon regarding pole attachment charges, $560,000 associated with two long-term fuel commodity contracts and two long-term fuel transportation contracts that are expiring and the balance represents incremental legal costs anticipated in the Energy Supply and Corporate Services areas.

c. The requested information is attached.

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

IN RE: PETITION FOR RATE INCREASE BY TAMPA ELECTRIC COMPANY	**))**	**DOCKET NO. 130040-EI**

EXHIBIT___(LK-18)

OF

LANE KOLLEN

ON BEHALF OF

THE WCF HOSPITAL UTILITY ALLIANCE

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

TAMPA ELECTRIC COMPANY
DOCKET NO. 130040-EI
HUA'S FIRST SET OF
INTERROGATORIES
INTERROGATORY NO. 125
PAGE 1 OF 1
FILED: JULY 5, 2013

125. Regarding Ashburn at 17:24-18:2. Please identify and provide the date(s) when Tampa Electric's transmission customers (*e.g.*, APP and Calpine) must exercise their option to request rollover of their existing contracts.

A. Calpine was required to provide notification by May 31, 2013. Tampa Electric has recently received a commitment from Calpine to roll-over 249 MW effective June 1, 2014 and ending May 31, 2019.

Auburndale Power Partners effectively has until December 31, 2013 to exercise their contract option. Tampa Electric has no current information to update related to this contract.

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

IN RE:	**PETITION FOR RATE INCREASE BY TAMPA ELECTRIC COMPANY**	**))**	**DOCKET NO. 130040-EI**

EXHIBIT___(LK-19)

OF

LANE KOLLEN

ON BEHALF OF

THE WCF HOSPITAL UTILITY ALLIANCE

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

**TAMPA ELECTRIC COMPANY
DOCKET NO. 130040-EI
HUA'S FIRST SET OF
INTERROGATORIES
INTERROGATORY NO. 131
PAGE 1 OF 1
FILED: JULY 5, 2013**

131. Regarding Chronister at 47:14-18. Please fully explain how Tampa Electric proposes to reflect any earnings from transmission revenue if Calpine or Auburndale extend or partially extend their agreements after the Commission concludes this proceeding, or if Tampa Electric enters into any other transmission agreement causing Tampa Electric to earn transmission revenues, not forecasted in Tampa Electric's rate case, in the 2014 test year or beyond.

A. On May 29, 2013 Tampa Electric was officially notified by Calpine that they would be renewing 249 MW of their existing firm transmission service for a five year term commencing June 1, 2014. Calpine was notified that they had until May 31, 2013 per the contract to renew the remaining 277 MW, and they chose not to extend the remaining MW of firm transmission service. Auburndale effectively has until December 31, 2013 to exercise their contract option, but the company has been made aware through verbal communications that an extension will not occur. Tampa Electric has calculated the anticipated incremental revenues from the 249 MW to be $4.92 million in the 2014 test year. As stated in witness Chronister's testimony, the company proposes to refund the incremental revenues associated with the transmission revenues from the 277 MW of firm service occurring during the first five months of 2014. The amount of the refund to customers through the fuel clause would be $2.28 million. The $4.93 million in revenues were calculated by multiplying the monthly rate per kW of 1.6134 times 249 MW plus the monthly rate for ancillary services, Schedule 1 of .0359 per kW times the 249 kW. The $2.28 million was calculated by multiplying 277 MW times the same rates for the first five months of 2014.

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

IN RE:	**PETITION FOR RATE INCREASE BY TAMPA ELECTRIC COMPANY**	**)** **)**	**DOCKET NO. 130040-EI**

EXHIBIT___(LK-20)

OF

LANE KOLLEN

ON BEHALF OF

THE WCF HOSPITAL UTILITY ALLIANCE

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

TAMPA ELECTRIC COMPANY
COST OF CAPITAL ADJUSTMENTS RECOMMENDED BY HUA
DOCKET NO. 130040-EI
TEST YEAR ENDING DECEMBER 31, 2014
($ MILLIONS)

I. Cost of Capital As Filed

	Capital Percent	Cost	Wtd Cost	Grossed Up Cost
Long Term Debt	35.15%	5.40%	1.90%	1.90%
Short Term Debt	0.57%	1.47%	0.01%	0.01%
Customer Deposits	2.60%	2.20%	0.06%	0.06%
Common Equity	42.26%	11.25%	4.75%	7.76%
Deferred Income Taxes	19.24%	0.00%	0.00%	0.00%
Tax Credits - Weighted Cost	0.18%	8.54%	0.02%	0.02%
Total Cost of Capital	100.00%		6.73%	9.74%

II. Cost of Capital with HUA's Reduction in ROE to 9.3%

	Capital Percent	Cost	Wtd Cost	Grossed Up Cost
Long Term Debt	35.15%	5.40%	1.90%	1.90%
Short Term Debt	0.57%	1.47%	0.01%	0.01%
Customer Deposits	2.60%	2.20%	0.06%	0.06%
Common Equity	42.26%	9.30%	3.93%	6.41%
Deferred Income Taxes	19.24%	0.00%	0.00%	0.00%
Tax Credits - Weighted Cost	0.18%	8.54%	0.02%	0.02%
Total Cost of Capital	100.00%		5.91%	8.39%
Reduction in Grossed Up ROR				1.35%
Rate Base as Filed				4,339.974
Reduction in Rev Req				(58.375)

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

IN RE: PETITION FOR RATE INCREASE BY TAMPA ELECTRIC COMPANY	**))**	**DOCKET NO. 130040-EI**

EXHIBIT___(LK-21)

OF

LANE KOLLEN

ON BEHALF OF

THE WCF HOSPITAL UTILITY ALLIANCE

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549

FORM 10-K

☒ **Annual Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934**

For the fiscal year ended December 31, 2009

OR

☐ **Transition Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934**

For the transition period from to

Commission File No.	Exact name of each Registrant as specified in its charter, state of incorporation, address of principal executive offices, telephone number	I.R.S. Employer Identification Number
1-8180	TECO ENERGY, INC. (a Florida corporation) TECO Plaza 702 N. Franklin Street Tampa, Florida 33602 (813) 228-1111	59-2052286
1-5007	TAMPA ELECTRIC COMPANY (a Florida corporation) TECO Plaza 702 N. Franklin Street Tampa, Florida 33602 (813) 228-1111	59-0475140

Securities registered pursuant to Section 12(b) of the Act:

Title of each class	Name of each exchange on which registered
TECO Energy, Inc. Common Stock, $1.00 par value	New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Act: NONE

Indicate by check mark if TECO Energy, Inc. is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. YES ☒ NO ☐

Indicate by check mark if Tampa Electric Company is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. YES ☐ NO ☒

Indicate by check mark if the registrants are not required to file reports pursuant to Section 13 or Section 15(d) of the Exchange Act. YES ☐ NO ☒

Indicate by check mark whether the registrants (1) have filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) have been subject to such filing requirements for the past 90 days. YES ☒ NO ☐

Indicate by check mark whether the registrants have submitted electronically and posted on their corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrants were required to submit and post such files). YES ☐ NO ☐

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrants' knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ☐

Indicate by check mark whether TECO Energy, Inc. is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act.

Large Accelerated filer ☒ Accelerated filer ☐ Non-Accelerated filer ☐ Smaller reporting company ☐

Indicate by check mark whether Tampa Electric Company is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act.

Large Accelerated filer ☐ Accelerated filer ☐ Non-Accelerated filer ☒ Smaller reporting company ☐

Indicate by check mark whether TECO Energy, Inc. is a shell company (as defined in Rule 12b-2 of the Act). YES ☐ NO ☒

Indicate by check mark whether Tampa Electric Company is a shell company (as defined in Rule 12b-2 of the Act). YES ☐ NO ☒

The aggregate market value of TECO Energy, Inc.'s common stock held by non-affiliates of the registrant as of Jun. 30, 2009 was $2,549,968,020 based on the closing sale price as reported on the New York Stock Exchange.

The aggregate market value of Tampa Electric Company's common stock held by non-affiliates of the registrant as of Jun. 30, 2009 was zero.

The number of shares of TECO Energy, Inc.'s common stock outstanding as of Feb. 22, 2010 was 213,857,116. As of Feb. 22, 2010, there were 10 shares of Tampa Electric Company's common stock issued and outstanding, all of which were held, beneficially and of record, by TECO Energy, Inc.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the Definitive Proxy Statement relating to the 2010 Annual Meeting of Shareholders of TECO Energy, Inc. are incorporated by reference into Part III.

Tampa Electric Company meets the conditions set forth in General Instruction (I) (1) (a) and (b) of Form 10-K and is therefore filing this form with the reduced disclosure format.

This combined Form 10-K represents separate filings by TECO Energy, Inc. and Tampa Electric Company. Information contained herein relating to an individual registrant is filed by that registrant on its own behalf. Tampa Electric Company makes no representations as to the information relating to TECO Energy, Inc.'s other operations.

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TAMPA ELECTRIC COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)

15. Other Comprehensive Income

Tampa Electric Company reported the following other comprehensive income (loss) for the years ended Dec. 31, 2009, 2008 and 2007, related to changes in the fair value of cash flow hedges and amortization of unrecognized benefit costs associated with the company's pension plans:

Other comprehensive income (loss)

(millions)	Gross	Tax	Net
2009			
Unrealized loss on cash flow hedges	$—	$—	$—
Plus: Gain reclassified to net income	1.2	(0.5)	0.7
Gain on cash flow hedges	1.2	(0.5)	0.7
Total other comprehensive income	$ 1.2	$(0.5)	$ 0.7
2008			
Unrealized loss on cash flow hedges	$ (3.6)	$ 1.4	$(2.2)
Less: Loss reclassified to net income	0.7	(0.3)	0.4
Loss on cash flow hedges	(2.9)	1.1	(1.8)
Total other comprehensive loss	$(2.9)	$ 1.1	$(1.8)
2007			
Unrealized loss on cash flow hedges	$ (8.2)	$ 3.2	$(5.0)
Less: Gain reclassified to net income	—	—	—
Loss on cash flow hedges	(8.2)	3.2	(5.0)
Total other comprehensive loss	$ (8.2)	$ 3.2	$(5.0)

Accumulated other comprehensive loss

(millions) Dec. 31,	2009	2008
Net unrealized loss from cash flow hedges (1)	$(6.1)	$(6.8)
Total accumulated other comprehensive loss	$(6.1)	$(6.8)

(1) Net of tax benefit of $3.8 million and $4.3 million as of Dec. 31, 2009 and 2008, respectively.

16. Restructuring Charges

On Jul. 30, 2009, TECO Energy, Inc. announced organizational changes and a new senior executive team structure as part of its response to industry changes, economic uncertainties and its commitment to maintain a lean and efficient organization. As a second step in response to these factors, on Aug. 31, 2009, the company decided on a total reduction in force which included approximately 216 jobs at Tampa Electric Company. The reduction in force was substantially completed by Dec. 31, 2009. In connection with this reduction in force, Tampa Electric Company incurred $23.1 million related to severance and benefits recognized on the Consolidated Condensed Statements of Income under "Restructuring charges" for the year ended Dec. 31, 2009. The total cash payments related to these actions are expected to be $26.3 million, including $4.9 million for the settlement of pension obligations (see Note 5), paid during 2009 and early 2010.

Restructuring Charges to be Incurred

(millions)	Termination of Benefits	Other Costs	Total
Total costs expected to be incurred	$ 23.1	$ —	$ 23.1
Current period costs incurred	(23.1)	—	(23.1)
Adjustments	—	—	—
Total costs remaining	$ —	$ —	$ —

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549

FORM 10-K

☒ **Annual Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934**

For the fiscal year ended December 31, 2010

OR

☐ **Transition Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934**

For the transition period from ______ to ______

Commission File No.	Exact name of each Registrant as specified in its charter, state of incorporation, address of principal executive offices, telephone number	I.R.S. Employer Identification Number
1-8180	**TECO ENERGY, INC.** (a Florida corporation) TECO Plaza 702 N. Franklin Street Tampa, Florida 33602 (813) 228-1111	59-2052286
1-5007	**TAMPA ELECTRIC COMPANY** (a Florida corporation) TECO Plaza 702 N. Franklin Street Tampa, Florida 33602 (813) 228-1111	59-0475140

Securities registered pursuant to Section 12(b) of the Act:

Title of each class	Name of each exchange on which registered
TECO Energy, Inc. Common Stock, $1.00 par value	New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Act: NONE

Indicate by check mark if TECO Energy, Inc. is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. YES ☒ NO ☐

Indicate by check mark if Tampa Electric Company is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. YES ☐ NO ☒

Indicate by check mark if the registrants are not required to file reports pursuant to Section 13 or Section 15(d) of the Exchange Act. YES ☐ NO ☒

Indicate by check mark whether the registrants (1) have filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) have been subject to such filing requirements for the past 90 days. YES ☒ NO ☐

as a result of the weak Florida economy, and voluntary conservation by residential customers, which we believe was in response to the generally weaker economic conditions. Off-system sales declined due to lower state-wide demand. Total heating and cooling degree days were 4% above normal and 10% above 2008 levels. The average number of retail customers decreased 0.1% for the year. Pretax base revenues increased approximately $72 million in 2009 from the higher base rates approved by the FPSC, which were effective in May 2009.

For the past three years, weather-normalized energy consumption per residential customer declined due to the combined effects of voluntary conservation efforts, residential vacancies and changes in appliance efficiency. It is now apparent that some of the robust residential customer growth in the 2005 through mid-2007 period, which was measured by new meter installations, was actually vacant residences with minimal energy usage. The average number of residential customers with minimal usage was approximately 8% of total residential customers in 2010, 2009 and 2008.

Electricity sales to the phosphate industry increased 5.1% in 2010, following a 6.5% decrease in 2009. The 2010 increase in sales to phosphate customers was driven by higher operating rates at the customer's facilities in response to higher demand for their products world wide. The 2009 decline in sales to phosphate customers was partially attributable to planned outages at their production facilities as the producers managed their product inventory levels during the economic downturn. Base revenues from phosphate sales represented about 3% of base revenues in 2010 and less than 3% in 2009. Sales to commercial customers decreased 0.8% in 2010 after a 2.0% decrease in 2009, reflecting the local economic conditions.

Energy sold to other utilities for resale increased 17.1% in 2010 due to increased demand throughout the State of Florida in response to cold winter weather early in the year. Energy sold to other utilities for resale decreased 50.2% in 2009 primarily due to lower energy demand state-wide and to lower natural gas prices through much of the summer, which made Tampa Electric's base-load coal generation not the lowest cost form of energy for spot sales.

Customer and Energy Sales Growth Forecast

The Florida economy has started to recover from the economic downturn, but unemployment remains above the national level and the housing market, which was a major driver of growth in the Florida economy for many years, is not expected to improve until unemployment declines (see the **Risk Factors** section). In general, economists are forecasting a slow improvement in the unemployment rate in 2011, and a stronger improvement in the economy in 2012 and beyond. The forecast used by Tampa Electric reflects a continuation of the modest customer growth trend that was experienced in 2010 in 2011. Following the very strong energy sales in 2010 due to weather, absolute levels of energy sales are expected to decline assuming normal weather. On a weather-normalized basis energy sales are expected to decline slightly due to lower customer usage in response to increased energy efficiency, voluntary conservation and the continued economic weakness. The average number of customers increased 0.6% in 2010 following a 0.1% decline in 2009. Actual average 2008 customer growth was 0.1% reflecting customer growth early in the year that was partially offset by a decline in the number of customers late in the year.

Longer-term, assuming continued economic recovery and that growth from population increases and more robust business expansion resumes, Tampa Electric expects average annual customer growth to return to a level of nearly 1.5% and weather-normalized average retail energy sales growth at about that same level starting in the 2012 time frame. This energy sales growth projection is lower than in periods prior to the economic downturn, reflecting changes in usage patterns and changes in population trends. These growth projections assume continued modest local area economic growth, normal weather, a recovery in the housing market over time, and a continuation of the current energy market structure.

The economy in Tampa Electric's service area grew modestly in 2010 after contracting in 2009 and 2008. The growth was lead primarily by the healthcare industry and tourism related businesses, but unemployment remains high. Initially, the contraction was centered in housing and related industries, but spread to the general economy later in 2007. The Tampa metropolitan area's civilian employment increased 0.3% in 2010 after decreasing 5.1% in 2009 and 2.7% in 2008. This level of job creation is slightly higher than the 0.05% increase experienced in Florida. The local Tampa area unemployment rate decreased to 12.0% at year-end 2010, compared to 12.4% at year-end 2009, and 8.3% at the end of 2008. The Tampa area year-end 2010 unemployment rate was the same as the state of Florida, but higher than the 9.4% for the nation, which is contrary to the trends experienced in previous economic slowdowns.

Following the expiration of the home buyer tax credit in June 2010, as in most areas of the country, the housing market in Tampa Electric's service area weakened for the remainder of 2010. As measured by the Case-Shiller Home Price Indices, home prices declined for much of the year and high numbers of foreclosures continued.

Operating Expenses

Total pretax operating expense decreased 6.5% in 2010 driven primarily by lower fuel expense. Excluding all FPSC-approved cost recovery clause-related expenses, the 2009 restructuring charges and the write-off of project development costs, operations and maintenance expense increased $5.1 million in 2010, due to the accrual of performance-based incentive compensation for all employees partially offset by lower spending on generating unit maintenance and other savings as a result of the 2009 restructuring actions. Tampa Electric expects operation and maintenance expense, excluding fuel and purchased power, to decrease in 2011, assuming normal levels of employee incentive compensation accruals.

Total pretax operating expense increased 3.5% in 2009, driven by higher other operating expenses and maintenance expenses, which included the write-off of project development costs, the write-off of disallowed rate case expenses, and restructuring costs. Excluding all FPSC-approved cost recovery clause-related expenses, restructuring charges and the project development write-off, operations and maintenance expense increased $8.7 million, compared to 2008, primarily due to higher spending on generating unit maintenance and repairs, higher expenses to operate the distribution system, higher employee-related expenses, and slightly higher bad debt expense, partially offset by savings in salaries and other benefits as a result of the restructuring actions taken late in the year.

In 2010, depreciation and amortization expense increased $9.5 million, reflecting the additions to facilities to serve customers, which included peaking combustion turbines, NO_x control projects and rail coal unloading facilities. In 2009, depreciation expense increased $9.1 million and taxes other than income, which include property taxes, were higher due to the peaking combustion turbines placed in service in 2009 and normal additions to facilities to serve customers. Depreciation expense is projected to increase in 2011, but at a level of about 50% of the 2010 increase due to routine plant additions to serve Tampa Electric's customer base and maintain system reliability, but without the major incremental project completions as in 2009.

Fuel Prices and Fuel Cost Recovery

In November 2010, the FPSC approved cost recovery rates for fuel and purchased power, capacity, environmental and conservation costs for the period January through December 2011. The rates include the expected cost for natural gas and coal in 2011, and the net over-recovery of fuel, purchased power and capacity clause expenses, which were collected in 2010 and 2009 following the March mid-course adjustment described below.

In November 2009, the FPSC approved cost recovery rates for fuel and purchased power, capacity, environmental and conservation costs for the period January through December 2010. The rates included the expected cost for natural gas and coal in 2010, the net over-recovery of fuel, purchased power and capacity clause expenses, which were collected in 2009 following the March adjustment, and the operating cost for and a return on the capital invested in the fourth SCR project to enter service at the Big Bend Power Station as well as the operation and maintenance expense associated with the projects (see the **Regulation** and **Environmental Compliance** sections).

In November 2008, the FPSC approved Tampa Electric's originally requested 2009 fuel rates. The rates included the costs for natural gas and coal expected in 2009, and the recovery of fuel and purchased power expenses, which were not collected in 2008. In March 2009, Tampa Electric filed a mid-course correction with the FPSC to adjust its projected 2009 fuel and purchased power costs to reflect the decline in commodity fuel prices, primarily natural gas. The revised forecast reduced fuel and purchased power costs by $191 million for 2009, which when combined with $35 million over recovery in late 2008, resulted in $226 million lower projected fuel and purchased power cost (see the **Regulation** section).

Total fuel cost decreased in 2010 due to significantly lower cost for natural gas partially offset by slightly higher cost for coal. Total fuel cost increased in 2009, due to higher cost for coal partially offset by lower cost for natural gas. Purchased power expense increased in 2010 due to higher volumes purchased, but at lower prices due to lower natural gas prices. Purchased power decreased in 2009 due to lower prices for natural gas, which is the primary fuel used by other generators in Florida. Delivered natural gas prices decreased 15.7% in 2010 due to abundant supplies from on-shore domestic natural gas produced from shale formations, and storage inventories above historic averages resulting from lower demand for natural gas from industrial users caused by economic conditions. Delivered coal costs increased 2.3% in 2010. Coal and natural gas prices were $3.12 per million Btu (/MMBtu) and $6.74/MMBtu, respectively, in 2010.

Natural gas futures as traded on the New York Mercantile Exchange (NYMEX) and various forecasts for natural gas prices indicate that natural gas prices will be stable for two to three years due to increased availability of on-shore domestic natural gas produced from shale formations. Coal prices, while less volatile, were relatively stable in 2010 after sharp increases in 2008 and 2007. Coal prices experienced a significant decline in 2009 for spot purchases, due to lower demand for coal fired generation of electricity as a result of the economic conditions. Tampa Electric's primary coal supplies are from the Illinois Basin, which have experienced upward movements in prices over the past several years but not of the same magnitude as prices in the Central Appalachian coal producing region. Tampa Electric's coal prices are expected to remain stable in 2011 due to longer-term supply contracts.

Energy Supply

On a retail energy supply basis, Tampa Electric generation accounted for 99%, 98% and 94% of the total retail energy sales in 2010, 2009 and 2008, respectively, with the remainder of the energy supplied by purchased power. Tampa Electric's generation increased in 2010 due to the conclusion of the major coal-fired unit outages for the installation of

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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549

FORM 10-K

☒ **Annual Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934**
For the fiscal year ended December 31, 2011

OR

☐ **Transition Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934**
For the transition period from to

Commission File No.	Exact name of each Registrant as specified in its charter, state of incorporation, address of principal executive offices, telephone number	I.R.S. Employer Identification Number
1-8180	**TECO ENERGY, INC.** (a Florida corporation) TECO Plaza 702 N. Franklin Street Tampa, Florida 33602 (813) 228-1111	59-2052286
1-5007	**TAMPA ELECTRIC COMPANY** (a Florida corporation) TECO Plaza 702 N. Franklin Street Tampa, Florida 33602 (813) 228-1111	59-0475140

Securities registered pursuant to Section 12(b) of the Act:

Title of each class	Name of each exchange on which registered
TECO Energy, Inc. Common Stock, $1.00 par value	New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Act: NONE

Indicate by check mark if TECO Energy, Inc. is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. YES ☒ NO ☐

Indicate by check mark if Tampa Electric Company is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. YES ☐ NO ☒

Indicate by check mark if the registrants are not required to file reports pursuant to Section 13 or Section 15(d) of the Exchange Act. YES ☐ NO ☒

Indicate by check mark whether the registrants (1) have filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) have been subject to such filing requirements for the past 90 days. YES ☒ NO ☐

Indicate by check mark whether the registrants have submitted electronically and posted on their corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrants were required to submit and post such files). YES ☒ NO ☐

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Electricity sales to the phosphate industry decreased 23.2% in 2011 after a 5.1% increase in 2010, driven by the return to service of a phosphate customer's self-generating capacity following an outage in 2010. The increase in sales to phosphate customers in 2010 was driven by higher operating rates at the customer's facilities in response to higher demand for their products worldwide and the self-generating capacity outage. Base revenues from phosphate sales represented almost 3% of base revenues in 2011 and 2010 and less than 3% in 2009. Sales to commercial customers decreased 0.2% in 2011, primarily reflecting the mild weather, and decreased 0.8% in 2010 reflecting the local economic conditions.

Customer and Energy Sales Growth Forecast

The Florida economy continues to recover from the economic downturn, as evidenced by lower levels of unemployment, and the new housing construction market, which was a major driver of growth in the Florida economy for many years, is improving, albeit slowly (see the **Risk Factors** section). In general, economists are forecasting a continued improvement in the unemployment rate in 2012, and an acceleration of improvement in the economy in 2013 and beyond. The 2012 forecast used by Tampa Electric reflects a continuation of the modest customer growth trend that was experienced in 2011. Following the lower energy sales in 2011 due to unusually mild and rainy weather, absolute levels of energy sales are expected to increase assuming normal weather. Energy sales are expected to reflect continued lower per customer usage in response to increased energy efficiency, voluntary conservation and economic conditions. The average number of customers increased 0.7% in 2011 following a 0.6% increase in 2010.

Longer term, assuming continued economic recovery and that growth from population increases and more robust business expansion resumes, Tampa Electric expects average annual customer growth to return to a level of nearly 1.5% and weather-normalized average retail energy sales growth about 0.5% lower than customer growth. This energy sales growth projection is lower than in periods prior to the economic downturn, reflecting changes in usage patterns and changes in population trends. These growth projections assume continued modest local area economic growth, normal weather, a recovery in the housing market over time, and a continuation of the current energy market structure.

The economy in Tampa Electric's service area continued to grow modestly in 2011 after modest growth in 2010 and contraction in 2009. The growth was led primarily by the business services, healthcare and tourism related businesses, but unemployment, while now below the state average, remains above the national average. The total nonfarm employment in the Tampa metropolitan area increased 1.2% in 2011 after decreasing 1.5% in 2010 and 5.8% in 2009. The increase in nonfarm employment compared favorably with the state of Florida's increase of 0.8%. The local Tampa area unemployment rate decreased to 9.5% at year-end 2011, compared to 12.0% at year-end 2010, and 12.4% at the end of 2009. The Tampa area year-end 2011 unemployment rate was below the state of Florida's 9.7% rate, but higher than the 8.5% for the nation.

Operating Expenses

Total pretax operating expenses decreased 8.2% in 2011 driven primarily by lower purchased power expense and lower other operating expense. Excluding all FPSC-approved cost-recovery clause-related expenses, operations and maintenance expense decreased $23.6 million driven primarily by lower accruals for performance-based incentive compensation for all employees and other benefit costs, lower power plant maintenance costs, and lower costs to operate and maintain the transmission and distribution system. Tampa Electric expects operations and maintenance expense to increase in 2012 driven primarily by higher employee-related expenses, and higher costs to operate the transmission, distribution and power generating systems.

Compared to 2010, depreciation and amortization expense increased $3.8 million, reflecting the additions to facilities to serve customers. Depreciation is expected to increase at similar levels in 2012.

Total pretax operating expense decreased 6.5% in 2010 driven primarily by lower fuel expense. Excluding all FPSC-approved cost recovery clause-related expenses, the 2009 restructuring charges and the write-off of project development costs, operations and maintenance expense increased $5.1 million in 2010, due to the accrual of performance-based incentive compensation for all employees partially offset by lower spending on generating unit maintenance and other savings as a result of the 2009 restructuring actions.

In 2010, depreciation and amortization expense increased $9.5 million, reflecting the additions to facilities to serve customers, which included peaking CTs, NO_x control projects and rail coal unloading facilities.

Fuel Prices and Fuel Cost Recovery

In November 2011, the FPSC approved cost-recovery rates for fuel and purchased power, capacity, environmental and conservation costs for 2012. The rates include the expected cost for natural gas and coal in 2012, and the net over-recovery of fuel, purchased power and capacity clause expenses which were collected in 2011 and 2010.

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549

FORM 10-K

☒ **Annual Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934**
For the fiscal year ended December 31, 2012

OR

☐ **Transition Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934**
For the transition period from to

Commission File No.	Exact name of each Registrant as specified in its charter, state of incorporation, address of principal executive offices, telephone number	I.R.S. Employer Identification Number
1-8180	**TECO ENERGY, INC.** (a Florida corporation) TECO Plaza 702 N. Franklin Street Tampa, Florida 33602 (813) 228-1111	59-2052286

Securities registered pursuant to Section 12(b) of the Act:

Title of each class	Name of each exchange on which registered
TECO Energy, Inc. Common Stock, $1.00 par value	New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Act: NONE

Indicate by check mark if TECO Energy, Inc. is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. YES ☒ NO ☐

Indicate by check mark if the registrants are not required to file reports pursuant to Section 13 or Section 15(d) of the Exchange Act. YES ☐ NO ☒

Indicate by check mark whether the registrants (1) have filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) have been subject to such filing requirements for the past 90 days. YES ☒ NO ☐

Indicate by check mark whether the registrants have submitted electronically and posted on their corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrants were required to submit and post such files). YES ☒ NO ☐

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrants' knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ☐

Indicate by check mark whether TECO Energy, Inc. is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act.

Large accelerated filer ☒ Accelerated filer ☐ Non-accelerated filer ☐ Smaller reporting company ☐

Indicate by check mark whether TECO Energy, Inc. is a shell company (as defined in Rule 12b-2 of the Act). YES ☐ NO ☒

The aggregate market value of TECO Energy, Inc.'s common stock held by non-affiliates of the registrant as of June 29, 2012 was approximately $3.85 billion based on the closing sale price as reported on the New York Stock Exchange.

The number of shares of TECO Energy, Inc.'s common stock outstanding as of Feb. 15, 2013 was 217,255,694. As of Feb. 15, 2013, there were 10 shares of Tampa Electric Company's common stock issued and outstanding, all of which were held, beneficially and of record, by TECO Energy, Inc.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the Definitive Proxy Statement relating to the 2013 Annual Meeting of Shareholders of TECO Energy, Inc. are incorporated by reference into Part III.

TAMPA ELECTRIC

Electric Operations Results

Net income in 2012 was $193.1 million, compared to $202.7 million in 2011.

Results in 2012 reflected a mild winter weather period and an extremely rainy summer period, and lower per-customer average usage, partially offset by 1.2% growth in the average number of customers, higher O&M expense and lower interest expenses. Net income in 2012 included $2.6 million of AFUDC–equity, which represents allowed equity cost capitalized to construction costs, compared with $1.0 million in the 2011 period.

Results in 2011 reflected the significant impact on energy sales of extremely mild weather, partially offset by a 0.7% higher average number of customers, and lower non-fuel O&M expense. Net income in 2011 included $1.0 million of AFUDC equity, compared with $1.9 million in the 2010 period.

In 2012, total degree days in Tampa Electric's service area were normal, but almost 3% below the prior year, reflecting mild winter weather and an unusually rainy summer weather pattern (the second wettest summer period on record) offset by higher than normal degree days in the normally mild spring and fall periods, which do not generate significantly higher energy sales. Pretax base revenue was almost $6.0 million lower than in 2011, primarily reflecting lower sales to residential customers from the milder weather, voluntary conservation that typically occurs during periods without extreme weather, and changes in customer usage patterns.

In 2012, total net energy for load was 0.3% higher than in 2011. Milder weather reduced sales to higher-margin residential and smaller commercial customers. Industrial-other sales were higher, reflecting improvements in the Florida economy, and higher energy sales to industrial-phosphate customers due to the transfer of certain load from self-generation to Tampa Electric's system. The energy sales shown in the summary table below reflect the energy sales based on the timing of billing cycles, which can vary from period to period.

In 2012, O&M expense, excluding all FPSC-approved cost-recovery clauses, increased $11.8 million reflecting higher generating system maintenance expenses, higher costs to operate and maintain the distribution system and higher pension and other employee benefit expenses, partially offset by lower bad-debt expense. Compared to the 2011 full-year period, depreciation and amortization expense increased $9.6 million, reflecting additions to facilities to serve customers. Interest expense decreased $7.4 million due to lower long-term debt interest rates and balances and a lower interest rate on customer deposits.

Compared to the cold winter and hot summer in 2010, the mild winter and wet summer in 2011 resulted in pretax base revenues $31 million lower than in 2010 (when revenues were reduced $24 million under a regulatory agreement), despite a 0.7% increase in the average number of customers and improvements in the local economy. In 2011, total retail net energy for load, which is a calendar measurement of retail energy sales rather than a billing-cycle measurement, decreased 5.7%, compared to the 2010 period. In 2011, total degree days in Tampa Electric's service area were 3% above normal, but 10% lower than in 2010. In 2011, although degree days were slightly above normal, periods of cold winter weather were not sustained long enough to generate typical winter heating load and summer season cooling degree days were above normal. In the summer season, rainfall was 14% above normal, which did not affect degree days but did lower energy sales primarily to residential customers.

In 2011, O&M expense, excluding all FPSC-approved cost-recovery clauses, decreased $23.6 million, driven primarily by lower accruals for performance-based incentive compensation for all employees and other benefit costs, lower power plant maintenance costs, and lower costs to operate and maintain the transmission and distribution system. Compared to 2010, depreciation and amortization expense increased $3.8 million, reflecting the additions to facilities to serve customers.

Base Rates

Tampa Electric's 2012 results reflect base rates established in March 2009, when the FPSC awarded $104.0 million higher revenue requirements effective in May 2009 that authorized an ROE mid-point of 11.25%, 54.0% equity in the capital structure, and 2009 13-month average rate base of $3.4 billion. In a series of subsequent decisions in 2009 and 2010, related to a calculation error and a step increase for combustion turbines and rail unloading facilities that entered service before the end of 2009, base rates increased an additional $33.5 million.

As a result of increasing pressure on O&M expense, and an economic recovery that has been slower than expected compared to the assumptions in Tampa Electric's last base rate proceeding initially filed in 2008, on Feb. 4, 2013, Tampa Electric notified the FPSC that it is planning to file a new base rate proceeding in April for new rates effective in early 2014. The actual revenue requirement calculation is not final, but is estimated to be approximately $135 million.

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

IN RE: PETITION FOR RATE INCREASE BY TAMPA ELECTRIC COMPANY	))	DOCKET NO. 130040-EI

EXHIBIT___(LK-22)

OF

LANE KOLLEN

ON BEHALF OF

THE WCF HOSPITAL UTILITY ALLIANCE

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

TECO ENERGY

March 20, 2013

Notice of Annual Meeting of Shareholders

Date: **May 1, 2013**

Time: **11:00 a.m.**

Place: **TECO Plaza**
702 North Franklin Street
Tampa, Florida 33602

Purpose: We are holding the annual meeting of the shareholders of TECO Energy, Inc. for shareholders to consider and vote upon the following matters:

1. The election of three director nominees named in the accompanying proxy statement.

2. The ratification of the selection of our independent auditor.

3. An advisory vote to approve named executive officer compensation.

4. Such other matters, including the shareholder proposal on pages 30-31 of the accompanying proxy statement, as may properly come before the meeting.

Shareholders of record at the close of business on February 22, 2013 will be entitled to vote at the meeting.

Even if you plan to attend the meeting, please either (i) vote by telephone or internet by following the instructions on the proxy card or the Notice of Internet Availability of Proxy Materials or (ii) mark, sign and date the proxy card and return it promptly in the accompanying envelope (if you received these materials by mail). If you received only a Notice of Internet Availability of Proxy Materials, you may also request a paper copy of the proxy card and submit your vote by mail, if you prefer. If you attend the meeting and wish to vote in person, your proxy will not be used.

By order of the Board of Directors,

David E. Schwartz
Corporate Secretary

TECO ENERGY, INC.
P.O. Box 111 Tampa, Florida 33601 (813) 228-1111

Compensation Committee Report

The Compensation Committee has reviewed and discussed the Compensation Discussion & Analysis set forth below with management and, based on this review and discussion, has recommended to the Board that it be included in this proxy statement.

By the Compensation Committee:
Paul L. Whiting (Chairman)
James L. Ferman, Jr.
Loretta A. Penn
William D. Rockford

Compensation Discussion and Analysis

This Compensation Discussion and Analysis (or "CD&A") explains how we use different elements of compensation to achieve the goals of our executive compensation program and how we determine the amounts of each component to pay.

The term "named executive officers" as used throughout this CD&A refers to the following executive officers named in the Summary Compensation Table on page 22:

- John B. Ramil, President and Chief Executive Officer
- Gordon L. Gillette, President, Tampa Electric Company
- Sandra W. Callahan, Senior Vice President – Finance and Accounting and Chief Financial Officer
- Clinton E. Childress, Formerly Senior Vice President – Corporate Services and Chief Human Resources Officer
- Charles A. Attal, Senior Vice President – General Counsel and Chief Legal Officer

The Compensation Committee makes decisions with respect to CEO compensation and equity-based incentives, after consultation with the Board. The Board makes all other executive compensation decisions after hearing the recommendations of the Compensation Committee. Therefore, in all cases where we refer to the Committee's actions (except with respect to CEO compensation or equity-based incentives), such actions are carried out through Board approval, upon the recommendation of the Compensation Committee.

Executive Summary

Pay for Performance

Our executive compensation program ties a significant portion of executive pay directly to company performance in order to link the interests of our executives to the long-term interests of our shareholders.

- ➢ Over 80% of our CEO's compensation and, on average, over two-thirds of the other named executive officers' compensation, is at risk and variable depending on corporate and individual performance
- ➢ 70% of long-term incentive awards are tied to relative total shareholder return
- ➢ 80% of annual incentive plan awards are based on the achievement of challenging corporate financial goals
- ➢ No annual incentive awards are paid unless a threshold level of income is achieved

We set well-defined, challenging goals for the annual incentive program and performance-based long-term incentives.

- ➢ Annual incentive goals are tied to business plans in order to provide incentives to management to create value consistent with the company's business strategy
- ➢ Long-term incentive goals are tied to total shareholder return relative to other companies in the industry to link executives' interests with the long-term interests of shareholders

We continually evaluate and update the executive compensation program.

- ➢ Our Compensation Committee and the Board monitor the program to ensure that best practices are being considered and that the program is operating as intended, while maintaining consistency within the key elements of compensation

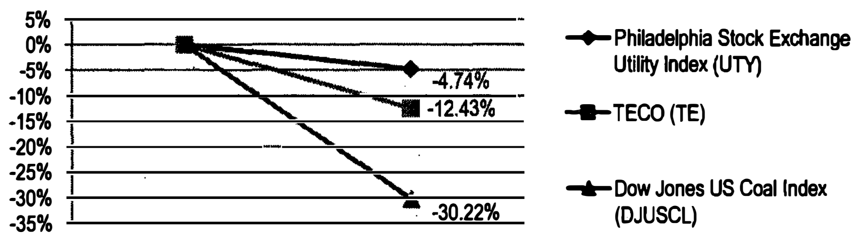
Impact of 2012 Company Performance on Pay

Linking pay with performance means that there is the opportunity to receive more compensation in years with above-target company and individual performance, and vice versa. In 2012, management produced strong results despite unfavorable weather throughout the year impacting sales for the Florida utilities and the changing market conditions impacting the coal company described below. Management also executed significant transactions and other actions that better position the company for the future, such as the completion of the sales of its Guatemalan subsidiaries, allowing the company to sharpen its focus on its regulated utilities, and the Florida Public Service Commission approval of the need for generation expansion at Tampa Electric's Polk Power Station. Based on such results, 2012 annual incentive awards were paid to the named executive officers at near target levels (see page 18 for more information regarding the financial results and annual incentive payout amounts for 2012). Please see our Annual Report on Form 10-K for the year ended December 31, 2012 for additional information regarding the company's 2012 financial results.

Impact of Relative Stock Performance on Realized Pay

Our relative total shareholder return for the three-year period ended March 31, 2012 was at the 66th percentile of the companies in the Dow Jones Electricity and Multiutility Groups (described on page 34) resulting in a payout of 121% for the performance shares that vested in 2012. While shareholder return was strong compared to utilities over this three-year period, the company's stock underperformed the utility industry over the past year. This was mainly attributable to the negative effect of the significantly weaker coal markets on the company's coal production subsidiary, which over the years has grown to be a significant source of income for the company. While the company took actions at its coal subsidiary to respond to these conditions, such as reducing production levels and personnel as part of its efforts to focus on margins rather than volumes, and, as illustrated by the graph below, the company's stock significantly outperformed the coal industry, the poor coal industry conditions still had a substantial impact on the company's stock during 2012.

2012 Stock Performance Compared to Utility and Coal Indexes



While management took actions to mitigate the impact of the weakening coal industry on our operations and results, and produced strong results at the utilities despite challenging conditions, we understand that our shareholders are negatively impacted when our stock price underperforms the utility industry. In light of this, seventy percent of the long-term incentive awards granted to named executive officers, which make up a significant portion of our executives' total compensation opportunity, is performance-based restricted stock that is dependent on our total shareholder return compared to companies in our industry. Based on our total shareholder return compared to peer companies as of December 31, 2012, all of the performance-based restricted stock granted in 2010, 2011, and 2012 would be forfeited, resulting in realizable compensation for those grants of $0 as of that date.

Governance and Risk-Mitigating Factors

Our Compensation Committee and the Board are committed to maintaining corporate governance protections as part of the executive compensation program, which further strengthen the tie between executive compensation and company performance.

- We have an incentive compensation recovery policy ("claw-back" policy), which applies to all officers in the event of any financial restatement (described in more detail on page 13).
- We have a policy prohibiting all executive officers from engaging in hedging transactions with respect to our stock, we have strong stock ownership guidelines (these policies are described in more detail below) and, as shown in the Stock Ownership Table on page 32, there are no company shares pledged by any of these officers.
- All restricted stock awards have "double-trigger" vesting, meaning that in the event of a change-in-control, vesting of shares is accelerated only if the grantee is also terminated without cause or terminates employment with good reason.

- Payouts under the annual incentive award plan are capped at 150% of the target amount.
- Payouts under the annual incentive award plan are based on both financial goals and individual business plan goals, and payouts under the performance share awards are based on relative performance goals. This mix of goals ensures that multiple aspects of business success are considered in determining compensation.
- We annually review the compensation program in light of key business risks to ensure that the program provides appropriate incentives, does not encourage executives to take excessive business risks, and contains risk-mitigating elements.

Competitive Pay Program

We provide compensation that is competitive and reasonable in order to attract and retain the talent needed to successfully manage and build our businesses.

- Total compensation is targeted at the 50th percentile of companies of similar size in our industry, which allows compensation to remain competitive for the executives and cost-effective for the company.
- While compensation is targeted at the 50th percentile, the Committee uses its discretion in applying market data to take into account individual performance, responsibilities and experience levels. For example, compensation is sometimes set below the 50th percentile when executives are promoted to a new position to allow them to grow into their new role; conversely, executives could be paid above the 50th percentile when they have demonstrated a successful track record in a position for a significant period of time.

Other Notable Policies and Practices

- We have Stock Ownership Guidelines of five times base salary for the CEO and three times base salary for other executive officers.

  Effective January 2013, the guidelines require that officers hold at least 50% of net, after-tax shares obtained through the vesting or exercise of long-term incentive awards until the share ownership guidelines are met. In addition, the Committee strengthened the guidelines by providing that unvested performance shares are not included in the total shares owned for purposes of the guidelines. The Committee reviews share ownership on an annual basis to ensure continued compliance with these guidelines and determined that, as of December 31, 2012, all executive officers were in compliance.
- Our Claw-Back Policy applies to all officers in the event of any financial restatement if a lower payment would have been made to the officer based upon the restated financial results, regardless of the cause of the restatement (whether or not due to fraud or the fault of the officer).

  The claw-back policy applies to annual incentive awards in the case of any financial restatements, and to proceeds from stock and option sales if an officer engaged in an act of embezzlement, fraud or breach of fiduciary duty that contributed to the need to restate the company's financials. The full text of the policy is included in the company's Corporate Governance Guidelines available in the Corporate Governance section of the Investor Relations page of our website, www.tecoenergy.com.
- Our Hedging Policy prohibits officers and directors from entering into hedging transactions with respect to our stock.

  The policy prohibits hedging transactions such as zero-cost collars and forward sale contracts, which would allow the person to continue to own the covered securities, but without the full risks and rewards of ownership, potentially causing that person's objectives to diverge from our other shareholders.
- Dividends are not paid on unvested performance shares, unless and until such shares vest
- We do not have employment agreements with our officers
- We do not provide extra pension service credits to executives
- We do not provide tax gross-ups on any benefits or perquisites, and our Compensation Committee determined not to provide any new excise tax gross-ups
- We do not have any corporate aircraft, therefore personal travel on corporate aircraft is not an issue for us
- We provide minimal perquisites; in 2012, perquisites or personal benefits or payments not available to all employees were less than $10,000 for each named executive officer
- The Compensation Committee has an independent compensation consultant, Steven Hall & Partners ("SH&P"), that performs no other services for the company

Elements of Compensation

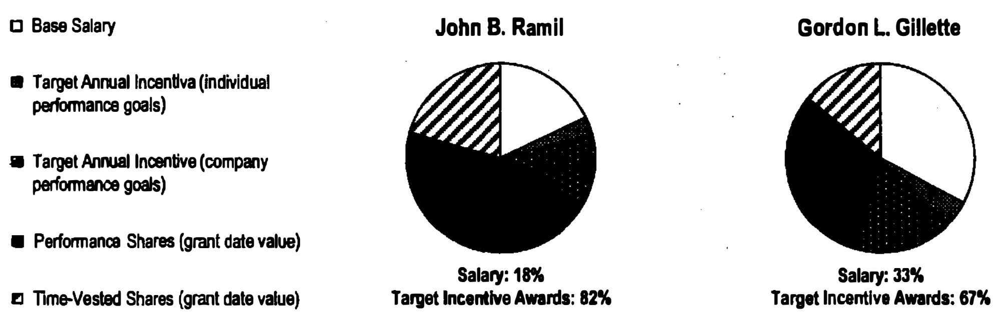
The table below shows the elements of our executive compensation program and briefly describes the purpose of each element.

Base Salary	Fixed amount of compensation targeted at the median of the marketplace in order to provide a competitive amount of fixed annual compensation. Permits us to continue to attract and retain highly qualified executives, and also provides stability for the executives, which allows them to stay focused on business issues. Performance review determines merit based increases.
Annual Incentive Awards	Annual cash incentive award based on the achievement of quantitative corporate financial goals (80%) and qualitative individual business plan goals (20%). Intended to encourage actions by the executives that contribute to our operating and financial results and to achieve other goals that the Board has recognized as important for the success of our businesses.
Long-Term Incentive Awards	Restricted stock: 70% performance shares; 30% time-vested shares. Designed to create a mutuality of interest with shareholders by motivating the executive officers and key personnel to manage the company's business so that the shareholders' investment will grow in value over time.
- Performance-Based Restricted Stock (referred to throughout as "performance shares")	Vests after three years based on total shareholder return compared to other companies in our industry. These awards will be forfeited if our performance is in the bottom quartile of our peers or upon voluntary departure from the company or termination with cause within this period. Directly ties a portion of compensation to a long-term performance measure relative to other companies in our industry, and aids in the retention of our executives.
- Time-Vested Restricted Stock	Vests after three years if still employed at the company. The ultimate value is dependent on our stock price, which aligns the executives' interest in stock value appreciation with our shareholders', and the three-year vesting period aids in the retention of our executives.
Pension Plan	Tax-qualified defined benefit pension plan available to all of our employees, which aids in attracting and retaining highly qualified employees.
Supplemental Retirement Plan	Supplements retirement benefits not available under the tax-qualified plan, which further strengthens the retention component of the pension plan by providing a meaningful incentive to stay with the company to retirement.
Change-in-Control Agreements	Provide severance payments if there is a change in control and executive is terminated without cause or terminates employment with good reason ("double-trigger"). These protections help to ensure retention and focus during times when the company could be acquired and executives could lose their jobs.

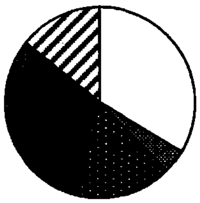
Proportion of Performance-Based Pay

Our compensation program is structured so that a significant portion of each named executive officer's direct compensation is variable and at risk dependent on performance, and as a result, the value of pay opportunities is variable and may ultimately not be delivered. The charts below show the amounts of compensation tied to company performance relative to other elements of direct compensation in 2012, based on target values of each element. The white area on the charts (base salary) is fixed compensation, while the remaining components of compensation are annual and long-term incentive awards, which have variable values and are at-risk, dependent upon the financial performance of the company, its stock price and the individual performance of the officers.

Mr. Ramil's 2012 base salary was well below the median salary of the pay peer group described below, while his total compensation was closer to (but still below) the median of that group, meaning that, compared to peer companies, a greater proportion of his compensation is at-risk, based on performance.

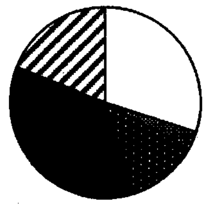


Sandra W. Callahan



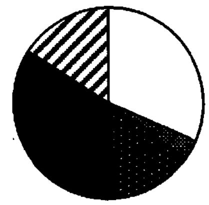
Salary: 34%
Target Incentive Awards: 66%

Clinton E. Childress



Salary: 29%
Target Incentive Awards: 71%

Charles A. Attal



Salary: 32%
Target Incentive Awards: 68%

Pay Peer Group

The Compensation Committee reviews market data provided by its independent compensation consultant to help establish executive compensation levels, in order to provide compensation packages competitive with those of our industry peers. This market data includes compensation data and pay practices from both the company's peer group identified below and broader compensation survey data. For 2012, the market data that the Compensation Committee reviewed included publicly disclosed compensation data from the following peer group (the "Pay Peer Group"), which was comprised of publicly-traded electric or electric and gas utility companies with revenues ranging between one-half and two-times the company's revenues:

Alliant Energy Corp.	Great Plains Energy Inc.	OGE Energy Corp.	Portland General Electric Co.
CMS Energy Corp.	Hawaiian Electric Industries Inc.	Pinnacle West Capital Corp.	SCANA Corp.
DPL Inc.	NV Energy Inc.	PNM Resources, Inc.	Westar Energy, Inc.
			Wisconsin Energy Corp.

Performance Share Peer Group

We use a pre-established industry index to determine our relative performance for determining the payout of the performance shares granted as a part of our long-term incentive awards. The payout of those awards is based on our total shareholder return compared to the companies listed in the Dow Jones Conventional Electricity and Multiutility subsectors of its Utilities index, referred to throughout this proxy statement as the Dow Jones Electricity and Multiutility Groups, which companies are listed on Appendix A to this proxy statement.

Compensation Review Process

After reviewing market data from its independent compensation consultant and other information described below, management developed total 2012 targeted compensation recommendations for each executive officer (other than for the CEO, for whom management did not provide a recommendation), which were then submitted to the Committee for approval. These recommendations were based on a review and assessment of the following:

- Proxy data from the companies in our Pay Peer Group
- Survey data
- Factors previously identified by the Committee, such as individual performance, time in position, scope of responsibility and experience

Total compensation for each named executive officer is generally targeted at the median of the market data for similar positions, while also taking into consideration the factors noted above. How market data is used in determining levels of compensation is discussed in more detail with respect to each element of compensation below.

For each executive officer, the Compensation Committee annually reviews a tally sheet, which shows each element of compensation discussed above, the total compensation paid to each executive officer for the past three years, and percentage changes year over year with respect to each element. The tally sheets also show the value of each executive officer's total equity holdings, for both vested and unvested or restricted holdings, and the amounts that would be payable to each executive officer in the event of voluntary termination, termination for cause, termination without cause, and termination in connection with a change in control of the company. This information provides the Committee with a clear picture of (i) how its decisions with respect to one element of compensation affect the total compensation package, (ii) how current compensation relates to compensation in previous years, and (iii) the total amount executive officers would receive, including the value of equity awards, under various termination scenarios. The Committee also reviews the total value of each executive officer's proposed salary, target bonus and grant date value of equity awards for the year compared to the median total compensation of individuals in similar positions as described above. Reviewing this information allows the Committee to make an overall assessment of the reasonableness of the total compensation that the company is providing to its executive officers.

As part of this review, the Committee also considers internal pay equity, both in terms of the total compensation of each executive officer as compared to the CEO, and within the officer group as compared to each other, considering individual responsibilities and experience levels. The Committee believes the executive compensation program should be internally consistent and equitable in order for it to achieve the objectives as outlined in the "Executive Summary" of this CD&A.

At the 2012 annual meeting of stockholders, shareholders were asked to cast an advisory vote on the compensation of our named executive officers as disclosed in the proxy statement for the 2012 annual meeting, and our shareholders overwhelmingly approved the proposal, with 94% of the votes cast in favor. The Committee reviewed the vote results, and in keeping with its commitment to continually evaluate and update the executive compensation program to ensure that best practices are being considered and that it is operating as intended, made some minor modifications to the program, such as strengthening the stock ownership guidelines, as described on page 13.

Discussion and Analysis of Each Element of Compensation

Base Salary

The Compensation Committee considers potential adjustments to each named executive officer's base salary on an annual basis. This process begins with setting a salary range for each officer grade based on market data for executives in similar positions from compensation and benefits survey data developed by national compensation consulting firms. After setting the salary ranges for each grade, the Committee then considers base salary adjustments for the executive officers, taking into account the Committee's evaluation of each executive officer's individual performance and responsibilities, and the market data described above, and in particular the median salary for similar positions using that market data. The Committee evaluates individual performance and responsibilities by reviewing a written assessment provided by the executive officer and by the person to whom that executive officer reports. The Committee believes that reviewing salary levels, market data and performance evaluations allows it to consider all appropriate variables, such as individual officer's responsibilities and experience levels, and to tailor salaries accordingly, while remaining competitive with the marketplace.

In early 2012, the Committee reviewed this information and took into consideration the relevant market data, the company's financial results from 2011, and the individual considerations described above. For 2012, all of the named executive officer salaries were within +/- 15% of the 50th percentile of the market data. The following table shows salary decisions for 2012 compared to 2011:

Name	*2011 Salary ($)*	*2012 Salary ($)*
John B. Ramil	750,000	750,000
Gordon L. Gillette	500,000	525,000
Sandra W. Callahan	410,000	450,000
Clinton E. Childress	334,750	352,800
Charles A. Attal	335,000	355,000

Annual Incentive Awards

Summary

The annual incentive awards paid for 2012 were based on a target award percentage and the level of achievement of the performance goals established for each executive officer at the beginning of 2012, as described below. TECO Energy officers' goals were based on achievement of TECO Energy financial performance targets, while operating company presidents' goals were based primarily on the performance of the operating company over which they have direct responsibility, with a smaller percentage tied to overall TECO Energy performance.

Determination of 2012 Target Award Levels

At the beginning of the year, the Compensation Committee set a target award percentage for the CEO and recommended a target award percentage for each of the other officers that they would receive if the performance goals were met. To determine the total annual incentive opportunity for the officer, the target award percentage was multiplied by the officer's base salary. Target award percentages were selected based on the market data described under "Compensation Review Process" above to provide a fully competitive total cash opportunity in line with the total target compensation amount determined for each executive officer, assuming payout of the annual incentive award at the target level. In setting the target award percentage, the Compensation Committee also considered the portion of compensation "at risk" and whether this portion was reflective of the level of that officer's accountability for contributing to financial results and the degree of influence that officer has over results and our success compared to other companies in our industry. The annual incentive award target award percentages for the named executive officers for 2012 are shown below.

Name	*2012 Annual Incentive Target Award (% of Salary)*	*2012 Annual Incentive Target Award Amount*
John B. Ramil	85%	$637,500
Gordon L. Gillette	65%	$341,250
Sandra W. Callahan	60%	$270,000
Clinton E. Childress	50%	$176,400
Charles A. Attal	55%	$195,250

Determination of 2012 Performance Metrics and Targets

Our annual incentive award plan provides for financial and/or operational effectiveness goals to be set each year for the plan participants. The Board set threshold, target and maximum goals for the income goals and capital expenditure goals as shown in the table below. Threshold performance represents the minimum performance that still warranted incentive recognition for that particular goal (paid at 50% of the target award level), and maximum performance represents the highest level likely to be attained (capped at 150% of the target award level for financial goals). The target income and capital expenditure goals described below were based on the relevant business plan income and capital expenditure targets, and the threshold and maximum goals were set at different percentages of achievement of the business plan, depending on the level of unpredictability of results at each company. These goals are designed to recognize exceptional performance for the year at above the 100% level, while only providing a payout when performance is better than the threshold.

Under the terms of the annual incentive award plan, if TECO Energy's threshold income goal is not achieved, then no incentive awards are paid to any officer, including the operating company officers.

Below are definitions for each of the goals used for the 2012 Annual Incentive Award Plan:

- Income Goals: income from continuing operations before charges and gains, calculated on the same basis as the results we refer to in communications with investors as our "non-GAAP results"
- Capital Expenditure Goals: cash outflows for investing activities, which is equal to capital expenditures and disbursements for the year, less allowance for funds used during construction and proceeds from the sale of property and equipment
- Individual Business Plan Goals: individual goals for each officer designed to help the company achieve its overall business plan goals (each named executive officer's individual goals are described on page 18)

The 2012 annual incentive goals are shown below.

	Relative Weightings		*2012 Financial Performance Goals (millions)*		
Performance Measure	*TECO Energy Officer %*	*Tampa Electric Co. President %*	*Threshold (50% Payout)*	*Target (100% Payout)*	*Maximum (150% Payout)*
TECO Energy Income Goal	60%	15%	$ 245.6	$291.4	$ 301.0
TECO Energy Cap Ex Goal	20%	5%	($553.6)	($493.0)-(513.6)	($453.0)
Tampa Electric Co. Income Goal	0%	45%	$ 221.7	$248.3	$ 258.0
Tampa Electric Co. Cap Ex Goal	0%	15%	($496.4)	($441.0)-(461.6)	($406.2)
Individual Business Plan Goals	20%	20%	Goals described below; Level of achievement can range from 0% to 200%		

To set individual business plan goals, at the beginning of the year, each executive officer worked with the person he or she reported to in order to identify individual goals that would help the company achieve its overall business plan goals. These individual goals were then reviewed by and discussed with the CEO, and then presented to the Compensation Committee for review and recommendation to the Board for approval. The CEO's individual goals were reviewed by and discussed with the Executive Chairman and then presented to the Compensation Committee for review and approval.

Individual business plan goals for the respective named executive officers are described below:

Description of 2012 Individual Business Plan Goals

John B. Ramil	Leadership of company execution of business plan; financial strategies and financial community communications; governmental affairs and regulatory matters; strategic planning and positioning for growth; corporate values
Gordon L. Gillette	Leadership of utility-related initiatives; growth strategies; customer relations, reliability and safety; leadership team development.
Sandra W. Callahan	Sustainable growth plans and allocation of internal resources; financial community visibility and communications; operating company financial performance and business plan initiatives; capital access and effective management of financial risk; implementing new financial systems; knowledge transfer initiatives
Clinton E. Childress	Supporting growth initiatives; continuous improvement program; corporate services, safety and process improvement goals; customer communications and community activities; implementation of technology improvements; succession planning, individual development and corporate values programs
Charles A. Attal	Cost-effective legal services supporting significant transactions, litigation, and growth strategies; policy strategies; development of legal services group and mentoring to increase legal acumen

Determination of 2012 Annual Incentive Plan Payouts

After the end of the year, the Committee calculated the amount of the annual incentive awards by multiplying levels of goal achievement by the weightings assigned to each goal, and then multiplying the total by the target award, producing the calculated award. The Committee then reviewed the calculated award in light of the participant's total performance during the year, and considered whether the plan formula would unduly penalize or reward management. In such cases, the Committee has discretion to increase or decrease awards to better meet the plan's intent of relating rewards to management performance; however in no event can the total payout exceed 150% of the target. The Committee did not make any adjustments to the 2012 awards calculated pursuant to the plan formula other than to take into account the sale of the TECO Guatemala segment, which closed in December 2012 and was accounted for as discontinued operations beginning in the third quarter of 2012. Actual results from this segment were included through September 30, 2012, and budgeted results were included for the fourth quarter; the proceeds from the sale and the book loss were excluded.

2012 Financial Goal Results

Performance Measure	*Target (millions)*	*2012 Results (millions)*	*Achievement Percentage*
TECO Energy Income Goal	$291.4	$265.9	69%
TECO Energy Cap Ex Goal	($493.0)-(513.6)	($486.9)	108%
Tampa Electric Company Income Goal	$248.3	$231.0	65%
Tampa Electric Co. Cap Ex Goal	($441.0)-(461.6)	($441.5)	100%

The level of achievement of the individual business plan goals is a qualitative determination made by the Compensation Committee after reviewing a performance evaluation of each executive officer with respect to each specific goal, which are first reviewed by the CEO and then presented to the Compensation Committee for its evaluation. The Committee recommends individual performance achievement percentages for Board approval for the named executive officers after this evaluation. Individual performance for the CEO is based on the Compensation Committee's qualitative assessment of his performance, which it makes after reviewing the recommendation of the Chairman. Based on these assessments, the 2012 individual business plan goal achievement percentages were as follows: John Ramil: 180%, Gordon Gillette: 180%, Sandra Callahan: 185%, Clinton Childress: 175%, and Charles Attai: 170%.

The 2012 awards to the executive officers under the annual incentive program, which are shown in the table below, were based on the achievement of the corporate financial goals and the individual business plan goals described above. The total amounts awarded under the 2012 annual incentive program are also shown under the "Non-Equity Incentive Plan Compensation" column in the Summary Compensation Table on page 22.

2012 Annual Incentive Award Payouts

Name	*2012 Annual Incentive Target Award Amount*	*2012 Annual Incentive Award Paid*	*2012 Award as Percentage of Target Award*
John B. Ramil	$637,500	$631,074	99%
Gordon L. Gillette	$341,250	$327,777	96%
Sandra W. Callahan	$270,000	$269,978	100%
Clinton E. Childress	$176,400	$172,858	98%
Charles A. Attal	$195,250	$189,377	97%

Long-Term Incentive Awards

Mix of Types of Awards

The long-term incentive component of our compensation program consists of equity-based grants, which in 2012 were in the form of 70% performance shares and 30% time-vested restricted stock. This mix is meant to tie the largest percentage of the equity incentives directly to our performance relative to companies in our industry, with the value of the remaining incentives also being tied to stock price and continued service.

The Committee does not grant stock options because it previously determined that restricted stock grants more closely serve the goals of tying compensation levels to company performance and promoting long-term retention of executives. Also, by granting restricted stock instead of stock options, fewer shares are used to deliver the same value to employees, resulting in less dilution to shareholders.

Performance Share Formula

The number of performance shares ultimately received by each executive is dependent upon the total shareholder return of our common stock over a three-year period relative to that of the median company of the companies listed in the Dow Jones Electricity and Multiutility Groups. The Committee determined that design for payout best reflects the objective granting the performance shares by directly tying a portion of compensation to a long-term performance measure relative to other companies in our industry, while the three-year performance period also aids in the retention of our executives.

Total return is calculated by dividing (1) the sum of (a) the difference between the share price at the end and beginning of the three-year performance period, and (b) the amount of dividends with respect to the three-year performance period, assuming dividend reinvestment, by (2) the closing share price at the beginning of the three-year performance period, with the share price in each case being determined by using the average closing price during the 20 trading days preceding (and inclusive of) the date of determination. Share price is equitably adjusted for stock splits and other similar corporate actions affecting stock. The table below shows the performance share payouts that correspond to our total shareholder return compared to the peer group described above. Payout is prorated for performance between the bottom quarter and top 10%.

Total Shareholder Return Relative to Peer Group	*Performance Share Payout %*
Bottom 25% of the Peer Group	0%
25th Percentile of the Peer Group	25%
Equal to the median of the Peer Group	100%
Top 10% of the Peer Group	150%

Equity Vesting Schedules

The performance shares vest at the end of the three-year performance period, depending on the formula as described above. At the end of the three-year period either (i) the performance shares are forfeited or (ii) the shares vest and, potentially, additional shares are granted. The time-vested restricted stock vests in a single installment three years from the date of grant. At the time of vesting of either the performance shares or time-vested restricted stock, the holder becomes the holder of shares of non-restricted common stock with the same terms as our common stock.

If employment is terminated during the three-year period without cause by the company or through a normal retirement by the employee (as described below in "Pension Benefits – Supplemental Plan"), a prorated amount of shares vest based on the amount of time employed during the three-year period, and in the case of the performance shares, based on the performance measurement at the time employment ended. (Beginning with the 2013 awards, the performance measurement would occur on the last business day of the quarter in which employment ended.) All shares are forfeited if employment is terminated for cause by the company or is terminated by the employee voluntarily (except for in the case of a normal retirement).

The agreements governing all outstanding time-vested restricted stock and performance share awards are "double-trigger" arrangements, such that vesting of the shares is only accelerated following a change in control if the grantee is also terminated without cause or terminates employment with good reason. (The payout of the performance shares under those circumstances would still be based on the applicable performance calculation.)

Determination of 2012 Long-Term Incentive Awards

In 2012, the Committee continued to use a total compensation approach to determine levels of long-term incentive awards. Long-term incentive awards were granted at levels that provided each executive officer with total target compensation that was in line with the total targeted compensation amounts developed for each officer using the data and process described under "Compensation Review Process" above.

The Committee also considered the total number of shares subject to equity incentive awards in relation to the total number of our outstanding shares, and reviewed information with respect to the estimated total and annual accounting expense associated with the equity incentive grants.

Using this information, the Committee made equity incentive award grants at a level that it believed would enable us to continue to attract, retain and motivate our executives, control dilution and maintain reasonable annual accounting expense.

The 2012 target long-term equity incentive award opportunity for each named executive officer is shown below based on the grant date present value of the shares on the date of grant:

	Performance Shares (Target Amount)		*Time-Based Restricted Stock*		
Name	*# of shares*	*Grant Date Present Value*	*# of shares*	*Grant date present value*	*Total Target LTI Opportunity*
John B. Ramil	122,121	$1,954,522	48,108	$864,982	$2,819,504
Gordon L. Gillette	31,752	$ 508,184	12,508	$224,894	$ 733,078
Sandra W. Callahan	26,867	$ 430,001	10,584	$190,300	$ 620,301
Clinton E. Childress	29,309	$ 469,085	11,546	$207,597	$ 676,682
Charles A. Attal	23,692	$ 379,186	9,333	$167,807	$ 546,993

Payment of Dividends

Dividends are not paid on unvested performance-based awards. (Dividends on such awards are accumulated and paid on the amount of the award that vests and are forfeited for any shares that do not vest.) Holders of time-vested restricted stock receive the same dividends as holders of other shares of our common stock.

Timing of Long-Term Incentive Awards

Prior to 2013, the Compensation Committee had a long-standing practice of making annual equity-incentive award grants on the date of our annual shareholders' meeting. On selected occasions, it has granted equity incentives upon election of a new executive officer. Beginning in 2013, the Committee determined to make annual equity-incentive award grants at its first quarterly meeting of the year, the same time it makes other compensation adjustments, to better facilitate compensation decisions reflective of total compensation rather than individual elements. In all cases, the grant date has been the same day that the Committee approved the grant. Stock options have not been granted since 2006. When they were granted, the exercise price for all stock options was set at the fair market value on the date of grant, determined by averaging our high and low stock price on the day preceding the date of grant.

Sale of Vested Shares by Executives

In granting equity incentive awards, the Committee is aware that each year in the late March to early May time frame, the restricted stock granted three years earlier will vest if the applicable vesting conditions are met and, thus, each year at about that time, shares may be sold by the executive officers or withheld by TECO Energy to pay the taxes due upon vesting. Accordingly, investors who see the reported sales of these shares by executive officers should not assume that such sales represent negative views of the company's prospects by the executive officers.

Retirement and Other Benefits

Supplemental Executive Retirement Plan

Our named executive officers participate in a supplemental retirement plan that provides benefits at a level not available under the tax-qualified plan and is meant as an additional aid in attracting and retaining officers in key positions. The Committee reviews the terms and benefits of this plan from time to time, and the consultant provides the Committee with market data showing the prevalence of similar plans at the peer group companies described above and the types of benefits provided by those plans.

ORIGINAL

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

IN RE: PETITION FOR RATE INCREASE BY TAMPA ELECTRIC COMPANY	))	DOCKET NO. 130040-EI

DIRECT TESTIMONY

AND EXHIBITS

OF

STEPHEN J. BARON

ON BEHALF OF THE

WCF HOSPITAL UTILITY ALLIANCE

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

IN RE: PETITION FOR RATE INCREASE BY TAMPA ELECTRIC COMPANY	**))**	**DOCKET NO. 130040-EI**

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BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

IN RE: PETITION FOR RATE INCREASE BY TAMPA ELECTRIC COMPANY	))	**DOCKET NO. 130040-EI**

DIRECT TESTIMONY OF STEPHEN J. BARON

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Stephen J. Baron. My business address is J. Kennedy and Associates, Inc. ("Kennedy and Associates"), 570 Colonial Park Drive, Suite 305, Roswell, Georgia 30075.

Q. What is your occupation and by whom are you employed?

A. I am the President and a Principal of Kennedy and Associates, a firm of utility rate, planning, and economic consultants in Atlanta, Georgia.

Q. Please describe briefly the nature of the consulting services provided by Kennedy and Associates.

A. Kennedy and Associates provides consulting services in the electric and gas utility industries. Our clients include state agencies, large consumers of electricity and other market participants. The firm provides expertise in system planning, load forecasting, financial analysis, cost-of-service, and rate design. Current clients include the Georgia and Louisiana Public Service Commissions, and consumer groups throughout the United States.

Q. Please state your educational background.

A. I graduated from the University of Florida in 1972 with a B.A. degree with high honors in Political Science and significant coursework in Mathematics and Computer Science. In 1974, I received a Master of Arts Degree in Economics, also from the University of Florida. My areas of specialization were econometrics, statistics, and public utility economics. My thesis concerned the development of an econometric model to forecast electricity sales in the State of Florida, for which I received a grant from the Public Utility Research Center of the University of Florida. In addition, I have advanced study and coursework in time series analysis and dynamic model building.

Q. Please describe your professional experience.

A. I have more than thirty years of experience in the electric utility industry in the areas of cost and rate analysis, forecasting, planning, and economic analysis.

Following the completion of my graduate work in economics, I joined the staff of the

Florida Public Service Commission ("Commission") in August of 1974 as a Rate Economist. My responsibilities included the analysis of rate cases for electric, telephone, and gas utilities, as well as the preparation of cross-examination material and the preparation of staff recommendations.

In December 1975, I joined the Utility Rate Consulting Division of Ebasco Services, Inc. as an Associate Consultant. In the seven years I worked for Ebasco, I received successive promotions, ultimately to the position of Vice President of Energy Management Services of Ebasco Business Consulting Company. My responsibilities included the management of a staff of consultants engaged in providing services in the areas of econometric modeling, load and energy forecasting, production cost modeling, planning, cost-of-service analysis, cogeneration, and load management.

I joined the public accounting firm of Coopers & Lybrand in 1982 as a Manager of the Atlanta Office of the Utility Regulatory and Advisory Services Group. In this capacity I was responsible for the operation and management of the Atlanta office. My duties included the technical and administrative supervision of the staff, budgeting, recruiting, and marketing as well as project management on client engagements. At Coopers & Lybrand, I specialized in utility cost analysis, forecasting, load analysis, economic analysis, and planning.

In January 1984, I joined the consulting firm of Kennedy and Associates as a Vice President and Principal. I became President of the firm in January 1991.

During the course of my career, I have provided consulting services to numerous industrial, commercial, Public Service Commission and utility clients, including international utility clients.

I have presented numerous papers and published an article entitled "How to Rate Load Management Programs" in the March 1979 edition of "Electrical World." My article on "Standby Electric Rates" was published in the November 8, 1984 issue of "Public Utilities Fortnightly." In February of 1984, I completed a detailed analysis entitled "Load Data Transfer Techniques" on behalf of the Electric Power Research Institute, which published the study.

I have presented testimony as an expert witness in Arizona, Arkansas, Colorado, Connecticut, Florida, Georgia, Indiana, Kentucky, Louisiana, Maine, Michigan, Minnesota, Maryland, Missouri, New Jersey, New Mexico, New York, North Carolina, Ohio, Pennsylvania, Texas, Utah, Virginia, West Virginia, Wisconsin, Wyoming, before the Federal Energy Regulatory Commission ("FERC"), and in United States Bankruptcy Court. A list of my specific regulatory appearances can be found in Baron Exhibit ____ (SJB-1).

Q. **Do you have previous experience in regulatory proceedings before the Commission?**

A. Yes. Initially in my career, as a Staff member of the Commission, I was involved in rate proceedings involving many of the electric utilities in the State of Florida, including Tampa Electric Company ("Tampa Electric," "TECO," or "Company"). Since that time, I have been involved in a number of Progress Energy and Florida Power and Light Company

("FPL") rate proceedings as well as a generic DSM proceeding for all Florida electric utilities.

Q. On whose behalf are you testifying in this proceeding?

A. I am testifying on behalf of the WCF Hospital Utility Alliance ("HUA"), a group of hospitals taking service from Tampa Electric.

Q. What is the purpose of your testimony?

A. I will address issues associated with Tampa Electric's proposed 12 Coincident Peak and 50% Average Demand ("12 CP and 50% AD") class cost of service study for production plant. As I will discuss, the Company's proposed class cost of service methodology to allocate fixed production costs is not reasonable and produces an unjustified cost shift to the general service demand ("GSD" or "general service demand") class.

The Company also has proposed to utilize a minimum distribution system ("MDS" or "minimum distribution system") methodology to classify and allocate distribution function costs. The Company's testimony appears to support the use of that methodology only if the Commission adopts the Company's proposed 12 CP and 50% AD class cost of service study. However, an interrogatory response provided by Tampa Electric witness William Ashburn appears to clarify that it is the Company's intent to support the use of the MDS methodology regardless of the class cost of service methodology the Commission requires for production plant. I strongly support the use of an MDS methodology. I will discuss the Company's MDS analysis and recommend that it be adopted by the Commission in this case regardless of the class cost of service methodology the Commission requires.

While Tampa Electric has presented a 12 CP and 1/13th AD class cost of service study, the Company did not include its MDS distribution cost classification and allocation methodology in this study. Though I generally believe it would be most appropriate to use a winter peak or a summer/winter peak methodology to allocate Tampa Electric's fixed production costs to rate classes, I will present a 12 CP and 1/13th AD methodology that incorporates the Company's MDS methodology for allocating distribution costs and recommend adoption of this study by the Commission in this case.

I will also discuss Tampa Electric's proposed revenue allocation to rate classes of its requested $133.645 million base rate revenue increase.[1] While I do not oppose the Company's general methodology to allocate the approved revenue increase to rate classes, the specific allocation proposed by Tampa Electric, which is based on its recommended class cost of service methodology, is not reasonable. I will present a more accurate revenue allocation based on the HUA recommended 12 CP and 1/13th AD + MDS analysis cost of service study.

Finally, I will address Tampa Electric's proposed general service rate class rate design. Specifically, I discuss the proposed increases to the GS energy and demand charges and will recommend an alternative based on cost of service unit cost results.

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[1] Tampa Electric's total revenue increase request is $134.841 million, comprised of a $133.645 million base rate increase and a $1.194 million increase in service charges.

Q. Would you summarize your conclusions and recommendations?

A. Yes.

- **Tampa Electric has based its proposed rate class increases on the results of its 12 CP and 50% Average Demand cost of service study. As I discuss in this testimony, the Company's proposal is unreasonable and not supported by any substantial evidence. Tampa Electric's proposal is not consistent with cost causation and has not been justified by the Company in this case. The main attribute of Tampa Electric's proposed 12 CP and 50% AD methodology is to shift costs without sufficient justification to general service demand customers. The Commission should adopt a 12 CP and 1/13th AD production demand method in this case.**

- **Tampa Electric has developed a reasonable Minimum Distribution System analysis to classify and allocate distribution costs to rate classes. This study follows the methodologies discussed by the National Association of Regulatory Utility Commissions ("NARUC") in its Electric Utility Cost Allocation Manual and is also consistent with widely used distribution cost of service methods adopted by regulatory commissions in other states. The Company's MDS study should be adopted by the Commission, together with a 12 CP and 1/13th AD production demand allocation method. The MDS analysis demonstrates that existing rates, without recognition of the minimum costs of connecting/serving a customer, will cause GSD customers to subsidize other customers.**

- **Any Commission approved revenue increase in this case should be apportioned to rate classes based on the results of the HUA recommended 12 CP and 1/13th AD + MDS class cost of service study so that class rate of return parities are set to 1.0, subject to the restriction that no rate class receives an increase greater than 150% of the system average base rate increase and that no class receives a rate decrease.**

- **Tampa Electric's proposed General Service Demand class rate design should be modified to provide a more reasonable balance between the proposed increases in the energy charges and the demand charge of the rate, following unit cost of service results.**

II. COST ALLOCATION ISSUES

Q. Have you reviewed the class cost of service studies filed by Tampa Electric in this case?

A. Yes. Consistent with the instructions for the Minimum Filing Requirements ("MFR"), Tampa Electric has prepared a 12 CP and 1/13th average demand based cost of service study in this case, but also has developed a 12 CP and 50% AD methodology. The Company recommends adoption by the Commission in this case of the 12 CP and 50% AD method. Tampa Electric also proposes a minimum distribution system methodology to classify and allocate distribution costs if the Commission adopts its recommended 12 CP and 50% AD method.

Q. Do you agree with the Company's class cost of service proposals?

A. In part. While I support the Company's proposed adoption of the MDS method to classify and allocate distribution costs, I strongly oppose Tampa Electric's recommendation to utilize a 12 CP and 50% AD methodology to allocate fixed production demand costs. I will address Tampa Electric's MDS methodology more fully in a subsequent section of my testimony.

With regard to Tampa Electric's 12 CP and 50% AD proposal, this production demand method is not supportable by any reasonable economic analysis or principle and simply results in a substantial cost shift to the general service class. Tampa Electric witness Ashburn's testimony does not provide any reasonable basis to adopt this method beyond a general observation that energy usage is a factor in determining what type of generation to install (i.e., base load vs. intermediate vs. peaking). However, there is no evidence presented to justify assigning 50% of fixed production demand related costs on the basis of rate class energy use, including energy use during off-peak periods as opposed to any other percentage, or to demonstrate that assignment of 50% of fixed production costs on the basis of energy use is more appropriate than an assignment of 8% as would occur under the 12 CP and $1/13^{th}$ AD class cost of service methodology the Commission has required for FPL and which the Commission has required other utilities to present in their MFRs. In fact, it appears that the cost shifting that occurs from this method may be one of the "principles" used by the Company. This is suggested by Tampa Electric's request for adoption of a 12 CP and 50% AD methodology, but lack of any analysis of whether a 12CP and 50% AD methodology is consistent with cost causation on Tampa Electric's system.

As I will discuss, this production cost allocation methodology unreasonably assigns fixed generation costs to higher load factor general service demand class customers who efficiently use the Company's generating capacity at relatively consistent levels throughout the day and throughout the year, therefore helping to defray the cost of such capacity. The price signals that would be sent to customers, if the Company's recommended methodology were adopted, would be counter to the efficient use of the Company's costly generating unit resources. It links off-peak energy usage to generation resource additions. That link, of course, is contrary to logic and erroneous. Off peak use of the utility's generation resources helps defray the fixed costs of those assets that otherwise would have to be recovered from peak period use.

Q. Would you discuss the problems that you have identified with Tampa Electric's proposed 12 CP and 50% AD production demand allocation method?

A. The 12 CP and 50% AD method is essentially a 50/50 demand/energy weighted allocation method. Its proponents generally argue that energy use or system load factor impacts the economic tradeoffs among the types of generation resources selected to meet customer demands. These advocates argue that the higher cost of base load capacity is only incurred because of the fuel savings that are provided by a base load (or intermediate load) resource relative to a simple cycle combustion turbine. Thus, the 12 CP and 50% AD method can generally be thought of as a substitution of capital investment in lieu of burning higher cost fuel in peaking units. The "capital substitution" methodology is a production cost allocation method that attempts to capture the economic trade-offs between high capital cost base load (or, perhaps intermediate load) generating resources that have lower operating costs (*i.e.*, lower fuel costs/mWh due to fuel type or lower heat rates), versus lower capital cost resources (such as simple cycle combustion turbines) that have higher operating costs (*i.e.*, higher fuel costs due to use of oil or natural gas, or higher heat rates). The concept underlying the "capital substitution" method is that higher energy use creates incentives to substitute higher capital cost resources for lower capital cost resources – thus, creating a linkage between energy use and capital costs.

Q. How is the principle of "cost causation" used to develop a class cost of service analysis?

A. As described on page 38 of the NARUC Electric Utility Cost Allocation Manual, "Cost causation is a phrase referring to an attempt to determine what, or who, is causing the costs to be incurred by the utility." In order to assess each rate class' share of total jurisdictional costs, all of the Company's costs are first functionalized into the major functions provided by the utility: production, transmission, distribution and customer related costs (such as customer accounting). For example, production costs, which would include generation plant in service, depreciation reserves and other rate base related costs, depreciation expense, O&M expenses, fuel and purchased power are assigned to the production function. Once functionalized, these costs are then classified as either demand related, energy related, or customer related. Finally, the functionalized and classified costs are then allocated to rate classes based on allocation factors tied to cost causation. Fixed demand related costs are generally caused by the need for generation resources to meet peak demands; energy related costs, such as fuel expenses, are caused by the total amount of energy use of each rate class.

Q. Does Tampa Electric's testimony in this case in support of its proposed 12 CP and 50% AD method provide any substantive evidence to justify allocation of 50% of the Company's fixed production demand costs on the basis of energy?

A. No. Tampa Electric witness Ashburn simply asserts that it reflects some measure of cost responsibility, but offers no specific evidence. He also cites as support the conclusion that the increase in the percentage of average demand in the production demand allocation factor from 8% using the 12 CP and 1/13th AD method to 25% under Tampa Electric's last approved method "resulted in a reduced revenue requirement allocation to the residential and small commercial rate classes" and that the proposed increase in the percentage to 50% "will further reduce that allocation."[2] A large, if not controlling, rationale for the Company's proposal in this case appears to be the end result, which is a cost shift to large customers. But simply deciding to switch cost responsibility, without a substantive link to cost incurrence, is not supported by traditional ratemaking and is thus not a good ratemaking policy.

Q. Why is it important to perform a reasonable allocation of costs to rate classes?

A. There are a number of reasons to do so. First, economic efficiency requires that rates reflect underlying costs. For example, while one could just divide Tampa Electric's total fuel costs by the number of customers on the system and send each customer a uniform

[2] Ashburn Direct Testimony at page 33.

bill, that approach would clearly be unfair and result in a substantial misallocation of resources by overpricing energy related fuel costs to most customers and under-pricing it to higher load factor customers. Cost causation dictates that these energy related costs be assigned on the basis of the energy (kWh) use of each rate class. Similarly, fixed demand related costs, such as the return on generation plant investment and fixed production O&M are incurred by the utility to meet the peak demand of its customers. Once these plants are constructed, these demand related costs are fixed and do not vary with the amount of energy used by customers. As a result, economic efficiency is best achieved by allocating fixed demand related costs on the basis of class peak demand.

In addition to economic efficiency, a related reason for allocating costs on the basis of cost causation is to prevent cross-subsidization of one rate class by another. Cross-subsidization occurs when one set of customers pays in excess of cost and another pays less than the cost of serving that set of customers.

Tampa Electric is proposing that this Commission adopt a methodology that classifies half of all of the Company's fixed production costs as demand related, compared to the current Tampa Electric method that classifies 75% of fixed production costs as demand related, which is already 25% less than strict cost causation would dictate. Strict cost causation, absent any other evidence to the contrary, would argue for a coincident peak allocator to assign cost responsibility for fixed, demand related costs. In the case of Tampa Electric, such an allocator would be a winter CP allocator or a combined winter/summer CP allocator. At a minimum, production demand related fixed costs should be allocated on the basis of 12 CP. The Commission has adopted a 12 CP and 1/13th allocator in many prior electric utility rate cases. While this allocator does include a small energy component, the practical effect of the 12 CP and 1/13th AD allocator is very close to a 100% demand 12 CP allocation method.

Moreover, Tampa Electric already classifies the Polk Unit 1 gasifier and the Big Bend Unit 4 scrubber as 100% energy. Its new proposal in this case further moves additional fixed production demand costs (rate of return, depreciation, fixed O&M expense) to an energy allocation. This means that customer usage in off-peak hours, weekends, off-peak months are deemed to cause the Company to install additional generation resources. There is no evidence to support this assertion; rather, the evidence refutes it.

Q. What evidence refutes Tampa Electric's purported justification for allocating 50% of fixed production costs as energy-related?

A. The theory relied on by Tampa Electric --"capital substitution"-- is that higher capital cost resources are procured because of the fuel savings, and those resources benefit customers relative to basic simple cycle combustion turbines (Ashburn Direct Testimony at page 32). While it is true that the Company has a substantial amount of coal fired generation, it has had this capacity for many years. The relevant price information that should be conveyed to Tampa Electric's customers must be premised on forward looking economic decisions, not decisions that were made 20 or 30 or more years ago. Tampa Electric's most recently installed base load coal unit became commercial in 1985 and was planned in the early 1980's. Its other coal units (Big Bend 1-3) became commercial beginning in 1970.

During this period, such factors as the Fuel Use Act that precluded or discouraged the installation of gas fired generation may have had a significant impact on the decisions regarding the type of generating capacity that was added to Tampa Electric's system. The "Powerplant and Industrial Fuel Use Act" was signed into law in 1978. Its key provisions prohibited the use of natural gas or petroleum as an energy source in any new electric power plant and prohibited the construction of any new electric power plant without the capability to use coal or any alternate fuel as a primary energy source. It would make no economic sense to send price signals to Tampa Electric's customers in 2014, based on economic relationships and/or government policies that existed 44 years ago but which are vastly different today.

Based on Tampa Electric's recently filed 10-Year Site Plan, the Company is planning on a combination of Combined Cycle Gas Turbines ("CCGT") and simple cycle Combustion Turbines ("CT") as feasible generation resource additions in the future. This is consistent with my experience for other utilities throughout the U.S., including FPL. With environmental restrictions (in particular the Environmental Protection Agency ("EPA") Green House Gas New Source Performance Standards for Coal Units rulemaking) and lower natural gas prices, new coal fired power plants are not economic compared to CCGT and CT resources. To test the reasonableness of Mr. Ashburn's testimony in support of Tampa Electric's recommended 12 CP and 50% AD method, I developed a set of screening curves that evaluate the relative economics of a higher cost CCGT compared to a CT.

Q. Would you describe the specific analysis that you developed?

A. Table 1 below summarizes CCGT and CT costs based on the U.S. Department of Energy, Energy Information Administration ("EIA") Annual Energy Outlook forecast for 2013 ("AEO 2013"). This forecast, which is prepared annually by EIA, provides projections of a significant number of energy industry metrics, including the U.S. electric utility industry. As part of its forecast, EIA prepares a set of assumptions that are incorporated into its models. Among these assumptions are a set of capital and operating costs for CCGT and CT generation resources. The data summarized in Table 1 is contained in EIA's January 2013 report entitled "Levelized Cost of New Generation Resources" in the Annual Energy Outlook 2013. Baron Exhibit__(SJB-2) contains an excerpt from this report.

Table 1
U.S. Average Levelized Costs (2011 $/mWh) - C/O Date: 2018*

	Conventional Combined Cycle	Advanced Combustion Turbine
Capacity Factor	87.0%	30.0%
Capital	15.8	30.4
Fixed O&M	1.7	2.6
Var O&M + Fuel	48.4	68.2
Total	65.9	101.2
Total Capital Cost/mW	$ 120,415	$ 79,891
Fixed O&M/mW	$ 12,956	$ 6,833
Total Fixed Cost/mW	$ 133,371	$ 86,724
Total Variable Cost/mWh	$ 48.40	$ 68.20

*Source: Energy Information Administration Annual Energy Outlook 2013, "Levelized Cost of New Generation Resources."

The cost data presented in Table 1, as noted in the table, are levelized $2011 costs for a

Conventional CCGT and an Advance CT, both with a commercial operation date of 2018. This comparison provides a reasonable estimate of the economic trade-offs between lower and higher capital cost resources. As shown in the table, the annual levelized fixed cost of a conventional CCGT is $133/kW, while for an Advanced CT the annual levelized fixed cost is $87/kW. The variable operating costs of the two resources are $48/mWh and $68/mWh respectively. Using this information, a screening curve comparison can be developed to identify the breakeven capacity factor or "hours use" of a kW of capacity between the two resources. A screening curve is a cost curve for the resource, reflecting both fixed costs (capital, O&M expense) and variable costs (fuel, variable O&M expense) at various capacity factor (hours use) levels. It is designed to compare the cost of alternative resources at different usage levels. Table 2 shows the resulting all-in levelized costs at various capacity factors.[3]

[3] The EIA data is presented in terms of constant dollar ($2011) levelized costs for ease of comparison.

Table 2
Screening Curve Analysis: CCGT vs. CT

Capacity Factor	mWh	Total Busbar Cost CCGT	Total Busbar Cost CT
4.0%	350	$ 429.03	$ 315.70
5.0%	438	$ 352.90	$ 266.20
10.0%	876	$ 200.65	$ 167.20
15.0%	1,314	$ 149.90	$ 134.20
20.0%	1,752	$ 124.53	$ 117.70
26.8%	2,348	$ 105.21	$ 105.14
30.0%	2,628	$ 99.15	$ 101.20
35.0%	3,066	$ 91.90	$ 96.49
40.0%	3,504	$ 86.46	$ 92.95
45.0%	3,942	$ 82.23	$ 90.20
50.0%	4,380	$ 78.85	$ 88.00
55.0%	4,818	$ 76.08	$ 86.20
60.0%	5,256	$ 73.78	$ 84.70
65.0%	5,694	$ 71.82	$ 83.43
70.0%	6,132	$ 70.15	$ 82.34
75.0%	6,570	$ 68.70	$ 81.40
80.0%	7,008	$ 67.43	$ 80.58
85.0%	7,446	$ 66.31	$ 79.85
90.0%	7,884	$ 65.32	$ 79.20
95.0%	8,322	$ 64.43	$ 78.62
100.0%	8,760	$ 63.63	$ 78.10

For example, the CCGT resource has a $2011 levelized total cost of $78.85 at a 50% capacity factor. This means that the CCGT would cost $78.85 per kW if it were operated for 4,380 hours per year. The CT cost, at the same 4,380 hour of operation would cost $88.00 per kW.

As shown in Table 2, the breakeven hours-use of the conventional CCGT and the advanced CT occurs at a capacity factor of 26.8%, which correlates with 2,348 hours of usage during the year. For operation at 2,348 hours or below, the CT is less costly, while for operation above 2,348 hours, the CCGT is less costly due to its lower heat rate (btu/kWh).

Q. What are the cost of service implications of this screening curve analysis with regard to the 12 CP and 50% AD methodology?

A. The screening curve economic comparison shows that beyond 2,348 hours of annual operation (27% of the hours of the year), the CCGT is less expensive and would be selected as the least cost resource. As long as the system's energy needs required the generation resource to operate at least 2,348 hours during the year, the least cost resource is the CCGT. Energy usage beyond 2,348 mWh per mW has no impact on the economic decision to select the higher capital cost CCGT resource (over the lower capital cost CT). Thus, from a cost of service/cost responsibility standpoint, any energy usage in hours greater than the top 2,348 peak hours during the year do not "cause" the higher capital costs of the CCGT resource (compared to the CT). Translating this into a class cost responsibility framework, energy usage in the remaining 6,432 hours during the year does not impose any additional capital costs on the system. This result is particularly important in assessing the reasonableness of the Company's proposed 12 CP and 50% AD method, which assigns fixed generation resource costs to rate classes on the basis of the classes' average demand during all 8,760 hours of the year. The screening curve economic analysis shows that energy usage in the 6,432 hours beyond the breakeven hours (2,348) is not responsible for any additional CCGT capacity costs (*i.e.*, those CCGT capital costs in excess of CT capital costs). Assigning 50% of all Tampa Electric fixed generation costs on the basis of class average demand, based on a theory that customers with higher load factors are causing these higher CCGT costs to be incurred, is contrary to the economic evidence of cost responsibility that shows that kWh energy usage in excess of a system-wide 26.8% load factor does not influence the decision concerning what type of generating unit to install. Perhaps that is why the Company does not base its request for use of the 12CP and 50% AD methodology on a cost causation analysis.

Q. Is there additional evidence that shows that larger customers with higher load factors, such as those that take service under the GSD rate schedule, do not cause the incurrence of the excess CCGT costs in proportion to their annual energy usage?

A. Yes. That is evident when one examines consumption patterns during the months that experience the highest load hours of the year as compared to the consumption patterns in other months.

Q. In which months of the year do the highest 2,348 load hours occur?

A. Using the hourly loads provided by Tampa Electric in response to The Florida Industrial Users Group First Set of Production of Documents request No. 3, I analyzed Tampa Electric's projected 2014 load data. Based on this analysis, the highest 2,348 hourly loads of the Company occur primarily in the summer months. Table 3 summarizes these results, together with the percentage share of energy usage for the residential class and for rate schedule GSD each month.

Table 3
Distribution of Highest 2,348 Load Hours
Test Year 2014

		Distribution of Sales	
Month	# of Hours	RS	GSD
Jan	80	8.2%	7.7%
Feb	35	7.0%	7.3%
Mar	45	6.4%	7.4%
Apr	108	6.5%	7.8%
May	267	7.7%	8.2%
Jun	373	9.8%	9.1%
Jul	379	10.5%	9.2%
Aug	372	10.4%	9.1%
Sep	359	10.7%	9.5%
Oct	232	8.8%	8.8%
Nov	52	7.0%	8.1%
Dec	46	6.9%	7.9%
Total	2,348	100.0%	100.0%
% Jun-Sep	63.2%	41.5%	36.8%

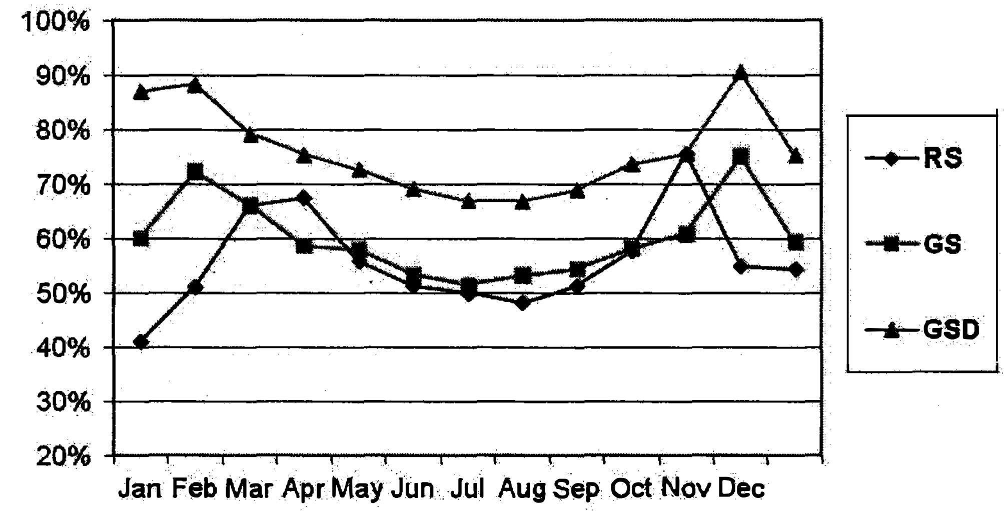
As can be seen in the table, the majority of the "highest load hours" occur during the summer months of June through September (63% of these high load hours occur in this period). Because rate schedule GSD has a flatter annual usage pattern over the year (due to its higher than average load factor), GSD consumes a relatively lower proportion of its energy in the summer months, compared to the residential class. Stated differently, the swing in percentages between the highest and lowest months for residential customers (*i.e.*, 10.7 -6.4 = 4.3 percentage points) is nearly twice as large as that experienced in serving GSD (*i.e.*, 9.5 – 7.3 = 2.3 percentage points). It is also very important to recognize that these percentages for rates Residential ("RS") and GSD summarize the total mWh during each month and do not differentiate between on-peak hours (when the highest loads occur) and off-peak hours. Most of the 2,348 hours that comprise the highest load hours occur during the four-month period from June through September.[4] While I do not have the breakdown of mWh usage by rate class on a monthly on-peak/off-peak basis, it seems reasonable to conclude consistent with the data set forth in Table 3, that a higher load factor rate class, such as GSD, would have a smaller proportion of its monthly usage during the June through September period.[5] This means that GSD's responsibility for load during the highest 2,348 hours of the year is likely to be much smaller than its overall percentage of energy use during each month.

Figure 1 contains an excerpt from the Company's workpapers that shows monthly coincident peak load factors for the residential, General Service Non-Demand ("GS") and GSD rate classes.

[4] While Tampa Electric is a traditionally winter peaking utility, there are many more high load hours during the summer months than during the winter months. The winter peaks tend to be short duration peaks driven by extreme weather, while the summer peaks are more extensive in duration.

[5] At an extreme of 100% load factor, the percentage of a rate class would have the same hourly mWh each hour of the month. In this case, the percentage of monthly on-peak energy use is exactly the percentage of the number of on-peak hours during the month. For example, in July, the number of on-peak hours using a typical "5 X 16" weekday period would be about 49%.

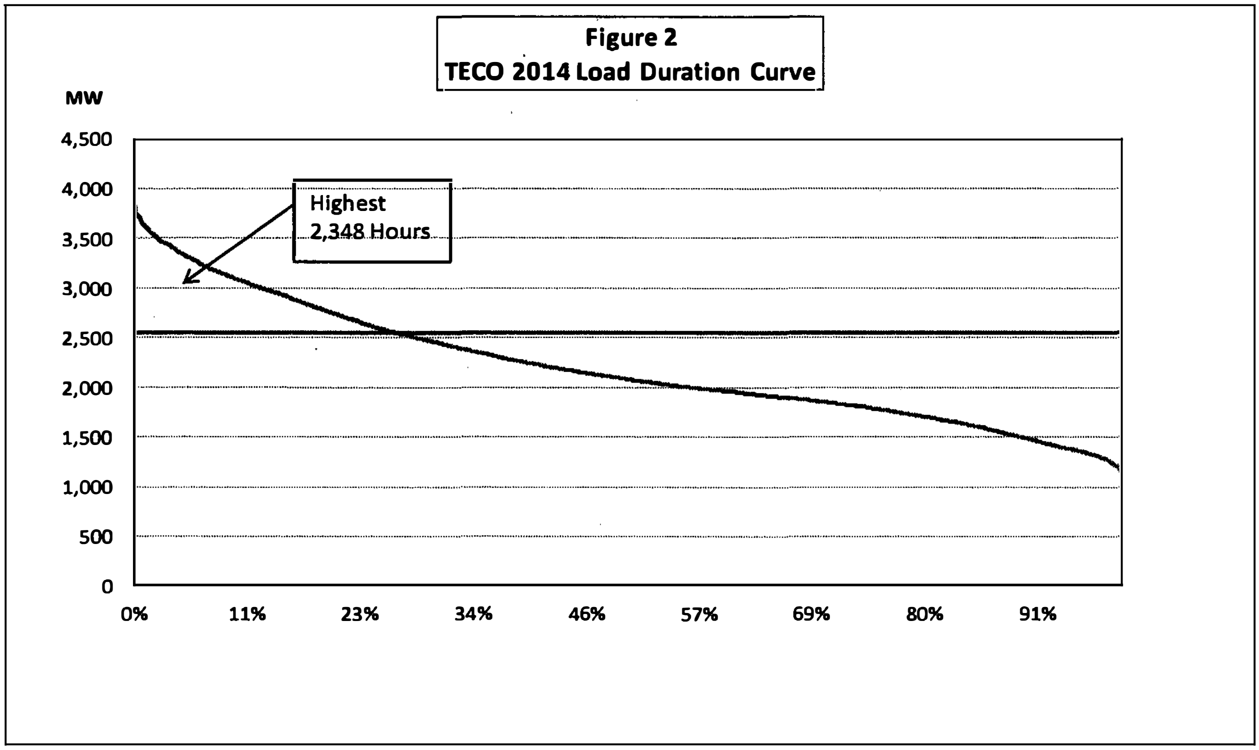
Figure 1
Load Factors (@CP)



This confirms that the GSD class has higher monthly load factors, which means that the GSD class has a higher percentage of its monthly energy use relative to the RS and GS classes occurring in the months of October through May. As a result, the need for generating capacity to serve the significant loads that occur from June through September is caused to a large degree by the RS and GS rate classes, not GSD. Moreover, it is the extended duration of the need for that capacity that drives the decision to install CCGT, rather than CT, capacity.

Q. Do you have any additional evidence to support your contention that the RS and GS rate classes drive the need for CCGT, rather than CT, technology?

A. Yes. Figure 2 below shows Tampa Electric's projected 2014 annual load duration curve using this same hourly load data. The data representing the highest 2,348 hours of load clearly demonstrate that only a small portion of the total annual energy usage by customers impacts the resource economics trade-off decision.



Q. Do these results demonstrate that using annual energy ("AD") in the Company's 12 CP and 50% AD method improperly allocates cost?

A. Yes. Because only energy usage during the highest 2,348 load hours of the year are relevant to generation resource trade-offs (*i.e.*, the trade-off discussed by Mr. Ashburn at page 32 of his testimony between high capital cost/low operating cost units and low capital cost/high operating cost units), <u>and</u> the fact that the higher load factor GSD customer class has a lower share of this energy, the 50% AD method is incorrect. If a 50% energy component is to be used, it should only be based on each class's share of energy during the top 2,348 hours of the year. In addition, if such a method were to be adopted, the "demand" portion of the allocator should only be the peak month CP or perhaps the summer and winter peak month CPs, not CP demands in all 12 months. As a result, I could support a single CP or winter/summer CP methodology to allocate the fixed costs of production plant, or an alternative methodology that allocates the fixed costs strictly on a demand basis. In any event, based on my analysis, I believe a 12 CP and 1/13th AD allocator would be far superior to the 12 CP and 50% AD methodology that Tampa Electric has proposed. Because the use of 12 CPs captures rate class usage during the 12 monthly peaks, plus the additional 1/13 energy (AD) component reflecting annual energy usage, this methodology, while still creating some subsidization by GSD customers, does a better job of capturing each rate class's cost responsibility for Tampa Electric's fixed production costs than Tampa Electric's proposed 12 CP and 50% AD methodology.

Q. Have you performed any additional analyses that demonstrate the unreasonableness of Tampa Electric's proposal?

A. Yes. Using the same EIA levelized cost data from the AEO 2013 forecast, I developed a screening curve analysis that compares a Conventional CCGT with a Conventional CT. The Conventional CT has somewhat different cost characteristics than the Advanced CT that I used in the screening curve analysis that I presented in Tables 1 and 2. Tables 4 and 5 summarize this analysis.

Table 4

U.S. Average Levelized Costs (2011 $/mWh) - C/O Date: 2018*

	Conventional Combined Cycle	Conventional Combustion Turbine
Capacity Factor	87.0%	30.0%
Capital	15.8	44.2
Fixed O&M	1.7	2.7
Var O&M + Fuel	48.4	80
Total	65.9	126.9
Total Capital Cost/mW	$ 120,415	$ 116,158
Fixed O&M/mW	$ 12,956	$ 7,096
Total Fixed Cost/mW	$ 133,371	$ 123,253
Total Variable Cost/mWh	$ 48.40	$ 80.00

*Source: Energy Information Administration Annual Energy Outlook 2013, "Levelized Cost of New Generation Resources."

Table 5
Screening Curve Analysis: CCGT vs. CT

		Total Busbar Cost	
Capacity Factor	mWh	CCGT	CT
3.7%	320	$ 465.52	$ 465.48
5.0%	438	$ 352.90	$ 361.40
10.0%	876	$ 200.65	$ 220.70
15.0%	1,314	$ 149.90	$ 173.80
20.0%	1,752	$ 124.53	$ 150.35
26.8%	2,348	$ 105.21	$ 132.50
30.0%	2,628	$ 99.15	$ 126.90
35.0%	3,066	$ 91.90	$ 120.20
40.0%	3,504	$ 86.46	$ 115.18
45.0%	3,942	$ 82.23	$ 111.27
50.0%	4,380	$ 78.85	$ 108.14
55.0%	4,818	$ 76.08	$ 105.58
60.0%	5,256	$ 73.78	$ 103.45
65.0%	5,694	$ 71.82	$ 101.65
70.0%	6,132	$ 70.15	$ 100.10
75.0%	6,570	$ 68.70	$ 98.76
80.0%	7,008	$ 67.43	$ 97.59
85.0%	7,446	$ 66.31	$ 96.55
90.0%	7,884	$ 65.32	$ 95.63
95.0%	8,322	$ 64.43	$ 94.81
100.0%	8,760	$ 63.63	$ 94.07

Based on this screening curve analysis, the breakeven hours use at which the CCGT becomes less expensive than the CT is 320 hours. Essentially, the CT is only the economic choice for a narrow peak window (such as a weather spike driven winter peak). The conclusion from this analysis is that only energy use in the highest 320 hours of load during the year impact the decision to incur the higher cost of an intermediate CCGT resource. Energy use during the remaining 8,440 hours of the year have no bearing on this economic decision and thus would not be a cost causative factor for the incurrence of fixed production demand costs.

Q. Based on your analysis, should the Commission adopt Tampa Electric's proposal to use a 12 CP and 50% AD method?

A. No. There is no basis for the Company's proposal. It simply results in a substantial cost shift from the RS and GS rate classes to larger customers.

Q. Should the Commission adopt Tampa Electric's current 12 CP and 25% AD method in this case?

A. No. First, the Company has not presented such a study in this case. More importantly, the 12 CP and 25% AD suffers from the same problems that I have identified for the 12 CP and 50% AD method, just not as severely. Nonetheless, there is no reasonable basis for the 12 CP and 25% AD method. Rather, based on the Commission's preference for the 12 CP and 1/13th AD methodology that it approved in numerous cases for FPL over the years (at least since 1983) and other Florida electric utilities, I recommend that the Commission adopt the 12 CP and 1/13th AD for Tampa Electric as well. In a subsequent section of my testimony, I will present a 12 CP and 1/13th AD method that also incorporates Tampa Electric's MDS distribution cost allocation analysis.

Q. Does the Tampa Electric system's generation resource mix (capacity mix) justify the 12 CP and 50% AD methodology, or even the 12 CP and 25% AD method?

A. No. Based on data from the 2013 10-Year Site Plans filed by FPL and Tampa Electric, the Base/Intermediate load generation capacity mixes of the two utilities are about the same (79% for Tampa Electric, 71% for FPL). The Commission has consistently (at least since 1983) found that the 12 CP and 1/13th AD method is appropriate for FPL. Based on the composition of generation resources, this cost allocation methodology is also appropriate for Tampa Electric.

Q. **Would you please discuss Tampa Electric's proposal to use a Minimum Distribution System methodology to classify and allocate distribution plant investment and expenses to retail rate classes?**

A. Yes. As discussed in Tampa Electric witness William Ashburn's testimony, the Company is proposing to utilize an MDS methodology to classify a portion of distribution plant and expenses as both demand related and customer related using a generally accepted method to identify the demand and customer components of FERC distribution plant accounts 364 (poles), accounts 365 to 367 (overhead and underground conductors and conduit) and account 368 (transformers). Tampa Electric previously classified 100% of these distribution costs as demand related. I fully support the Company's proposed MDS recommendation in this case and believe that it is a valid, proper and reasonable approach for use in the class cost of service study.

Q. **What is the basis, from a cost causation perspective, to classify these distribution costs as both demand and customer related?**

A. As described in the NARUC Electric Utility Cost Allocation Manual, the underlying argument in support of a customer component is that there is a minimal level of distribution investment necessary to connect a customer to the distribution system (lines, poles, transformers) that is independent of the level of demand of the customer.[6] The amount of

[6] An excerpt from the NARUC manual that discusses the classification of distribution costs is contained in Baron Exhibit__(SJB-3).

distribution cost that is a function of the requirement to interconnect the customer, regardless of the customer's size, is appropriately assigned to rate classes on the basis of the number of customers, rather than on the kW demand of the class. As stated on page 90 of the NARUC cost allocation manual:

> When the utility installs distribution plant to provide service to a customer and to meet the individual customer's peak demand requirements, the utility must classify distribution plant data separately into demand- and customer-related costs.

Q. Would you briefly explain the conceptual basis for a minimum distribution cost methodology?

A. As discussed in the NARUC cost allocation manual, there are two approaches that are typically used to develop a customer component of distribution plant and expenses. Each methodology ("zero-intercept" and "minimum size") attempts to measure the customer component of various distribution plant accounts (e.g., poles, primary lines, secondary lines, line transformers, etc.). Each of the two methods is designed to estimate the component of distribution plant cost that is incurred by a utility to effectively interconnect a customer to the system, as opposed to providing a specific level of power (kW demand) to the customer. Essentially, the "minimum size methodology" represents the cost that would be incurred, irrespective of differences in the kW demand of a distribution customer. It is this cost, which is not related to customer usage levels, that is used to identify the portion of distribution costs that should be allocated to rate classes based on the number of primary and secondary distribution customers taking service in the class.

Conceptually, this analysis is designed to estimate the behavior of costs statistically, as the Company meets growth in both the number of distribution customers and the loads of these customers. For example, new distribution investment in poles, or underground conductors, for a new subdivision may be associated with unsold, or unoccupied homes that have "0" kW demand – yet the cost for these facilities is still incurred. Similarly, distribution facilities must be installed to meet the needs of part time residents that may have little or no demand during a portion of the year – yet the cost of such distribution facilities still must be incurred and does not vary as a result of the fact that such facilities serve part-time residents. The MDS methodology gives recognition to this circumstance by assigning a portion of the cost of these facilities based on the existence of a "customer," and not just the level of the customer's kW demand.

Q. Do other major electric utility operations in Florida incorporate minimum distribution system classifications in class cost of service studies?

A. Yes. In a recent Gulf Power Company ("GPC") rate case (Docket No. 110138-EI), GPC presented and strongly supported the use of an MDS methodology to develop its class cost of service study. GPC's cost of service witness in that case, Michael O'Sheasy, testified in support of an MDS methodology as follows:

> Q. Please explain why the Minimum Distribution System methodology is important to Gulf and its customers?
>
> A. As I discuss in more detail later, some costs of the distribution system beyond the customer meter and service drop do not vary with customers' use of electricity. The Minimum Distribution System (MDS) methodology is necessary to accurately determine and allocate these customer-related distribution costs. The misclassification of costs that results from not using the MDS methodology sends misleading price signals to customers.

> This misclassification also results in different customer rate classes bearing more or less costs than their cost-causative share of distribution costs. It is therefore important to examine these customer-related costs and classify them appropriately, which the MDS methodology enable us to do. [O'Sheasy Direct Testimony at pages 16 -17, Gulf Power Company Docket No. 110138-EI].

Q. Do you agree with Mr. O'Sheasy's quoted testimony on the MDS issue?

A. Yes. There is no question that some portion of each of Tampa Electric's distribution accounts 364 to 368 is customer related. If a Tampa Electric customer were to decrease its usage to 0 kW, all of the poles, overhead conductors, underground conductors and transformers would <u>not</u> somehow disappear or be used to supply customers in other parts of the system. An MDS methodology recognizes this and reasonably reflects it in the Company's class cost of service study.

Q. Did the Commission adopt GPC's MDS methodology in Docket No. 110138-EI?

A. It is my understanding, based on a review of the Commission's Order in that case, that the Commission approved a Stipulation adopting the methodology "solely for use in designing rates in this case." At least for that GPC case, the conceptual framework that some portion of distribution accounts 364 through 368 is customer related has been accepted, even if it is only for "use in designing rates" in that case.

Q. How do Tampa Electric's MDS results compare to the MDS classifications developed by GPC?

A. As reported by Mr. Ashburn, Tampa Electric's analysis classifies 64% of poles, 9% of conductors and 24% of transformers as customer related. GPC's analysis of its distribution plant costs produced very similar results. Table 6 summarizes the comparison.

Table 6
Comparison of TECO and Gulf Power Company MDS Results

		TECO		Gulf Power Company	
Account	Description	% Cust	% Dem	% Cust	% Dem
364	Poles	64%	36%	65%	35%
365, 366,367	Conductors	9%	91%	8% *	92%
368	Transformers	24%	76%	25%	75%

* GPC % weighted by TECO plant-in-service for accounts 365 to 367.

Q. Have regulatory commissions in other states adopted the minimum distribution system method?

A. Yes. While I have not conducted a comprehensive study, a number of commissions have authorized the MDS methodology. Jurisdictions authorizing the MDS method for utilities in their states that I am specifically familiar with include: Wisconsin, Pennsylvania, Kentucky, Virginia, Georgia, and Ohio.

Q. Do you believe that a minimum distribution system is appropriate for Tampa Electric?

A. Yes. Given the importance of the cost of service results (parities) in setting rates, it is reasonable and appropriate for the Commission to adopt Tampa Electric's proposed MDS methodology. From a cost causation standpoint, the argument supporting this approach is that all of these minimal facilities are needed to interconnect a customer to the Tampa Electric system, including meeting minimum safety standards set forth in the National Electric Safety Code ("NESC"), which the Commission requires be adhered to for all Florida electric utilities.

Q. Have you developed a 12 CP and 1/13th AD cost of service study that incorporates Tampa Electric's MDS study to classify and allocate distribution costs?

A. Yes. Using the Company's cost of service model, I modified Tampa Electric's filed 12 CP and 1/13th AD cost of service study to include the MDS analysis that Tampa Electric developed for its recommended 12 CP and 50% AD method. Baron Exhibit__(SJB-4) contains a summary of this study. Table 7 summarizes the rate class rates of return and parities for this study and compares these results to the Company's 12 CP and 50% AD study, under current rates. It shows that when each rate class' contribution to the Company's return is measured in relation to each class' contribution to the Company's incurrence of costs, it is clear that the GSD rate class has been substantially over-contributing to Tampa Electric's return, and the RS class has been substantially under-contributing.

Table 7
Cost of Service Results with MDS
@ Present Rate Revenues During Test Year Before Increase*

	12CP & 1/13th		12CP & 50%	
	ROR	Index	ROR	Index
RS	4.10%	0.85	4.43%	0.92
GS	4.67%	0.97	4.84%	1.00
GSD	5.49%	1.14	5.06%	1.05
IS	9.95%	2.06	7.43%	1.54
LS ENERGY	6.42%	1.33	2.39%	0.49
LS FACILITIES	8.96%	1.85	8.96%	1.85
Total	4.84%	1.00	4.84%	1.00

*These ROR Parity results reflect the revenues paid by each customer class at present rate levels, before the requested TECO rate increases, under the Company's proposed COS method compared to the HUA proposed 12 CP & 1/13th AD + MDS method.

Q. **To the extent that Mr. Ashburn, at page 34, lines 3 through 8 of his testimony, is arguing that the MDS methodology should only be adopted by the Commission if the Company's preferred 12 CP and 50% AD method is also adopted, would there be any basis to link these two methodologies in that manner?**

A. No. First, the two methodologies are independent; the 12 CP and 50% AD method is associated with the allocation of fixed production costs, while the MDS method is used to allocate the cost of distribution facilities. Second, linking the two methodologies defies any concept of "principle" underlying the adoption of a class cost of service study. This rationale seems to be driven exclusively by the outcome of the cost allocation study, not its underlying reasonableness or how well it reflects cost causation.

Q. Has the Company provided any additional clarification to Mr. Ashburn's testimony on the appropriateness of employing the MDS methodology with the 12 CP and 1/13th AD or other production demand cost allocation methodologies?

A. Yes. In its response to HUA's First Set of Interrogatories, Interrogatory No. 90, Mr. Ashburn confirms that he did not intend to state that the MDS methodology should only be employed if the 12 CP and 50% AD method is adopted. Baron Exhibit__(SJB-5) contains a copy of this interrogatory response.

III. ALLOCATION OF THE AUTHORIZED REVENUE INCREASE

Q. Have you reviewed Tampa Electric's proposed allocation of its requested $133.645 million revenue increase to rate classes?

A. Yes. Tampa Electric's analysis is presented in Mr. Ashburn's Exhibit__(WRA-1), Document No. 2. The allocation of the Company's requested increase follows the results of its recommended 12 CP and 50% AD + MDS cost of service study, such that each rate class is assigned an increase that Tampa Electric calculates would bring that rate class to parity with the System average rate of return, subject to two limitations: no class should receive a rate decrease and no class should receive an increase greater than 1.5 times the average increase. Based on Tampa Electric's preferred cost of service study, only the lighting class increase is impacted by the limitations.

Q. Do you agree with Tampa Electric's general methodology to assign rate class increases in this case?

A. Yes. However, since I am recommending an alternative cost of service study using the 12 CP and 1/13th AD + MDS methodology, I have revised Tampa Electric's revenue allocation using the cost of service study results shown in my Exhibit__(SJB-4). Baron Exhibit__(SJB-6) contains the results of this revenue allocation analysis, which allocates the overall revenue increase to bring each rate class to a parity of 1.0, subject to a limitation that no rate class receives a decrease and that no class receives an increase greater than 1.5 times the retail average increase. The analysis shown in Exhibit__(SJB-6) compares Tampa Electric's proposed revenue responsibility to that proposed by HUA, inclusive of HUA's recommended revenue requirement adjustments presented by Mr. Kollen. Table 8 below summarizes these increases.[7]

[7] The HUA revenue requirement adjustments presented by Mr. Kollen have been applied to Tampa Electric's requested $133.645 million rate schedule increases. HUA has not taken a position on Tampa Electric's proposed $1.194 million increase in service charges, which has not been adjusted.

Table 8
Proposed Revenue Responsibility

Rate Class	TECO Proposed Increase Increase $	 % Present Base Rev.	HUA Proposed Increase Increase $	 % Present Base Rev.	Difference (HUA vs. TECO) Increase $	 % Present Base Rev.
Residential (RS,RSVP) General Service Non-Demand (GS,TS)	$ 94,742	17.30%	$ 24,480	4.47%	$ (70,262)	-12.83%
General Service Demand (GSD, SBF) Interruptible Service (IS)	$ 37,168	11.64%	$ 4,951	1.55%	$ (32,217)	-10.09%
Lighting (LS-1)						
A. - Energy	$ 1,737	31.78%	$ 22	0.40%	$ (1,716)	-31.38%
B. - Facilities	$ -	0.00%	$ -	0.00%	$ -	0.00%
Total	$ 133,647	14.72%	$ 29,452	3.24%	$(104,195)	-11.48%

Q. **Under your proposal, the GSD rate class would obtain a greater reduction in rates, relative to Tampa Electric's proposal than would be obtained by the RS and GS rate classes. Why is this occurring?**

A. That result is a consequence of moving each rate class closer to parity, which is the widely accepted goal in performing class cost of service/revenue apportionment analyses. That consequence also is not surprising in light of the class cost of service results that I presented in Table 7.

Q. **Are you recommending the apportionment of the Commission approved revenue**

increase to rate classes based on the contribution to Tampa Electric's cost of service shown for each class in your Table 8?

A. Yes, with the caveat that these increases are based on HUA's recommended revenue requirement adjustments presented in the testimony of Mr. Kollen and Mr. Baudino. As summarized in Mr. Kollen's testimony, HUA is recommending that Tampa Electric be awarded an overall revenue increase in this case of no more than $30.6 million. I recommend that the approved increase be allocated using the results of a compliance cost of service study based on the 12 CP and 1/13th AD + MDS methodology that I am recommending in this case. In the alternative, I recommend that the approved increase be allocated proportionately to the HUA increases shown in Table 8.

IV. RATE DESIGN ISSUES

Q. Have you reviewed Tampa Electric's proposed GSD/GSDT rate design?

A. Yes. The Company is proposing a number of increases and decreases to various GSD and GSDT rate elements (customer, energy and demand charges) to recover its recommended GSD rate class increase. Table 9 below summarizes the increases proposed for GSDT.

Table 9
TECO Proposed GSDT Rate Design

Charge		Present		Proposed		Unit Cost	% Increase
T-O-D							
Secondary	$	57.00	$	30.00	$	28.21	-47.4%
Primary	$	130.00	$	130.00	$	126.56	0.0%
Subtransmission	$	930.00	$	990.00	$	987.60	6.5%
Demand Charge - $ per kW							
T-O-D							
Base	$	2.84	$	3.23	$	3.31	13.7%
Peak	$	5.57	$	6.27			12.6%
Energy Charge - $ per MWh							
T-O-D							
On-Peak	$	28.98	$	39.99			38.0%
Off-Peak	$	10.46	$	9.60	$	9.60	-8.2%

The overall base rate increase proposed for rate GSDT is about 13.5%. However, the Company is proposing a 38% increase to the GSDT on-peak (non-fuel) energy charge, which is substantially above the unit cost of service ($39.99/mWh vs. $9.6/mWh). There is no unit cost of service difference associated with non-fuel variable cost between the on-peak and off-peak periods. Therefore, the unit energy cost for the on-peak period is also $9.6/mWh.

Q. What process did Tampa Electric use to develop its GSD and GSDT rate design?

A. According to the Company's workpapers, Tampa Electric designed GSD and GSDT jointly by first increasing the GSD demand charge by the overall GSD rate class increase, setting the off-peak GSDT demand charge at unit cost and then calculating the on-peak GSDT demand charge by taking the difference between the GSD demand charge and the GSDT off-peak demand charge. For the energy charges, the Company determined the GSD energy charge as the residual necessary to produce the GSD target revenues. The GSDT energy charges were developed jointly with the GSD energy charge by setting the off-peak energy charge to unit cost of service and the on-peak GSDT energy charge using test year on and off-peak GSDT energy ratios.

Q. Do you believe that the Company's GSD/GSDT rate design is reasonable?

A. No. As I noted, the proposed on-peak GSDT energy charge is more than 4 times larger than unit cost of service, which does not reflect any on/off-peak differentials. Because the GSDT energy charge represents non-fuel energy costs, there is no basis to impose such a large differential between the on and off-peak energy charges. A more reasonable approach in this case is to set the off-peak GSDT energy charge at unit cost, impose no increase to the already excessive on-peak GSDT energy charge and then solve for the remaining revenue requirements for rate GSD/GSDT by adjusting the on-peak demand charge (the off-peak demand charge is appropriately being set at unit cost in Tampa Electric's proposed rate, which is reasonable). Baron Exhibit__(SJB-7) summarizes my recommended rate design using this approach. This methodology, which is revenue neutral within the GSD/GSDT/SBFT rate class, places a higher priority on setting the energy charges at unit cost of service (or, in the case of the on-peak GSDT energy charge, moving towards cost of service) and then uses the demand charges as a residual to meet the overall GSD rate class revenue target.

Q. Does that complete your prepared testimony?

A. Yes.

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

IN RE: PETITION FOR RATE INCREASE BY TAMPA ELECTRIC COMPANY	))	DOCKET NO. 130040-EI

EXHIBIT___(SJB-1)

OF

STEPHEN J. BARON

ON BEHALF OF THE

WCF HOSPITAL UTILITY ALLIANCE

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

Expert Testimony Appearances
of
Stephen J. Baron
As of June 2013

Date	Case	Jurisdict.	Party	Utility	Subject
4/81	203(B)	KY	Louisville Gas & Electric Co.	Louisville Gas & Electric Co.	Cost-of-service.
4/81	ER-81-42	MO	Kansas City Power & Light Co.	Kansas City Power & Light Co.	Forecasting.
6/81	U-1933	AZ	Arizona Corporation Commission	Tucson Electric Co.	Forecasting planning.
2/84	8924	KY	Airco Carbide	Louisville Gas & Electric Co.	Revenue requirements, cost-of-service, forecasting, weather normalization.
3/84	84-038-U	AR	Arkansas Electric Energy Consumers	Arkansas Power & Light Co.	Excess capacity, cost-of-service, rate design.
5/84	830470-EI	FL	Florida Industrial Power Users' Group	Florida Power Corp.	Allocation of fixed costs, load and capacity balance, and reserve margin. Diversification of utility.
10/84	84-199-U	AR	Arkansas Electric Energy Consumers	Arkansas Power and Light Co.	Cost allocation and rate design.
11/84	R-842651	PA	Lehigh Valley Power Committee	Pennsylvania Power & Light Co.	Interruptible rates, excess capacity, and phase-in.
1/85	85-65	ME	Airco Industrial Gases	Central Maine Power Co.	Interruptible rate design.
2/85	I-840381	PA	Philadelphia Area Industrial Energy Users' Group	Philadelphia Electric Co.	Load and energy forecast.
3/85	9243	KY	Alcan Aluminum Corp., et al.	Louisville Gas & Electric Co.	Economics of completing fossil generating unit.
3/85	3498-U	GA	Attorney General	Georgia Power Co.	Load and energy forecasting, generation planning economics.
3/85	R-842632	PA	West Penn Power Industrial Intervenors	West Penn Power Co.	Generation planning economics, prudence of a pumped storage hydro unit.
5/85	84-249	AR	Arkansas Electric Energy Consumers	Arkansas Power & Light Co.	Cost-of-service, rate design return multipliers.
5/85		City of	Chamber of	Santa Clara	Cost-of-service, rate design.

**Expert Testimony Appearances
of
Stephen J. Baron
As of June 2013**

Date	Case	Jurisdict.	Party	Utility	Subject
		Santa Clara	Commerce	Municipal	
6/85	84-768-E-42T	WV	West Virginia Industrial Intervenors	Monongahela Power Co.	Generation planning economics, prudence of a pumped storage hydro unit.
6/85	E-7 Sub 391	NC	Carolina Industrials (CIGFUR III)	Duka Power Co.	Cost-of-service, rate design, interruptible rate design.
7/85	29046	NY	Industrial Energy Users Association	Orange and Rockland Utilities	Cost-of-service, rate design.
10/85	85-043-U	AR	Arkansas Gas Consumers	Arkla, Inc.	Regulatory policy, gas cost-of-service, rate design.
10/85	85-63	ME	Airco Industrial Gases	Central Maine Power Co.	Feasibility of interruptible rates, avoided cost.
2/85	ER-8507698	NJ	Air Products and Chemicals	Jersey Central Power & Light Co.	Rate design.
3/85	R-850220	PA	West Penn Power Industrial Intervenors	West Penn Power Co.	Optimal reserve, prudence, off-system sales guarantee plan.
2/86	R-850220	PA	West Penn Power Industrial Intervenors	West Penn Power Co.	Optimal reserve margins, prudence, off-system sales guarantee plan.
3/86	85-299U	AR	Arkansas Electric Energy Consumers	Arkansas Power & Light Co.	Cost-of-service, rate design, revenue distribution.
3/86	85-726-EL-AIR	OH	Industrial Electric Consumers Group	Ohio Power Co.	Cost-of-service, rate design, interruptible rates.
5/86	86-081-E-GI	WV	West Virginia Energy Users Group	Monongahela Power Co.	Generation planning economics, prudence of a pumped storage hydro unit.
8/86	E-7 Sub 408	NC	Carolina Industrial Energy Consumers	Duke Power Co.	Cost-of-service, rate design, interruptible rates.
10/86	U-17378	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Excess capacity, economic analysis of purchased power.
12/86	38063	IN	Industrial Energy	Indiana & Michigan	Interruptible rates.

Expert Testimony Appearances
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As of June 2013

Date	Case	Jurisdict.	Party	Utility	Subject
			Consumers	Power Co.	
3/87	EL-86-53-001 EL-86-57-001	Federal Energy Regulatory Commission (FERC)	Louisiana Public Service Commission Staff	Gulf States Utilities, Southern Co.	Cost/benefit analysis of unit power sales contract.
4/87	U-17282	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Load forecasting and imprudence damages, River Bend Nuclear unit.
5/87	87-023-E-C	WV	Airco Industrial Gases	Monongahela Power Co.	Interruptible rates.
5/87	87-072-E-G1	WV	West Virginia Energy Users' Group	Monongahela Power Co.	Analyze Mon Power's fuel filing and examine the reasonableness of MP's claims.
5/87	86-524-E-SC	WV	West Virginia Energy Users' Group	Monongahela Power Co.	Economic dispatching of pumped storage hydro unit.
5/87	9781	KY	Kentucky Industrial Energy Consumers	Louisville Gas & Electric Co.	Analysis of impact of 1986 Tax Reform Act.
6/87	3673-U	GA	Georgia Public Service Commission	Georgia Power Co.	Economic prudence, evaluation of Vogtle nuclear unit - load forecasting, planning.
6/87	U-17282	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Phase-in plan for River Bend Nuclear unit.
7/87	85-10-22	CT	Connecticut Industrial Energy Consumers	Connecticut Light & Power Co.	Methodology for refunding rate moderation fund.
8/87	3673-U	GA	Georgia Public Service Commission	Georgia Power Co.	Test year sales and revenue forecast.
9/87	R-850220	PA	West Penn Power Industrial Intervenors	West Penn Power Co.	Excess capacity, reliability of generating system.
10/87	R-870651	PA	Duquesne Industrial Intervenors	Duquesne Light Co.	Interruptible rate, cost-of-service, revenue allocation, rate design.

Expert Testimony Appearances
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As of June 2013

Date	Case	Jurisdict.	Party	Utility	Subject
10/87	I-860025	PA	Pennsylvania Industrial Intervenors		Proposed rules for cogeneration, avoided cost, rate recovery.
10/87	E-015/ GR-87-223	MN	Taconite Intervenors	Minnesota Power & Light Co.	Excess capacity, power and cost-of-service, rate design.
10/87	8702-EI	FL	Occidental Chemical Corp.	Florida Power Corp.	Revenue forecasting, weather normalization.
12/87	87-07-01	CT	Connecticut Industrial Energy Consumers	Connecticut Light Power Co.	Excess capacity, nuclear plant phase-in.
3/88	10064	KY	Kentucky Industrial Energy Consumers	Louisville Gas & Electric Co.	Revenue forecast, weather normalization rate treatment of cancelled plant.
3/88	87-183-TF	AR	Arkansas Electric Consumers	Arkansas Power & Light Co.	Standby/backup electric rates.
5/88	870171C001	PA	GPU Industrial Intervenors	Metropolitan Edison Co.	Cogeneration deferral mechanism, modification of energy cost recovery (ECR).
6/88	870172C005	PA	GPU Industrial Intervenors	Pennsylvania Electric Co.	Cogeneration deferral mechanism, modification of energy cost recovery (ECR).
7/88	88-171-EL-AIR 88-170-EL-AIR Interim Rate Case	OH	Industrial Energy Consumers	Cleveland Electric/ Toledo Edison	Financial analysis/need for interim rate relief.
7/88	Appeal of PSC	19th Judicial Docket U-17282	Louisiana Public Service Commission Circuit Court of Louisiana	Gulf States Utilities	Load forecasting, imprudence damages.
11/88	R-880989	PA	United States Steel	Carnegie Gas	Gas cost-of-service, rate design.
11/88	88-171-EL-AIR 88-170-EL-AIR	OH	Industrial Energy Consumers	Cleveland Electric/ Toledo Edison. General Rate Case.	Weather normalization of peak loads, excess capacity, regulatory policy.
3/89	870216/283 284/286	PA	Armco Advanced Materials Corp.,	West Penn Power Co.	Calculated avoided capacity, recovery of capacity payments.

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As of June 2013

Date	Case	Jurisdict.	Party	Utility	Subject
			Allegheny Ludlum Corp.		
8/89	8555	TX	Occidental Chemical Corp.	Houston Lighting & Power Co.	Cost-of-service, rate design.
8/89	3840-U	GA	Georgia Public Service Commission	Georgia Power Co.	Revenue forecasting, weather normalization.
9/89	2087	NM	Attorney General of New Mexico	Public Service Co. of New Mexico	Prudence - Palo Verde Nuclear Units 1, 2 and 3, load forecasting.
10/89	2262	NM	New Mexico Industrial Energy Consumers	Public Service Co. of New Mexico	Fuel adjustment clause, off-system sales, cost-of-service, rate design, marginal cost.
11/89	38728	IN	Industrial Consumers for Fair Utility Rates	Indiana Michigan Power Co.	Excess capacity, capacity equalization, jurisdictional cost allocation, rate design, interruptible rates.
1/90	U-17282	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Jurisdictional cost allocation, O&M expense analysis.
5/90	890366	PA	GPU Industrial Intervenors	Metropolitan Edison Co.	Non-utility generator cost recovery.
6/90	R-901609	PA	Armco Advanced Materials Corp., Allegheny Ludlum Corp.	West Penn Power Co.	Allocation of QF demand charges in the fuel cost, cost-of-service, rate design.
9/90	8278	MD	Maryland Industrial Group	Baltimore Gas & Electric Co.	Cost-of-service, rate design, revenue allocation.
12/90	U-9346 Rebuttal	MI	Association of Businesses Advocating Tariff Equity	Consumers Power Co.	Demand-side management, environmental externalities.
12/90	U-17282 Phase IV	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Revenue requirements, jurisdictional allocation.
12/90	90-205	ME	Airco Industrial Gases	Central Maine Power Co.	Investigation into interruptible service and rates.

Expert Testimony Appearances
of
Stephen J. Baron
As of June 2013

Date	Case	Jurisdict.	Party	Utility	Subject
1/91	90-12-03 Interim	CT	Connecticut Industrial Energy Consumers	Connecticut Light & Power Co.	Interim rate relief, financial analysis, class revenue allocation.
5/91	90-12-03 Phase II	CT	Connecticut Industrial Energy Consumers	Connecticut Light & Power Co.	Revenue requirements, cost-of-service, rate design, demand-side management.
8/91	E-7, SUB SUB 487	NC	North Carolina Industrial Energy Consumers	Duke Power Co.	Revenue requirements, cost allocation, rate design, demand-side management.
8/91	8341 Phase I	MD	Westvaco Corp.	Potomac Edison Co.	Cost allocation, rate design, 1990 Clean Air Act Amendments.
8/91	91-372 EL-UNC	OH	Armco Steel Co., L.P.	Cincinnati Gas & Electric Co.	Economic analysis of cogeneration, avoid cost rate.
9/91	P-910511 P-910512	PA	Allegheny Ludlum Corp., Armco Advanced Materials Co., The West Penn Power Industrial Users' Group	West Penn Power Co.	Economic analysis of proposed CWIP Rider for 1990 Clean Air Act Amendments expenditures.
9/91	91-231 -E-NC	WV	West Virginia Energy Users' Group	Monongahela Power Co.	Economic analysis of proposed CWIP Rider for 1990 Clean Air Act Amendments expenditures.
10/91	8341 - Phase II	MD	Westvaco Corp.	Potomac Edison Co.	Economic analysis of proposed CWIP Rider for 1990 Clean Air Act Amendments expenditures.
10/91	U-17282	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Results of comprehensive management audit.
Note: No testimony was prefiled on this.					
11/91	U-17949 Subdocket A	LA	Louisiana Public Service Commission Staff	South Central Bell Telephone Co. and proposed merger with Southern Bell Telephone Co.	Analysis of South Central Bell's restructuring and
12/91	91-410-EL-AIR	OH	Armco Steel Co., Air Products & Chemicals, Inc.	Cincinnati Gas & Electric Co.	Rate design, interruptible rates.

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Date	Case	Jurisdict.	Party	Utility	Subject
12/91	P-880286	PA	Armco Advanced Materials Corp., Allegheny Ludlum Corp.	West Penn Power Co.	Evaluation of appropriate avoided capacity costs - QF projects.
1/92	C-913424	PA	Duquesne Interruptible Complainants	Duquesne Light Co.	Industrial interruptible rate.
6/92	92-02-19	CT	Connecticut Industrial Energy Consumers	Yankee Gas Co.	Rate design.
8/92	2437	NM	New Mexico Industrial Intervenors	Public Service Co. of New Mexico	Cost-of-service.
8/92	R-00922314	PA	GPU Industrial Intervenors	Metropolitan Edison Co.	Cost-of-service, rate design, energy cost rate.
9/92	39314	ID	Industrial Consumers for Fair Utility Rates	Indiana Michigan Power Co.	Cost-of-service, rate design, energy cost rate, rate treatment.
10/92	M-00920312 C-007	PA	The GPU Industrial Intervenors	Pennsylvania Electric Co.	Cost-of-service, rate design, energy cost rate, rate treatment.
12/92	U-17949	LA	Louisiana Public Service Commission Staff	South Central Bell Co.	Management audit.
12/92	R-00922378	PA	Armco Advanced Materials Co. The WPP Industrial Intervenors	West Penn Power Co.	Cost-of-service, rate design, energy cost rate, SO_2 allowance rate treatment.
1/93	8487	MD	The Maryland Industrial Group	Baltimore Gas & Electric Co.	Electric cost-of-service and rate design, gas rate design (flexible rates).
2/93	E002/GR-92-1185	MN	North Star Steel Co. Praxair, Inc.	Northern States Power Co.	Interruptible rates.
4/93	EC92 21000 ER92-806-000 (Rebuttal)	Federal Energy Regulatory Commission	Louisiana Public Service Commission Staff	Gulf States Utilities/Entergy agreement.	Merger of GSU into Entergy System; impact on system
7/93	93-0114-E-C	WV	Airco Gases	Monongahela Power Co.	Interruptible rates.

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8/93	930759-EG	FL	Florida Industrial Power Users' Group	Generic - Electric Utilities	Cost recovery and allocation of DSM costs.
9/93	M-009 30406	PA	Lehigh Valley Power Committee	Pennsylvania Power & Light Co.	Ratemaking treatment of off-system sales revenues.
11/93	346	KY	Kentucky Industrial Utility Customers	Generic - Gas Utilities	Allocation of gas pipeline transition costs - FERC Order 636.
12/93	U-17735	LA	Louisiana Public Service Commission Staff	Cajun Electric Power Cooperative	Nuclear plant prudence, forecasting, excess capacity.
4/94	E-015/ GR-94-001	MN	Large Power Intervenors	Minnesota Power Co.	Cost allocation, rate design, rate phase-in plan.
5/94	U-20178	LA	Louisiana Public Service Commission	Louisiana Power & Light Co.	Analysis of least cost integrated resource plan and demand-side management program.
7/94	R-00942986	PA	Armco, Inc.; West Penn Power Industrial Intervenors	West Penn Power Co.	Cost-of-service, allocation of rate increase, rate design, emission allowance sales, and operations and maintenance expense.
7/94	94-0035-E-42T	WV	West Virginia Energy Users Group	Monongahela Power Co.	Cost-of-service, allocation of rate increase, and rate design.
8/94	EC94 13-000	Federal Energy Regulatory Commission	Louisiana Public Service Commission	Gulf States Utilities/Entergy	Analysis of extended reserve shutdown units and violation of system agreement by Entergy.
9/94	R-00943 081 R-00943 081C0001	PA	Lehigh Valley Power Committee	Pennsylvania Public Utility Commission	Analysis of interruptible rate terms and conditions, availability.
9/94	U-17735	LA	Louisiana Public Service Commission	Cajun Electric Power Cooperative	Evaluation of appropriate avoided cost rate.
9/94	U-19904	LA	Louisiana Public Service Commission	Gulf States Utilities	Revenue requirements.
10/94	5258-U	GA	Georgia Public Service Commission	Southern Bell Telephone & Telegraph Co.	Proposals to address competition in telecommunication markets.

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11/94	EC94-7-000 ER94-898-000	FERC	Louisiana Public Service Commission	El Paso Electric and Central and Southwest	Merger economics, transmission equalization hold harmless proposals.
2/95	941-430EG	CO	CF&I Steel, L.P.	Public Service Company of Colorado	Interruptible rates, cost-of-service.
4/95	R-00943271	PA	PP&L Industrial Customer Alliance	Pennsylvania Power & Light Co.	Cost-of-service, allocation of rate increase, rate design, interruptible rates.
6/95	C-00913424 C-00946104	PA	Duquesne Interruptible Complainants	Duquesne Light Co.	Interruptible rates.
8/95	ER95-112 -000	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Open Access Transmission Tariffs - Wholesale.
10/95	U-21485	LA	Louisiana Public Service Commission	Gulf States Utilities Company	Nuclear decommissioning, revenue requirements, capital structure.
10/95	ER95-1042 -000	FERC	Louisiana Public Service Commission	System Energy Resources, Inc.	Nuclear decommissioning, revenue requirements.
10/95	U-21485	LA	Louisiana Public Service Commission	Gulf States Utilities Co.	Nuclear decommissioning and cost of debt capital, capital structure.
11/95	I-940032	PA	Industrial Energy Consumers of Pennsylvania	State-wide - all utilities	Retail competition issues.
7/96	U-21496	LA	Louisiana Public Service Commission	Central Louisiana Electric Co.	Revenue requirement analysis.
7/96	8725	MD	Maryland Industrial Group	Baltimore Gas & Elec. Co., Potomac Elec. Power Co., Constellation Energy Co.	Ratemaking issues associated with a Merger.
8/96	U-17735	LA	Louisiana Public Service Commission	Cajun Electric Power Cooperative	Revenue requirements.
9/96	U-22092	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Decommissioning, weather normalization, capital structure.

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Date	Case	Jurisdict.	Party	Utility	Subject
2/97	R-973877	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy Co.	Competitive restructuring policy issues, stranded cost, transition charges.
6/97	Civil Action No. 94-11474	US Bank-ruptcy Court Middle District of Louisiana	Louisiana Public Service Commission	Cajun Electric Power Cooperative	Confirmation of reorganization plan; analysis of rate paths produced by competing plans.
6/97	R-973953	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy Co.	Retail competition issues, rate unbundling, stranded cost analysis.
6/97	8738	MD	Maryland Industrial Group	Generic	Retail competition issues
7/97	R-973954	PA	PP&L Industrial Customer Alliance	Pennsylvania Power & Light Co.	Retail competition issues, rate unbundling, stranded cost analysis.
10/97	97-204	KY	Alcan Aluminum Corp. Southwire Co.	Big River Electric Corp.	Analysis of cost of service issues - Big Rivers Restructuring Plan
10/97	R-974008	PA	Metropolitan Edison Industrial Users	Metropolitan Edison Co.	Retail competition issues, rate unbundling, stranded cost analysis.
10/97	R-974009	PA	Pennsylvania Electric Industrial Customer	Pennsylvania Electric Co.	Retail competition issues, rate unbundling, stranded cost analysis.
11/97	U-22491	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Decommissioning, weather normalization, capital structure.
11/97	P-971265	PA	Philadelphia Area Industrial Energy Users Group	Enron Energy Services Power, Inc./ PECO Energy	Analysis of Retail Restructuring Proposal.
12/97	R-973981	PA	West Penn Power Industrial Intervenors	West Penn Power Co.	Retail competition issues, rate unbundling, stranded cost analysis.
12/97	R-974104	PA	Duquesne Industrial Intervenors	Duquesne Light Co.	Retail competition issues, rate unbundling, stranded cost analysis.
3/98 (Allocated Stranded Cost Issues)	U-22092	LA	Louisiana Public Service Commission	Gulf States Utilities Co.	Retail competition, stranded cost quantification.

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Date	Case	Jurisdict.	Party	Utility	Subject
3/98	U-22092		Louisiana Public Service Commission	Gulf States Utilities, Inc.	Stranded cost quantification, restructuring issues.
9/98	U-17735		Louisiana Public Service Commission	Cajun Electric Power Cooperative, Inc.	Revenue requirements analysis, weather normalization.
12/98	8794	MD	Maryland Industrial Group and Millennium Inorganic Chemicals Inc.	Baltimore Gas and Electric Co.	Electric utility restructuring, stranded cost recovery, rate unbundling.
12/98	U-23358	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Nuclear decommissioning, weather normalization, Entergy System Agreement.
5/99 (Cross-Answering Testimony)	EC-98-40-000	FERC	Louisiana Public Service Commission	American Electric Power Co. & Central South West Corp.	Merger issues related to market power mitigation proposals.
5/99 (Response Testimony)	98-426	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas & Electric Co.	Performance based regulation, settlement proposal issues, cross-subsidies between electric. gas services.
6/99	98-0452	WV	West Virginia Energy Users Group	Appalachian Power, Monongahela Power, & Potomac Edison Companies	Electric utility restructuring, stranded cost recovery, rate unbundling.
7/99	99-03-35	CT	Connecticut Industrial \Energy Consumers	United Illuminating Company	Electric utility restructuring, stranded cost recovery, rate unbundling.
7/99	Adversary Proceeding No. 98-1065	U.S. Bankruptcy Court	Louisiana Public Service Commission	Cajun Electric Power Cooperative	Motion to dissolve preliminary injunction.
7/99	99-03-06	CT	Connecticut Industrial Energy Consumers	Connecticut Light & Power Co.	Electric utility restructuring, stranded cost recovery, rate unbundling.
10/99	U-24182	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Nuclear decommissioning, weather normalization, Entergy System Agreement.
12/99	U-17735	LA	Louisiana Public Service Commission	Cajun Electric Power Cooperative, Inc.	Ananlysi of Proposed Contract Rates, Market Rates.

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03/00	U-17735	LA	Louisiana Public Service Commission	Cajun Electric Power Cooperative, Inc.	Evaluation of Cooperative Power Contract Elections
03/00	99-1658-EL-ETP	OH	AK Steel Corporation	Cincinnati Gas & Electric Co.	Electric utility restructuring, stranded cost recovery, rate Unbundling.
08/00	98-0452 E-GI	WVA	West Virginia Energy Users Group	Appalachian Power Co. American Electric Co.	Electric utility restructuring rate unbundling.
08/00	00-1050 E-T 00-1051-E-T	WVA	West Virginia Energy Users Group	Mon Power Co. Potomac Edison Co.	Electric utility restructuring rate unbundling.
10/00	SOAH 473-00-1020 PUC 2234	TX	The Dallas-Fort Worth Hospital Council and The Coalition of Independent Colleges And Universities	TXU, Inc.	Electric utility restructuring rate unbundling.
12/00	U-24993	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Nuclear decommissioning, revenue requirements.
12/00	EL00-66-000 & ER00-2854 EL95-33-002	LA	Louisiana Public Service Commission	Entergy Services Inc.	Inter-Company System Agreement: Modifications for retail competition, interruptible load.
04/01	U-21453, U-20925, U-22092 (Subdocket B) Addressing Contested Issues	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Jurisdictional Business Separation - Texas Restructuring Plan
10/01	14000-U	GA	Georgia Public Service Commission Adversary Staff	Georgia Power Co.	Test year revenue forecast.
11/01	U-25687	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Nuclear decommissioning requirements transmission revenues.
11/01	U-25965	LA	Louisiana Public Service Commission	Generic	Independent Transmission Company ("Transco"). RTO rate design.
03/02	001148-EI	FL	South Florida Hospital and Healthcare Assoc.	Florida Power & Light Company	Retail cost of service, rate design, resource planning and demand side management.

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06/02	U-25965	LA	Louisiana Public Service Commission	Entergy Gulf States Entergy Louisiana	RTO Issues
07/02	U-21453	LA	Louisiana Public Service Commission	SWEPCO, AEP	Jurisdictional Business Sep. - Texas Restructuring Plan.
08/02	U-25888	LA	Louisiana Public Service Commission	Entergy Louisiana, Inc. Entergy Gulf States, Inc.	Modifications to the Inter-Company System Agreement, Production Cost Equalization.
08/02	EL01-88-000	FERC	Louisiana Public Service Commission	Entergy Services Inc. and the Entergy Operating Companies	Modifications to the Inter-Company System Agreement, Production Cost Equalization.
11/02	02S-315EG	CO	CF&I Steel & Climax Molybdenum Co.	Public Service Co. of Colorado	Fuel Adjustment Clause
01/03	U-17735	LA	Louisiana Public Service Commission	Louisiana Coops	Contract Issues
02/03	02S-594E	CO	Cripple Creek and Victor Gold Mining Co.	Aquila, Inc.	Revenue requirements, purchased power.
04/03	U-26527	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Weather normalization, power purchase expenses, System Agreement expenses.
11/03	ER03-753-000	FERC	Louisiana Public Service Commission Staff	Entergy Services, Inc. and the Entergy Operating Companies	Proposed modifications to System Agreement Tariff MSS-4.
11/03	ER03-583-000 ER03-583-001 ER03-583-002 ER03-681-000, ER03-681-001 ER03-682-000, ER03-682-001 ER03-682-002	FERC	Louisiana Public Service Commission	Entergy Services, Inc., the Entergy Operating Companies, EWO Marketing, L.P, and Entergy Power, Inc.	Evaluation of Wholesale Purchased Power Contracts.
12/03	U-27136	LA	Louisiana Public Service Commission	Entergy Louisiana, Inc.	Evaluation of Wholesale Purchased Power Contracts.
01/04	E-01345-03-0437	AZ	Kroger Company	Arizona Public Service Co.	Revenue allocation rate design.
02/04	00032071	PA	Duquesne Industrial Intervenors	Duquesne Light Company	Provider of last resort issues.

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Date	Case	Jurisdict.	Party	Utility	Subject
03/04	03A-436E	CO	CF&I Steel, LP and Climax Molybedenum	Public Service Company of Colorado	Purchased Power Adjustment Clause.
04/04	2003-00433 2003-00434	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas & Electric Co. Kentucky Utilities Co.	Cost of Service Rate Design
0-6/04	03S-539E	CO	Cripple Creek, Victor Gold Mining Co., Goodrich Corp., Holcim (U.S.,), Inc., and The Trane Co.	Aquila, Inc.	Cost of Service, Rate Design Interruptible Rates
06/04	R-00049255	PA	PP&L Industrial Customer Alliance PPLICA	PPL Electric Utilities Corp.	Cost of service, rate design, tariff issues and transmission service charge.
10/04	04S-164E	CO	CF&I Steel Company, Climax Mines	Public Service Company of Colorado	Cost of service, rate design, Interruptible Rates.
03/05	Case No. 2004-00426 Case No. 2004-00421	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Louisville Gas & Electric Co.	Environmental cost recovery.
06/05	050045-EI	FL	South Florida Hospital and Healthcare Assoc.	Florida Power & Light Company	Retail cost of service, rate design
07/05	U-28155	LA	Louisiana Public Service Commission Staff	Entergy Louisiana, Inc. Entergy Gulf States, Inc.	Independent Coordinator of Transmission – Cost/Benefit
09/05	Case Nos. 05-0402-E-CN 05-0750-E-PC	WVA	West Virginia Energy Users Group	Mon Power Co. Potomac Edison Co.	Environmental cost recovery, Securitization, Financing Order
01/06	2005-00341	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Company	Cost of service, rate design, transmission expenses. Congestion Cost Recovery Mechanism
03/06	U-22092	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Separation of EGSI into Texas and Louisiana Companies.
04/06	U-25116	LA	Louisiana Public Service Commission Staff	Entergy Louisiana, Inc.	Transmission Prudence Investigation
06/06	R-00061346 C0001-0005	PA	Duquesne Industrial Intervenors & IECPA	Duquesne Light Co.	Cost of Service, Rate Design, Transmission Service Charge, Tariff Issues
06/06	R-00061366 R-00061367 P-00062213		Met-Ed Industrial Energy Users Group and Penelec Industrial Customer	Metropolitan Edison Co. Pennsylvania Electric Co.	Generation Rate Cap, Transmission Service Charge, Cost of Service, Rate Design, Tariff Issues

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Date	Case	Jurisdict.	Party	Utility	Subject
	P-00062214		Alliance		
07/06	U-22092 Sub-J	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Separation of EGSI into Texas and Louisiana Companies.
07/06	Case No. 2006-00130 Case No. 2006-00129	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Louisville Gas & Electric Co.	Environmental cost recovery.
08/06	Case No. PUE-2006-00065	VA	Old Dominion Committee For Fair Utility Rates	Appalachian Power Co.	Cost Allocation, Allocation of Rev Incr, Off-System Sales margin rate treatment
09/06	E-01345A-05-0816	AZ	Kroger Company	Arizona Public Service Co.	Revenue allocation, cost of service, rate design.
11/06	Doc. No. 97-01-15RE02	CT	Connecticut Industrial Energy Consumers	Connecticut Light & Power United Illuminating	Rate unbundling issues.
01/07	Case No. 06-0960-E-42T	WV	West Virginia Energy Users Group	Mon Power Co. Potomac Edison Co.	Retail Cost of Service Revenue apportionment
03/07	U-29764	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc. Entergy Louisiana, LLC	Implementation of FERC Decision Jurisdictional & Rate Class Allocation
05/07	Case No. 07-63-EL-UNC	OH	Ohio Energy Group	Ohio Power, Columbus Southern Power	Environmental Surcharge Rate Design
05/07	R-00049255 Remand	PA	PP&L Industrial Customer Alliance PPLICA	PPL Electric Utilities Corp.	Cost of service, rate design, tariff issues and transmission service charge.
06/07	R-00072155	PA	PP&L Industrial Customer Alliance PPLICA	PPL Electric Utilities Corp.	Cost of service, rate design, tariff issues.
07/07	Doc. No. 07F-037E	CO	Gateway Canyons LLC	Grand Valley Power Coop.	Distribution Line Cost Allocation
09/07	Doc. No. 05-UR-103	WI	Wisconsin Industrial Energy Group, Inc.	Wisconsin Electric Power Co.	Cost of Service, rate design, tariff issues, Interruptible rates.
11/07	ER07-682-000	FERC	Louisiana Public Service Commission Staff	Entergy Services, Inc. and the Entergy Operating Companies	Proposed modifications to System Agreement Schedule MSS-3. Cost functionalization issues.
1/08	Doc. No. 20000-277-ER-07	WY	Cimarex Energy Company	Rocky Mountain Power (PacifiCorp)	Vintage Pricing, Marginal Cost Pricing Projected Test Year
1/08	Case No. 07-551	OH	Ohio Energy Group	Ohio Edison, Toledo Edison Cleveland Electric Illuminating	Class Cost of Service, Rate Restructuring, Apportionment of Revenue Increase to

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2/08	ER07-956	FERC	Louisiana Public Service Commission Staff	Entergy Services, Inc. and the Entergy Operating Companies	Rate Schedules Entergy's Compliance Filing System Agreement Bandwidth Calculations.
2/08	Doc No. P-00072342	PA	West Penn Power Industrial Intervenors	West Penn Power Co.	Default Service Plan issues.
3/08	Doc No. E-01933A-05-0650	AZ	Kroger Company	Tucson Electric Power Co.	Cost of Service, Rate Design
05/08	08-0278 E-GI	WV	West Virginia Energy Users Group	Appalachian Power Co. American Electric Power Co.	Expanded Net Energy Cost "ENEC" Analysis.
6/08	Case No. 08-124-EL-ATA	OH	Ohio Energy Group	Ohio Edison, Toledo Edison Cleveland Electric Illuminating	Recovery of Deferred Fuel Cost
7/08	Docket No. 07-035-93	UT	Kroger Company	Rocky Mountain Power Co.	Cost of Service, Rate Design
08/08	Doc. No. 6680-UR-116	WI	Wisconsin Industrial Energy Group, Inc.	Wisconsin Power and Light Co.	Cost of Service, rate design, tariff Issues, Interruptible rates.
09/08	Doc. No. 6690-UR-119	WI	Wisconsin Industrial Energy Group, Inc.	Wisconsin Public Service Co.	Cost of Service, rate design, tariff Issues, Interruptible rates.
09/08	Case No. 08-936-EL-SSO	OH	Ohio Energy Group	Ohio Edison, Toledo Edison Cleveland Electric Illuminating	Provider of Last Resort Competitive Solicitation
09/08	Case No. 08-935-EL-SSO	OH	Ohio Energy Group	Ohio Edison, Toledo Edison Cleveland Electric Illuminating	Provider of Last Resort Rate Plan
09/08	Case No. 08-917-EL-SSO 08-918-EL-SSO	OH	Ohio Energy Group	Ohio Power Company Columbus Southern Power Co.	Provider of Last Resort Rate Plan
10/08	2008-00251 2008-00252	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas & Electric Co. Kentucky Utilities Co.	Cost of Service, Rate Design
11/08	08-1511 E-GI	WV	West Virginia Energy Users Group	Mon Power Co. Potomac Edison Co.	Expanded Net Energy Cost "ENEC" Analysis.
11/08	M-2008-2036188, M-2008-2036197	PA	Met-Ed Industrial Energy Users Group and Penelec Industrial Customer Alliance	Metropolitan Edison Co. Pennsylvania Electric Co.	Transmission Service Charge
01/09	ER08-1056	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	Entergy's Compliance Filing System Agreement Bandwidth Calculations.

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01/09	E-01345A-08-0172	AZ	Kroger Company	Arizona Public Service Co.	Cost of Service, Rate Design
02/09	2008-00409	KY	Kentucky Industrial Utility Customers, Inc.	East Kentucky Power Cooperative, Inc.	Cost of Service, Rate Design
5/09	PUE-2009 -00018	VA	VA Committee For Fair Utility Rates	Dominion Virginia Power Company	Transmission Cost Recovery Rider
5/09	09-0177-E-GI	WV	West Virginia Energy Users Group	Appalachian Power Company	Expanded Net Energy Cost "ENEC" Analysis
6/09	PUE-2009 -00016	VA	VA Committee For Fair Utility Rates	Dominion Virginia Power Company	Fuel Cost Recovery Rider
6/09	PUE-2009 -00038	VA	Old Dominion Committee For Fair Utility Rates	Appalachian Power Company	Fuel Cost Recovery Rider
7/09	080677-EI	FL	South Florida Hospital and Healthcare Assoc.	Florida Power & Light Company	Retail cost of service, rate design
8/09	U-20925 (RRF 2004)	LA	Louisiana Public Service Commission Staff	Entergy Louisiana LLC	Interruptible Rate Refund Settlement
9/09	09AL-299E	CO	CF&I Steel Company Climax Molybdenum	Public Service Company of Colorado	Energy Cost Rate issues
9/09	Doc. No. 05-UR-104	WI	Wisconsin Industrial Energy Group, Inc.	Wisconsin Electric Power Co.	Cost of Service, rate design, tariff Issues, Interruptible rates.
9/09	Doc. No. 6680-UR-117	WI	Wisconsin Industrial Energy Group, Inc.	Wisconsin Power and Light Co.	Cost of Service, rate design, tariff Issues, Interruptible rates.
10/09	Docket No. 09-035-23	UT	Kroger Company	Rocky Mountain Power Co.	Cost of Service, Allocation of Rev Increase
10/09	09AL-299E	CO	CF&I Steel Company Climax Molybdenum	Public Service Company of Colorado	Cost of Service, Rate Design
11/09	PUE-2009 -00019	VA	VA Committee For Fair Utility Rates	Dominion Virginia Power Company	Cost of Service, Rate Design
11/09	09-1485 E-P	WV	West Virginia Energy Users Group	Mon Power Co. Potomac Edison Co.	Expanded Net Energy Cost "ENEC" Analysis.
12/09	Case No. 09-906-EL-SSO	OH	Ohio Energy Group	Ohio Edison, Toledo Edison Cleveland Electric Illuminating	Provider of Last Resort Rate Plan

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12/09	ER09-1224	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	Entergy's Compliance Filing System Agreement Bandwidth Calculations.
12/09	Case No. PUE-2009-00030	VA	Old Dominion Committee For Fair Utility Rates	Appalachian Power Co.	Cost Allocation, Allocation of Rev Increase, Rate Design
2/10	Docket No. 09-035-23	UT	Kroger Company	Rocky Mountain Power Co.	Rate Design
3/10	Case No. 09-1352-E-42T	WV	West Virginia Energy Users Group	Mon Power Co. Potomac Edison Co.	Retail Cost of Service Revenue apportionment
3/10	E015/ GR-09-1151	MN	Large Power Intervenors	Minnesota Power Co.	Cost of Service, rate design
4/10	EL09-61	FERC	Louisiana Public Service Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	System Agreement Issues Related to off-system sales
4/10	2009-00459	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Company	Cost of service, rate design, transmission expenses.
4/10	2009-00548 2009-00549	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas & Electric Co. Kentucky Utilities Co.	Cost of Service, Rate Design
7/10	R-2010-2161575	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy Company	Cost of Service, Rate Design
09/10	2010-00167	KY	Kentucky Industrial Utility Customers, Inc.	East Kentucky Power Cooperative, Inc.	Cost of Service, Rate Design
09/10	10M-245E	CO	CF&I Steel Company Climax Molybdenum	Public Service Company of Colorado	Economic Impact of Clean Air Act
11/10	10-0699-E-42T	WV	West Virginia Energy Users Group	Appalachian Power Company	Cost of Service, Rate Design, Transmission Rider
11/10	Doc. No. 4220-UR-116	WI	Wisconsin Industrial Energy Group, Inc.	Northern States Power Co. Wisconsin	Cost of Service, rate design
12/10	10A-554EG	CO	CF&I Steel Company Climax Molybdenum	Public Service Company	Demand Side Management Issues
12/10	10-2586-EL-SSO	OH	Ohio Energy Group	Duke Energy Ohio	Provider of Last Resort Rate Plan Electric Security Plan
3/11	20000-384-ER-10	WY	Wyoming Industrial Energy Consumers	Rocky Mountain Power Wyoming	Electric Cost of Service, Revenue Apportionment, Rate Design

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5/11	2011-00036	KY	Kentucky Industrial Utility Customers, Inc.	Big Rivers Electric Corporation	Cost of Service, Rate Design
6/11	Docket No. 10-035-124	UT	Kroger Company	Rocky Mountain Power Co.	Class Cost of Service
6/11	PUE-2011 -00045	VA	VA Committee For Fair Utility Rates	Dominion Virginia Power Company	Fuel Cost Recovery Rider
07/11	U-29764	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc. Entergy Louisiana, LLC	Entergy System Agreement - Successor Agreement, Revisions, RTO Day 2 Market Issues
07/11	Case Nos. 11-346-EL-SSO 11-348-EL-SSO	OH	Ohio Energy Group	Ohio Power Company Columbus Southern Power Co.	Electric Security Rate Plan, Provider of Last Resort Issues
08/11	PUE-2011-00034	VA	Old Dominion Committee For Fair Utility Rates	Appalachian Power Co.	Cost Allocation, Rate Recovery of RPS Costs
09/11	2011-00161 2011-00162	KY	Kentucky Industrial Utility Consumers	Louisville Gas & Electric Co. Kentucky Utilities Company	Environmental Cost Recovery
09/11	Case Nos. 11-346-EL-SSO 11-348-EL-SSO	OH	Ohio Energy Group	Ohio Power Company Columbus Southern Power Co.	Electric Security Rate Plan, Stipulation Support Testimony
10/11	11-0452 E-P-T	WV	West Virginia Energy Users Group	Mon Power Co. Potomac Edison Co.	Energy Efficiency/Demand Reduction Cost Recovery
11/11	11-1274 E-P	WV	West Virginia Energy Users Group	Mon Power Co. Potomac Edison Co.	Expanded Net Energy Cost "ENEC" Analysis.
11/11	E-01345A-11-0224	AZ	Kroger Company	Arizona Public Service Co.	Decoupling
12/11	E-01345A-11-0224	AZ	Kroger Company	Arizona Public Service Co.	Cost of Service, Rate Design
3/12	Case No. 2011-00401	KY	Kentucky Industrial Utility Consumers	Kentucky Power Company	Environmental Cost Recovery
4/12	2011-00036 Rehearing Case	KY	Kentucky Industrial Utility Customers, Inc.	Big Rivers Electric Corporation	Cost of Service, Rate Design
5/12	2011-346 2011-348	OH	Ohio Energy Group	Ohio Power Company	Electric Security Rate Plan Interruptible Rate Issues
6/12	PUE-2012 -00051	VA	Old Dominion Committee For Fair Utility Rates	Appalachian Power Company	Fuel Cost Recovery Rider

**Expert Testimony Appearances
of
Stephen J. Baron
As of June 2013**

Date	Case	Jurisdict.	Party	Utility	Subject
6/12	12-00012 12-00026	TN	Eastman Chemical Co. Air Products and Chemicals, Inc.	Kingsport Power Company	Demand Response Programs
6/12	Docket No. 11-035-200	UT	Kroger Company	Rocky Mountain Power Co.	Class Cost of Service
6/12	12-0275- E-GI-EE	WV	West Virginia Energy Users Group	Appalachian Power Company	Energy Efficiency Rider
6/12	12-0399- E-P	WV	West Virginia Energy Users Group	Appalachian Power Company	Expanded Net Energy Cost ("ENEC")
7/12	120015-EI	FL	South Florida Hospital and Healthcare Assoc.	Florida Power & Light Company	Retail cost of service, rate design
7/12	2011-00063	KY	Kentucky Industrial Utility Customers, Inc.	Big Rivers Electric Corporation	Environmental Cost Recovery
8/12	Case No. 2012-00226	KY	Kentucky Industrial Utility Consumers	Kentucky Power Company	Real Time Pricing Tariff
9/12	ER12-1384	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Entergy System Agreement, Cancelled Plant Cost Treatment
9/12	2012-00221 2012-00222	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas & Electric Co. Kentucky Utilities Co.	Cost of Service, Rate Design
11/12	12-1238 E-GI	WV	West Virginia Energy Users Group	Mon Power Co. Potomac Edison Co.	Expanded Net Energy Cost Recovery Issues
12/12	U-29764	LA	Louisiana Public Service Commission Staff	Entergy Gulf States Louisiana	Purchased Power Contracts
12/12	EL09-61	FERC	Louisiana Public Service Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	System Agreement Issues Related to off-system sales Damages Phase
12/12	E-01933A- 12-0291	AZ	Kroger Company	Tucson Electric Power Co.	Decoupling
1/13	12-1188 E-PC	WV	West Virginia Energy Users Group	Appalachian Power Company	Securitization of ENEC Costs
4/13	12-1571 E-PC	WV	West Virginia Energy Users Group	Mon Power Co. Potomac Edison Co.	Generation Resource Transition Plan Issues
4/13	PUE-2012 -00141	VA	Old Dominion Committee For Fair Utility Rates	Appalachian Power Company	Generation Asset Transfer Issues

Expert Testimony Appearances
of
Stephen J. Baron
As of June 2013

Date	Case	Jurisdict.	Party	Utility	Subject
6/13	12-1655 E-PC	WV	West Virginia Energy Users Group	Appalachian Power Company	Generation Asset Transfer Issues
06/13	U-32675	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc. Entergy Louisiana, LLC	MISO Joint Implementation Plan Issues

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

IN RE: PETITION FOR RATE INCREASE BY	)	DOCKET NO. 130040-EI
TAMPA ELECTRIC COMPANY	)	

EXHIBIT___(SJB-2)

OF

STEPHEN J. BARON

ON BEHALF OF THE

WCF HOSPITAL UTILITY ALLIANCE

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

Independent Statistics & Analysis
U.S. Energy Information Administration

January 2013

Levelized Cost of New Generation Resources in the Annual Energy Outlook 2013

This paper presents average levelized costs for generating technologies that are brought on line in 2018[1] as represented in the National Energy Modeling System (NEMS) for the *Annual Energy Outlook 2013* (AEO2013) Early Release Reference case.[2] Both national values and the minimum and maximum values across the 22 U.S. regions of the NEMS electricity market module are presented.

Levelized cost is often cited as a convenient summary measure of the overall competiveness of different generating technologies. It represents the per-kilowatthour cost (in real dollars) of building and operating a generating plant over an assumed financial life and duty cycle. Key inputs to calculating levelized costs include overnight capital costs, fuel costs, fixed and variable operations and maintenance (O&M) costs, financing costs, and an assumed utilization rate for each plant type.[3] The importance of the factors varies among the technologies. For technologies such as solar and wind generation that have no fuel costs and relatively small O&M costs, the levelized cost changes in rough proportion to the estimated overnight capital cost of generation capacity. For technologies with significant fuel cost, both fuel cost and overnight cost estimates significantly affect the levelized cost. The availability of various incentives, including state or federal tax credits, can also impact the calculation of levelized cost. The values shown in the tables in this discussion do not incorporate any such incentives.[4] As with any projection, there is uncertainty about all of these factors and their values can vary regionally and across time as technologies evolve and fuel prices change.

It is important to note that, while levelized costs are a convenient summary measure of the overall competiveness of different generating technologies, actual plant investment decisions are affected by the specific technological and regional characteristics of a project, which involve numerous other considerations. The ***projected utilization rate***, which depends on the load shape and the existing resource mix in an area where additional capacity is needed, is one such factor. The ***existing resource mix*** in a region can directly affect the economic viability of a new investment through its effect on the economics surrounding the displacement of existing resources. For example, a wind resource that would primarily displace existing natural gas

[1] 2018 is shown because the long lead time needed for some technologies means that the plant could not be brought on line prior to 2018 unless it was already under construction.
[2] The full report is available at http://www.eia.gov/forecasts/aeo/er/index.cfm.
[3] The specific assumptions for each of these factors are given in the *Assumptions to the Annual Energy Outlook*, available at http://www.eia.doe.gov/oiaf/aeo/index.html.
[4] These results do not include targeted tax credits such as the production or investment tax credit available for some technologies. Costs are estimated using tax depreciation schedules consistent with current law, which vary by technology.

generation will usually have a different value than one that would displace existing coal generation.

A related factor is the ***capacity value,*** which depends on both the existing capacity mix and load characteristics in a region. Since load must be balanced on a continuous basis, units whose output can be varied to follow demand (dispatchable technologies) generally have more value to a system than less flexible units (non-dispatchable technologies) or those whose operation is tied to the availability of an intermittent resource. The levelized costs for dispatchable and nondispatchable technologies are listed separately in the tables, because caution should be used when comparing them to one another.

Since projected utilization rates, the existing resource mix, and capacity values can all vary dramatically across regions where new generation capacity may be needed, the direct comparison of the levelized cost of electricity across technologies is often problematic and can be misleading as a method to assess the economic competitiveness of various generation alternatives. Conceptually, a better assessment of economic competitiveness can be gained through consideration of avoided cost, a measure of what it would cost the grid to generate the electricity that is otherwise displaced by a new generation project, as well as its levelized cost. Avoided cost, which provides a proxy measure for the annual economic value of a candidate project, may be summed over its financial life and converted to a stream of equal annual payments, which may then be divided by average annual output of the project to develop a figure that expresses the "levelized" avoided cost of the project. This levelized avoided cost may then be compared to the levelized cost of the candidate project to provide an indication of whether or not the project's value exceeds its cost. If multiple technologies are available to meet load, comparisons of each project's levelized avoided cost to its levelized project cost may be used to determine which project provides the best net economic value. Estimating avoided costs is more complex than for simple levelized costs, because they require tools to simulate the operation of the power system with and without any project under consideration. The economic decisions regarding capacity additions in EIA's long-term projections reflect these concepts rather than simple comparisons of levelized project costs across technologies.

Policy-related factors, such as investment or production tax credits for specified generation sources, can also impact investment decisions. Finally, although levelized cost calculations are generally made using an assumed set of capital and operating costs, the inherent uncertainty about future fuel prices and future policies, may cause plant owners or investors who finance plants to place a value on ***portfolio diversification.*** While EIA considers many of these factors in its analysis of technology choice in the electricity sector, these concepts are not well represented in the context of levelized cost figures.

The levelized cost shown for each utility-scale generation technology in the tables in this discussion are calculated based on a 30-year cost recovery period, using a real after tax weighted average cost of capital (WACC) of 6.6 percent. In reality, the cost recovery period and cost of capital can vary by technology and project type. In the AEO2013 reference case a 3-percentage point increase in the cost of capital is added when evaluating investments in greenhouse gas (GHG) intensive technologies like coal-fired power and coal-to-liquids (CTL) plants without carbon control and sequestration (CCS). While the 3-percentage point adjustment is somewhat arbitrary, in levelized cost terms its impact is similar to that of an emissions fee of $15 per metric ton of carbon dioxide (CO_2) when investing in a new coal plant without CCS, similar to the costs used by utilities and regulators in their resource planning. The adjustment should not be seen as an increase in the actual cost of financing, but rather as representing the implicit hurdle being added to GHG-intensive projects to account for the possibility they may eventually have to purchase allowances or invest in other GHG emission-reducing projects that offset their emissions. As a result, the levelized capital costs of coal-fired plants without CCS are higher than would otherwise be expected.

Some technologies, notably solar photovoltaic (PV), are used in both utility-scale plants and distributed end-use residential and commercial applications. As noted above, the levelized cost calculations presented in the tables apply only to utility-scale use of those technologies.

In the tables in this discussion, the levelized cost for each technology is evaluated based on the capacity factor indicated, which generally corresponds to the high end of its likely utilization range. Simple combustion turbines (conventional or advanced technology) that are typically used for peak load duty cycles are evaluated at a 30-percent capacity factor. The duty cycle for intermittent renewable resources, wind and solar, is not operator controlled, but dependent on the weather or solar cycle (that is, sunrise/sunset) and so will not necessarily correspond to operator dispatched duty cycles. As a result, their levelized costs are not directly comparable to those for other technologies (even where the average annual capacity factor may be similar) and therefore are shown in separate sections within each of the tables. The capacity factors shown for solar, wind, and hydroelectric resources in Table 1 are simple averages of the capacity factor for the marginal site in each region. These capacity factors can vary significantly by region and can represent resources that may or may not get built in EIA capacity projections. These capacity factors should not be interpreted as representing EIA's estimate or projection of the gross generating potential of resources actually projected to be built.

As mentioned above, the costs shown in Table 1 are national averages. However, as shown in Table 2, there is significant regional variation in levelized costs based on local labor markets and the cost and availability of fuel or energy resources such as windy sites. For example, levelized wind costs for incremental capacity coming on line in 2018 range from $73.5/MWh in the region with the best available resources in 2018 to $99.8/MWh in regions where levelized costs are highest due to lower quality wind resources and/or higher capital costs at the best sites where additional wind capacity could be added. Costs shown for wind may include additional costs associated with transmission upgrades needed to access remote resources, as well as other factors that markets may or may not internalize into the market price for wind power.

Table 1. Estimated levelized cost of new generation resources, 2018

Plant type	Capacity factor (%)	U.S. average levelized costs (2011 $/megawatthour) for plants entering service in 2018				
		Levelized capital cost	Fixed O&M	Variable O&M (including fuel)	Transmission investment	Total system levelized cost
Dispatchable Technologies						
Conventional Coal	85	65.7	4.1	29.2	1.2	100.1
Advanced Coal	85	84.4	6.8	30.7	1.2	123.0
Advanced Coal with CCS	85	88.4	8.8	37.2	1.2	135.5
Natural Gas-fired						
Conventional Combined Cycle	87	15.8	1.7	48.4	1.2	67.1
Advanced Combined Cycle	87	17.4	2.0	45.0	1.2	65.6
Advanced CC with CCS	87	34.0	4.1	54.1	1.2	93.4
Conventional Combustion Turbine	30	44.2	2.7	80.0	3.4	130.3
Advanced Combustion Turbine	30	30.4	2.6	68.2	3.4	104.6
Advanced Nuclear	90	83.4	11.6	12.3	1.1	108.4
Geothermal	92	76.2	12.0	0.0	1.4	89.6
Biomass	83	53.2	14.3	42.3	1.2	111.0
Non-Dispatchable Technologies						
Wind	34	70.3	13.1	0.0	3.2	86.6
Wind - Offshore	37	193.4	22.4	0.0	5.7	221.5
Solar PV[1]	25	130.4	9.9	0.0	4.0	144.3
Solar Thermal	20	214.2	41.4	0.0	5.9	261.5
Hydro[2]	52	78.1	4.1	6.1	2.0	90.3

[1] Costs are expressed in terms of net AC power available to the grid for the installed capacity.
[2] As modeled, hydro is assumed to have seasonal storage so that it can be dispatched within a season, but overall operation is limited by resources available by site and season.
Note: These results do not include targeted tax credits such as the production or investment tax credit available for some technologies, which could significantly affect the levelized cost estimate. For example, new solar thermal and PV plants are eligible to receive a 30-percent investment tax credit on capital expenditures if placed in service before the end of 2016, and 10 percent thereafter. New wind, geothermal, biomass, hydroelectric, and landfill gas plants are eligible to receive either: (1) a $22 per MWh ($11 per MWh for technologies other than wind, geothermal and closed-loop biomass) inflation-adjusted production tax credit over the plant's first ten years of service or (2) a 30-percent investment tax credit, if placed in service before the end of 2013 (or 2012, for wind only).
Source: U.S. Energy Information Administration, Annual Energy Outlook 2013, December 2012, DOE/EIA-0383(2012)

Table 2. Regional variation in levelized cost of new generation resources, 2018

Plant type	Range for total system levelized costs (2011 \$/megawatthour) for plants entering service in 2018		
	Minimum	Average	Maximum
Dispatchable Technologies			
Conventional Coal	89.5	100.1	118.3
Advanced Coal	112.6	123.0	137.9
Advanced Coal with CCS	123.9	135.5	152.7
Natural Gas-fired			
Conventional Combined Cycle	62.5	67.1	78.2
Advanced Combined Cycle	60.0	65.6	76.1
Advanced CC with CCS	87.4	93.4	107.5
Conventional Combustion Turbine	104.0	130.3	149.8
Advanced Combustion Turbine	90.3	104.6	119.0
Advanced Nuclear	104.4	108.4	115.3
Geothermal	81.4	89.6	100.3
Biomass	98.0	111.0	130.8
Non-Dispatchable Technologies			
Wind	73.5	86.6	99.8
Wind - Offshore	183.0	221.5	294.7
Solar PV[1]	112.5	144.3	224.4
Solar Thermal	190.2	261.5	417.6
Hydro[2]	58.4	90.3	149.2

[1] Costs are expressed in terms of net AC power available to the grid for the installed capacity.
[2] As modeled, hydro is assumed to have seasonal storage so that it can be dispatched within a season, but overall operation is limited by resources available by site and season.
Note: The levelized costs for non-dispatchable technologies are calculated based on the capacity factor for the marginal site modeled in each region, which can vary significantly by region. The capacity factor ranges for these technologies are as follows: Wind – 30% to 39%, Wind Offshore – 33% to 42%, Solar PV- 22% to 32%, Solar Thermal – 11% to 26%, and Hydro – 30% to 65%. The levelized costs are also affected by regional variations in construction labor rates and capital costs as well as resource availability.
Source: U.S. Energy Information Administration, Annual Energy Outlook 2013,December 2012, DOE/EIA-0383(2012)

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

IN RE: PETITION FOR RATE INCREASE BY TAMPA ELECTRIC COMPANY	**)** **)**	**DOCKET NO. 130040-EI**

EXHIBIT___(SJB-3)

OF

STEPHEN J. BARON

ON BEHALF OF THE

WCF HOSPITAL UTILITY ALLIANCE

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

ELECTRIC UTILITY COST ALLOCATION MANUAL

NATIONAL ASSOCIATION OF REGULATORY UTILITY COMMISSIONERS

January, 1992

PREFACE

This project was jointly assigned to the NARUC Staff Subcommittees on Electricity and Economics in February, 1985. Jack Doran, at the California PUC had led a task force in 1969 that wrote the original **Cost Allocation Manual**; the famous "Green Book". I was asked to put together a task force to revise it and include a Marginal Cost section.

I knew little about the subject and was not sure what I was getting into so I asked Jack how he had gone about drafting the first book. "Oh" he said, "There wasn't much to it. We each wrote a chapter and then exchanged them and rewrote them." What Jack did not tell me was that like most NARUC projects, the work was done after five o'clock and on weekends because the regular work always takes precedence. It is a good thing we did not realize how big a task we were tackling or we might never have started.

There was great interest in the project so when I asked for volunteers, I got plenty. We split into two working groups; embedded cost and marginal cost. Joe Jenkins from the Florida PSC headed up the Embedded Cost Working Group and Sarah Voll from the New Hampshire PUC took the Marginal Cost Working Group. We followed Jack's suggestions but, right from the beginning, we realized that once the chapters were technically correct, we would need a single editor to cast them all "into one hand" as Joe Jenkins put it. Steven Mintz from the Department of Energy volunteered for this task and has devoted tremendous effort to polishing the book into the final product you hold in your hands. Victoria Jow at the California PUC took Steven's final draft and desktop published the entire document using Ventura Publisher.

We set the following objectives for the manual:

- It should be simple enough to be used as a primer on the subject for new employees yet offer enough substance for experienced witnesses.
- It must be comprehensive yet fit in one volume.
- The writing style should be non-judgmental; not advocating any one particular method but trying to include all currently used methods with pros and cons.

It is with extreme gratitude that I acknowledge the energy and dedication contributed by the following task force members over the last five years.

Steven Mintz, Department of Energy, Editor; Joe Jenkins, Florida PSC, Leader, Embedded Cost Working Group; Sarah Voll, New Hampshire PUC, Leader, Marginal Cost Working Group; Victoria Jow, California PUC; John A. Anderson, ELCON; Jess Galura, Sacramento MUD; Chris Danforth, California PUC; Alfred Escamilla, Southern California Edison; Byron Harris, West Virginia CAD; Steve Houle, Texas Utility Electric Co.; Kevin Kelly, formally NRRI; Larry Klapow California PUC; Jim Ketter P.E., Missouri PSC; Ed Lucero, Price Waterhouse; J. Robert Malko, Utah State University; George McCluskey, New Hampshire PUC; Marge Meeter, Florida PSC; Gordon Murdock, The FERC; Dennis Nightingale, North Carolina UC; John Orecchio, The FERC; Carl Silsbee, Southern California Edison; Ben Turner, North Carolina UC; Dr. George Parkins, Colorado PUC; Warren Wendling, Colorado PUC; Schef Wright, formally Florida PSC; **IN MEMORIAL** Bob Kennedy Jr., Arkansas PSC.

Julian Ajello
California PUC

CHAPTER 6

CLASSIFICATION AND ALLOCATION OF DISTRIBUTION PLANT

Distribution plant equipment reduces high-voltage energy from the transmission system to lower voltages, delivers it to the customer and monitors the amounts of energy used by the customer.

Distribution facilities provide service at two voltage levels: primary and secondary. Primary voltages exist between the substation power transformer and smaller line transformers at the customer's points of service. These voltages vary from system to system and usually range between 480 volts to 35 KV. In the last few years, advances in equipment and cable technology have permitted the use of higher primary distribution voltages. Primary voltages are reduced to more usable secondary voltages by smaller line transformers installed at customer locations along the primary distribution circuit. However, some large industrial customers may choose to install their own line transformers and take service at primary voltages because of their large electrical requirements.

In some cases, the utility may choose to install a transformer for the exclusive use of a single commercial or industrial customer. On the other hand, in service areas with high customer density, such as housing tracts, a line transformer will be installed to serve many customers. In this case, secondary voltage lines run from pole-to-pole or from handhole-to-handhole, and each customer is served by a drop tapped off the secondary line leading directly to the customer's premise.

I. COST ACCOUNTING FOR DISTRIBUTION PLANT AND EXPENSES

The Federal Energy Regulatory Commission (FERC) Uniform System of Accounts requires separate accounts for distribution investment and expenses. Distribution plant accounts are summarized and classified in Table 6-1. Distribution expense accounts are summarized and classified in Table 6-2. Some utilities may choose to establish subaccounts for more detailed cost reporting.

TABLE 6-1

CLASSIFICATION OF DISTRIBUTION PLANT[1]

FERC Uniform System of Accounts No.	Description	Demand Related	Customer Related
	Distribution Plant [2]		
360	Land & Land Rights	X	X
361	Structures & Improvements	X	X
362	Station Equipment	X	-
363	Storage Battery Equipment	X	-
364	Poles, Towers, & Fixtures	X	X
365	Overhead Conductors & Devices	X	X
366	Underground Conduit	X	X
367	Underground Conductors & Devices	X	X
368	Line Transformers	X	X
369	Services	-	X
370	Meters	-	X
371	Installations on Customer Premises	-	X
372	Leased Property on Customer Premises	-	X
373	Street Lighting & Signal Systems [1]	-	-

[1]Assignment or "exclusive use" costs are assigned directly to the customer class or group which exclusively uses such facilities. The remaining costs are then classified to the respective cost components.

[2]The amounts between classification may vary considerably. A study of the minimum intercept method or other appropriate methods should be made to determine the relationships between the demand and customer components.

TABLE 6-2

CLASSIFICATION OF DISTRIBUTION EXPENSES[1]

FERC Uniform System of Accounts No.	Description	Demand Related	Customer Related
	Operation [2]		
580	Operation Supervision & Engineering	X	X
581	Load Dispatching	X	-
582	Station Expenses	X	-
583	Overhead Line Expenses	X	X
584	Underground Line Expenses	X	X
585	Street Lighting & Signal System Expenses [1]	-	-
586	Meter Expenses	-	X
587	Customer Installation Expenses	-	X
588	Miscellaneous Distribution Expenses	X	X
589	Rents	X	X
	Maintenance [2]		
590	Maintenance Supervision & Engineering	X	X
591	Maintenance of Structures	X	X
592	Maintenance of Station Equipment	X	-
593	Maintenance of Overhead Lines	X	X
594	Maintenance of Underground Lines	X	X
595	Maintenance of Line Transformers	X	X
596	Maint. of Street Lighting & Signal Systems [1]	-	-
597	Maintenance of Meters	-	X
598	Maint. of Miscellaneous Distribution Plants	X	X

[1]Direct assignment or "exclusive use" costs are assigned directly to the customer class or group which exclusively uses such facilities. The remaining costs are then classified to the respective cost components.

[2]The amounts between classifications may vary considerably. A study of the minimum intercept method or other appropriate methods should be made to determine the relationships between the demand and customer components.

To ensure that costs are properly allocated, the analyst must first classify each account as demand-related, customer-related, or a combination of both. The classification depends upon the analyst's evaluation of how the costs in these accounts were incurred. In making this determination, supporting data may be more important than theoretical considerations.

Allocating costs to the appropriate groups in a cost study requires a special analysis of the nature of distribution plant and expenses. This will ensure that costs are assigned to the correct functional groups for classification and allocation. As indicated in Chapter 4, all costs of service can be identified as energy-related, demand-related, or customer-related. Because there is no energy component of distribution-related costs, we need consider only the demand and customer components.

To recognize voltage level and use of facilities in the functionalization of distribution costs, distribution line costs must be s parated into overhead and underground, and primary and secondary voltage classifications. A typical functionalization and classification of distribution plant would appear as follows:

Substations:		Demand
Distribution:	Overhead Primary	
		Demand
		Customer
	Overhead Secondary	
		Demand
		Customer
	Underground Primary	
		Demand
		Customer
	Underground Secondary	
		Demand
		Customer
	Line Transformers	
		Demand
		Customer
Services:	Overhead	
		Demand
		Customer
	Underground	
		Demand
		Customer
Meters:		Customer
Street Lighting:		Customer
Customer Accounting:		Customer
Sales:		Customer

From this breakdown it can be seen that each distribution account must be analyzed before it can be assigned to the appropriate functional category. Also, these accounts must be classified as demand-related, customer-related, or both. Some utilities assign distribution to customer-related expenses. Variations in the demands of various customer groups are used to develop the weighting factors for allocating costs to the appropriate group.

II. DEMAND AND CUSTOMER CLASSIFICATIONS OF DISTRIBUTION PLANT ACCOUNTS

When the utility installs distribution plant to provide service to a customer and to meet the individual customer's peak demand requirements, the utility must classify distribution plant data separately into demand- and customer-related costs.

Classifying distribution plant as a demand cost assigns investment of that plant to a customer or group of customers based upon its contribution to some total peak load. The reason is that costs are incurred to serve area load, rather than a specific number of customers.

Distribution substations costs (which include Accounts 360 -Land and Land Rights, 361 - Structures and Improvements, and 362 -Station Equipment), are normally classified as demand-related. This classification is adopted because substations are normally built to serve a particular load and their size is not affected by the number of customers to be served.

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. As shown in Table 6-1, each primary plant account can be separately classified into a demand and customer component. Two methods are used to determine the demand and customer components of distribution facilities. They are, the minimum-size-of-facilities method, and the minimum-intercept cost (zero-intercept or positive-intercept cost, as applicable) of facilities.

A. The Minimum-Size Method

Classifying distribution plant with the minimum-size method assumes that a minimum size distribution system can be built to serve the minimum loading requirements of the customer. The minimum-size method involves determining the minimum size pole, conductor, cable, transformer, and service that is currently installed by the utility. Normally, the average book cost for each piece of equipment determines the price of all installed units. Once determined for each primary plant account, the minimum size distribution system is classified as customer-related costs. The demand-related costs for each account are the difference between the total investment in the account and customer-related costs. Comparative studies between the minimum-size and other methods show that it generally produces a larger customer component than the zero-intercept method (to be discussed). The following describes the methodologies for determining the minimum size for distribution plant Accounts 364, 365, 366, 367, 368, and 369.

1. Account 364 - Poles, Towers, and Fixtures

- Determine the average installed book cost of the minimum height pole currently being installed.
- Multiply the average book cost by the number of poles to find the customer component. Balance of plant account is the demand component.

2. Account 365 - Overhead Conductors and Devices

- Determine minimum size conductor currently being installed.
- Multiply average installed book cost per mile of minimum size conductor by the number of circuit miles to determine the customer component. Balance of plant account is demand component. (Note: two conductors in minimum system.)

3. Accounts 366 and 367 - Underground Conduits, Conductors, and Devices

- Determine minimum size cable currently being installed.
- Multiply average installed book cost per mile of minimum size cable by the circuit miles to determine the customer component. Balance of plant Account 367 is demand component. (Note: one cable with ground sheath is minimum system.) Account 366 conduit is assigned, basedon ratio of cable account.
- Multiply average installed book cost of minimum size transformer by number of transformers in plant account to determine the customer component. Balance of plant account is demand component.

4. Account 368 - Line Transformers

- Determine minimum size transformer currently being installed.

- Multiply average installed book cost of minimum size transformer by number of transformers in plant account to determine the customer component.

5. Account 369 - Services

- Determine minimum size and average length of services currently being installed.
- Estimate cost of minimum size service and multiply by number of services to get customer component.
- If overhead and underground services are booked separately, they should be handled separately. Most companies do not book service by size. This requires an engineering estimate of the cost of the minimum size, average length service. The resultant estimate is usually higher than the average book cost. In addition, the estimate should be adjusted for the average age of service, using a trend factor.

B. The Minimum-Intercept Method

The minimum-intercept method seeks to identify that portion of plant related to a hypothetical no-load or zero-intercept situation. This requires considerably more data and calculation than the minimum-size method. In most instances, it is more accurate, although the differences may be relatively small. The technique is to relate installed cost to current carrying capacity or demand rating, create a curve for various sizes of the equipment involved, using regression techniques, and extend the curve to a no-load intercept. The cost related to the zero-intercept is the customer component. The following describes the methodologies for determining the minimum intercept for distribution-plant Accounts 364, 365, 366, 367, and 368.

1. Account 364 - Poles, Towers, and Fixtures

- Determine the number, investment, and average installed book cost of distribution poles by height and class of pole. (Exclude stubs for guying.)
- Determine minimum intercept of pole cost by creating a regression equation, relating classes and heights of poles, and using the Class 7 cost intercept for each pole of equal height weighted by the number of poles in each height category.
- Multiply minimum intercept cost by total number of distribution poles to get customer component.

- Balance of pole investment is assigned to demand component.

- Total account dollars are assigned based on ratio of pole investment. (Transformer platforms in Account 364 are all demand-related. They should be removed before determining the account ratio of customer- and demand-related costs, and then they should be added to the demand portion of Account 364.)

2. Account 365 - Overhead Conductors and Devices

- If accounts are divided between primary and secondary voltages, develop a customer component separately for each. The total investment is assigned to primary and secondary; then the customer component is developed for each. Since conductors generally are of many types and sizes, select those sizes and types which represent the bulk of the investment in this account, if appropriate.

- When developing the customer component, consider only the investment in conductors, and not such devices as circuit breakers, insulators, switches, etc. The investment in these devices will be assigned later between the customer and demand component, based on the conductor assignment.

  - Determine the feet, investment, and average installed book cost per foot for distribution conductors by size and type.

  - Determine minimum intercept of conductor cost per foot using cost per foot by size and type of conductor weighted by feet or investment in each category, and developing a cost for the utility's minimum size conductor.

  - Multiply minimum intercept cost by the total number of circuit feet times 2. (Note that circuit feet, not conductor feet, are used to get customer component.)

  - Balance of conductor investment is assigned to demand.

  - Total primary or secondary dollars in the account, including devices, are assigned to customer and demand components based on conductor investment ratio.

3. Accounts 366 and 367 - Underground Conduits, Conductors, and Devices

- The customer demand component ratio is developed for conductors and applied to conduits. Underground conductors are generally booked by type and size of conductor for both one-conductor (1/c) cable and three-conductor (3/c) cables. If conductors are booked by voltage, as between primary and secondary, a customer component is developed for each. If network and URD investments are segregated, a customer component must be developed for each.

- The conductor sizes and types for the customer component derivation are restricted to l/c cable. Since there are generally many types and sizes of l/c cable, select those sizes and types which represent the bulk of the investment, when appropriate.

  - Determine the feet, investment, and average installed book cost per foot for l/c cables by size and type of cable.

  - Determine minimum intercept of cable cost per foot using cost per foot by size and type of cable weighted by feet of investment in each category.

  - Multiply minimum intercept cost by the total number of circuit feet (l/c cable with sheath is considered a circuit) to get customer component.

  - Balance of cable investment is assigned to demand.

  - Total dollars in Accounts 366 and 367 are assigned to customer and demand components based on conductor investment ratio.

4. Account 368 - Line Transformers

- The line transformer account covers all sizes and voltages for single- and three-phase transformers. Only single-phase sizes up to and including 50 KVA should be used in developing the customer components. Where more than one primary distribution voltage is used, it may be appropriate to use the transformer price from one or two predominant, selected voltages.

  - Determine the number, investment, and average installed book cost per transformer by size and type (voltage).

  - Determine zero intercept of transformer cost using cost per transformer by type, weighted by number for each category.

  - Multiply zero intercept cost by total number of line transformers to get customer component.

  - Balance of transformer investment is assigned to demand component.

  - Total dollars in the account are assigned to customer and demand components based on transformer investment ratio from customer and demand components.

C. The Minimum-System vs. Minimum-Intercept Approach

When selecting a method to classify distribution costs into demand and customer costs, the analyst must consider several factors. The minimum-intercept method can sometimes produce statistically unreliable results. The extension of the regression equation beyond the boundaries of the data normally will intercept the Y axis at a positive value. In some cases, because of incorrect accounting data or some other abnormality in the data, the regression equation will intercept the Y axis at a negative value. When this happens, a review of the accounting data must be made, and suspect data deleted.

The results of the minimum-size method can be influenced by several factors. The analyst must determine the minimum size for each piece of equipment: "Should the minimum size be based upon the minimum size equipment currently installed, historically installed, or the minimum size necessary to meet safety requirements?" The manner in which the minimum size equipment is selected will directly affect the percentage of costs that are classified as demand and customer costs.

Cost analysts disagree on how much of the demand costs should be allocated to customers when the minimum-size distribution method is used to classify distribution plant. When using this distribution method, the analyst must be aware that the minimum-size distribution equipment has a certain load-carrying capability, which can be viewed as a demand-related cost.

When allocating distribution costs determined by the minimum-size method, some cost analysts will argue that some customer classes can receive a disproportionate share of demand costs. Their rationale is that customers are allocated a share of distribution costs classified as demand-related. Then those customers receive a second layer of demand costs that have been mislabeled customer costs because the minimum-size method was used to classify those costs.

Advocates of the minimum-intercept method contend that this problem does not exist when using their method. The reason is that the customer cost derived from the minimum-intercept method is based upon the zero-load intercept of the cost curve. Thus, the customer cost of a particular piece of equipment has no demand cost in it whatsoever.

D. Other Accounts

The preceding discussion of the merits of minimum-system versus the zero-intercept classification schemes will affect the major distribution-plant accounts for FERC Accounts 364 through 368. Several other plant accounts remain to be classified. While the classification of the following distribution-plant accounts is an important step, it is not as controversial as the classification of substations, poles, transformers, and conductors.

1. Account 369 - Services

This account is generally classified as customer-related. Classification of services may also include a demand component to reflect the fact that larger customers will require more costly service drops.

2. Account 370 - Meters

Meters are generally classified on a customer basis. However, they may also be classified using a demand component to show that larger-usage customers require more expensive metering equipment.

3. Account 371 - Installations on Customer Premises

This account is generally classified as customer-related and is often directly assigned. The kind of equipment in this account often influences how this account is treated. The equipment in this account is owned by the utility, but is located on the customer's side of the meter. A utility will often include area lighting equipment in this account and assign the investment directly to the lighting customer class.

4. Account 373 - Street Lighting and Signal Systems

This account is generally customer-related and is directly assigned to the street customer class.

III. ALLOCATION OF THE DEMAND AND CUSTOMER COMPONENTS OF DISTRIBUTION PLANT

After completing the classification of distribution plant accounts, the next major step in the cost of service process is to allocate the classified costs. Generally, determining the distribution-demand allocator will require more data and analysis than determining the customer allocators. Following are procedures used to calculate the demand and customer allocation factors.

A. Development of the Distribution Demand Allocators

There are several factors to consider when allocating the demand components of distribution plant. Distribution facilities, from a design and operational perspective, are installed primarily to meet localized area loads. Distribution substations are designed to meet the maximum load from the distribution feeders emanating from the substation.

Similarly, when designing primary and secondary distribution feeders, the distribution engineer ensures that sufficient conductor and transformer capacity is available to meet the customer's loads at the primary- and secondary-distribution service levels. Local area loads are the major factors in sizing distribution equipment. Consequently, customer-class noncoincident demands (NCPs) and individual customer maximum demands are the load characteristics that are normally used to allocate the demand component of distribution facilities. The customer-class load characteristic used to allocate the demand component of distribution plant (whether customer class NCPs or the summation of individual customer maximum demands) depends on the load diversity that is present at the equipment to be allocated. The load diversity at distribution substations and primary feeders is usually high. For this reason, customer-class peaks are normally used for the allocation of these facilities. The facilities nearer the customer, such as secondary feeders and line transformers, have much lower load diversity. They are normally allocated according to the individual customer's maximum demands. Although these are the methods normally used for the allocation of distribution demand costs, some exceptions exist.

The load diversity differences for some utilities at the transmission and distribution substation levels may not be large. Consequently, some large distribution substations may be allocated using the same method as the transmission system. Before the cost analyst selects a method to allocate the different levels of distribution facilities, he must know the design and operational characteristics of the distribution system, as well as the demand losses at each level of the distribution system.

As previously indicated, the distribution system consists of several levels. The first level starts at the distribution substation, and the last level ends at the customer's meters. Power losses occur at each level and should be included in the demand allocators. Power losses are incorporated into the demand allocators by showing different demand loss factors at each predominant voltage level. The demand loss factor used to develop the primary-distribution demand allocator will be slightly larger than the demand loss factor used to develop the secondary demand allocator. When developing the distribution demand allocator, be aware that some customers take service at different voltage levels.

Cost analysts developing the allocator for distribution of substations or primary demand facilities must ensure that only the loads of those customers who benefit from these facilities are included in the allocator. For example, the loads of customers who take service at transmission level should not be reflected in the distribution substation or primary demand allocator. Similarly, when analysts develop the allocator for secondary demand facilities, the loads for customers served by the primary distribution system should not be included.

Utilities can gather load data to develop demand allocators, either through their load research program or their transformer load management program. In most cases, the load research program gathers data from meters on the customers' premises. A more complex procedure is to use the transformer load management program.

This procedure involves simulating load profiles for the various classes of equipment on the distribution system. This provides information on the nature of the load diversity between the customer and the substation, and its effect on equipment cost. Determining demand allocators through simulation provides a first-order load approximation, which represents the peak load for each type of distribution equipment.

The concept of peak load or "equipment peak" for each piece of distribution equipment can be understood by considering line transformers. If a given transformer's loading for each hour of a month can be calculated, a transformer load curve can be developed. By knowing the types of customers connected to each load management transformer, a simulated transformer load profile curve can be developed for the system. This can provide each customer's class demand at the time of the transformer's peak load. Similarly, an equipment peak can be defined for equipment at each level of the distribution system. Although the equipment peak obtained by this method may not be ideal, it will closely approximate the actual peak. Thus, this method should reflect the different load diversities among customers at each level of the distribution system. An illustration of the simulation procedure is provided in Appendix 6-A.

B. Allocation of Customer-Related Costs

When the demand-customer classification has been completed, most of the assumptions will have been made that affect the results of the completed cost of service study.

The allocation of the customer-related portion of the various plant accounts is based on the number of customers by classes of service, with appropriate weightings and adjustments. Weighting factors reflect differences in characteristics of customers within a given class, or between classes. Within a class, for instance, we may want to give more weighting of a certain plant account to rural customers, as compared to urban customers. The metering account is a clear example of an account requiring weighting for differences between classes. A metering arrangement for a single industrial customer may be 20 to 80 times as costly as the metering for one residential customer.

While customer allocation factors should be weighted to offset differences among various types of customers, highly refined weighting factors or detailed and time consuming studies may not seem worthwhile. Such factors applied in this final step of the cost study may affect the final results much less than such basic assumptions as the demand-allocation method or the technique for determining demand-customer classifications.

Expense allocations generally are based on the comparable plant allocator of the various classes. For instance, maintenance of overhead lines is generally assumed to be directly related to plant in overhead conductors and devices. Exceptions to this rule will occur in some accounts. Meter expenses, for example, are often a function of maintenance and testing schedules related more to revenue per customer than to the cost of the meters themselves.

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

IN RE: PETITION FOR RATE INCREASE BY TAMPA ELECTRIC COMPANY	))	DOCKET NO. 130040-EI

EXHIBIT___(SJB-4)

OF

STEPHEN J. BARON

ON BEHALF OF THE

WCF HOSPITAL UTILITY ALLIANCE

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

PRESENT RATE STRUCTURE
PROD. CAP. ALLOC. METHOD: 12CP & 1/13th AD
PROJECTED CALENDAR YEAR 2014; FULLY ADJUSTED DATA
MINIMUM DISTRIBUTION SYSTEM (MDS) EMPLOYED

TAMPA ELECTRIC COMPANY
ALLOCATED CLASS COST OF SERVICE & ROR STUDY
(000's)

SUMMARY - CLASS ROR'S & REVENUE REQUIREMENTS -ROR

LINE NO.		FPSC JURIS	RS	GS	GSD	IS	LS ENERGY	LS FACILITIES	ALLOC FACTOR
1	OPERATING REVENUES								
2	Sales Revenue	907,769	489,649	57,954	290,676	28,538	5,467	35,484	
3	Other Revenues	42,895	30,466	3,310	8,165	516	358	80	
4									
5	TOTAL OPERATING REVENUES	950,664	520,115	61,264	298,841	29,054	5,825	35,564	
6									
7									
8	OPERATING EXPENSES								
9	Power Transactions	9,301	4,350	521	3,893	426	112	-	
10	O&M Expense	354,533	210,165	24,525	101,391	8,330	2,379	7,744	
11	Deprec & Amortiz Expense	233,881	133,949	14,865	67,914	4,646	1,092	11,413	
12	Taxes Other than Income	65,769	38,105	4,169	19,678	1,380	337	2,100	
13	Income Taxes	77,391	32,570	4,548	30,274	4,773	575	4,650	
14	Gain/(Loss) on Disposal	(132)	(75)	(8)	(40)	(3)	(1)	(4)	
15									
16	TOTAL OPERATING EXPENSES	740,763	419,063	48,639	223,110	19,552	4,495	25,903	
17									
18									
19	NET OPERATING INCOME	209,901	101,052	12,625	75,731	9,502	1,330	9,661	
20									
21									
22	RATE BASE								
23	Plant in Service	6,506,194	3,724,688	407,918	1,992,891	135,715	31,587	213,396	
24	Plant Held for Future Use	35,409	19,858	2,128	12,517	784	122	-	
25	Working Capital	61,119	24,389	3,147	30,050	3,769	1,015	(1,251)	
26	Construction Work In Progress	174,146	95,030	10,557	62,639	4,910	476	334	
27	Less: Depreciation Reserve	2,438,894	1,397,968	153,242	718,835	49,666	12,488	104,696	
28									
29	TOTAL RATE BASE	4,339,974	2,465,997	270,507	1,379,462	95,512	20,712	107,783	
30									
31									
32									
33	RATE OF RETURN (%)	4.84	4.10	4.67	5.49	9.95	6.42	8.96	
34									
35	RATE OF RETURN INDEX	1.00	0.85	0.97	1.14	2.06	1.33	1.85	

PRESENT RATE STRUCTURE
PROD. CAP. ALLOC. METHOD: 12CP & 1/13th AD
PROJECTED CALENDAR YEAR 2014; FULLY ADJUSTED DATA
MINIMUM DISTRIBUTION SYSTEM (MDS) EMPLOYED

TAMPA ELECTRIC COMPANY
ALLOCATED CLASS COST OF SERVICE & ROR STUDY
(000's)

SUMMARY - CLASS ROR'S & REVENUE REQUIREMENTS - ROR

LINE NO.		FPSC JURIS	RS	GS	GSD	IS	LS ENERGY	LS FACILITIES	ALLOC FACTOR
	Less:								
	Long Term Debt	1.90%	1.90%	1.90%	1.90%	1.90%	1.90%	1.90%	
	Short Term Debt	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	
	Deferred Revenue	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
	Customer Deposits	0.06%	0.06%	0.06%	0.06%	0.06%	0.06%	0.06%	
	Preferred Stock	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
	Tax Credits	0.02%	0.02%	0.02%	0.02%	0.02%	0.02%	0.02%	
	Subtotal	1.99%	1.99%	1.99%	1.99%	1.99%	1.99%	1.99%	
	Wtd Return on Equity	2.85%	2.11%	2.68%	3.50%	7.96%	4.43%	6.97%	
	Equity Ratio	42.23%	42.23%	42.23%	42.23%	42.23%	42.23%	42.23%	
	RETURN ON EQUITY	6.74%	4.99%	6.34%	8.29%	18.85%	10.49%	16.51%	
36	DEVELOPMENT OF REVENUE REQUIREMENTS								
37	Total Rate Base	4,339,974	2,465,997	270,507	1,379,462	95,512	20,712	107,783	
38	Total Cost of Capital	6.74%	6.74%	6.74%	6.74%	6.74%	6.74%	6.74%	
39	(@ 11.25% ROE)								
40	Total Required Net Operating Income	292,514	166,208	18,232	92,976	6,438	1,396	7,265	
41									
42	Less: Achieved Net Operating Income	209,901	101,052	12,625	75,731	9,502	1,330	9,661	
43									
44	Equals: Return Deficiency/(Surplus)	82,613	65,156	5,607	17,244	(3,064)	66	(2,396)	
45	Times: Expansion Factor	1.6322	1.6322	1.6322	1.6322	1.6322	1.6322	1.6322	
46									
47	Equals: Revenue Deficiency/ (Surplus)	134,841	106,348	9,151	28,146	(5,002)	108	(3,911)	
48									
49	Plus: Revenues @ Present Rates	950,664	520,115	61,264	296,841	29,054	5,825	35,564	
50									
51	Equals: Total Revenue Requirements	1,085,505	626,463	70,416	326,987	24,052	5,933	31,653	
52	Less: Other Revenues	(42,895)	(30,466)	(3,310)	(8,165)	(516)	(358)	(80)	
53									
54	Equals: Total Sales Revenue Requirements	1,042,610	595,997	67,105	318,822	23,536	5,575	31,573	
55									
56	Sales Revenue Requirements Index	0.87	0.82	0.86	0.91	1.21	0.98	1.12	

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

IN RE: PETITION FOR RATE INCREASE BY TAMPA ELECTRIC COMPANY	))	DOCKET NO. 130040-EI

EXHIBIT___(SJB-5)

OF

STEPHEN J. BARON

ON BEHALF OF THE

WCF HOSPITAL UTILITY ALLIANCE

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

**TAMPA ELECTRIC COMPANY
DOCKET NO. 130040-EI
HUA'S FIRST SET OF
INTERROGATORIES
INTERROGATORY NO. 90
PAGE 1 OF 1
FILED: JULY 5, 2013**

90. Regarding Ashburn at 30:25-32:3. Please provide a detailed explanation of your reasons for proposing the use of the MDS costing methodology only if the commission adopts the 12 CP and 50% AD methodology for allocating the cost of production plant. Your answer should explain why you believe it is appropriate to use the MDS costing methodology in connection with the 12 CP and 50% AD methodology for allocating the costs of production plant but not using the MDS cost of methodology if the Commission requires the use of the 12 CP and 1/13th AD methodology for allocating the cost of production plants.

A. Witness Ashburn did not intend for the referenced testimony to be interpreted as saying that the MDS costing methodology is to be employed only if the Commission adopts the 12 CP and 50% AD methodology for allocating the cost of production plant. Witness Ashburn recognizes that MDS relates to the allocation of distribution costs and the 12 CP and 50% AD methodology relates to the allocation of production capacity costs.

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

IN RE:	**PETITION FOR RATE INCREASE BY TAMPA ELECTRIC COMPANY**	**))**	**DOCKET NO. 130040-EI**

EXHIBIT___(SJB-6)

OF

STEPHEN J. BARON

ON BEHALF OF THE

WCF HOSPITAL UTILITY ALLIANCE

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

TAMPA ELECTRIC COMPANY
HUA DEVELOPMENT OF PROPOSED (TARGET) BASE REVENUE INCREASE BY RATE CLASS
TEST PERIOD: PROJECTED CALENDAR YEAR 2014
COST OF SERVICE: 12 CP & 1/13th AD; MINIMUM DISTRIBUTION SYSTEM (MDS)
($000)

			(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(L)
							Net Base Rev. Deficiency			HUA Proposed Base Revenue Increase					
Line		Rate Class	Cost of Service	Present Base Revenue	Base Revenue Deficiency	Proposed Additional Revenue Credits	$	%	Increase @ TECO $134 million $	Increase $	Present Base Rev.	Total Revenue Incl..clauses	Proposed Base Revenue	Unbilled Revenue Change	Target Proposed Billed Base Revenue
					(A) - (B)		(C) - (D)	(E) / (B)			(H) / (B)	(H)/Tot.Rev.	(B) + (G)		(J) - (K)
1	I.	Residential (RS,RSVP)	$ 595,997	$ 489,649	$ 106,348	$ 1,049	$ 105,299	21.50%							
2															
3	II.	General Service													
4		Non-Demand (GS,TS)	67,105	57,954	9,151	$ 115	$ 9,035	15.59%							
5															
6															
7		Sub-Total: I. + II.	$ 663,102	$ 547,604	$ 115,498	$ 1,164	$ 114,334	20.88%	$ 111,083	$ 24,480	4.47%	2.45%	$ 572,084	$ (13)	$ 572,097
8															
9															
10	III.	General Service													
11		Demand (GSD, SBF)	318,822	290,676	28,146										
12															
13	IV.	Interruptible Service (IS)	23,536	28,538	(5,002)										
14															
15															
16		Sub-Total: III. + IV.	342,358	319,213	23,145	23	$ 23,121	7.24%	$ 22,464	$ 4,951	1.55%	0.69%	$ 324,164	$ (9)	$ 324,173
17															
18															
19	V.	Lighting (LS-1)													
20		A. - Energy	5,575	5,467	108	$ 6	$ 101	1.86%	$ 99	$ 22	0.40%	0.14%	$ 5,489	$ -	$ 5,489
21		B. - Facilities	31,573	35,484	(3,911)	$ -	$ (3,911)	-11.02%	0	0	0%	0%	$ 35,484	$ -	$ 35,484
22															
23															
24		Total	$ 1,042,608	$ 907,769	$ 134,839	$ 1,194	$ 133,645	14.72%	$ 133,645	$ 29,452	3.24%	1.66%	$ 937,221	$ (22)	$ 937,243

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

IN RE:	**PETITION FOR RATE INCREASE BY TAMPA ELECTRIC COMPANY**	**))**	**DOCKET NO. 130040-EI**

EXHIBIT___(SJB-7)

OF

STEPHEN J. BARON

ON BEHALF OF THE

WCF HOSPITAL UTILITY ALLIANCE

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

HUA Proposed GSD Rate Design

				HUA PROPOSED			TECO PROPOSED
	UNITS	PRESENT RATES	PRESENT REVENUES	PROPOSED RATES	PROPOSED REVENUES	% Change	% Change
GSD SECONDARY							
Basic Service Charge	133,380	57.00	7,602,660	30.00	4,001,400	-47.4%	-47.4%
Energy Charge	4,227,035	15.83	66,913,964	15.15	64,039,580	-4.3%	15.5%
Demand Charge	11,304,861	8.41	95,073,881	10.80	122,092,499	28.4%	13.0%
Delivery Voltage Credit	-	-	-	-	-		
Emergency Relay Charge	394,900	0.60	236,940	0.66	260,634	10.0%	10.0%
Power Factor Charge	13,652	2.00	27,304	2.00	27,304	0.0%	0.0%
Power Factor Credit	26,197	(1.00)	(26,197)	(1.00)	(26,197)	0.0%	0.0%
Metering Voltage Credit	-	-	-	-	-		
Total Base Revenue			169,828,552		190,395,220	12.1%	11.3%
GSD PRIMARY							
Basic Service Charge	698	130.00	90,740	130.00	90,740	0.0%	0.0%
Energy Charge	269,403	15.83	4,264,649	15.15	4,081,455	-4.3%	15.5%
Demand Charge	664,406	8.41	5,587,654	10.80	7,175,585	28.4%	13.0%
Delivery Voltage Credit	616,657	(0.73)	(450,160)	(0.80)	(492,279)	9.4%	9.4%
Emergency Relay Charge	183,567	0.60	110,140	0.66	121,154	10.0%	10.0%
Power Factor Charge	6,392	2.00	12,784	2.00	12,784	0.0%	0.0%
Power Factor Credit	13,756	(1.00)	(13,756)	(1.00)	(13,756)	0.0%	0.0%
Metering Voltage Credit		-1%	(95,113)	-1%	(108,849)	14.4%	14.3%
Total Base Revenue			9,506,939		10,866,834	14.3%	14.1%
GSDT SECONDARY							
Basic Service Charge	10,897	57.00	621,129	30.00	326,910	-47.4%	-47.4%
Energy Charge - On-Pk	484,173	28.98	14,031,334	29.01	14,045,859	0.1%	38.0%
Energy Charge - Off-Pk	1,349,819	10.46	14,119,107	9.60	12,958,262	-8.2%	-8.2%
Demand Charge - Billing	3,520,497	2.84	9,998,211	3.23	11,371,205	13.7%	13.7%
Demand Charge - Peak	3,395,235	5.57	18,911,459	7.57	25,701,929	35.9%	12.6%
Delivery Voltage Credit	-	-	-	-	-		
Emergency Relay Charge	665,384	0.60	399,230	0.66	439,153	10.0%	10.0%
Power Factor Charge	23,014	2.00	46,028	2.00	46,028	0.0%	0.0%
Power Factor Credit	78,197	(1.00)	(78,197)	(1.00)	(78,197)	0.0%	0.0%
Metering Voltage Credit		0%	-	0%	-		
Total Base Revenue			58,048,301		64,811,150	11.7%	13.2%
GSDT PRIMARY							
Basic Service Charge	651	130.00	84,630	130.00	84,630	0.0%	0.0%
Energy Charge - On-Pk	233,926	28.98	6,779,175	29.01	6,786,193	0.1%	38.0%
Energy Charge - Off-Pk	638,923	10.46	6,683,135	9.60	6,133,661	-8.2%	-8.2%
Demand Charge - Billing	1,635,266	2.84	4,644,155	3.23	5,281,909	13.7%	13.7%
Demand Charge - Peak	1,585,799	5.57	8,832,900	7.57	12,004,498	35.9%	12.6%
Delivery Voltage Credit	1,374,995	(0.73)	(1,003,746)	(0.80)	(1,097,662)	9.4%	9.4%
Emergency Relay Charge	751,104	0.60	450,662	0.66	495,729	10.0%	10.0%
Power Factor Charge	17,812	2.00	35,624	2.00	35,624	0.0%	0.0%
Power Factor Credit	41,203	(1.00)	(41,203)	(1.00)	(41,203)	0.0%	0.0%
Metering Voltage Credit		-1%	(263,807)	-1%	(295,987)	12.2%	14.1%
Total Base Revenue			26,201,526		29,387,391	12.2%	14.1%
GSDT SUBTRANSMISSION							
Basic Service Charge	25	930.00	23,250	990.00	24,750	6.5%	6.5%
Energy Charge - On-Pk	298	28.98	8,636	29.01	8,645	0.1%	38.0%
Energy Charge - Off-Pk	902	10.46	9,435	9.60	8,659	-8.2%	-8.2%
Demand Charge - Billing	1,183	2.84	3,360	3.23	3,821	13.7%	13.7%
Demand Charge - Peak	1,080	5.57	6,016	7.57	8,176	35.9%	12.6%
Delivery Voltage Credit	7,640	(1.16)	(8,862)	(2.50)	(19,103)	115.6%	115.6%
Emergency Relay Charge	-	0.60	-	0.66	-		
Power Factor Charge	686	2.00	1,372	2.00	1,372	0.0%	0.0%
Power Factor Credit	-	(1.00)	-	(1.00)	-		
Metering Voltage Credit		-2%	(399)	-2%	(231)	-42.0%	-32.7%
Total Base Revenue			42,807		36,088	-15.7%	-11.4%
Total GSD/GSDT Base Revenue			263,628,125		295,496,684	12.1%	12.1%

ORIGINAL

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

IN RE: PETITION FOR RATE INCREASE BY TAMPA ELECTRIC COMPANY	))	DOCKET NO. 130040-EI

DIRECT TESTIMONY

AND EXHIBITS

OF

RICHARD A. BAUDINO

ON BEHALF OF THE

WCF HOSPITAL UTILITY ALLIANCE

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

July 15, 2013

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GLOSSARY OF TERMS

CAPM	Capital Asset Pricing Model
CBOE	Chicago Board of Options Exchange
Commission	Florida Public Service Commission
Company	Tampa Electric Company
DCF	Discounted cash flow
FOMC	Federal Open Market Committee
HUA	WCF Hospital Utility Alliance
Kennedy and Associates	J. Kennedy and Associates, Inc.
Moody’s	Moody's Investor’s Services
RRA	Regulatory Research Associates
ROE	Return on equity
S&P	Standard and Poor’s
Tampa Electric	Tampa Electric Company
TECO Energy, Inc.	TECO Energy

I. QUALIFICATIONS AND SUMMARY

Q. Please state your name and business address.

A. My name is Richard A. Baudino. My business address is J. Kennedy and Associates, Inc. ("Kennedy and Associates"), 570 Colonial Park Drive, Suite 305, Roswell, Georgia 30075.

Q. What is your occupation and by whom are you employed?

A. I am a consultant with Kennedy and Associates.

Q. Please describe your education and professional experience.

A. I received my Master of Arts degree with a major in Economics and a minor in Statistics from New Mexico State University in 1982. I also received my Bachelor of Arts Degree with majors in Economics and English from New Mexico State in 1979.

I began my professional career with the New Mexico Public Service Commission Staff in October 1982 and was employed there as a Utility Economist. During my employment with the Staff, my responsibilities included the analysis of a broad range of issues in the ratemaking field. Areas in which I testified included cost of service, rate of return, rate design, revenue requirements, analysis of sale/leasebacks of generating plants, utility finance issues, and generating plant phase-ins.

In October 1989, I joined the utility consulting firm of Kennedy and Associates as a Senior Consultant where my duties and responsibilities covered substantially the same areas as those during my tenure with the New Mexico Public Service Commission Staff. I became Manager in July 1992 and was named Director of Consulting in January 1995. Currently, I am a consultant with Kennedy and Associates.

Exhibit No. ____(RAB-1) summarizes my expert testimony experience.

Q. On whose behalf are you testifying?

A. I am testifying on behalf of the WCF Hospital Utility Alliance ("HUA").

Q. What is the purpose of your Direct Testimony?

A. The purpose of my direct testimony is to address the allowed return on equity and capital structure for ratemaking purposes for Tampa Electric Company ("Tampa Electric" or "Company").

Q. Please summarize your Direct Testimony.

A. I recommend that the Florida Public Service Commission ("Commission") approve a rate of return on equity ("ROE") for Tampa Electric of 9.30%. This recommendation is based on the results from my Discounted Cash Flow ("DCF") analyses for a comparison group of electric companies that has similar bond ratings to Tampa Electric. I also employed the Capital Asset Pricing Model ("CAPM"), but did not directly incorporate the results into my recommendation. In my opinion, a return on equity of 9.30% is a reasonable, even generous, estimate of the required return on equity for an electric company such as Tampa Electric. As I will demonstrate in the following sections of my testimony, the market evidence I have examined supports my ROE recommendation.

I also recommend that the Commission reject the return on equity recommendation of 11.25% of Mr. Robert Hevert, witness for Tampa Electric. As I will demonstrate in Section IV of my Direct Testimony, Mr. Hevert's analyses systematically overstate the current investor required ROE for Tampa Electric.

Q. What exhibits are you sponsoring as a part of your Direct Testimony?

A. I am sponsoring the following exhibits as a part of my Direct Testimony:

Exhibit No. ___(RAB-1) - Resume and Testimony Experience of Richard A Baudino

Exhibit No. ___(RAB-2) - Historical Bond Yields

Exhibit No. ___(RAB-3) - FOMC June 19, 2013 Press Release

Exhibit No. ___(RAB-4) - Historical Daily VIX Values

Exhibit No. ___(RAB-5) - Excerpts from TECO Energy Dec. 31, 2012 SEC 10-K

Exhibit No. ___(RAB-6) - Excerpts from TECO Energy Investor Presentations

Exhibit No. ___(RAB-7) - Tampa Electric Discovery Responses

Exhibit No. ___(RAB-8) - Comparison Group Dividend Yield Calculations

Exhibit No. ___(RAB-9) - Comparison Group Growth and DCF ROE Calculation

Exhibit No. ___(RAB-10) - CAPM ROE Analysis - Comparison Group

Exhibit No. ___(RAB-11) - CAPM Analysis - Historic Market Premium

II. REVIEW OF ECONOMIC AND FINANCIAL CONDITIONS

Q. Mr. Baudino, what has the trend been in long-term capital costs over the last few years?

A. Exhibit No. ___(RAB-2) presents a graphic depiction of the trend in interest rates from January 2002 through May 2013. The interest rates shown in this exhibit are for the 20-year U.S. Treasury Bond and the average public utility bond from the Mergent Bond Record. Exhibit No. ___(RAB-2) shows that the yields on long-term Treasury and utility bonds have declined substantially since early 2002. For example, the average public utility bond yield in January 2002 was 7.69% and the 20-year Treasury Bond yield was 5.69%. As of May 2013 the average public utility bond yield was 4.24% and represents a decline of 345 basis points, or 3.45% from January 2002. Likewise, the 20-year Treasury bond declined to 2.73% in May 2013, a decline of 2.96% from January 2002. Interest rates during 2013 have been at historically low levels.

In 2008, world financial markets experienced tumultuous changes and volatility not seen since the Great Depression. As noted in the SBBI 2009 Yearbook, both large and small company stocks declined around 37% for the year.[1] Investors, in a flight to quality and safety, also pulled their funds out of those corporate bonds that were perceived to be higher risk and invested in the safety of Treasury securities. The 2009 SBBI Yearbook reported that long-term Treasury Bonds returned 25.87% during 2008, while long-term corporate bonds returned 8.78%. Thus, bonds significantly outperformed stocks in 2008. The stocks of electric utilities did not fare well during the financial market upheaval of 2008. The Dow Jones Utility Average

1 *2009 Ibbotson SBBI Classic Yearbook*, Morningstar, page 11.

was down from its opening level in January 2008 of 532.50 to 370.76 at the end of December, a decline of 30.4%. This decline was smaller than the decline in the overall stock market. Utility bond yields also increased significantly during the year, rising from 6.08% in January to a high of 7.80% in November. As investors flocked to the safety of Treasury securities, the yield spread between long-term Treasury securities and the index of public utility bonds widened from 1.73% in January to 3.69% in December, the highest spread during the entire period shown in Exhibit No. ___(RAB-2).

In 2009 and continuing through 2012, utility bond yields fell significantly from November 2008 levels, as did the spread between public utility bond yields and long-term Treasuries. The average utility bond yield in December 2012 was 4.1%, a decline of 370 basis points, or 3.70%, from November 2008. At the end of December 2012 the yield spread between utility bonds and the long-term Treasury bond declined to 1.63%. This is much closer to the historical spread.

On June 19, 2013, the Federal Reserve issued a Federal Open Market Committee ("FOMC") press release indicating that it intended to extend what has been termed "Operation Twist." This refers to the Federal Reserve maturity extension program whereby the Federal Reserve redeems or sells shorter-term treasury securities and uses the proceeds to buy longer-term securities. In its press release, the Federal Reserve stated:

> To support a stronger economic recovery and to help ensure that inflation, over time, is at the rate most consistent with its

> dual mandate, the Committee decided to continue purchasing additional agency mortgage-backed securities at a pace of $40 billion per month and longer-term Treasury securities at a pace of $45 billion per month. The Committee is maintaining its existing policy of reinvesting principal payments from its holdings of agency debt and agency mortgage-backed securities in agency mortgage-backed securities and of rolling over maturing Treasury securities at auction. Taken together, these actions should maintain downward pressure on longer-term interest rates, support mortgage markets, and help to make broader financial conditions more accommodative. [Exhibit No. ____(RAB-3) at p. 1].

By reducing the supply of longer-term Treasury securities, the prices of these securities will rise, putting downward pressure on long-term interest rates.

Q. Please compare current financial market conditions with the conditions that were present in Tampa Electric's last rate case, Docket No. 080317-EI.

A. Tampa Electric's last rate case began in August 2008 and the Commission issued its Final Order on April 30, 2009. As I stated earlier, the latter part of 2008 was marked by a severe financial crisis. In 2009 the financial markets began to slowly recover from the tumultuous volatility and substantial losses sustained in 2008 and the country had fallen into a deep recession. The yield on the average public utility bond was 6.48% in August 2008 and by the time the Commission issued its Final Order, that bond yield had risen to 6.9%. The Commission noted on page 47 of its Order that the witnesses in the case recognized that the economy was not in a "normal or stable state."[2] The Commission authorized an ROE of 11.25% with a range of plus

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2 Order No. PSC-09-0283-FOF-EI, *In re: Petition for rate increase by Tampa Electric Co.*, Docket No. 080317-EI, at p. 47 (issued Apr. 30, 2009).

or minus 100 basis points.

Since 2009, financial markets have recovered from the tumult of 2008 and interest rates are near historic lows. The Dow Jones Utility Average, which closed at 334.20 in April 2009, closed at 482.16 as of May 30, 2013, a rise of approximately 44%.

In addition the Chicago Board of Options Exchange ("CBOE") VIX index, a well-known measure of stock market volatility has declined significantly since 2009. At the end of April 2009 the VIX stood at 36.5. At the end of June 2013, the VIX stood at 16.86, indicating far less stock market volatility at the time of this proceeding vis-à-vis Tampa Electric's last rate case. Exhibit No. ____(RAB-4)

Q. What does this suggest for the return on equity in this proceeding?

A. It suggests that the ROE in this case should be considerably lower than in Tampa Electric's last rate case. My ROE analysis in the next section of my testimony supports this conclusion.

Q. How does the investment community regard the electric utility industry as a whole?

A. The June 21, 2013 Value Line report on the Electric Utility (Central) group of companies noted the following regarding the effect of the current low interest rate environment on electric utilities:

> Since mid-May, the prices of most electric utility stocks have declined, while the Value Line Composite Average is almost unchanged. Even so, most electric utility issues are up solidly year to date, and are still trading within their 2016-2018

> Target Price Ranges. Historically, this is an indication that these equities are expensively priced. Income-oriented investors don't have a lot of options, with money market and savings instruments having such low yields. They must be cognizant of the market risks they are assuming when they purchase stocks for their generous dividends.

Q. Briefly describe Tampa Electric Company.

A. Tampa Electric is a wholly owned electric operating subsidiary of TECO Energy, Inc. ("TECO Energy"). According to TECO Energy's 2012 10-K Report, during calendar year 2012, Tampa Electric generated $1,981.3 million in revenues, 48% derived from residential sales, 31% from commercial sales, 9% from industrial sales, and 12% from other sources, including bulk power and sales for resale. Exhibit No. ____(RAB-5) at p. 5. Tampa Electric derives 61% of its generation from coal and 39% from natural gas. The Company's owned generating units supply 94% of total system load requirements, with the remaining 6% coming from purchased power. Exhibit No. ____(RAB-5) at p. 6.

Tampa Electric's "[f]uel, purchased power, conservation and certain environmental costs are recovered through levelized monthly charges established pursuant to the [Commission's] cost-recovery clauses." Exhibit No. ____(RAB-5) at p. 9. According to TECO Energy's 2012 10-K, "Tampa Electric expects that the costs to comply with new environmental regulations would be eligible for recovery through the [environmental cost recovery clause]." Exhibit No. ____(RAB-5) at p. 8. Tampa Electric expects to undertake capital investments from 2013 through 2017 totaling approximately $2.3 billion. Exhibit No. ___ (RAB-7) at p. 7. These expenditures will support system growth and reliability, environmental compliance and computer system improvements.

Q. What are the current bond ratings for Tampa Electric?

A. Tampa Electric's senior unsecured bond ratings are currently A3 from Moody's Investor's Services ("Moody's") and BBB+ from Standard and Poor's ("S&P"). Both of these rating agencies have stable ratings outlooks for the Company.

In its Credit Opinion dated May 30, 2013, Moody's noted the following ratings drivers for Tampa Electric:

- Supportive Florida regulatory framework that provides timely recovery of prudently incurred costs and investments.
- Strong credit metrics elevated by bonus depreciation.
- Sizeable increase in capital expenditures funded through debt and parent contributions.
- Solid liquidity profile.

In its Summary Analysis dated June 17, 2013, S&P assigned Tampa Electric an excellent business risk profile and a significant financial risk profile. With respect to business risk, S&P's ratings scale ranges from vulnerable to excellent, meaning that Tampa Electric is at the top of the scale. S&P stated that Tampa Electric's excellent business risk reflects monopolistic, rate-regulated electric and gas businesses that provide an essential service. S&P also stated:

> Tampa Electric Co.'s service territory has faced a strong downturn due to the slowed economy and depressed housing market. However, recent housing statistics and state unemployment rates signal a slow but recovering economy. Although historically high growth rates seen in the past in these areas may take some time to come back, Florida continues to offer attractive incentives that should favor its economy.

With respect to "significant" financial risk, S&P noted that Tampa Electric's financial profile "reflects the consolidated financial measures of its parent, TECO Energy." S&P's ratings scale ranges from "highly leveraged" to "minimal".

TECO Energy's Chief Executive Officer ("CEO") stated in a May 2012 presentation that "TECO Energy expects to generate significant free cash flow after dividends for the next several years", there were "[n]o significant TECO Energy debt maturities until 2015", and TECO Energy expects "cash generation to retire 2015 debt." Exhibit No. ____(RAB-6) at p. 12. In addition, Schedule D-4a, page 2, of Tampa Electric's MFRs show that Tampa Electric will not have any long term debt maturing until April, 2016.

According to S&P's June 17, 2013 Summary Analysis, TECO Energy has announced that "it had entered into a stock purchase agreement to acquire New Mexico Gas Co." S&P's assessment of Tampa Electric's financial risk "previously assumed that the proceeds from [TECO Energy's sale of its] Guatemala assets would be used for reduction of debt" but now S&P's assessment "assumes that this cash will be used for the acquisition" of New Mexico Gas Co.

Additionally, Witness Callahan noted on page 22 of her testimony that the Regulatory Research Associates ("RRA") ranked the Commission as "Above Average 3" on a scale that runs from Above Average 1 to Below Average 3. As such, there are only three state/district regulatory bodies out of the 51 jurisdictions evaluated by RRA that have a better ranking than the Commission. Exhibit No. ____ (SWC-1), Document No. 9 (Alabama, Virginia, and Wisconsin). Notably, the rankings "are intended to be comparative in nature" and are based on a curve so that the majority of jurisdictions receive a ranking of Average 2. Exhibit No. ____ (RAB_7) at pp. 20-21.

Q. Mr. Baudino, what is your conclusion regarding the financial health and overall risk of Tampa Electric?

A. Since its last rate proceeding before the Commission, the Company has had low cost access to capital markets for its construction program and for other corporate purposes. Tampa Electric spent approximately $1.476 billion on capital expenditures from 2009 through 2012. Exhibit No. ____(RAB-7) at p. 1. During that time, Tampa Electric (1) entered a debt exchange in December 2010 with a principal amount of approximately $232 million, maturing in approximately 11 years, at a coupon rate of 5.4%, (2) issued $250 million of 30-year bonds in June 2012 at a coupon rate of 4.10% and (3) issued $225 million of 10-year bonds in September 2012 at a coupon rate of 2.60%. MFR Schedule D-4a at p. 3.

Tampa Electric also benefits from several Commission-approved cost recovery clauses that reduce its business and financial risk profiles and help stabilize its revenues and earnings. Its bond ratings currently enjoy a stable credit outlook from Moody's and S&P. Overall Tampa Electric remains an electric utility with solid financial health and an excellent business risk position.

As I described earlier in my testimony, current interest rates are at or near historic lows. This suggests a much lower return on equity, other things equal, for Tampa Electric than the Commission approved in Docket No. 080317-EI.

III. DETERMINATION OF FAIR RATE OF RETURN

Q. **Please describe the methods you employed in estimating a fair rate of return for Tampa Electric.**

A. I employed a Discounted Cash Flow ("DCF") analysis for a group of comparison electric companies to estimate the cost of equity for the Company's regulated electric operations. I also employed several Capital Asset Pricing Model ("CAPM") analyses using both historical and forward-looking data.

Q. **What are the main guidelines to which you adhere in estimating the cost of equity for a firm?**

A. Generally speaking, the estimated cost of equity should be comparable to the returns of other firms with similar risk and should be sufficient for the firm to attract capital. These are the basic standards set out by the United States Supreme Court in *Federal Power Comm'n v. Hope Natural Gas Co.*, 320 U.S. 591 (1944) ("Hope") and

Bluefield W.W. & Improv. Co. v. Public Service Comm'n, 262 U.S. 679 (1922) ("Bluefield").

From an economist's perspective, the notion of "opportunity cost" plays a vital role in estimating the return on equity. One measures the opportunity cost of an investment equal to what one would have obtained in the next best alternative. For example, let us suppose that an investor decides to purchase the stock of a publicly traded electric utility. That investor made the decision based on the expectation of dividend payments and growth over time; however, that investor's opportunity cost is measured by what she or he could have invested in as the next best alternative. That alternative could have been another utility stock, a utility bond, a mutual fund, a money market fund, or any other number of comparable investment vehicles.

The key determinant in deciding whether to invest, however, is based on comparative levels of risk and expected return. Our hypothetical investor would not invest in a particular electric company stock if it offered a return lower than other investments of similar risk. The opportunity cost simply would not justify such an investment. Thus, the task for the rate of return analyst is to estimate a return that is equal to the return being offered by other risk-comparable firms.

Q. What are the major types of risk faced in holding the stock of utility companies?

A. In general, risk associated with the holding of common stock can be separated into three major categories: business risk, financial risk, and liquidity risk. Business risk refers to risks inherent in the operation of the business. Volatility of the firm's sales, long-term demand for its product(s), and quality of management are several factors that affect business risk. The quality of regulation at the state and federal levels also plays an important role in business risk for regulated utility companies.

Financial risk refers to the impact on a firm's future cash flows from the use of debt in the capital structure. Interest payments to bondholders represent a prior call on the firm's cash flows and must be met before income is available to the common shareholders. Other things being equal, as the percentage of debt interest to total income increases, so does the financial risk.

Liquidity risk refers to the ability of an investor to quickly sell an investment without a substantial price concession. The easier it is for an investor to sell an investment for cash, the lower the liquidity risk will be. Stock markets, such as the New York and American Stock Exchanges, help ease liquidity risk substantially. Investors who own stocks that are traded in these markets know on a daily basis what the market prices of their investments are and that they can sell these investments fairly quickly. Many electric utility stocks are traded on the New York Stock Exchange and are considered liquid investments.

Q. Are there any sources available to investors that quantify the risks facing a company?

A. Yes. Bond and credit ratings are tools that investors use to assess the risk comparability of firms. Bond rating agencies such as Moody's and S&P perform detailed analyses of factors that contribute to the risk of a particular investment. The end result of their analyses is a bond and/or credit rating that reflects these risks. These ratings are widely available and relied upon by investors.

Discounted Cash Flow ("DCF") Model

Q. Please describe the basic DCF approach.

A. The basic DCF approach is rooted in valuation theory. It is based on the premise that the value of a financial asset is determined by its ability to generate future net cash flows. In the case of a common stock, those future cash flows generally take the form of dividends and appreciation in stock price. The value of the stock to investors is based on the discounted present value of future cash flows to the investor. The general equation then is:

$$V = \frac{R}{(1+r)} + \frac{R}{(1+r)^2} + \frac{R}{(1+r)^3} + \cdots \frac{R}{(1+r)^n}$$

Where: *V = asset value*
R = yearly cash flows
r = discount rate

This is no different from determining the value of any asset from an economic point of view; however, the commonly employed DCF model makes certain simplifying assumptions. One is that the stream of income from the equity share is assumed to be perpetual; that is, there is no salvage or residual value at the end of some maturity date (as is the case with a bond). Another important assumption is that financial markets are reasonably efficient; that is, they correctly evaluate the cash flows relative to the appropriate discount rate, thus rendering the stock price efficient relative to other alternatives. Finally, the model I employ also assumes a constant growth rate in dividends. The fundamental relationship employed in the DCF method is described by the formula:

$$k = {}^{D_1}/_{P_0} + g$$

Where: D_1 = *the next period dividend*
P_0 = *current stock price*
g = *expected growth rate*
k = *investor-required return*

Under the formula, it is apparent that "k" must reflect the investors' expected return. Use of the DCF method to determine an investor-required return is complicated by the need to express investors' expectations relative to dividends, earnings, and book value over an infinite time horizon. Financial theory suggests that stockholders purchase common stock on the assumption that there will be some change in the rate of dividend payments over time. We assume that the rate of growth in dividends is constant over the assumed time horizon, but the model could easily handle varying growth rates if we knew what they were. Finally, the relevant time frame is prospective rather than retrospective.

Q. What was your first step in conducting your DCF analysis for Tampa Electric?

A. My first step was to construct a comparison group of companies with a risk profile that is reasonably similar to Tampa Electric. Since Tampa Electric is a subsidiary of TECO Energy, it is not publicly traded, thus one cannot estimate a DCF cost of equity on this company directly. It is necessary to use a group of companies that are similarly situated and have reasonably similar risk profiles to Tampa Electric.

Q. Please describe your approach for selecting a comparison group of electric companies.

A. I used several criteria to select a comparison group. First, using the July 2013 issue of AUS Utility Reports, I selected electric companies whose bonds were rated Baa/BBB by either Moody's or S&P. Tampa Electric currently carries senior unsecured bond ratings of BBB+ from S&P and A3 from Moody's, so using the either/or criterion for a BBB/Baa rating assures that the companies in the comparison group carry bond ratings that are slightly below or similar to Tampa Electric. In fact, using a slightly lower Moody's bond rating than Tampa Electric's A3 rating suggests that my ROE analysis is conservative.

From this group, I then eliminated companies that had recently cut or eliminated dividends, were recently or currently involved in merger activities, or had recent experience with significant earnings fluctuations. Companies that did not pass these screens are not appropriate candidates to which one can apply the DCF formula because of unrepresentative market prices (in terms of companies that are merger candidates) or non-constant growth in earnings or dividends. I also eliminated any companies that had recently been or were currently being restructured in a significant way. These screens eliminated the following companies:

- El Paso Electric Company - resumed dividend payments in 2011 after several years of no dividends.
- Entergy Corporation - pending sale of transmission assets to ITC Corporation.
- FirstEnergy Corporation - unstable earnings per share in 2011 and 2012, reduced unregulated earnings.
- NV Energy Inc. - pending acquisition by MidAmerican Energy Holdings Company.
- OGE Energy Corp. - affect on stock price from formation of Master Limited Partnership with CenterPoint Energy.
- PNM Resources - non-constant dividend and earnings growth rates from Value Line (12.5% and 12.0%, respectively).
- TECO Energy - pending purchase of New Mexico Gas Company.

I also eliminated Ameren Corporation and Edison International from the group because Value Line noted that these companies are being affected by low power prices and/or activities associated with their merchant and unregulated generation assets.[3] According to Value Line, Edison International is a different company in 2013 than it was in 2012. Edison International booked a $5.11 per share loss from its discontinued unregulated power generating business. Likewise, Value Line

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3 Value Line Investment Survey, report for Ameren dated June 21, 2013 and for Edison International dated May 3, 2013.

reported that Ameren discontinued its merchant generation business and booked an $0.82 per share loss in the March quarter of 2013. Value Line currently forecasts negative earnings and book value growth rate for Ameren.

Finally, I eliminated PG&E Corporation due to ongoing effects from a gas pipeline explosion.[4] This uncertainty is affecting near-term earnings growth forecasts for PG&E.

The resulting comparison group of 16 electric companies that I used in my analysis is shown in the table below.

4 Value Line Investment Survey, report for PG&E dated May 3, 2013.

TABLE 1
ELECTRIC UTILITY COMPARISON GROUP

		S&P	Moody's
1	American Electric Power Co.	BBB	Baa2
2	Black Hills Corporation	BBB+	A3
3	Cleco Corporation	BBB	Baa2
4	CMS Energy Corporation	BBB/BBB-	Baa2
5	Consolidated Edison, Inc.	A-	A3/Baa1
6	Dominion Resources, Inc.	A	Baa1
7	Great Plains Energy Incorporated	BBB/BBB-	Baa1/Baa2
8	Hawaiian Electric Industries, Inc.	BBB-	Baa2
9	Otter Tail Corp.	BBB-/BB+	Baa2
10	Pepco Holdings, Inc.	A-/BBB+	Baa1/Baa2
11	Pinnacle West Capital Corp.	BBB+	Baa1
12	SCANA Corporation	BBB+	Baa1/Baa2
13	UIL Holdings Corporation	BBB	Baa2
14	UNS Energy Corp.	BBB-	Baa2
15	Westar Energy, Inc.	BBB+	A3
16	Wisconsin Energy Corporation	A-/BBB+	A2/A3

Q. What was your first step in determining the DCF return on equity for the comparison group?

A. I first determined the current dividend yield, D_1/P_0, from the basic equation. My general practice is to use six months as the most reasonable period over which to estimate the dividend yield. The six-month period I used covered the months from January through June 2013. I obtained historical prices and dividends from Yahoo! Finance. The annualized dividend divided by the average monthly price represents the average dividend yield for each month in the period.

The resulting average dividend yield for the group is 4.00%. These calculations are shown in Exhibit No. ____(RAB-8).

Q. What was the range of monthly dividend yields during the six-month period?

A. Page 3 of Exhibit No. ____(RAB-8) shows that the monthly average yields for the comparison group ranged from 3.80% in April to 4.19% in January, with the most recent June yield being 4.11%. In my opinion, the average six-month yield of 4.00% is a reasonable proxy for the current dividend yield in this case.

Q. Having established the average dividend yield, how did you determine the investors' expected growth rate for the electric comparison group?

A. The investors' expected growth rate, in theory, correctly forecasts the constant rate of growth in dividends. The dividend growth rate is a function of earnings growth and the payout ratio, neither of which is known precisely for the future. We refer to a perpetual growth rate since the DCF model has no arbitrary cut-off point. We must estimate the investors' expected growth rate because there is no way to know with absolute certainty what investors expect the growth rate to be in the short term, much less in perpetuity.

In this analysis, I relied on three major sources of analysts' forecasts for growth. These sources are the Value Line Investment Survey, Zacks, and Thomson Financial.

Q. Please briefly describe Value Line, Zacks, and Thomson Financial.

A. The Value Line Investment Survey is a widely used and respected source of investor information that covers several thousand companies. It is updated quarterly and probably represents the most comprehensive of all investment information services. It provides both historical and forecasted information on a number of data elements.

Value Line neither participates in financial markets as a broker nor works for the utility industry in any capacity of which I am aware.

Zacks is an investment service that gathers opinions from a variety of analysts on earnings growth forecasts for numerous firms including regulated electric utilities. The estimates of the analysts responding are combined to produce consensus average estimates of earnings growth.

Like Zacks, Thomson Financial also provides investment research on numerous companies. Thomson also compiles and reports consensus analysts' forecasts of earnings growth. I obtained the Thomson Financial forecasts from Yahoo! Finance.

Both Zacks and Thomson Financial provide five-year earnings growth forecasts, which I have used in my DCF analyses.

Q. Why did you rely on analysts' forecasts in your analysis?

A. Return on equity analysis is a forward-looking process. Five-year or ten-year historical growth rates may not accurately represent investor expectations for dividend growth. Analysts' forecasts for earnings and dividend growth provide better proxies for the expected growth component in the DCF model than historical growth rates. Analysts' forecasts are also widely available to investors and by virtue of their continual updating and marketing by their sponsor obviously fill a market demand for such information.

Q. How did you utilize your data sources to estimate growth rates for the comparison group?

A. Exhibit No.____(RAB-9) presents the Value Line, Zacks, and Thomson Financial forecasted growth estimates. These earnings and dividend growth estimates for the comparison group are summarized on Columns (1) through (5) of Exhibit No.____(RAB-9).

I also adjusted the Value Line dividend growth rate for Pinnacle West Capital Corp. to recognize 4 dividend payments in 2012, rather than the five declarations that were included by Value Line in the "Div'd Decl'd per sh" line in that Company's report. This reduced the three-year historical average dividends per share data that I used to calculate compound growth through the 2016 - 2018 time period. This had the effect of increasing the compound dividend growth rate from 2.0% to 3.62%.

I also utilized the sustainable growth formula in estimating the expected growth rate. The sustainable growth method, also known as the retention ratio method, recognizes that the firm retains a portion of its earnings to fuel growth in dividends. These retained earnings, which are plowed back into the firm's asset base, are expected to earn a rate of return. This, in turn, generates growth in the firm's book value, market value, and dividends.

The sustainable growth method is calculated using the following formula:

$$G = B * R$$

Where: G = *expected retention growth rate*
B = *the firm's expected retention ratio*
R = *the expected return*

In its proper form, this calculation is forward-looking. That is, the investors' expected retention ratio and return must be used in order to measure what investors anticipate will happen in the future. Data on expected retention ratios and returns may be obtained from Value Line.

The expected sustainable growth estimates for the comparison group are presented in Column (3) on page 1 of Exhibit No. ____(RAB-9). The data came from the Value Line forecasts for the comparison group.

Q. How did you approach the calculation of earnings growth forecasts in this case?

A. For purposes of this case, I looked at two different methods for calculating the expected growth rates for my comparison group. For Method 1, I calculated the average of all the growth rates for the companies in my comparison group using Value Line, Zacks, and Thomson. For Method 2, I calculated the median growth rates for my comparison group. The median value represents the middle value in a data range and is not influenced by excessively high or low numbers in the data set. The median growth rate for each forecast provides additional valuable information regarding expected growth rates for the group.

I also excluded the Value Line earnings growth estimate of 21.50% for Otter Tail Corp. from the calculation of the average Value Line earnings growth estimate. Clearly, 21.50% is an anomalous percentage and would only serve to inflate the average earnings growth calculation for the comparison group. By way of comparison, the next highest growth rate estimate for the companies in my comparison group in 12.0%.

The expected growth rates produced from these two methods fall in a range from 3.31% to 5.95%.

Q. How did you proceed to determine the DCF return on equity for the electric comparison group?

A. To estimate the expected dividend yield (D_1) for the group, the current dividend yield must be moved forward in time to account for dividend increases over the next twelve months. I estimated the expected dividend yield by multiplying the current dividend yield by one plus one-half the expected growth rate.

I then added the expected growth rates to the expected dividend yield. The calculations of the resulting DCF returns on equity for both methods are presented on page 2 of Exhibit No. ____(RAB-9).

Q. Please explain how you calculated your DCF cost of equity estimates.

A. Page 2 of Exhibit No. ____(RAB-9) presents the DCF results utilizing the two different methods I described earlier. Method 1 utilizes the average growth rates for the comparison group. I used the Value Line earnings and dividend growth forecasts and the consensus analysts' forecasts. The average for the comparison group is 9.32% and the midpoint is 9.08%.

Method 2 employs the median growth rates from Value Line, Zacks, and Thomson. The average DCF return on equity is 9.08% and the midpoint of the results is 8.73%.

Capital Asset Pricing Model

Q. Briefly summarize the Capital Asset Pricing Model ("CAPM") approach.

A. The theory underlying the CAPM approach is that investors, through diversified portfolios, may combine assets to minimize the total risk of the portfolio. Diversification allows investors to diversify away risks specific to a particular company so that the investor is left only with market risk that affects all companies. Thus, the CAPM theory identifies two types of risks for a security: company-specific risk and market risk. Company-specific risk includes such events as strikes, management errors, marketing failures, lawsuits, and other events that are unique to a particular firm. Market risk includes inflation, business cycles, war, variations in interest rates, and changes in consumer confidence. Market risk tends to affect all stocks and cannot be diversified away. The idea behind the CAPM is that diversified investors are rewarded with returns based on market risk.

Within the CAPM framework, the expected return on a security is equal to the risk-free rate of return plus a risk premium that is proportional to the security's market, or non-diversifiable, risk. Beta is the factor that reflects the inherent market risk of a security and measures the volatility of a particular security relative to the overall market for securities. For example, a stock with a beta of 1.0 indicates that if the market rises by 15%, that stock will also rise by 15%. This stock moves in tandem with movements in the overall market. Stocks with a beta of 0.5 will only rise or fall 50% as much as the overall market. So with an increase in the market of 15%, this stock will only rise 7.5%. Stocks with betas greater than 1.0 will rise and fall more than the overall market. Thus, beta is the measure of the relative risk of individual securities vis-à-vis the market.

Based on the foregoing discussion, the equation for determining the return for a security in the CAPM framework is:

$$K = Rf + \beta(MRP)$$

Where: K = *Required Return on equity*
Rf = *Risk-free rate*
MRP = *Market risk premium*
β = *Beta*

This equation tells us about the risk/return relationship posited by the CAPM. Investors are risk averse and will only accept higher risk if they expect to receive higher returns. These returns can be determined in relation to a stock's beta and the market risk premium. The general level of risk aversion in the economy determines the market risk premium. If the risk-free rate of return is 3.0% and the required return on the total market is 15%, then the risk premium is 12%. Any stock's required return can be determined by multiplying its beta by the market risk premium. Stocks with betas greater than 1.0 are considered riskier than the overall market and will have higher required returns. Conversely, stocks with betas less than 1.0 will have required returns lower than the market as a whole.

Q. In general, are there concerns regarding the use of the CAPM in estimating the return on equity?

A. Yes. There is some controversy surrounding the use of the CAPM.[5] There is evidence that beta is not the primary factor in determining the risk of a security. Beta coefficients usually describe only a small amount of total investment risk. Finally, a considerable amount of judgment must be employed in determining the risk-free rate and market return portions of the CAPM equation. The analyst's application of judgment can significantly influence the results obtained from the CAPM. My past experience with the CAPM indicates that it is prudent to use a wide variety of data in estimating returns. Of course, the range of results may also be wide, indicating the difficulty in obtaining a reliable estimate from the CAPM.

Q. How did you estimate the market return portion of the CAPM?

A. The first source I used was the Value Line Investment Analyzer, Plus Edition, for June 25, 2013. This edition covers nearly 7,000 stocks. The Value Line Investment Analyzer provides a summary statistical report detailing, among other things, forecasted growth in earnings and book value for the companies Value Line follows. I have presented these two growth rates and the average on page 2 of Exhibit No.____(RAB-10). The average growth rate is 11.43%. Combining this growth rate with the average expected dividend yield of the Value Line companies of 0.71% results in an expected market return of 12.18%. The detailed calculations are shown on page 1 of Exhibit No.____(RAB-10).

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5 For a more complete discussion of some of the controversy surrounding the use of the CAPM, refer to *A Random Walk Down Wall Street* by Burton Malkiel, pp. 206– 211, 2007 edition.

I also considered a supplemental check to this market estimate. Morningstar publishes a study of historical returns on the stock market in its *Ibbotson SBBI 2013 Valuation Yearbook*. Some analysts employ this historical data to estimate the market risk premium of stocks over the risk-free rate. The assumption is that a risk premium calculated over a long period of time is reflective of investor expectations going forward. Exhibit No. ____(RAB-11) presents the calculation of the market return using the historical data.

Q. Please address the use of historical earned returns to estimate the market risk premium.

A. The use of historic earned returns on the S&P 500 to estimate the current market risk premium is rather suspect because it naively assumes that investors currently expect historic risk premiums to continue unchanged into the future regardless of present or forecasted economic conditions. Brigham, Shome, and Vinson noted the following with respect to the use of historic risk premiums calculated using the returns as reported by Ibbotson and Sinquefield (referred to in the quote as "I&S"):

> There are both conceptual and measurement problems with using I&S data for purposes of estimating the cost of capital. Conceptually, there is no compelling reason to think that investors expect the same relative returns that were earned in the past. Indeed, evidence presented in the following sections indicates that relative expected returns should, and do, vary significantly over time. Empirically, the measured historic premium is sensitive both to the choice of estimation horizon and to the end points. These choices are essentially arbitrary, yet can result in significant differences in the final outcome.[6]

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6 Brigham, E.F., Shome, D.K. and Vinson, S.R., "The Risk Premium Approach to Measuring a Utility's Cost

In summary, the use of historic earned returns should be viewed with a great deal of caution. There is no real support for the proposition that an unchanging, mechanically applied historical risk premium is representative of current investor expectations and return requirements.

Q. How did you determine the risk free rate?

A. I used the average yields on the 20-year Treasury bond and five-year Treasury note over the six-month period from January through June 2013. The 20-year Treasury bond is often used by rate of return analysts as the risk-free rate, but it contains a significant amount of interest rate risk. Interest rate risk is the inverse relationship between interest rates and prices. Generally, the longer the term of the bond, the more risk the investor assumes regarding changes in interest rates over time. The five-year Treasury note carries less interest rate risk than the 20-year bond and is more stable than three-month Treasury bills. Therefore, I have employed both of these securities as proxies for the risk-free rate of return. This approach provides a reasonable range over which the CAPM may be estimated.

Q. What is your estimate of the market risk premium?

A. Exhibit No.____(RAB-10), line 9 of page 1, presents my estimates of the market risk premium based on a DCF analysis applied to current market data. The market risk premium is 9.42% using the 20-year Treasury bond and 11.31% using the five-year Treasury bond.

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of Equity," *Financial Management*, Spring 1985, pp. 33-45.

Utilizing the historical Ibbotson data on market returns, the market risk premium ranges from 4.70% to 6.70%. This is shown on Exhibit No.____(RAB-11).

Q. How did you determine the value for beta?

A. I obtained the betas for the companies in the electric company comparison group from most recent Value Line reports. The average of the Value Line betas for the electric group is .71.

Q. Please summarize the CAPM results.

A. The CAPM results using the 20-year and five-year Treasury bond yields and Value Line market return data range from 8.89% to 9.44%. Exhibit No. ___ (RAB-10) at p. 1, line 14.

The CAPM results using the historical Ibbotson data range from 6.10% to 7.52%. These results are shown on Exhibit No.____(RAB-11).

<u>Conclusions and Recommendations</u>

Q. Please summarize the cost of equity you recommend the Commission adopt for Tampa Electric.

A. I recommend that the Commission adopt the DCF model I developed and the cost of equity estimates for the comparison group of electric utility companies that I compiled. The results for the electric company comparison group using the constant-growth DCF model and the expected growth rate forecasts ranged from 8.73% to

9.32%. Based on this range of results, I recommend that the Commission adopt a 9.30% return on equity for Tampa Electric in this proceeding, which is at the top end of reasonable returns established by these estimates of investor required ROEs. I offer this recommendation to the Commission as a just and reasonable estimate of investor return on equity requirements for an electric utility such as Tampa Electric.

Finally, it should be noted that most of the CAPM results are significantly lower than the DCF results in this proceeding. This is especially the case with the historical formulation of the CAPM. I do not rely on the CAPM for my ROE recommendation, but these results suggest that my recommended ROE of 9.30% is generous based on current capital market conditions.

Capital Structure and Weighted Cost of Capital

Q. Did you review Tampa Electric's requested capital structure?

A. Yes. The Company's requested capital structure and weighted cost of capital is presented in Schedule D-1A and is supported by the Direct Testimony of Tampa Electric witnesses Hevert and Callahan. Tampa Electric's proposed equity ratio for purposes of this case is 54.2%.

Q. How does Tampa Electric's proposed level of equity compare to the equity levels for the companies in your comparison group?

A. Tampa Electric's proposed level of equity is significantly higher than the average of the companies in my comparison group. Table 2 below presents the common equity ratios for the comparison group. I obtained the data from the Value Line Investment Survey and from AUS Utility Reports, July 2013.

TABLE 2
COMPARISON GROUP CAPITAL STRUCTURES

		2012 Value Line Common Equity	AUS Common Equity
1	American Electric Power Co.	49.4%	45.0%
2	Black Hills Corporation	56.8%	49.5%
3	Cleco Corporation	54.4%	53.1%
4	CMS Energy Corporation	31.6%	30.1%
5	Consolidated Edison, Inc.	54.1%	49.8%
6	Dominion Resources, Inc.	38.2%	33.4%
7	Great Plains Energy Incorporated	54.4%	46.1%
8	Hawaiian Electric Industries, Inc.	53.1%	47.4%
9	Otter Tail Corp.	54.4%	54.6%
10	Pepco Holdings, Inc.	52.7%	42.3%
11	Pinnacle West Capital Corp.	55.4%	53.0%
12	SCANA Corporation	45.6%	43.7%
13	UIL Holdings Corporation	41.1%	38.9%
14	UNS Energy Corp.	37.7%	37.0%
15	Westar Energy, Inc.	48.8%	45.7%
16	Wisconsin Energy Corporation	48.0%	44.9%
	Average	48.5%	44.7%

Source: Value Line Reports 2013; AUS Utility Reports, July 2013

It is clear from Table 2 that Tampa Electric's equity ratio greatly exceeds the average equity ratio of the comparison group. This suggests that Tampa Electric's lower financial risk relative to the comparison group should result in a lower required return on equity by investors in Tampa Electric. However, for purposes of this case, I will recommend an ROE for Tampa Electric consistent with the ROE results from the comparison group. This underscores the reasonableness of my ROE recommendation for Tampa Electric in this proceeding.

Q. Please provide Tampa Electric's proposed capital structure and your calculation of its weighted cost of capital.

A. Please refer to Table 3 below for the calculation of my recommended weighted cost of capital for Tampa Electric. Using the Company's requested capital structure, the weighted cost of capital is 5.91%.

TABLE 3
HUA ADJUSTED WEIGHTED COST OF CAPITAL

	Amount	Pct.	Cost	Weighted Cost
Long-Term Debt	$1,525,392	35.15%	5.40%	1.90%
Short-term Debt	$24,646	0.57%	1.47%	0.01%
Customer Deposits	$112,864	2.60%	2.20%	0.06%
Preferred Stock	$0	0.00%	0.00%	0.00%
Common Equity	1,833,899	42.26%	9.30%	3.93%
ADIT	835,173	19.24%	0.00%	0.00%
Tax Credits	7,999	0.18%	8.54%	0.02%
Totals	$4,339,973	100.00%		5.91%

IV. RESPONSE TO TAMPA ELECTRIC TESTIMONY

Q. Have you reviewed the Direct Testimony of Mr. Robert Hevert?

A. Yes.

Q. Please summarize Mr. Hevert's testimony and approach to return on equity.

A. Mr. Hevert employed three methods to estimate the investor required rate of return for Tampa Electric: (1) the constant growth DCF model, (2) the CAPM, and (3) the bond yield plus risk premium model. On page 19 of his Direct Testimony, Mr. Hevert explained that he relied on the results of the constant growth DCF model and considered the CAPM and risk premium approaches as "corroborating methodologies." Mr. Hevert also devoted Section VII of his Direct Testimony to a discussion of business risks facing Tampa Electric. In Section VIII, Mr. Hevert included a discussion of current capital market conditions and analyzed yield spreads in support of his 11.25% ROE recommendation.

With respect to the DCF model, Mr. Hevert developed a proxy group consisting of eleven companies using several selection criteria. His constant growth DCF results ranged from 8.80% to 13.19%.

With respect to the CAPM, Mr. Hevert's results ranged from 7.42% to 12.20%.

Finally, Mr. Hevert's formulation of the bond yield plus risk premium approach resulted in a ROE range of 10.23% to 10.76%.

Based on the results of his analyses and judgment, Mr. Hevert recommended a ROE range for Tampa Electric of 10.50% to 11.50%, concluding that the cost of equity for Tampa Electric is 11.25%

Q. Please summarize your conclusions with respect to Mr. Hevert's ROE recommendation of 11.25%.

A. Mr. Hevert's analyses systematically overstated the investor required ROE for a regulated electric company such as Tampa Electric.

First, Mr. Hevert included proxy company growth rates that are excessive and unrepresentative of investor expected long-run growth rates for regulated electric utility companies like Tampa Electric. Adjusting Mr. Hevert's DCF analysis to remove these excessive growth rates appreciably lowers his DCF ROE.

Second, Mr. Hevert's CAPM range of results is biased upward by using forecasted Treasury Bond yields. Forecasted bond yields are not appropriate for formulating a CAPM ROE. Instead, current market bond yields should be used because they reflect current investor expectations and market return requirements. Mr. Hevert's CAPM results using the current Treasury Bond yield are similar to mine, although he should also have used the 5-year Treasury Bill as an appropriate proxy for the risk-free rate of return. Mr. Hevert also included a CAPM analysis using the Sharpe ratio, which is an inappropriate modification to the traditional CAPM analysis that should be rejected by the Commission.

Third, Mr. Hevert's bond yield plus risk premium analysis is also inflated by using forecasted bond yields. In addition, the risk premium method is far less precise that the DCF method, which uses current market data that are more reflective of investor required returns today.

DCF Analyses

Q. Please summarize Mr. Hevert's approach to the DCF model and its results.

A. Mr. Hevert began his DCF analysis with the selection of a proxy group of companies. Mr. Hevert discusses his approach and the selection criteria he used beginning on page 14 of his Direct Testimony. After applying these screening criteria, Mr. Hevert went on to eliminate Edison International and Integrys Energy Group. His final proxy group of eleven companies is presented on page 17 of his Direct Testimony.

Q. What are Mr. Hevert's DCF ROE results using this proxy group?

A. Mr. Hevert summarized his DCF results on pages 26 and 27 of his Direct Testimony. The proxy group results range from 8.80% to 13.19%.

Q. Do these ranges represent reasonable estimates of the investor-required roe for a company like Tampa Electric?

A. No. Mr. Hevert's DCF results are significantly overstated.

Q. What is the main cause of Mr. Hevert's overstatement of the DCF model?

A. The main cause is Mr. Hevert's inclusion of excessive earnings growth forecasts that significantly bias his DCF results upward.

As I mentioned in Section III of my Direct Testimony, I omitted PNM Resources from my comparison group of electric companies. This is due to excessive, non-constant earnings and dividend growth rates currently being forecasted by Value Line for PNM. Mr. Hevert's Exhibit No. ___ (RBH-1), Document No. 2 clearly bears this out, with a Value Line earnings growth estimate of 16.00%. Including this growth rate in his DCF analysis biased his ROE result upward.

This is also the case for Otter Tail Corp. Mr. Hevert included a Value Line earnings growth estimate of 24.0% in his DCF ROE calculations, again biasing his results substantially upward.

Growth rates of 16% and 24% have no place in a DCF ROE analysis for regulated electric utilities. These growth rates are clearly the product of special circumstances with PNM Resources and Otter Tail and should be excluded from Mr. Hevert's analysis. Given the evidence concerning expected growth rates for my comparison group, 16% and 24% earnings growth rates are in no way representative of investors' anticipated performance for Tampa Electric.

Q. Did you prepare an analysis that adjusted for the excessive growth rates and resulting ROEs that you just discussed?

A. Yes. Please refer to Table 4, which presents adjusted results for Mr. Hevert's DCF analyses. I developed this table using Mr. Hevert's spreadsheet that was provided as part of his work papers. I chose to use the DCF ROE results from the 180-day average of stock prices for Mr. Hevert's group because I also used a six-month average of stock prices in my comparison group DCF analysis. Excluding Otter Tail and PNM Resources results in an average DCF ROE of 9.62%.

TABLE 4
ADJUSTED HEVERT GROUP DCF ROE

Company	Mean ROE
American Electric Power Company, Inc.	7.76%
Cleco Corp.	7.98%
Empire District Electric	12.79%
Great Plains Energy Inc.	10.81%
IDACORP, Inc.	6.93%
Otter Tail Corporation	16.90%
Pinnacle West Capital Corp.	11.29%
PNM Resources, Inc.	14.19%
Portland General Electric Company	7.91%
Southern Company	9.38%
Westar Energy, Inc.	11.76%
Group Average	10.70%
Group Average excl. Otter Tail and PNM	9.62%

Q. **Are the revised results in Table 4 still overstated?**

A. Yes. They are overstated because Mr. Hevert did not include Value Line's dividend growth forecasts. Currently, Value Line is forecasting lower near-term dividend growth than earnings growth. As may be seen from the results in my Exhibit No.____(RAB-9), median and average dividend growth for my comparison group is 3.31% and 4.29%, respectively. This is much lower than the earnings growth rates I used in my analysis, which range from 5.17% to 5.95%.

With respect to regulated utility companies, dividend growth provides the primary source of cash flow to the investor. It is certainly the case that earnings growth fuels dividend growth and should be considered in estimating the ROE using the DCF model. However, Value Line's dividend growth forecasts are widely available to investors and can reasonably be assumed to influence their expectations with respect to growth. I weighted earnings growth 75% and dividend growth 25% in my growth calculations,[7] so I acknowledge that earnings growth is the primary factor considered by investors. But it should not be considered the only factor.

Q. What are the current dividend growth rates for the companies in Mr. Hevert's proxy group?

A. Table 5 below presents the Value Line projected dividend growth rates for the companies in Mr. Hevert's proxy group excluding PNM Resources. The average dividend growth rate for his proxy group is 4.91% and the median growth rate is 3.62%.

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7 In other words, my average comparison group growth rate averaged three earnings growth estimates and one dividend growth estimate.

TABLE 5
HEVERT PROXY GROUP
DIVIDEND GROWTH RATES

Company	V/L Dividend Growth
American Electric Power Company, Inc.	4.09%
Cleco Corp.	10.00%
Empire District Electric	3.50%
Great Plains Energy Inc.	6.00%
IDACORP, Inc.	7.00%
Pinnacle West Capital Corp.	3.62%
Portland General Electric Company	3.50%
Southern Company	3.50%
Westar Energy, Inc.	3.00%
Average	4.91%
Median	3.62%

Q. What would be the resulting DCF ROE using the average dividend growth rate?

A. Excluding PNM Resources and Otter Tail, Mr. Hevert's proxy group dividend yield using the 180-day average stock price would be 4.11%. The resulting DCF ROE would then be:

4.11%(1 + (0.5 * 4.91%) + 4.21% =*
4.21% + 4.91% =
9.12% DCF ROE

CAPM

Q. Briefly summarize Mr. Hevert's approach to estimating the CAPM ROE.

A. On page 30 of his Direct Testimony, Mr. Hevert testified that he used three estimates of the yield on 30-year Treasury Bonds as proxies for the risk-free rate: the current

30-day average yield of 3.12%, a near-term projected yield of 3.25%, and a long-term projected yield of 5.10%. Mr. Hevert did not consider any shorter maturity bonds, such as the 5-year Treasury note.

Mr. Hevert then calculated two different ex-ante measures of total market returns. The first utilized an estimated total market return on the S&P 500 based on data from Bloomberg and Capital IQ. Total market returns from these two sources were rather close, with a 13.00% market return using Bloomberg data and a 12.93% return using Capital IQ data. The second utilized an approach that employed Mr. Hevert's estimate of the Sharpe ratio applied to the historical market risk premium of 6.60%, which resulted in an estimated market risk premium of 6.03%.

Mr. Hevert used two different estimates for beta: Bloomberg and Value Line.

Using the current 30-year Treasury bond yield, Mr. Hevert's CAPM results ranged from 7.42% to 10.22%. Using the forecasted long-term 30-year Treasury bond yield, his results ranged from 9.41% to 12.20%. CAPM results using the near-term projected bond yield did not differ significantly from the results using the current bond yield.

Q. Is it appropriate to use forecasted or projected bond yields in the CAPM?

A. No. Current interest rates embody all of the relevant market data and expectations of investors, including expectations of changing future interest rates. The forecasted Treasury bond yields used by Mr. Hevert are speculative at best and may or may not come to pass. Current interest rates present tangible market evidence of investor return requirements today, and these are the interest rates that should be used in both the CAPM and in the bond yield plus risk premium analysis. To the extent that investors give forecasted interest rates any weight at all, they are already incorporated in current securities prices.

Q. Should Mr. Hevert have considered shorter term Treasury yields in his CAPM analyses?

A. Yes. In theory, the risk-free rate should have no interest rate risk. 30-year Treasury Bonds do tend to face this risk, which is the risk that interest rates could rise in the future and lead to a capital loss for the bondholder. Typically, the longer the duration of the bond, the more interest rate risk will increase. The 5-year Treasury note has much less interest rate risk than 20-year or 30-year Treasury Bonds and may be considered one reasonable proxy for a risk-free security. My CAPM analysis shows that the ROE using a 5-year Treasury note would be only 9.16%. This is much lower than any of the CAPM estimates provided by Mr. Hevert.

Q. Do you agree with adjusting the historical risk premium using the Sharpe ratio?

A. No, I do not. Mr. Hevert's use of the Sharpe ratio substantially deviates from common formulations of the CAPM and, in my view, it is highly unlikely that investors would use such an unorthodox method to derive their expected market risk premium and CAPM return. Mr. Hevert provided no support that investors actually use the Sharpe ratio in the manner he put forward in his Direct Testimony. I recommend that the Commission reject Mr. Hevert's alternative CAPM using the Sharpe ratio.

Risk Premium

Q. Please summarize Mr. Hevert's risk premium approach.

A. Mr. Hevert developed a historical risk premium using Commission-allowed returns for regulated utility companies and 30-year Treasury bond yields from 1980 through February 13, 2013. He used regression analysis to estimate the value of the inverse relationship between interest rates and risk premiums during that period. His Exhibit No. ___ (RBH-1), Document No. 6 shows the risk premium return on equity to be in a range of 10.23% to 10.74%. The 10.74% result was derived using Mr. Hevert's projected Treasury Bond yield of 5.10%.

Q. Please respond to Mr. Hevert's risk premium analysis.

A. First, the bond yield plus risk premium approach is imprecise and can only provide very general guidance on the current authorized ROE for a regulated electric utility. Risk premiums can change substantially over time. As such, this approach is a "blunt instrument," if you will, for estimating the ROE in regulated proceedings. In my view, a properly formulated DCF model using current stock prices and growth forecasts is far more reliable and accurate than the bond yield plus risk premium approach, which relies on a historical risk premium analysis over a certain period of time.

Second, I recommend that the Commission reject the use of the forecasted Treasury bond yield of 5.10% for the same reasons I described in my response to Mr. Hevert's CAPM approach.

<u>Other ROE Considerations</u>

Q. On page 45 of his Direct Testimony, Mr. Hevert concluded that Tampa Electric's capital spending program suggested an ROE above the mean results of his cost of equity analyses. Do you agree?

A. No. The Commission should not inflate Tampa Electric's ROE due to its capital spending program.

First, my ROE analyses do not support an ROE above 9.30% for Tampa Electric in today's capital markets. In this low interest rate environment, an 11.25% ROE can in no way be justified on the basis of current financial market evidence.

Second, any risk regarding the Company's capital spending program has already been accounted for in its BBB+/A3 bond ratings. By estimating the cost of equity using companies with similar bond ratings, the resulting ROE will need no further upward adjustment. Notably, besides the screens used to select his proxy group, Mr. Hevert did not perform any company by company study of the risks of the proxy companies he selected. Exhibit No. ___ (RAB-7) at pp. 2-3. In other words, he has not performed a comprehensive analysis to determine whether Tampa Electric is more risky than the proxy group he selected and should therefore be provided a ROE at the high end of his range of returns. Neither he, nor other Tampa Electric witnesses testifying concerning Tampa Electric's capital expenditures and rate of return, performed any study to compare the magnitude of Tampa Electric's forecasted capital expenditures with those of other electric utilities or the proxy group. Exhibit No. ___ (RAB-7) at pp. 4-7. In fact the only document that Tampa Electric could produce that purportedly compared Tampa Electric's forecasted capital expenditures to other utilities, actually compared TECO Energy's (not Tampa Electric) forecasted capital expenditures to other electric utility holding companies. Exhibit No. ___ (RAB-7) at pp. 8-12. In addition, that study showed that TECO Energy's forecasted capital expenditures (1) in 2013 were the 27th highest (in the lowest quintile), (2) in 2014 were the 24th highest (*i.e.*, in the bottom third), and (3) in 2015 were the 28th highest (again in the lowest quintile) out of 34 holding companies. Exhibit No. ____(RAB-7) at p. 10.

Third, it is important to note that Tampa Electric's 54.2% equity ratio is far higher than the average common equity ratio of my comparison group, which ranges from 44.7% to 48.5%. Given Tampa Electric's higher equity ratio, a further upward adjustment to the ROE is not justifiable. Obviously, investors would be pleased with a ROE of 11.25%, but Florida ratepayers would have to shoulder a burdensome increase in rates to support this ROE, compared to the 9.3% I recommend. I suggest to the Commission that my recommended 9.3% ROE represents a fair and reasonable balance of interests between ratepayers and shareholders. Notably, in May 2013, TECO Energy provided a presentation to investors suggesting that it expects that its cash flow will be sufficient to "[s]upport Tampa Electric's capital spending program without issuing equity." Exhibit No. ___ (RAB-6) at p. 6. In May 2012, TECO Energy asserted that it "expects to generate significant free cash flow after dividends for the next several years" and that it expected "cash generation to retire 2015 debt." Exhibit No. ____ (RAB-6) at p. 12.

Tampa Electric's purported need for a high common equity ratio and ROE to support its "financial integrity" is also not supported by the Company. Prior to filing its testimony, Tampa Electric failed to "quantify or compare the costs and benefits of maintaining or enhancing Tampa Electric's 'financial integrity.' " Exhibit No. ___ (RAB-7) at p. 13; *see* Exhibit No. ___ (RAB-7) at pp. 14-18.

Despite not studying the costs and benefits, Tampa Electric increased its investor sourced common equity ratio from 47.12% in the first quarter of 2007 to 53.78% in the fourth quarter of 2012. Exhibit No. ___ (RAB-7) at p. 28. There is also a noticeable increase in Tampa Electric's common equity ratio before it filed this rate case. From the first quarter of 2007 through the third quarter of 2012, Tampa Electric's common equity ratio never exceeded 52.04%, but now that Tampa Electric has filed for an increase in base rates, it common equity ratio has increased to 54.2%. Exhibit No. ___ (RAB-7) at p. 28.

Q. Beginning on page 45 of his Direct Testimony, Mr. Hevert discussed the need to reflect flotation costs in the allowed ROE, though he did not make a specific adjustment for flotation costs. Should the Commission add a flotation cost adjustment to the cost of equity for Tampa Electric?

A. No. In my opinion, it is likely that flotation costs are already accounted for in current stock prices and that adding an adjustment for flotation costs amounts to double counting. A DCF model using current stock prices should already account for investor expectations regarding the collection of flotation costs. Multiplying the dividend yield by a 4% flotation cost adjustment, for example, essentially assumes that the current stock price is wrong and that it must be adjusted downward to increase the dividend yield and the resulting cost of equity. I do not believe that this is an appropriate assumption. Current stock prices most likely already account for flotation costs, to the extent that such costs are even accounted for by investors.

In addition, TECO Energy recently stated that it will "[s]upport Tampa Electric's capital spending program without issuing equity." Exhibit No. ___ (RAB-6) at p. 6.

Q. On page 64 of his direct testimony, Mr. Hevert concluded that simply observing that long-term Treasury rates are at historically low levels is not a sufficient level of analysis to conclude that the cost of equity for regulated utilities is at a "commensurately low level." Please respond to Mr. Hevert's position here.

A. Although utility ROEs may not have fallen in lock step with Treasury bond yields, these lower yields indicate that required returns on common equity are indeed lower than they otherwise would be if Treasury yields were higher. Utility company stocks are interest rate sensitive and required returns tend to rise and fall with the general movement of interest rates.

Mr. Hevert's Exhibit No. ___ (RBH-1), Document No. 6 also provides support for the proposition that required ROEs are lower than they were during the time of Tampa Electric's last rate case. According to the allowed ROE data in Exhibit No. ___ (RBH-1), Document No. 6, the average allowed ROE from August 2008 through April 2009 was 10.5%. I would note that Tampa Electric's allowed ROE of 11.25% was by far the highest Commission-allowed ROE during that period. During 2013, the average allowed ROE was 9.75%. Thus, allowed ROEs have declined in connection with the decline in Treasury bond yields since the Company's last rate proceeding, although they have not declined as much.

In conclusion, current market evidence and recent Commission allowed returns all show that Mr. Hevert's recommended ROE of 11.25% for Tampa Electric is excessive, unreasonable, and should be rejected by the Commission.

Q. Does this complete your prepared direct testimony?

A. Yes.

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

IN RE: PETITION FOR RATE INCREASE BY TAMPA ELECTRIC COMPANY	))	DOCKET NO. 130040-EI

EXHIBIT___(RAB-1)

OF

RICHARD A. BAUDINO

ON BEHALF OF THE

THE WCF HOSPITAL UTILITY ALLIANCE

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

RESUME OF RICHARD A. BAUDINO

EDUCATION

New Mexico State University, M.A.
Major in Economics
Minor in Statistics

New Mexico State University, B.A.
Economics
English

Thirty years of experience in utility ratemaking. Broad based experience in revenue requirement analysis, cost of capital, utility financing, phase-ins, auditing and rate design. Has designed revenue requirement and rate design analysis programs.

REGULATORY TESTIMONY

Preparation and presentation of expert testimony in the areas of:

Cost of Capital for Electric, Gas and Water Companies
Electric, Gas, and Water Utility Cost Allocation and Rate Design
Revenue Requirements
Gas and Electric industry restructuring and competition
Fuel cost auditing
Ratemaking Treatment of Generating Plant Sale/Leasebacks

RESUME OF RICHARD A. BAUDINO

EXPERIENCE

1989 to Present: **Kennedy and Associates: Consultant** - Responsible for consulting assignments in the area of revenue requirements, rate design, cost of capital, economic analysis of generation alternatives, gas industry restructuring and competition.

1982 to 1989: **New Mexico Public Service Commission Staff: Utility Economist** - Responsible for preparation of analysis and expert testimony in the areas of rate of return, cost allocation, rate design, finance, phase-in of electric generating plants, and sale/leaseback transactions.

CLIENTS SERVED

Regulatory Commissions

Louisiana Public Service Commission
Georgia Public Service Commission
New Mexico Public Service Commission

Other Clients and Client Groups

Ad Hoc Committee for a Competitive Electric Supply System
Air Products and Chemicals, Inc.
Arkansas Electric Energy Consumers
Arkansas Gas Consumers
AK Steel
Armco Steel Company, L.P.
Assn. of Business Advocating Tariff Equity
CF&I Steel, L.P.
Climax Molybdenum Company
Cripple Creek & Victor Gold Mining Co.
General Electric Company
Holcim (U.S.) Inc.
IBM Corporation
Industrial Energy Consumers
Kentucky Industrial Utility Consumers
Lexington-Fayette Urban County Government
Large Electric Consumers Organization
Newport Steel
Northwest Arkansas Gas Consumers
Maryland Energy Group
Occidental Chemical
PSI Industrial Group
Large Power Intervenors (Minnesota)
Tyson Foods
West Virginia Energy Users Group
The Commercial Group
Wisconsin Industrial Energy Group
South Florida Hospital and Health Care Assn.
PP&L Industrial Customer Alliance
Philadelphia Area Industrial Energy Users Gp.
West Penn Power Intervenors
Duquesne Industrial Intervenors
Met-Ed Industrial Users Gp.
Penelec Industrial Customer Alliance
Penn Power Users Group
Columbia Industrial Intervenors
U.S. Steel & Univ. of Pittsburg Medical Ctr.
Multiple Intervenors
Maine Office of Public Advocate
Missouri Office of Public Counsel
University of Massachusetts - Amherst
WCF Hospital Utility Alliance

Expert Testimony Appearances
of
Richard A. Baudino
As of July 2013

Date	Case	Jurisdict.	Party	Utility	Subject
3/83	1780	NM	New Mexico Public Service Commission	Boles Water Co.	Rate design, rate of return.
10/83	1803, 1817	NM	New Mexico Public Service Commission	Southwestern Electric Coop	Rate design.
11/84	1833	NM	New Mexico Public Service Commission	El Paso Electric Co.	Service contract approval, rate design, performance standards for Palo Verde nuclear generating system
1983	1835	NM	New Mexico Public Service Commission	Public Service Co. of NM	Rate design.
1984	1846	NM	New Mexico Public Service Commission	Sangre de Cristo Water Co.	Rate design.
02/85	1906	NM	New Mexico Public Service Commission	Southwestern Public Service Co.	Rate of return.
09/85	1907	NM	New Mexico Public Service Commission	Jornada Water Co.	Rate of return.
11/85	1957	NM	New Mexico Public Service Commission	Southwestern Public Service Co.	Rate of return.
04/86	2009	NM	New Mexico Public Service Commission	El Paso Electric Co.	Phase-in plan, treatment of sale/leaseback expense.
06/86	2032	NM	New Mexico Public Service Commission	El Paso Electric Co.	Sale/leaseback approval.
09/86	2033	NM	New Mexico Public Service Commission	El Paso Electric Co.	Order to show cause, PVNGS audit.
02/87	2074	NM	New Mexico Public Service Commission	El Paso Electric Co.	Diversification.
05/87	2089	NM	New Mexico Public Service Commission	El Paso Electric Co.	Fuel factor adjustment.
08/87	2092	NM	New Mexico Public Service Commission	El Paso Electric Co.	Rate design.
10/87	2146	NM	New Mexico Public Service Commission	Public Service Co. of New Mexico	Financial effects of restructuring, reorganization.
07/88	2162	NM	New Mexico Public Service Commission	El Paso Electric Co.	Revenue requirements, rate design, rate of return.

Expert Testimony Appearances
of
Richard A. Baudino
As of July 2013

Date	Case	Jurisdict.	Party	Utility	Subject
01/89	2194	NM	New Mexico Public Service Commission	Plains Electric G&T Cooperative	Economic development.
1/89	2253	NM	New Mexico Public Service Commission	Plains Electric G&T Cooperative	Financing.
08/89	2259	NM	New Mexico Public Service Commission	Homestead Water Co.	Rate of return, rate design.
10/89	2262	NM	New Mexico Public Service Commission	Public Service Co. of New Mexico	Rate of return.
09/89	2269	NM	New Mexico Public Service Commission	Ruidoso Natural Gas Co.	Rate of return, expense from affiliated interest.
12/89	89-208-TF	AR	Arkansas Electric Energy Consumers	Arkansas Power & Light Co.	Rider M-33.
01/90	U-17282	LA	Louisiana Public Service Commission	Gulf States Utilities	Cost of equity.
09/90	90-158	KY	Kentucky Industrial Utility Consumers	Louisville Gas & Electric Co.	Cost of equity.
09/90	90-004-U	AR	Northwest Arkansas Gas Consumers	Arkansas Western Gas Co.	Cost of equity, transportation rate.
12/90	U-17282 Phase IV	LA	Louisiana Public Service Commission	Gulf States Utilities	Cost of equity.
04/91	91-037-U	AR	Northwest Arkansas Gas Consumers	Arkansas Western Gas Co.	Transportation rates.
12/91	91-410-EL-AIR	OH	Air Products & Chemicals, Inc., Armco Steel Co., General Electric Co., Industrial Energy Consumers	Cincinnati Gas & Electric Co.	Cost of equity.
05/92	910890-EI	FL	Occidental Chemical Corp.	Florida Power Corp.	Cost of equity, rate of return.
09/92	92-032-U	AR	Arkansas Gas Consumers	Arkansas Louisiana Gas Co.	Cost of equity, rate of return, cost-of-service.
09/92	39314	ID	Industrial Consumers for Fair Utility Rates	Indiana Michigan Power Co.	Cost of equity, rate of return.

Expert Testimony Appearances
of
Richard A. Baudino
As of July 2013

Date	Case	Jurisdict.	Party	Utility	Subject
09/92	92-009-U	AR	Tyson Foods	General Waterworks	Cost allocation, rate design.
01/93	92-346	KY	Newport Steel Co.	Union Light, Heat & Power Co.	Cost allocation.
01/93	39498	IN	PSI Industrial Group	PSI Energy	Refund allocation.
01/93	U-10105	MI	Association of Businesses Advocating Tariff Equality (ABATE)	Michigan Consolidated Gas Co.	Return on equity.
04/93	92-1464-EL-AIR	OH	Air Products and Chemicals, Inc., Armco Steel Co., Industrial Energy Consumers	Cincinnati Gas & Electric Co.	Return on equity.
09/93	93-189-U	AR	Arkansas Gas Consumers	Arkansas Louisiana Gas Co.	Transportation service terms and conditions.
09/93	93-081-U	AR	Arkansas Gas Consumers	Arkansas Louisiana Gas Co.	Cost-of-service, transportation rates, rate supplements; return on equity; revenue requirements.
12/93	U-17735	LA	Louisiana Public Service Commission Staff	Cajun Electric Power Cooperative	Historical reviews; evaluation of economic studies.
03/94	10320	KY	Kentucky Industrial Utility Customers	Louisville Gas & Electric Co.	Trimble County CWIP revenue refund.
4/94	E-015/ GR-94-001	MN	Large Power Intervenors	Minnesota Power Co.	Evaluation of the cost of equity, capital structure, and rate of return.
5/94	R-00942993	PA	PG&W Industrial Intervenors	Pennsylvania Gas & Water Co.	Analysis of recovery of transition costs.
5/94	R-00943001	PA	Columbia Industrial Intervenors	Columbia Gas of Pennsylvania	Evaluation of cost allocation, rate design, rate plan, and carrying charge proposals.

Expert Testimony Appearances
of
Richard A. Baudino
As of July 2013

Date	Case	Jurisdict.	Party	Utility	Subject
7/94	R-00942986	PA	Armco, Inc., West Penn Power Industrial Intervenors	West Penn Power Co.	Return on equity and rate of return.
7/94	94-0035-E-42T	WV	West Virginia Energy Users' Group	Monongahela Power Co.	Return on equity and rate of return.
8/94	8652	MD	Westvaco Corp.	Potomac Edison Co.	Return on equity and rate of return.
9/94	930357-C	AR	West Central Arkansas Gas Consumers	Arkansas Oklahoma Gas Corp.	Evaluation of transportation service.
9/94	U-19904	LA	Louisiana Public Service Commission	Gulf States Utilities	Return on equity.
9/94	8629	MD	Maryland Industrial Group	Baltimore Gas & Electric Co.	Transition costs.
11/94	94-175-U	AR	Arkansas Gas Consumers	Arkla, Inc.	Cost-of-service, rate design, rate of return.
3/95	RP94-343-000	FERC	Arkansas Gas Consumers	NorAm Gas Transmission	Rate of return.
4/95	R-00943271	PA	PP&L Industrial Customer Alliance	Pennsylvania Power & Light Co.	Return on equity.
6/95	U-10755	MI	Association of Businesses Advocating Tariff Equity	Consumers Power Co.	Revenue requirements.
7/95	8697	MD	Maryland Industrial Group	Baltimore Gas & Electric Co.	Cost allocation and rate design.
8/95	95-254-TF U-2811	AR	Tyson Foods, Inc.	Southwest Arkansas Electric Cooperative	Refund allocation.
10/95	ER95-1042-000	FERC	Louisiana Public Service Commission	Systems Energy Resources, Inc.	Return on Equity.
11/95	I-940032	PA	Industrial Energy Consumers of Pennsylvania	State-wide - all utilities	Investigation into Electric Power Competition.
5/96	96-030-U	AR	Northwest Arkansas Gas Consumers	Arkansas Western Gas Co.	Revenue requirements, rate of return and cost of service.

Expert Testimony Appearances
of
Richard A. Baudino
As of July 2013

Date	Case	Jurisdict.	Party	Utility	Subject
7/96	8725	MD	Maryland Industrial Group	Baltimore Gas & Electric Co., Potomac Electric Power Co. and Constellation Energy Corp.	Return on Equity.
7/96	U-21496	LA	Louisiana Public Service Commission	Central Louisiana Electric Co.	Return on equity, rate of return.
9/96	U-22092	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Return on equity.
1/97	RP96-199-000	FERC	The Industrial Gas Users Conference	Mississippi River Transmission Corp.	Revenue requirements, rate of return and cost of service.
3/97	96-420-U	AR	West Central Arkansas Gas Corp.	Arkansas Oklahoma Gas Corp.	Revenue requirements, rate of return, cost of service and rate design.
7/97	U-11220	MI	Association of Business Advocating Tariff Equity	Michigan Gas Co. and Southeastern Michigan Gas Co.	Transportation Balancing Provisions
7/97	R-00973944	PA	Pennsylvania American Water Large Users Group	Pennsylvania-American Water Co.	Rate of return, cost of service, revenue requirements.
3/98	8390-U	GA	Georgia Natural Gas Group and the Georgia Textile Manufacturers Assoc.	Atlanta Gas Light	Rate of return, restructuring issues, unbundling, rate design issues.
7/98	R-00984280	PA	PG Energy, Inc.	PGE Industrial Intervenors	Cost allocation.
8/98	U-17735	LA	Louisiana Public Service Commission	Cajun Electric Power Cooperative	Revenue requirements.
10/98	97-596	ME	Maine Office of the Public Advocate	Bangor Hydro-Electric Co.	Return on equity, rate of return.
10/98	U-23327	LA	Louisiana Public Service Commission	SWEPCO, CSW and AEP	Analysis of proposed merger.
12/98	98-577	ME	Maine Office of the Public Advocate	Maine Public Service Co.	Return on equity, rate of return.
12/98	U-23358	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Return on equity, rate of return.
3/99	98-426	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas and Electric Co	Return on equity.

Expert Testimony Appearances
of
Richard A. Baudino
As of July 2013

Date	Case	Jurisdict.	Party	Utility	Subject
3/99	99-082	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co.	Return on equity.
4/99	R-984554	PA	T. W. Phillips Users Group	T. W. Phillips Gas and Oil Co.	Allocation of purchased gas costs.
6/99	R-0099462	PA	Columbia Industrial Intervenors	Columbia Gas of Pennsylvania	Balancing charges.
10/99	U-24182	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Cost of debt.
10/99	R-00994782	PA	Peoples Industrial Intervenors	Peoples Natural Gas Co.	Restructuring issues.
10/99	R-00994781	PA	Columbia Industrial Intervenors	Columbia Gas of Pennsylvania	Restructuring, balancing charges, rate flexing, alternate fuel.
01/00	R-00994786	PA	UGI Industrial Intervenors	UGI Utilities, Inc.	Universal service costs, balancing, penalty charges, capacity assignment.
01/00	8829	MD	Maryland Industrial Gr. & United States	Baltimore Gas & Electric Co.	Revenue requirements, cost allocation, rate design.
02/00	R-00994788	PA	Penn Fuel Transportation	PFG Gas, Inc., and	Tariff charges, balancing provisions.
05/00	U-17735	LA	Louisiana Public Service Comm.	Louisiana Electric Cooperative	Rate restructuring.
07/00	2000-080	KY	Kentucky Industrial Utility Consumers	Louisville Gas and Electric Co.	Cost allocation.
07/00	U-21453 U-20925 (SC), U-22092 (SC) (Subdocket E)	LA	Louisiana Public Service Comm.	Southwestern Electric Power Co.	Stranded cost analysis.
09/00	R-00005654	PA	Philadelphia Industrial And Commercial Gas Users Group.	Philadelphia Gas Works	Interim relief analysis.
10/00	U-21453 U-20925 (SC), U-22092 (SC) (Subdocket B)	LA	Louisiana Public Service Comm.	Entergy Gulf States, Inc.	Restructuring, Business Separation Plan.

Expert Testimony Appearances of Richard A. Baudino As of July 2013

Date	Case	Jurisdict.	Party	Utility	Subject
11/00	R-00005277 (Rebuttal)	PA	Penn Fuel Transportation Customers	PFG Gas, Inc. and North Penn Gas Co.	Cost allocation issues.
12/00	U-24993	LA	Louisiana Public Service Comm.	Entergy Gulf States, Inc.	Return on equity.
03/01	U-22092	LA	Louisiana Public Service Comm.	Entergy Gulf States, Inc.	Stranded cost analysis.
04/01	U-21453 U-20925 (SC), U-22092 (SC) (Subdocket B) (Addressing Contested Issues)	LA	Louisiana Public Service Comm.	Entergy Gulf States, Inc.	Restructuring issues.
04/01	R-00006042	PA	Philadelphia Industrial and Commercial Gas Users Group	Philadelphia Gas Works	Revenue requirements, cost allocation and tariff issues.
11/01	U-25687	LA	Louisiana Public Service Comm.	Entergy Gulf States, Inc.	Return on equity.
03/02	14311-U	GA	Georgia Public Service Commission	Atlanta Gas Light	Capital structure.
08/02	2002-00145	KY	Kentucky Industrial Utility Customers	Columbia Gas of Kentucky	Revenue requirements.
09/02	M-00021612	PA	Philadelphia Industrial And Commercial Gas Users Group	Philadelphia Gas Works	Transportation rates, terms, and conditions.
01/03	2002-00169	KY	Kentucky Industrial Utility Customers	Kentucky Power	Return on equity.
02/03	02S-594E	CO	Cripple Creek & Victor Gold Mining Company	Aquila Networks – WPC	Return on equity.
04/03	U-26527	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Return on equity.
10/03	CV020495AB	GA	The Landings Assn., Inc.	Utilities Inc. of GA	Revenue requirement & overcharge refund
03/04	2003-00433	KY	Kentucky Industrial Utility Customers	Louisville Gas & Electric	Return on equity, Cost allocation & rate design

Expert Testimony Appearances
of
Richard A. Baudino
As of July 2013

Date	Case	Jurisdict.	Party	Utility	Subject
03/04	2003-00434	KY	Kentucky Industrial Utility Customers	Kentucky Utilities	Return on equity
4/04	04S-035E	CO	Cripple Creek & Victor Gold Mining Company, Goodrich Corp., Holcim (U.S.) Inc., and The Trane Co.	Aquila Networks – WPC	Return on equity.
9/04	U-23327, Subdocket B	LA	Louisiana Public Service Commission	Southwestern Electric Power Company	Fuel cost review
10/04	U-23327 Subdocket A	LA	Louisiana Public Service Commission	Southwestern Electric Power Company	Return on Equity
06/05	050045-EI	FL	South Florida Hospital and HealthCare Assoc.	Florida Power & Light Co.	Return on equity
08/05	9036	MD	Maryland Industrial Group	Baltimore Gas & Electric Co.	Revenue requirement, cost allocation, rate design, Tariff issues.
01/06	2005-0034	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Co.	Return on equity.
03/06	05-1278-E-PC-PW-42T	WV	West Virginia Energy Users Group	Appalachian Power Company	Return on equity.
04/06	U-25116	LA	Louisiana Public Service Commission	Entergy Louisiana, LLC	Transmission Issues
07/06	U-23327	LA	Louisiana Public Service Commission	Southwestern Electric Power Company	Return on equity, Service quality
08/06	ER-2006-0314	MO	Missouri Office of the Public Counsel	Kansas City Power & Light Co.	Return on equity, Weighted cost of capital
08/06	06S-234EG	CO	CF&I Steel, L.P. & Climax Molybdenum	Public Service Company of Colorado	Return on equity, Weighted cost of capital
01/07	06-0960-E-42T	WV	West Virginia Energy Users Group	Monongahela Power & Potomac Edison	Return on Equity
01/07	43112		AK Steel, Inc.	Vectren South, Inc.	Cost allocation, rate design
05/07	2006-661		Maine Office of the Public Advocate	Bangor Hydro-Electric	Return on equity, weighted cost of capital.
09/07	07-07-01		Connecticut Industrial Energy Consumers	Connecticut Light & Power	Return on equity, weighted cost of capital
10/07	05-UR-103		Wisconsin Industrial Energy Group, Inc.	Wisconsin Electric Power Co.	Return on equity

Expert Testimony Appearances
of
Richard A. Baudino
As of July 2013

Date	Case	Jurisdict.	Party	Utility	Subject
11/07	29797		Louisiana Public Service Commission	Cleco Power LLC & Southwestern Elec. Power	Lignite Pricing, support of settlement
01/08	07-551-EL-AIR		Ohio Energy Group	Ohio Edison, Cleveland Electric, Toledo Edison	Return on equity
03/08	07-0585, 07-0585, 07-0587, 07-0588, 07-0589, 07-0590, (consol.)	IL	The Commercial Group	Ameren	Cost allocation, rate design
04/08	07-0566	IL	The Commercial Group	Commonwealth Edison	Cost allocation, rate design
06/08	R-2008-2011621	PA	Columbia Industrial Intervenors	Columbia Gas of PA	Cost and revenue allocation, Tariff issues
07/08	R-2008-2028394	PA	Philadelphia Area Industrial Energy users Group	PECO Energy	Cost and revenue allocation, Tariff issues
07/08	R-2008-2039634	PA	PPL Gas Large Users Gp.	PPL Gas	Retainage, LUFG Pct.
08/08	6680-UR-116	WI	Wisconsin Industrial Energy Group	Wisconsin P&L	Cost of Equity
08/08	6690-UR-119	WI	Wisconsin Industrial Energy Group	Wisconsin PS	Cost of Equity
09/08	ER-2008-0318	MO	The Commercial Group	AmerenUE	Cost and revenue allocation
10/08	R-2008-2029325	PA	U.S. Steel & Univ. of Pittsburgh Med. Ctr.	Equitable Gas Co.	Cost and revenue allocation
10/08	08-G-0609	NY	Multiple Intervenors	Niagara Mohawk Power	Cost and Revenue allocation

Expert Testimony Appearances of Richard A. Baudino As of July 2013

Date	Case	Jurisdict.	Party	Utility	Subject
12/08	27800-U	GA	Georgia Public Service Commission	Georgia Power Company	CWIP/AFUDC issues, Review financial projections
03/09	ER08-1056	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Capital Structure
04/09	E002/GR-08-1065		The Commercial Group	Northern States Power	Cost and revenue allocation and rate design
05/09	08-0532		The Commercial Group	Commonwealth Edison	Cost and revenue allocation
07/09	080677-EI		South Florida Hospital and Health Care Assn.	Florida Power & Light	Cost of equity, capital structure, Cost of short-term debt
07/09	U-30975	LA	Louisiana PSC	Cleco LLC, Southwestern Public Service Co.	Lignite mine purchase
10/09	4220-UR-116	WI	Wisconsin Industrial Energy Group	Northern States Power	Class cost of service, rate design
10/09	M-2009-2123945	PA	PP&L Industrial Customer Alliance	PPL Electric Utilities	Smart Meter Plan cost allocation
10/09	M-2009-2123944	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy Company	Smart Meter Plan cost allocation
10/09	M-2009-2123951	PA	West Penn Power Industrial Intervenors	West Penn Power	Smart Meter Plan cost allocation
11/09	M-2009-2123948	PA	Duquesne Industrial Intervenors	Duquesne Light Company	Smart Meter Plan cost allocation
11/09	M-2009-2123950	PA	Met-Ed Industrial Users Gp. Penelec Industrial Customer Alliance, Penn Power Users Group	Metropolitan Edison, Pennsylvania Electric Co., Pennsylvania Power Co.	Smart Meter Plan cost allocation
03/10	09-1352-E-42T	WV	West Virginia Energy Users Gp.	Monongahela Power, Potomac Edison	Return on equity, rate of return
03/10	E015/GR-09-1151	MN	Large Power Intervenors	Minnesota Power	Return on equity, rate of return
04/10	2009-00459	KY	Kentucky Industrial Utility Consumers	Kentucky Power	Return on equity

Expert Testimony Appearances
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Richard A. Baudino
As of July 2013

Date	Case	Jurisdict.	Party	Utility	Subject
04/10	2009-00548 2009-00549	KY	Kentucky Industrial Utility Consumers	Louisville Gas and Electric, Kentucky Utilities	Return on equity
05/10	10-0261-E-GI	WV	West Virginia Energy Users Group	Appalachian Power Co./ Wheeling Power Co.	EE/DR Cost Recovery, Allocation, & Rate Design
05/10	R-2009-2149262	PA	Columbia Industrial Intervenors	Columbia Gas of PA	Class cost of service & cost allocation
06/10	2010-00036	KY	Lexington-Fayette Urban County Government	Kentucky American Water Company	Return on equity, rate of return, revenue requirements
06/10	R-2010-2161694	PA	PP&L Industrial Customer Alliance	PPL Electric Utilities	Rate design, cost allocation
07/10	R-2010-2161575	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy Co.	Return on equity
07/10	R-2010-2161592	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy Co.	Cost and revenue allocation
07/10	9230	MD	Maryland Energy Group	Baltimore Gas and Electric	Electric and gas cost and revenue allocation; return on equity
09/10	10-70	MA	University of Massachusetts-Amherst	Western Massachusetts Electric Co.	Cost allocation and rate design
10/10	R-2010-2179522	PA	Duquesne Industrial Intervenors	Duquesne Light Company	Cost and revenue allocation, rate design
11/10	P-2010-2158084	PA	West Penn Power Industrial Intervenors	West Penn Power Co.	Transmission rate design
11/10	10-0699-E-42T	WV	West Virginia Energy Users Group	Appalachian Power Co. & Wheeling Power Co.	Return on equity, rate of Return
11/10	10-0467	IL	The Commercial Group	Commonwealth Edison	Cost and revenue allocation and rate design
04/11	R-2010-2214415	PA	Central Pen Gas Large Users Group	UGI Central Penn Gas, Inc.	Tariff issues, revenue allocation
07/11	R-2011-2239263	PA	Philadelphia Area Energy Users Group	PECO Energy	Retainage rate
08/11	R-2011-2232243	PA	AK Steel	Pennsylvania-American Water Compay	Rate Design
08/11	11AL-151G	CO	Climax Molybdenum	PS of Colorado	Cost allocation
09/11	11-G-0280	NY	Multiple Intervenors	Corning Natural Gas Co.	Cost and revenue allocation
10/11	4220-UR-117	WI	Wisconsin Industrial Energy Gp.	Northern States Power	Cost and revenue allocation, rate design

Expert Testimony Appearances
of
Richard A. Baudino
As of July 2013

Date	Case	Jurisdict.	Party	Utility	Subject
02/12	11AL-947E	CO	Climax Molybdenum, CF&I Steel	Public Svc. Of Colorado	Return on equity, wtd. cost of capital
07/12	120015-EI	FL	South Florida Hospitals and Health Care Assn.	Florida Power and Light Co.	Return on equity, wtd. cost of capital
07/12	12-0613-E-PC	WV	West Virginia Energy Users Gp.	Allegheny Power Company	Special rate proposal for Century Aluminum
07/12	R-2012-2290597	PA	PP&L Industrial Customer Alliance	PPL Electric Utilities Corp.	Cost allocation
09/12	05-UR-106	WI	Wisconsin Industrial Energy Group	Wisconsin Electric Power Co.	Class cost of service, cost and revenue allocation, rate design
09/12	2012-00221 2012-00222	KY	Kentucky Industrial Utility Consumers	Louisville Gas and Electric, Kentucky Utilities	Return on equity
10/12	9299	MD	Maryland Energy Group	Baltimore Gas & Electric	Cost and revenue allocation, rate design Cost of equity, weighted cost of capital
10/12	4220-UR-118	WI	Wisconsin Industrial Energy Group	Northern States Power Company	Class cost of service, cost and revenue allocation, rate design
10/12	473-13-0199	TX	Steering Committee of Cities Served by Oncor	Cross Texas Transmission, LLC	Return on equity, capital structure
01/13	R-2012-2321748 et al.	PA	Columbia Industrial Intervenors	Columbia Gas of Pennsylvania	Cost and revenue allocation
02/13	12AL-1052E	CO	Cripple Creek & Victor Gold Mining, Holcim (US) Inc.	Black Hills/Colorado Electric Utility Company	Cost and revenue allocations
06/13	8009	VT	IBM Corporation	Vermont Gas Systems	Cost and revenue allocation, rate design
07/13	130040-EI	FL	WCF Hospital Utility Alliance	Tampa Electric Co.	Return on equity, rate of return

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

IN RE: PETITION FOR RATE INCREASE BY TAMPA ELECTRIC COMPANY	**))**	**DOCKET NO. 130040-EI**

EXHIBIT___(RAB-2)

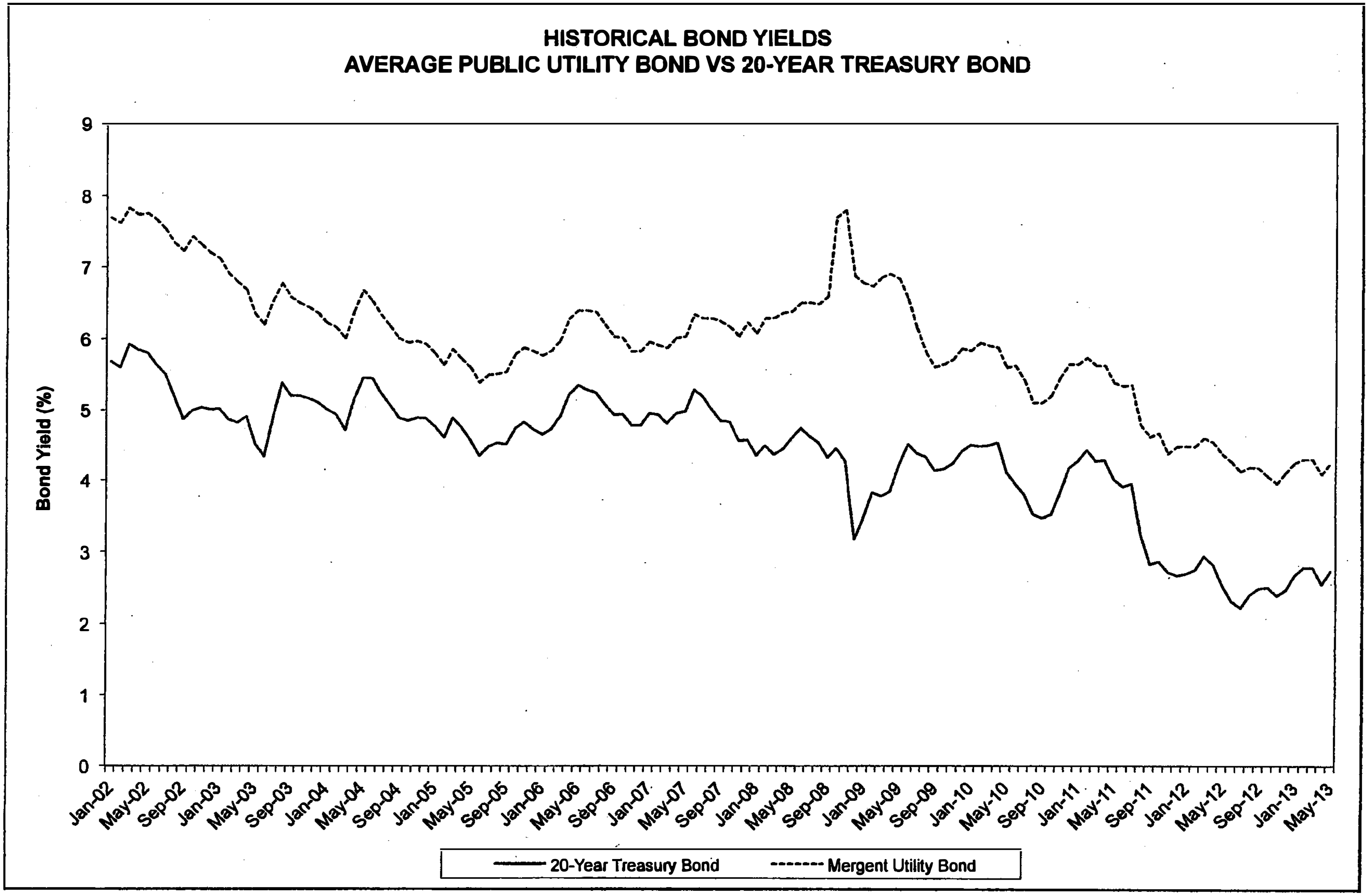
OF

RICHARD A. BAUDINO

ON BEHALF OF THE

THE WCF HOSPITAL UTILITY ALLIANCE

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA



Docket No. 130040-EI
Historical Bond Yields
Exhibit RAB-2, Page 1 of 1

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

IN RE: PETITION FOR RATE INCREASE BY TAMPA ELECTRIC COMPANY) DOCKET NO. 130040-EI

EXHIBIT___(RAB-3)

OF

RICHARD A. BAUDINO

ON BEHALF OF THE

THE WCF HOSPITAL UTILITY ALLIANCE

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

Press Release

FEDERAL RESERVE press release

Release Date: June 19, 2013

For immediate release

Information received since the Federal Open Market Committee met in May suggests that economic activity has been expanding at a moderate pace. Labor market conditions have shown further improvement in recent months, on balance, but the unemployment rate remains elevated. Household spending and business fixed investment advanced, and the housing sector has strengthened further, but fiscal policy is restraining economic growth. Partly reflecting transitory influences, inflation has been running below the Committee's longer-run objective, but longer-term inflation expectations have remained stable.

Consistent with its statutory mandate, the Committee seeks to foster maximum employment and price stability. The Committee expects that, with appropriate policy accommodation, economic growth will proceed at a moderate pace and the unemployment rate will gradually decline toward levels the Committee judges consistent with its dual mandate. The Committee sees the downside risks to the outlook for the economy and the labor market as having diminished since the fall. The Committee also anticipates that inflation over the medium term likely will run at or below its 2 percent objective.

To support a stronger economic recovery and to help ensure that inflation, over time, is at the rate most consistent with its dual mandate, the Committee decided to continue purchasing additional agency mortgage-backed securities at a pace of $40 billion per month and longer-term Treasury securities at a pace of $45 billion per month. The Committee is maintaining its existing policy of reinvesting principal payments from its holdings of agency debt and agency mortgage-backed securities in agency mortgage-backed securities and of rolling over maturing Treasury securities at auction. Taken together, these actions should maintain downward pressure on longer-term interest rates, support mortgage markets, and help to make broader financial conditions more accommodative.

The Committee will closely monitor incoming information on economic and financial developments in coming months. The Committee will continue its purchases of Treasury and agency mortgage-backed securities, and employ its other policy tools as appropriate, until the outlook for the labor market has improved substantially in a context of price stability. The Committee is prepared to increase or reduce the pace of its purchases to maintain appropriate policy accommodation as the outlook for the labor market or inflation changes. In determining the size, pace, and composition of its asset purchases, the Committee will continue to take appropriate account of the likely efficacy and costs of such purchases as well as the extent of progress toward its economic objectives.

To support continued progress toward maximum employment and price stability, the Committee expects that a highly accommodative stance of monetary policy will remain appropriate for a considerable time after the asset purchase program ends and the economic recovery strengthens. In particular, the Committee decided to keep the target range for the federal funds rate at 0 to 1/4 percent and currently anticipates that this exceptionally low range for the federal funds rate will be appropriate at least as long as the unemployment rate remains above 6-1/2 percent, inflation between one and two years ahead is projected to be no more than a half percentage point above the Committee's 2 percent longer-run goal, and longer-term inflation expectations continue to be well anchored. In determining how long to maintain a highly accommodative stance of monetary policy, the Committee will also consider other information, including additional measures of labor market conditions, indicators of inflation pressures and inflation expectations, and readings on financial developments. When the Committee decides to begin to remove policy accommodation, it will take a balanced approach consistent with its longer-run goals of maximum employment and inflation of 2 percent.

Voting for the FOMC monetary policy action were: Ben S. Bernanke, Chairman; William C. Dudley, Vice Chairman; Elizabeth A. Duke; Charles L. Evans; Jerome H. Powell; Sarah Bloom Raskin; Eric S. Rosengren; Jeremy C. Stein; Daniel K. Tarullo; and Janet L. Yellen. Voting against the action was James Bullard, who believed that the Committee should signal more strongly its willingness to defend its inflation goal in light of recent low inflation readings, and Esther L. George, who was concerned that the continued high level of monetary accommodation increased the risks of future economic and financial imbalances and, over time, could cause an increase in long-term inflation expectations.

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

IN RE: PETITION FOR RATE INCREASE BY TAMPA ELECTRIC COMPANY	))	DOCKET NO. 130040-EI

EXHIBIT___(RAB-4)

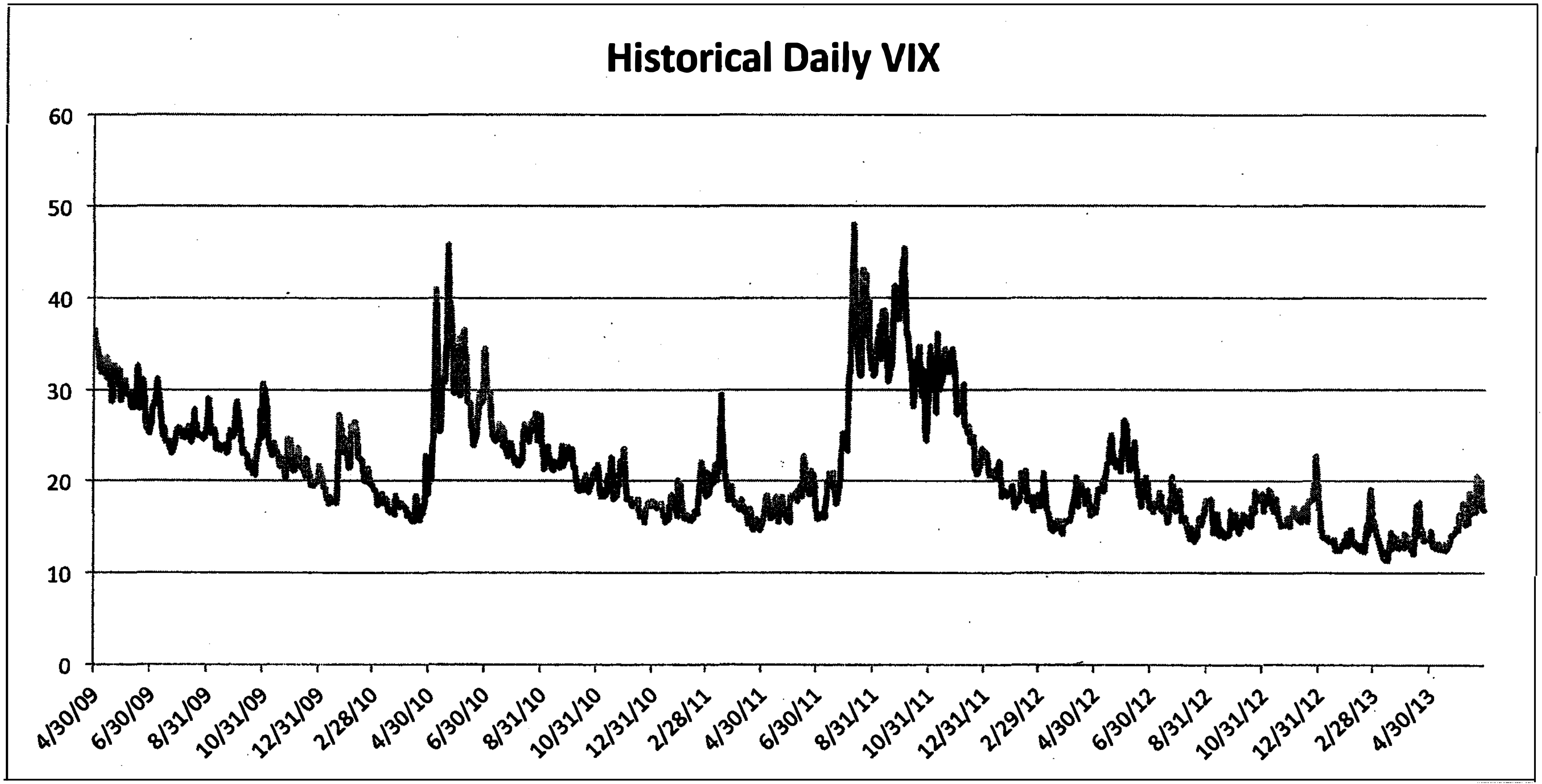
OF

RICHARD A. BAUDINO

ON BEHALF OF THE

THE WCF HOSPITAL UTILITY ALLIANCE

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA



Docket No. 130040-EI
Historical Daily VIX Values
Exhibit RAB-4, Page 1 of 1

Source: CBOE.com

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

IN RE: PETITION FOR RATE INCREASE BY TAMPA ELECTRIC COMPANY	))	DOCKET NO. 130040-EI

EXHIBIT___(RAB-5)

OF

RICHARD A. BAUDINO

ON BEHALF OF THE

THE WCF HOSPITAL UTILITY ALLIANCE

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549

FORM 10-K

_X_ Annual Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934
For the fiscal year ended December 31, 2012

OR

___ Transition Report Pursuant to Section 13 or 15(d) of the Securities xchange Act of 1934
For the transition period from ______ to ______

Commission File No.	Exact name of each Registrant as specified in its charter, state of incorporation, address of principal executive offices, telephone number	I.R.S. Employer Identification Number
1-8180	**TECO ENERGY, INC.** (a Florida corporation) T CO Plaza 702 N. Franklin Street Tampa, Florida 33602 (813) 228-1111	59-2052286
1-5007	**TAMPA ELECTRIC COMPANY** (a Florida corporation) T CO Plaza 702 N. Franklin Street Tampa, Florida 33602 (813) 228-1111	59-0475140

Securities registered pursuant to Section 12(b) of the Act:

Title of each class	Name of each exchange on which registered
TECO Energy, Inc. Common Stock, $1.00 par value	New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Act: NONE

Indicate by check mark if T CO Energy, Inc. is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act.
YES [X] NO [ ]

Indicate by check mark if Tampa Electric Company is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act.
YES [ ] NO [X]

Indicate by check mark if the registrants are not required to file reports pursuant to Section 13 or Section 15(d) of the Exchange Act.
YES [ ] NO [X]

Indicate by check mark whether the registrants (1) have filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) have been subject to such filing requirements for the past 90 days.
YES [X] NO [ ]

Indicate by check mark whether the registrants have submitted electronically and posted on their corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrants were required to submit and post such files).
YES [X] NO [ ]

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrants' knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. [ ]

Indicate by check mark whether TECO Energy, Inc. is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act.

Large accelerated filer [X] Accelerated filer [ ] Non-accelerated filer [ ] Smaller reporting company [ ]

Indicate by check mark whether Tampa Electric Company is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting

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DEFINITIONS

Acronyms and defined terms used in this and other filings with the U.S. Securities and Exchange Commission include the following:

Term	Meaning
ABS	asset-backed security
ADR	American depository receipt
AFUDC	allowance for funds used during construction
AFUDC - debt	debt component of allowance for funds used during construction
AFUDC - equity	equity component of allowance for funds used during construction
AMT	alternative minimum tax
AOCI	accumulated other comprehensive income
APBO	accumulated postretirement benefit obligation
ARO	asset retirement obligation
BACT	Best Available Control Technology
BTU	British Thermal Unit
capacity clause	capacity cost-recovery clause, as established by the FPSC
CCRs	coal combustion residuals
CERCLA	Comprehensive Environmental Response, Compensation and Liability Act of 1980
CGESJ	Central Generadora Eléctrica San José, Limitada, owner of the San José Power Station in Guatemala
CMMA	Cardno MM&A
CMO	collateralized mortgage obligation
CNG	compressed natural gas
CPI-U	consumer price index - all urban consumers
CO_2	carbon dioxide
CT	combustion turbine
DECA II	Distribución Eléctrica Centro Americana, II, S.A.
DOE	U.S. Department of Energy
ECRC	environmental cost recovery clause
EEGSA	Empresa Eléctrica de Guatemala, S.A., the largest private distribution company in Central America
EEI	Edison Electric Institute
EGWP	Employee Group Waiver Plan
EPA	U.S. Environmental Protection Agency
EPS	earnings per share
ERISA	Employee Retirement Income Security Act
EROA	expected return on plan assets
ERP	enterprise resource planning
FASB	Financial Accounting Standards Board
FDEP	Florida Department of Environmental Protection
FERC	Federal Energy Regulatory Commission
FGT	Florida Gas Transmission Company
FPSC	Florida Public Service Commission
fuel clause	fuel and purchased power cost-recovery clause, as established by the FPSC
GAAP	generally accepted accounting principles
GHG	greenhouse gas(es)
HCIDA	Hillsborough County Industrial Development Authority
HPP	Hardee Power Partners
IFRS	International Financial Reporting Standards
IGCC	integrated gasification combined-cycle
IOU	investor owned utility
IRS	Internal Revenue Service
ISDA	International Swaps and Derivatives Association
ISO	independent system operator
ITCs	investment tax credits
kW	Kilowatt(s)
kWh	kilowatt-hour(s)

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LIBOR	London Interbank Offered Rate
MAP-21	Moving Ahead for Progress in the 21st Century Act
MARN	Ministry of Environment, Guatemala
MBS	mortgage-backed securities
MD&A	Management's Discussion and Analysis
met	mettalurgical
MMA	The Medicare Prescription Drug, Improvement and Modernization Act of 2003
MMBTU	one million British Thermal Units
MRV	market-related value
MSHA	Mine Safety and Health Administration
MW	megawatt(s)
MWh	megawatt-hour(s)
NAESB	North American Energy Standards Board
NAV	net asset value
NERC	North American Electric Reliability Corporation
NOL	net operating loss
Note __	Note __ to consolidated financial statements
NO_x	nitrogen oxide
NPNS	normal purchase normal sale
NYMEX	New York Mercantile Exchange
O&M expenses	operations and maintenance expenses
OATT	open access transmission tariff
OCI	other comprehensive income
OTC	over-the-counter
OTTI	other than temporary impairment
PBGC	Pension Benefit Guarantee Corporation
PBO	postretirement benefit obligation
PCI	pulverized coal injection
PCIDA	Polk County Industrial Development Authority
PGA	purchased gas adjustment
PGS	Peoples Gas System, the gas division of Tampa Electric Company
PPA	power purchase agreement
PPSA	Power Plant Siting Act
PRP	potentially responsible party
PUHCA 2005	Public Utility Holding Company Act of 2005
REIT	real estate investment trust
REMIC	real estate mortgage investment conduit
RFP	request for proposal
ROE	return on common equity
Regulatory ROE	return on common equity as determined for regulatory purposes
RPS	renewable portfolio standards
RTO	regional transmission organization
S&P	Standard and Poor's
SCR	selective catalytic reduction
SEC	U.S. Securities and Exchange Commission
SO_2	sulfur dioxide
SERP	Supplemental Executive Retirement Plan
SPA	stock purchase agreement
STIF	short-term investment fund
TCAE	Tampa Centro Americana de Electridad, Limitada, majority owner of the Alborada Power Station
Tampa Electric	Tampa Electric, the electric division of Tampa Electric Company

TEC	Tampa Electric Company, the principal subsidiary of TECO Energy, Inc.
TECO Diversified	TECO Diversified, Inc., a subsidiary of TECO Energy, Inc. and parent of TECO Coal Corporation
TECO Coal	TECO Coal Corporation, and its subsidiaries, a coal producing subsidiary of TECO Diversified
TECO Finance	TECO Finance, Inc., a financing subsidiary for the unregulated businesses of TECO Energy, Inc.
TECO Guatemala	TECO Guatemala, Inc., a subsidiary of TECO Energy, Inc., parent company of formerly owned generating and transmission assets in Guatemala.
TEMSA	Tecnología Marítima, S.A., a provider of dry bulk and coal unloading services located in Guatemala
TRC	TEC Receivables Company
USACE	U.S. Army Corps of Engineers
VIE	variable interest entity
WRERA	The Worker, Retiree and Employer Recovery Act of 2008

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Revenues from Continuing Operations *(millions)*	*2012*	*2011*	*2010*
Tampa Electric	$ 1,981.3	$ 2,020.6	$ 2,163.2
PGS	398.9	453.5	529.9
Total regulated businesses	$ 2,380.2	$ 2,474.1	$ 2,693.1
TECO Coal	608.9	733.0	690.0
Other and Eliminations	7.5	2.8	(19.6)
Total revenues from continuing operations	$ 2,996.6	$ 3,209.9	$ 3,363.5

For additional financial information regarding TECO Energy's significant business segments including geographic areas, see **Note 14** to the TECO Energy **Consolidated Financial Statements**.

Discontinued Operations/Asset Dispositions

TECO Energy, Inc. completed the sale of its generating and transmission assets in Guatemala during 2012 as part of a business strategy to focus on the domestic electric and gas utilities.

On Sept. 27, 2012, TECO Guatemala entered into an agreement to sell all of the equity interests in the Alborada and San José power stations, related facilities and operations in Guatemala, for a total purchase price of $227.5 million in cash. The sale of the Alborada Power Station closed on the same date for a selling price of $12.5 million.

On Dec. 19, 2012, the closing occurred on the sale of the San José power station and related facilities in Guatemala for a purchase price of $215.0 million.

See **Notes 19, 20** and **21** to the **TECO Energy, Inc. Consolidated Financial Statements** for more information regarding these discontinued operations and asset dispositions.

TAMPA ELECTRIC – Electric Operations

TEC was incorporated in Florida in 1899 and was reincorporated in 1949. TEC is a public utility operating within the State of Florida. Its Tampa Electric division is engaged in the generation, purchase, transmission, distribution and sale of electric energy. The retail territory served comprises an area of about 2,000 square miles in West Central Florida, including Hillsborough County and parts of Polk, Pasco and Pinellas Counties, with an estimated population of over one million. The principal communities served are Tampa, Temple Terrace, Winter Haven, Plant City and Dade City. In addition, Tampa Electric engages in wholesale sales to utilities and other resellers of electricity. It has three electric generating stations in or near Tampa, one electric generating station in southwestern Polk County, Florida and one electric generating station in long-term reserve standby located near Sebring, a city in Highlands County in South Central Florida.

Tampa Electric had 2,369 employees as of Dec. 31, 2012, of which 906 were represented by the International Brotherhood of Electrical Workers and 167 were represented by the Office and Professional Employees International Union.

In 2012, approximately 48% of Tampa Electric's total operating revenue was derived from residential sales, 31% from commercial sales, 9% from industrial sales and 12% from other sales, including bulk power sales for resale. Approximately 5% of revenues were attributable to governmental municipalities. The sources of operating revenue and MWH sales for the years indicated were as follows:

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The transmission rate case updated Tampa Electric's charges under its FERC-approved OATT for the various forms of wholesale transmission service it provides. These rates were last updated in 2003, pursuant to a settlement agreement between the company and its then transmission customers. The wholesale requirements rate proceeding addressed the rates and terms and conditions of Tampa Electric's existing wholesale customers.

The FERC approved Tampa Electric's proposed transmission rates as filed with the FERC, which became effective Sept. 14, 2010, subject to refund. The FERC also approved Tampa Electric's proposed wholesale requirements rates, as filed with the FERC, which became effective March 1, 2011, subject to refund. The proposed and ultimately accepted wholesale requirements and transmission rates did not have a material impact on Tampa Electric's results.

Settlements were reached with the applicable customers in both cases during 2011 and filed with the FERC during the first quarter of 2012. The FERC accepted these settlements as filed, and the settlements took effect during the latter part of 2012. Refunds with interest were provided to the customers last year for the differences between the settlement rates and the charges that were earlier approved by the FERC to be implemented conditionally.

Transactions between Tampa Electric and its affiliates are subject to regulation by the FPSC and FERC, and any charges deemed to be imprudently incurred may be disallowed for recovery from Tampa Electric's retail and wholesale customers.

On Nov. 6, 2012, Tampa Electric received notification from the FERC that its accounting practices and financial reporting processes would be audited, along with its compliance with the FERC's records retention requirements. This is considered a routine audit by the FERC staff, though it has been approximately 20 years since Tampa Electric last had a FERC accounting audit.

Federal, state and local environmental laws and regulations cover air quality, water quality, land use, power plant, substation and transmission line siting, noise and aesthetics, solid waste and other environmental matters (see the **Environmental Matters** section).

Competition

Tampa Electric's retail electric business is substantially free from direct competition with other electric utilities, municipalities and public agencies. At the present time, the principal form of competition at the retail level consists of self-generation available to larger users of electric energy. Such users may seek to expand their alternatives through various initiatives, including legislative and/or regulatory changes that would permit competition at the retail level. Tampa Electric intends to retain and expand its retail business by managing costs and providing quality service to retail customers.

Unlike the retail electric business, Tampa Electric competes in the wholesale power market with other energy providers in Florida, including approximately 30 other investor-owned, municipal and other utilities, as well as co-generators and other unregulated power generators with uncontracted excess capacity. Entities compete to provide energy on a short-term basis (i.e., hourly or daily) and on a long-term basis. Competition in these markets is primarily based on having available energy to sell to the wholesale market and the price. In Florida, available energy for the wholesale markets is affected by the state's PPSA, which sets the state's electric energy and environmental policy, and governs the building of new generation involving steam capacity of 75 MW or more. The PPSA requires that applicants demonstrate that a plant is needed prior to receiving construction and operating permits. The effect of the PPSA has been to limit the number of unregulated generating units with excess capacity for sale in the wholesale power markets in Florida.

Tampa Electric is not a major participant in the wholesale market because it uses its lower cost generation to serve its retail customers rather than the wholesale market. Over the past three years, gross revenues from wholesale sales, which include fuel that is a pass-through cost, have averaged approximately 1% of Tampa Electric's total revenue.

FPSC rules promote cost-competitiveness in the building of new steam generating capacity by requiring IOUs, such as Tampa Electric, to issue RFPs prior to filing a petition for Determination of Need for construction of a power plant with a steam cycle greater than 75 MW. These rules, which allow independent power producers and others to bid to supply the new generating capacity, provide a mechanism for expedited dispute resolution, allow bidders to submit new bids whenever the IOU revises its cost estimates for its self-build option, require IOUs to disclose the methodology and criteria to be used to evaluate the bids and provide more stringent standards for the IOUs to recover cost overruns in the event that the self-build option is deemed the most cost-effective.

Fuel

Approximately 61% of Tampa Electric's generation of electricity for 2012 was coal-fired, with natural gas representing approximately 39% and oil representing less than 1%. Tampa Electric used its generating units to meet approximately 94% of the total system load requirements, with the remaining 6% coming from purchased power. Tampa Electric's average delivered fuel cost per MMBTU and average delivered cost per ton of coal burned have been as follows:

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Average cost per MMBTU	*2012*	*2011*	*2010*	*2009*	*2008*
Coal	$ 3.57	$ 3.46	$ 3.08	$ 3.05	$ 2.91
Oil	25.88	21.21	16.43	16.01	20.48
Gas (Natural)	5.34	6.20	6.74	8.00	10.61
Composite	4.19	4.38	4.46	5.02	5.56
Average cost per ton of coal burned	84.59	83.17	74.80	72.98	69.14

Tampa Electric's generating stations burn fuels as follows: Bayside Station burns natural gas; Big Bend Station, which has SO_2 scrubber capabilities and NO_x reduction systems, burns a combination of high-sulfur coal and petroleum coke, No. 2 fuel oil and natural gas at CT4; Polk Power Station burns a blend of low-sulfur coal and petroleum coke (which is gasified and subject to sulfur and particulate matter removal prior to combustion), natural gas and oil; and Phillips Station, which burned residual fuel oil and was placed on long-term standby in September 2009.

Coal. Tampa Electric burned approximately 4.7 million tons of coal and petroleum coke during 2012 and estimates that its combined coal and petroleum coke consumption will be about 4.8 million tons in 2013. During 2012, Tampa Electric purchased approximately 80% of its coal under long-term contracts with four suppliers, and approximately 20% of its coal and petroleum coke in the spot market. Tampa Electric expects to obtain approximately 71% of its coal and petroleum coke requirements in 2013 under long-term contracts with four suppliers and the remaining 29% in the spot market.

Tampa Electric's long-term contracts provide for revisions in the base price to reflect changes in several important cost factors and for suspension or reduction of deliveries if environmental regulations should prevent Tampa Electric from burning the coal supplied, provided that a good faith effort has been made to continue burning such coal.

In 2012, approximately 86% of Tampa Electric's coal supply was deep-mined, approximately 8% was surface-mined and the remaining was petroleum coke. Federal surface-mining laws and regulations have not had any material adverse impact on Tampa Electric's coal supply or results of its operations. Tampa Electric cannot predict, however, the effect of any future mining laws and regulations.

Natural Gas. As of Dec. 31, 2012, approximately 65% of Tampa Electric's 1,250,000 MMBTU gas storage capacity was full. Tampa Electric has contracted for 70% of its expected gas needs for the April 2013 through October 2013 period. In early March 2013, to meet its generation requirements, Tampa Electric expects to issue RFPs to meet its remaining 2013 gas needs and begin contracting for its 2014 gas needs. Additional volume requirements in excess of projected gas needs are purchased on the short-term spot market.

Oil. Tampa Electric has agreements in place to purchase low sulfur No. 2 fuel oil for its Big Bend and Polk Power stations. All of these agreements have prices that are based on spot indices.

Franchises and Other Rights

Tampa Electric holds franchises and other rights that, together with its charter powers, govern the placement of Tampa Electric's facilities on the public rights-of-way as it carries for its retail business in the localities it serves. The franchises specify the negotiated terms and conditions governing Tampa Electric's use of public rights-of-way and other public property within the municipalities it serves during the term of the franchise agreement. The franchises are irrevocable and not subject to amendment without the consent of Tampa Electric (except to the extent certain city ordinances relating to permitting and like matters are modified from time to time), although, in certain events, they are subject to forfeiture.

Florida municipalities are prohibited from granting any franchise for a term exceeding 30 years. The City of Temple Terrace reserved the right to purchase Tampa Electric's property used in the exercise of its franchise if the franchise is not renewed. In the absence of such right to purchase, based on judicial precedent, if the franchise agreement is not renewed, Tampa Electric would be able to continue to use public rights-of-way within the municipality, subject to reasonable rules and regulations imposed by the municipalities.

Tampa Electric has franchise agreements with 13 incorporated municipalities within its retail service area. These agreements have various expiration dates through September 2040.

Franchise fees payable by Tampa Electric, which totaled $44.3 million at Dec. 31, 2012, are calculated using a formula based primarily on electric revenues and are collected on customers' bills.

Utility operations in Hillsborough, Pasco, Pinellas and Polk Counties outside of incorporated municipalities are conducted in each case under one or more permits to use state or county rights-of-way granted by the Florida Department of Transportation or the County Commissioners of such counties. There is no law limiting the time for which such permits may be granted by counties. There are no fixed expiration dates for the Hillsborough County, Pinellas County and Polk County agreements. The agreement covering electric operations in Pasco County expires in 2023.

Environmental Matters

Tampa Electric operates stationary sources with air emissions regulated by the Clean Air Act, and material Clean Water Act implications and impacts by federal and state legislative initiatives. Tampa Electric Company, through its Tampa

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Electric and PGS divisions, is a PRP for certain superfund sites and, through its PGS division, for certain former manufactured gas plant sites.

Emission Reductions

Tampa Electric has undertaken major steps to dramatically reduce its air emissions through a series of voluntary actions, including technology selection (e.g., IGCC) and conversion of coal-fired units to natural-gas fired combined cycle); implementation of a responsible fuel mix taking into account price and reliability impacts to its customers; a substantial capital expenditure program to add BACT emissions controls; implementation of additional controls to accomplish early reductions of certain emissions; and enhanced controls and monitoring systems for certain pollutants.

Tampa Electric, through voluntary negotiations in 1999 with the EPA, the U.S. Department of Justice and the FDEP, signed a Consent Decree, as settlement of federal and state litigation to dramatically decrease emissions from its power plants. Tampa Electric has notified the parties that all obligations of the Consent Decree have been fulfilled and intends to file documents with the court to terminate the Consent Decree in 2013.

The emission reduction requirements of these agreements resulted in the repowering of the coal-fired Gannon Power Station to natural gas, which was renamed as the H. L. Culbreath Bayside Power Station (Bayside Power Station), enhanced availability of flue-gas desulfurization systems (scrubbers) at Big Bend Station to help reduce SO_2, and installation of SCR systems for NO_x reduction on Big Bend Units 1 through 4. Cost recovery for the SCRs began for each unit in the year that the unit entered service through the ECRC (see the **Regulation** section).

As a result of the actions taken under the consent decree, emissions of all pollutant types have been significantly reduced. Since 1998, Tampa Electric has reduced annual SO_2, NOx and PM emissions from its facilities by 164,000 tons (94%), 63,000 tons (91%) and 4,500 tons (87%), respectively.

Reductions in mercury emissions also have occurred due to the repowering of the Gannon Power Station to the Bayside Power Station. At the Bayside Power Station, where mercury levels have decreased 99% below 1998 levels, there are virtually zero mercury emissions. Additional mercury reductions have been achieved from the installation of the SCRs at Big Bend Power Station, which have led to a system wide reduction of mercury emissions of more than 90% from 1998 levels.

Carbon Reductions and GHG

Tampa Electric has historically supported voluntary efforts to reduce carbon emissions and has taken significant steps to reduce overall emissions at Tampa Electric's facilities. Since 1998, Tampa Electric has reduced its system-wide emissions of CO_2 by approximately 20%, bringing emissions to near 1990 levels. Tampa Electric expects emissions of CO_2 to remain near 1990 levels until the addition of the next baseload unit, which is scheduled to be in service in January 2017 (see the **Tampa Electric** and **Capital Expenditures** sections). Tampa Electric estimates that the repowering to natural gas and the shut-down of the Gannon Station coal-fired units resulted in an annual decrease in CO_2 emissions of approximately 4.8 million tons below 1998 levels. During this same time frame, the numbers of retail customers and retail energy sales have risen by approximately 25%.

Tampa Electric expects that the costs to comply with new environmental regulations would be eligible for recovery through the ECRC. If approved as prudent, the costs required to comply with CO_2 emissions reductions would be reflected in customers' bills. If the regulation allowing cost recovery is changed and the cost of compliance is not recovered through the ECRC, Tampa Electric could seek to recover those costs through a base-rate proceeding, but cannot predict whether the FPSC would grant such recovery.

Superfund and Former Manufactured Gas Plant Sites

TEC, through its Tampa Electric division, is a PRP for certain superfund sites and, through its PGS division, for certain former manufactured gas plant sites. While the joint and several liability associated with these sites presents the potential for significant response costs, as of Dec. 31, 2012, TEC has estimated its ultimate financial liability to be approximately $37.5 million (primarily related to PGS), and this amount has been reflected in the company's financial statements. The environmental remediation costs associated with these sites, which are expected to be paid over many years, are not expected to have a significant impact on customer prices. The amounts represent only the estimated portion of the cleanup costs attributable to TEC. The estimates to perform the work are based on actual estimates obtained from contractors or TEC's experience with similar work, adjusted for site specific conditions and agreements with the respective governmental agencies. The estimates are made in current dollars, are not discounted and do not assume any insurance recoveries.

Allocation of the responsibility for remediation costs among TEC and other PRPs is based on each party's relative ownership interest in or usage of a site. Accordingly, TEC's share of remediation costs varies with each site. In virtually all instances where other PRPs are involved, those PRPs are considered credit-worthy.

Factors that could impact these estimates include the ability of other PRPs to pay their pro-rata portion of the cleanup costs, additional testing and investigation which could expand the scope of the cleanup activities, additional liability that might arise from the cleanup activities themselves or changes in laws or regulations that could require additional remediation. Under current regulation, these additional costs would be eligible for recovery through customer rates.

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REGULATION

Tampa Electric's and PGS's retail operations are regulated by the FPSC, which has jurisdiction over retail rates, quality of service and reliability, issuances of securities, planning, siting and construction of facilities, accounting and depreciation practices, and other matters.

In general, the FPSC's pricing objective is to set rates at a level that provides an opportunity for the utility to collect total revenues (revenue requirements) equal to its cost to provide service, plus a reasonable return on invested capital.

For both Tampa Electric and PGS, the costs of owning, operating and maintaining the utility systems, excluding fuel and conservation costs as well as purchased power and certain environmental costs for the electric system, are recovered through base rates. These costs include O&M expense, depreciation and taxes, as well as a return on investment in assets used and useful in providing electric and natural gas distribution services (rate base). The rate of return on rate base, which is intended to approximate the individual company's weighted cost of capital, primarily includes its costs for debt, deferred income taxes at a zero-cost rate and an allowed ROE. Base rates are determined in FPSC revenue requirement and rate setting hearings which occur at irregular intervals at the initiative of Tampa Electric, PGS, the FPSC or other parties.

Tampa Electric is also subject to regulation by the FERC in various respects, including wholesale power sales, certain wholesale power purchases, transmission and ancillary services, and accounting practices.

Federal, state and local environmental laws and regulations cover air quality, water quality, land use, power plant, substation and transmission line siting, noise and aesthetics, solid waste and other environmental matters (see the **Environmental Compliance** section).

Tampa Electric - Base Rates

Tampa Electric's rates and allowed ROE range of 10.25% to 12.25%, with a midpoint of 11.25%, were established in 2009, and are in effect until such time as changes are occasioned by an agreement approved by the FPSC or other FPSC actions as a result of rate or other proceedings initiated by Tampa Electric, the FPSC or other interested parties.

Tampa Electric's base rates were established in March 2009, when the FPSC awarded $104 million higher revenue requirements effective in May 2009 that authorized an ROE mid-point of 11.25%, 54.0% equity in the capital structure, and 2009 13-month average rate base of $3.4 billion. In a series of subsequent decisions in 2009 and 2010 related to a calculation error and a step increase for five peaking combustion turbines and solid-fuel rail unloading facilities at the Big Bend Power Station that entered service before the end of 2009, base rates increased an additional $33.5 million.

As a result of increasing pressure on O&M expense, higher depreciation expense from required infrastructure added to serve customers, and an economic recovery that has been slower than expected compared to the assumptions in Tampa Electric's last base rate proceeding in 2009, on Feb. 4, 2013, Tampa Electric notified the FPSC that it is planning to file a new base rate proceeding in April for new rates effective in early 2014. The actual revenue requirement calculation is not final, but is estimated to be approximately $135 million.

Tampa Electric Cost-Recovery Clauses

Fuel, purchased power, conservation and certain environmental costs are recovered through levelized monthly charges established pursuant to the FPSC's cost-recovery clauses. These charges, which are reset annually in an FPSC proceeding, are based on estimated fuel, environmental compliance, conservation programs and purchased power costs and estimated customer usage for a calendar year recovery period, with a true-up adjustment to reflect the variance of actual costs to projected costs for prior periods. The FPSC may disallow recovery of any costs it considers unreasonable or imprudently incurred.

In September 2012, Tampa Electric filed with the FPSC for approval of cost-recovery rates for fuel and purchased power, capacity, environmental and conservation costs for the period January through December 2013. In November 2012, the FPSC approved Tampa Electric's requested rates. The rates include the projected cost for natural gas, oil and coal, including transportation, for 2012 and the net over-recovery of fuel, purchased power and capacity clause expenses, which were collected in 2012 and 2011. Rates approved for 2013 also reflected a two-tiered residential fuel factor structure with a lower factor for the first 1,000 kWh used each month. Due to increased reliance on natural gas to fuel its generating fleet and continued low natural gas prices, Tampa Electric's residential customer rate per 1,000 kWh decreased 4% from $106.90 in 2012 to $102.58 in 2013.

Transmission and Wholesale Rate Cases

In July 2010, Tampa Electric filed transmission rate and wholesale requirements cases with the FERC. The

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

IN RE: PETITION FOR RATE INCREASE BY TAMPA ELECTRIC COMPANY	))	DOCKET NO. 130040-EI

EXHIBIT___(RAB-6)

OF

RICHARD A. BAUDINO

ON BEHALF OF THE

THE WCF HOSPITAL UTILITY ALLIANCE

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

TECO ENERGY

TECO Energy
American Gas Association Financial Forum

Naples, FL
May 6, 2013

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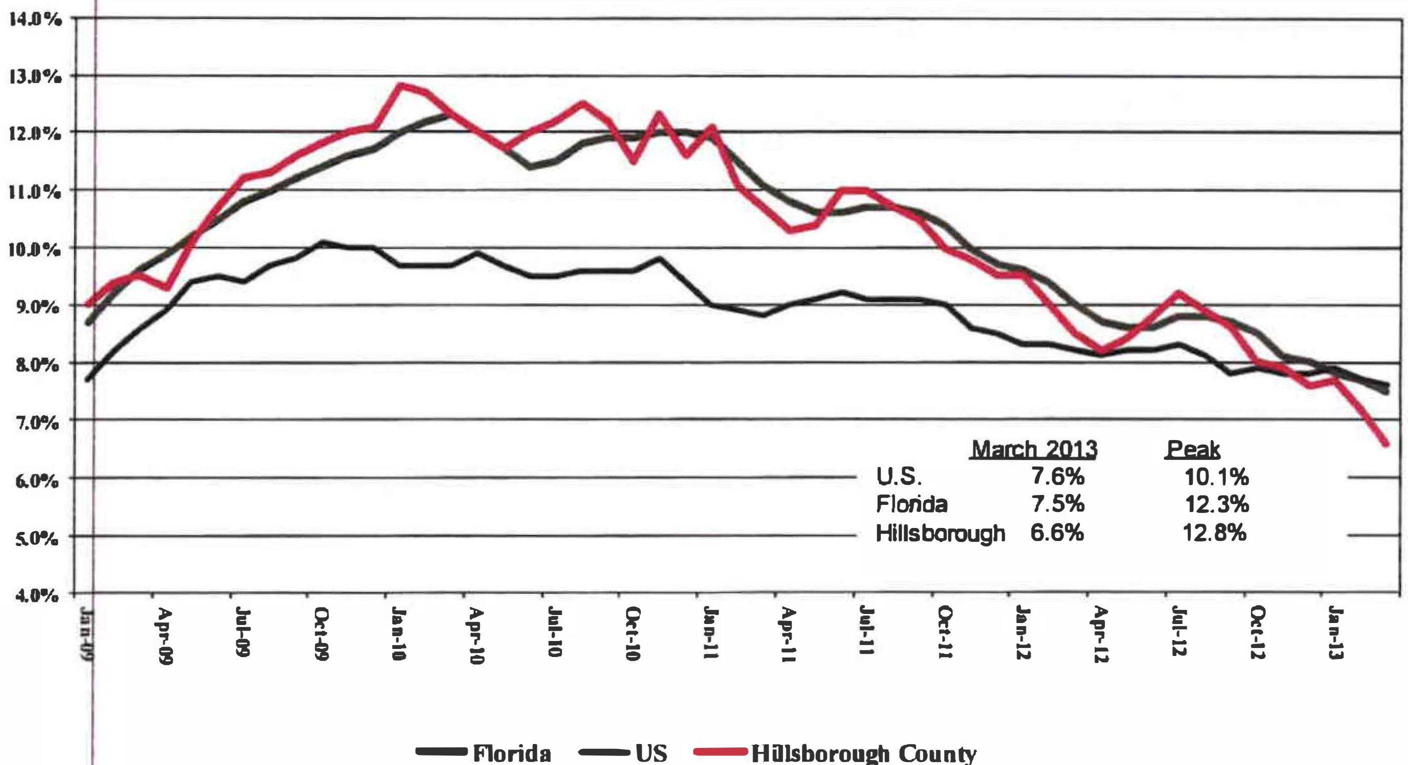
Exhibit RAB-6, Page 1 of 19

Unemployment Trends



	March 2013	Peak
U.S.	7.6%	10.1%
Florida	7.5%	12.3%
Hillsborough	6.6%	12.8%

Source: Florida Agency for Workforce Innovation

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TECO ENERGY

Tampa MSA Employment Trends

Source: Florida Agency for Workforce Innovation

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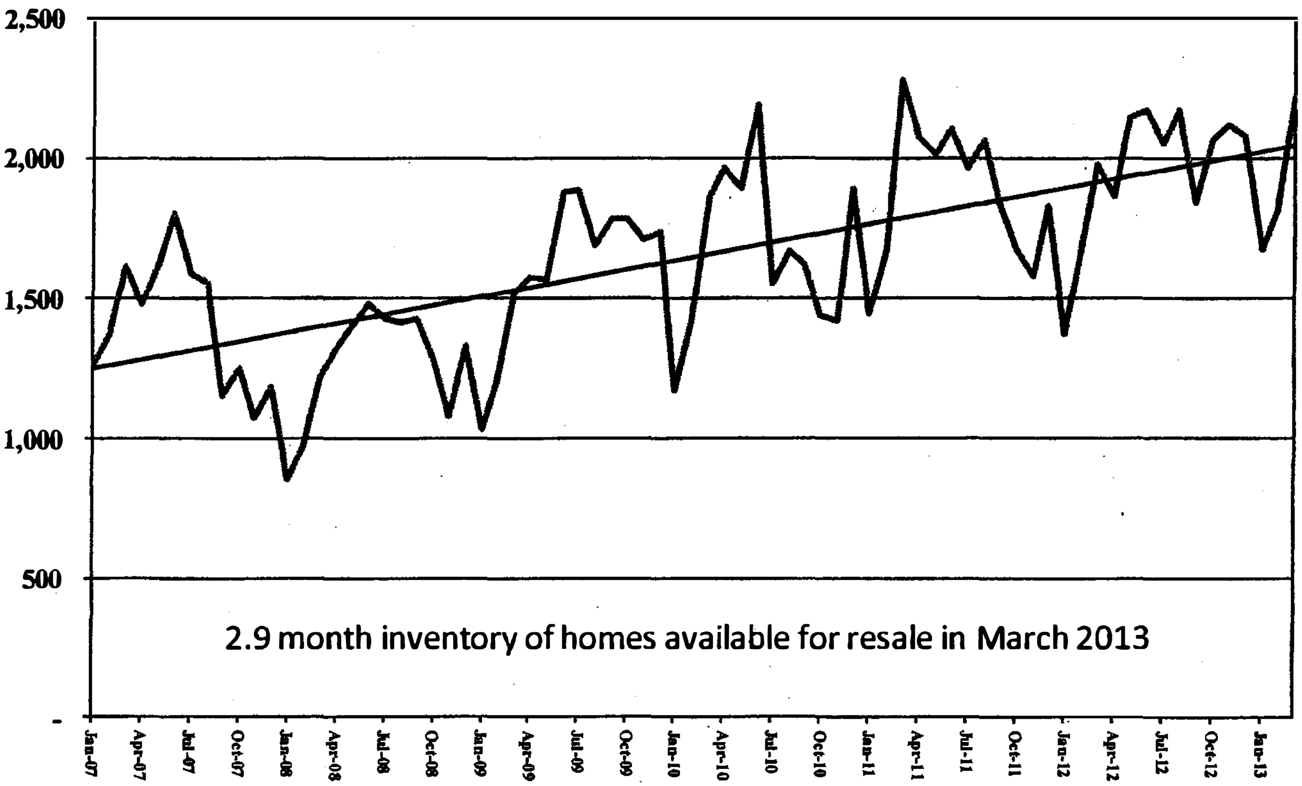
TECO ENERGY

Tampa Area Existing Home Resales



Source: Greater Tampa Association of Realtors

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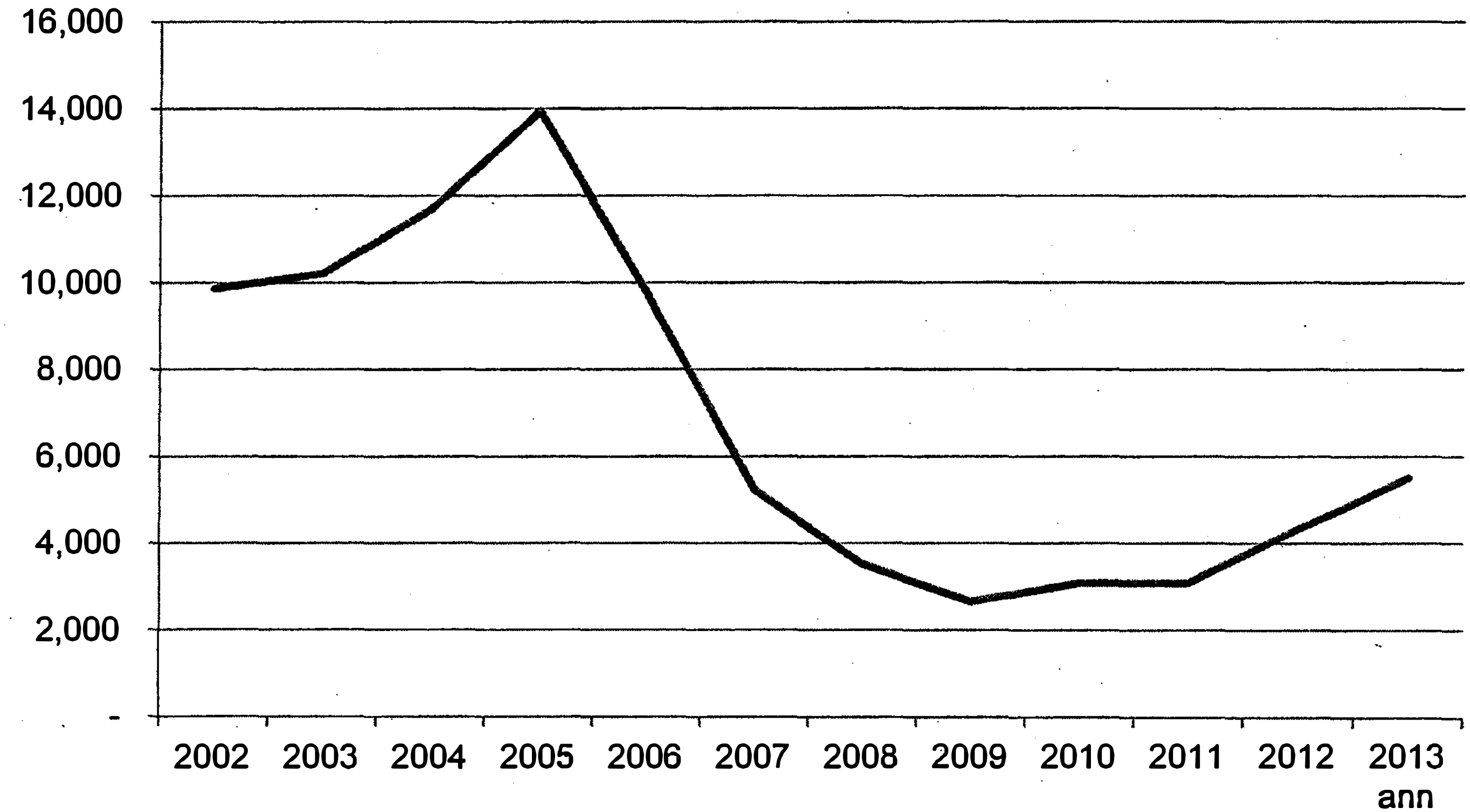
Annual Single Family Building Permits



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TECO ENERGY

Parent Cash Overview

- NOL position provides significant cash to parent
  - NOL tax asset $465 million at 3/31/13
  - AMT credit carry forwards $215 million at 3/31/13
- Bonus depreciation and repair treatment have extended NOL realization
  - Expect to realize NOL benefits through 2017, AMT carry forwards available after NOL's are exhausted
  - Most recent impact coincides with Tampa Electric's need for cash from parent to support capital structure ($220 - $250 million)
  - Majority of proceeds from the sale of TECO Guatemala will support investment in Tampa Electric in this time period
- Support Tampa Electric's capital spending program without issuing equity

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TECO ENERGY

Conclusion

- Meeting the challenges of 2013
  - Tampa Electric's need for base rate relief
  - Maintaining TECO Coal profitability in weak coal market
- Outlook for improved 2014 financial results is strong
  - New rates at Tampa Electric
  - Continued growth in the state and local economies
  - Investments in our core utilities
    - Investment in Polk 2 – 5 conversion
    - Conversions from petroleum and propane to natural gas and compressed natural gas vehicle conversions growing
- Strong cash flow generation supports growth
- Significant balance sheet and credit ratings improvements

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TECO ENERGY

TECO Energy

American Gas Association Financial Forum

Scottsdale, AZ

May 7, 2012

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TECO
ENERGY

John Ramil

Chief Executive Officer

Docket No. 130040-EI
TECO Energy Investor Presentations
Exhibit RAB-6, Page 9 of 19

TECO ENERGY

Florida Economy

- Unemployment rate declining
  - U.S. 8.2 %, Florida 9.0%, Hillsborough County 8.5%
  - Florida's civilian labor force grew 56,000 over past 12 months
- Employment is increasing
  - Florida added 90,000 jobs in the last year
    - Retail trade, transportation, professional services, private health and education services and tourism related
  - Tampa area added more than 20,000 jobs in the last year
    - Second largest job growth in Florida over that period
- Taxable sales are increasing
- Outlook is for continued improvement in the economy

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TECO ENERGY

Florida Economy

- Housing market continues to improve
  - Metrostudy data indicates Tampa area new home construction activity is increasing
    - Single family building permits trending up
  - Existing home resales +5% 12-months ended March 2012
  - Inventory of existing homes for sale less than 6 months
    - Does not include foreclosures not on the market
  - Average selling prices generally improving
- Foreclosure activity in Tampa Electric's primary service area are comparable to national trends
  - RealtyTrac data indicates 11,000 homes in foreclosure in Hillsborough County, up from year-end, but down from 16,000 March 2011

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TECO ENERGY

Expect Significant Cash Generation

- TECO Energy expects to generate significant free cash flow after dividends for the next several years
  - Strong cash generation from operating companies
  - Net Operating Loss (NOL) position for income tax purposes
    - $450 million balance at 12/31/11
    - Expect to pay minimal cash taxes through 2016
  - No significant TECO Energy debt maturities until 2015
    - Expect cash generation to retire 2015 debt
- Tampa Electric and PGS expect to fund growth through internally generated funds, equity contributions from parent and external debt financing

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TECO ENERGY

Conclusion

- Florida economy is improving
- Expect the Florida utilities to earn allowed returns
- Long-term growth at Tampa Electric from investment in generating capacity
- Strong cash flow generation
  - Ability to fund capital expenditures
- Dividend policy targeting a payout ratio of 60-70% of consolidated net income

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APPENDIX

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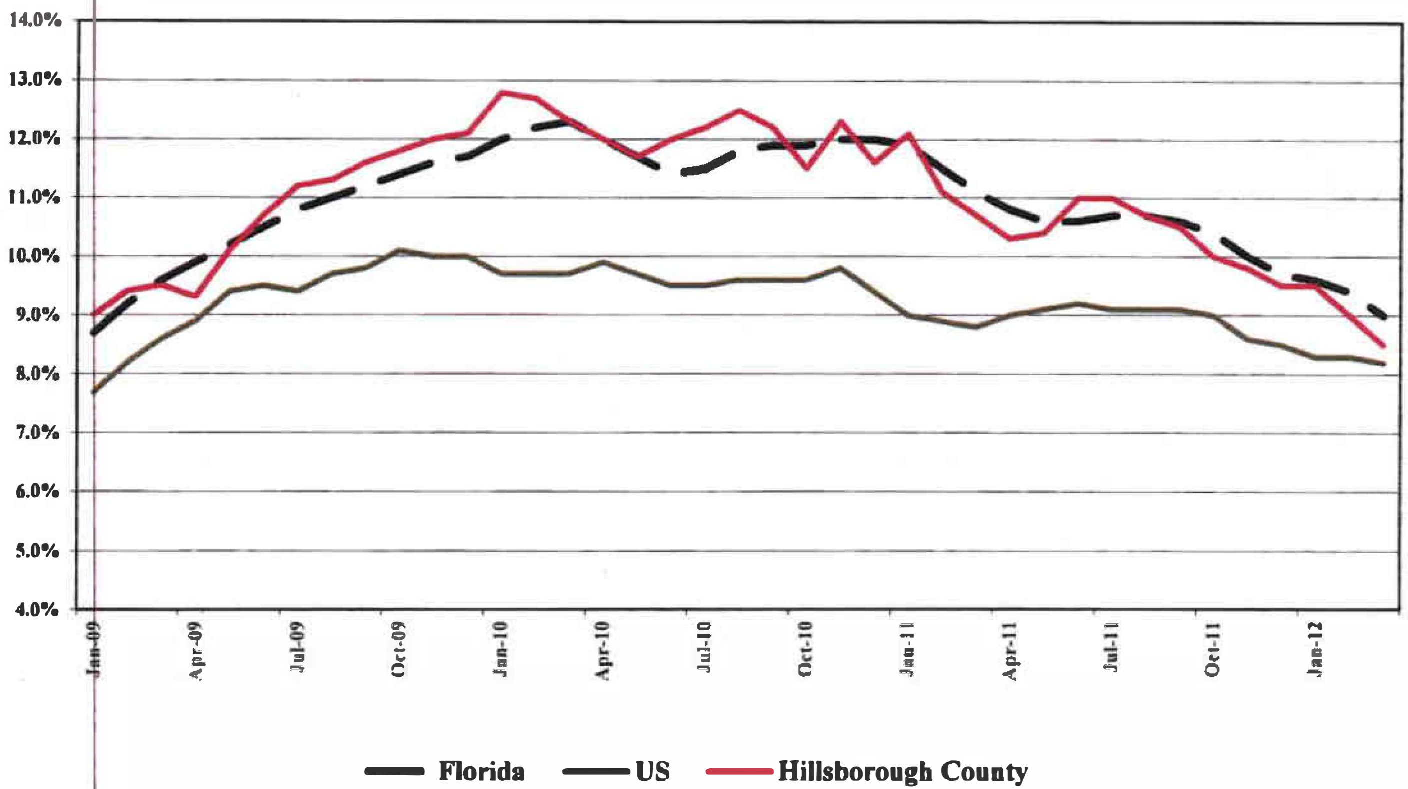
TECO ENERGY

Unemployment Trends



Source: Florida Agency for Workforce Innovation

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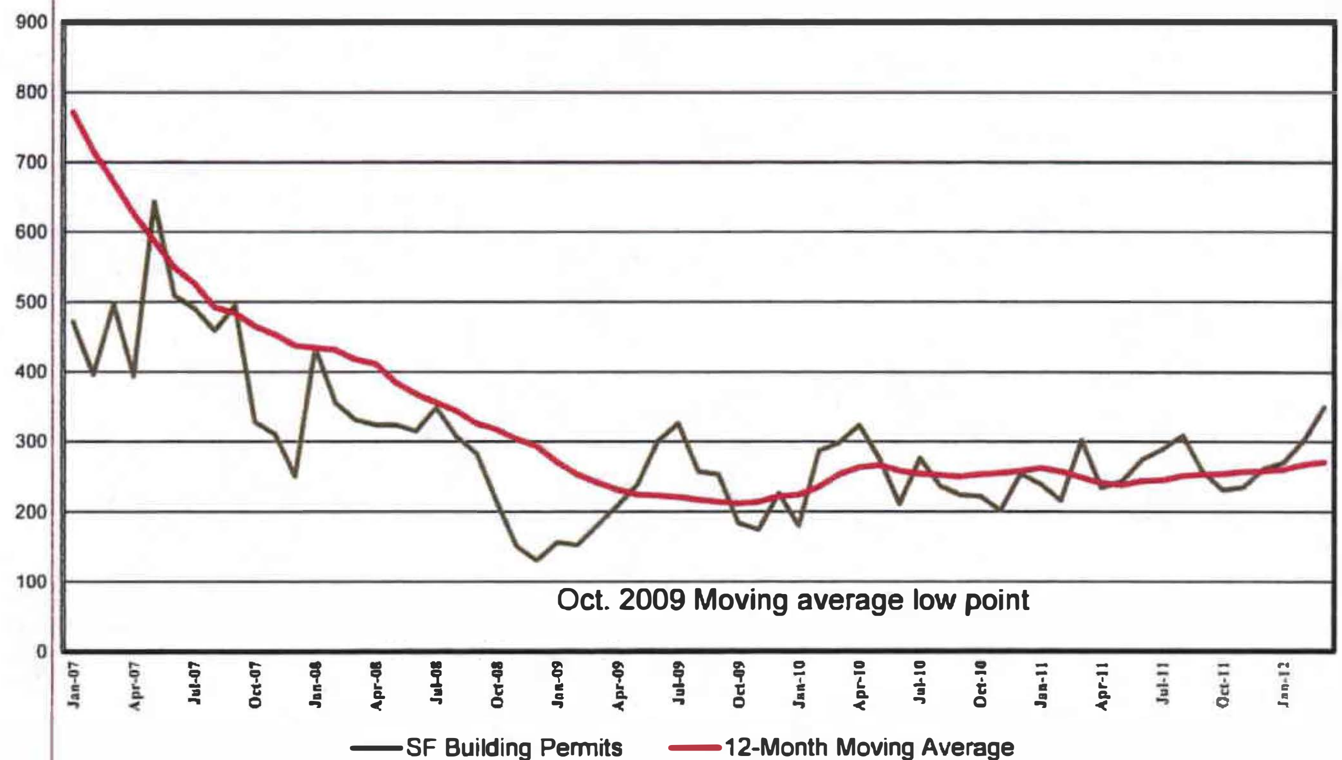
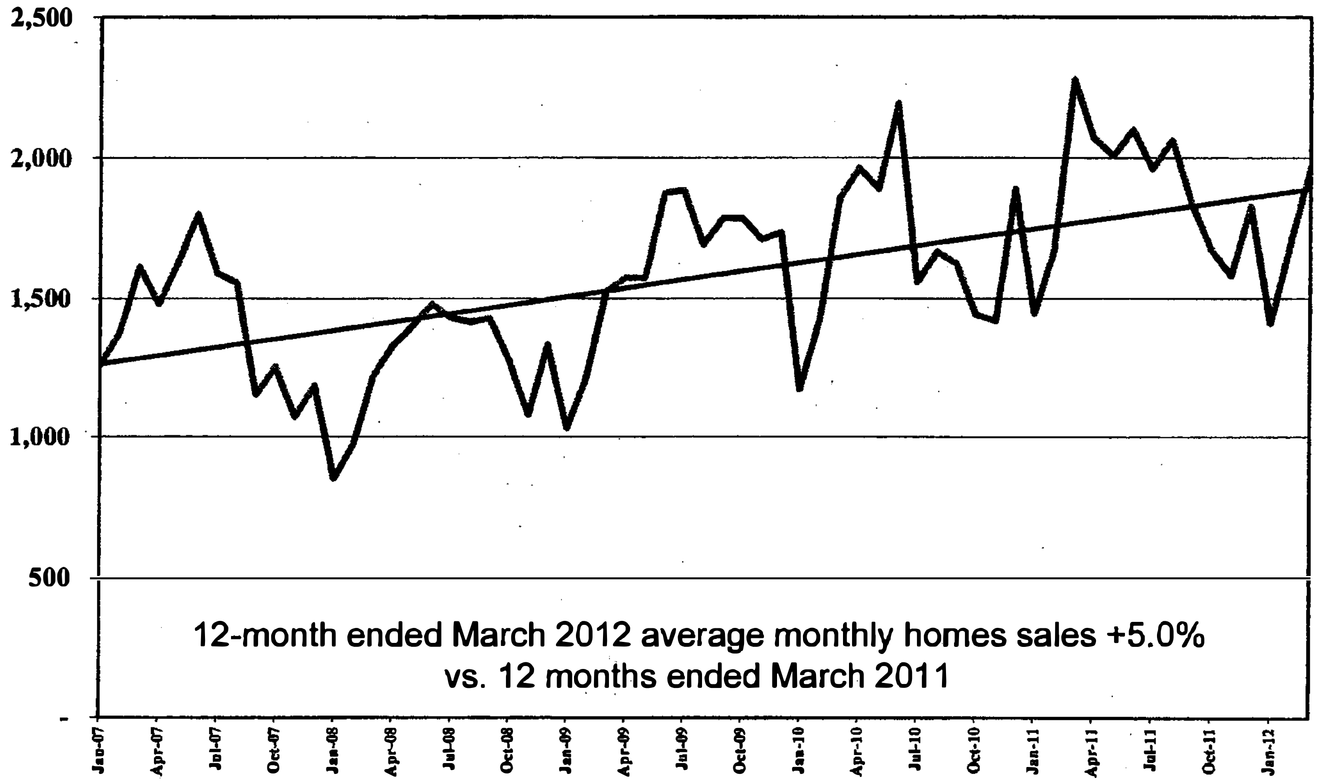
Single Family Building Permits



TECO ENERGY

Tampa Area Existing Home Resales



Source: Greater Tampa Association of Realtors

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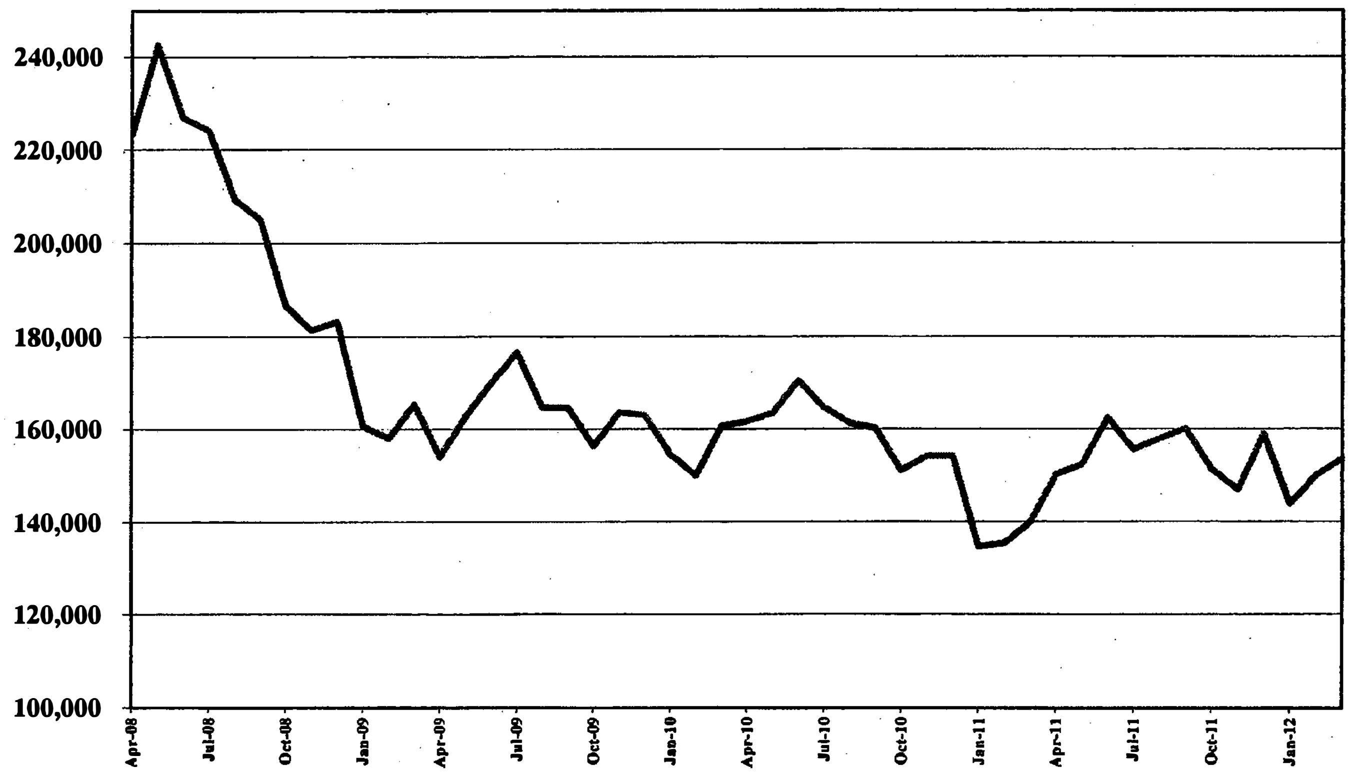
TECO ENERGY

Tampa Area Existing Home Average Resale Prices



Source: Greater Tampa Association of Realtors

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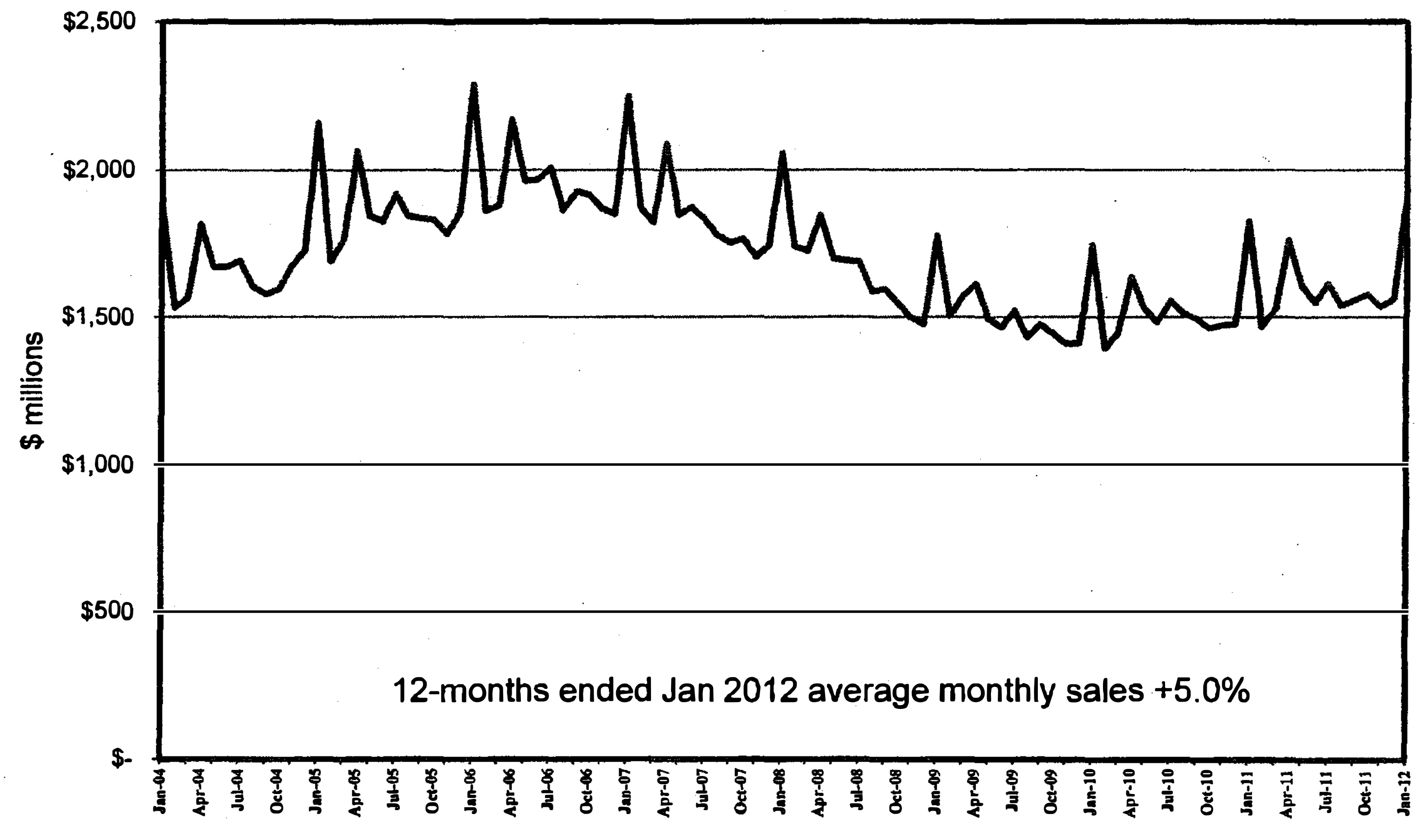
TECO ENERGY

Hillsborough County Monthly Taxable Sales



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BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

IN RE: PETITION FOR RATE INCREASE BY TAMPA ELECTRIC COMPANY	**))**	**DOCKET NO. 130040-EI**

EXHIBIT___(RAB-7)

OF

RICHARD A. BAUDINO

ON BEHALF OF THE

THE WCF HOSPITAL UTILITY ALLIANCE

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

TAMPA ELECTRIC COMPANY
DOCKET NO. 130040-EI
HUA'S FIRST SET OF INTERROGATORIES
INTERROGATORY NO. 3
PAGE 1 OF 1
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3. Regarding Gillete at 5:18-25 and 15:4-9. Please provide the annual amounts Tampa Electric has spent on capital expenditures since January 1, 2009.

A.

2009	$506,047,000
2010	$301,000,000
2011	$325,701,000
2012	$342,884,000
2013	$420,570,000 Budget
2014	$640,637,000 Budget

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DOCUMENT NO. 61
BATES STAMPED PAGE: 1902
FILED: JULY 5, 2013

61. Regarding Hevert at 39:15-17. Please provide the company by company analysis of each proxy company's risk profiles performed prior to April 5, 2013.

A. Please refer to Mr. Hevert's response to OPC's Fourth Set of Interrogatories No. 35, as filed on May 20, 2013.

TAMPA ELECTRIC COMPANY
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OPC'S FOURTH SET OF INTERROGATORIES
INTERROGATORY NO. 35
PAGE 1 OF 1
FILED: MAY 20, 2013

35. Proxy Groups. With reference to pages 14, line 9, to page 15, line 4, of Witness Robert B. Hevert's direct testimony please:

a. List all companies initially considered for inclusion in the proxy group;

b. For the companies eliminated by each of the screens, provide the reason and/or the metric that led to the elimination from the proxy group;

c. The reasoning to use the 60% figure; and

d. The reasoning to use the 90% figure.

A. a–b Please see response to OPC's 4th request for PODs (No. 35) on Tampa Electric's External SharePoint Site, (BS 500) Attachment 35.xlsx.

c. As noted on pages 13-14 of the direct testimony of Robert B. Hevert, witness Hevert's objective in selecting a proxy group is that the proxy group is highly representative of the risks and prospects faced by Tampa Electric, which is a 100 percent rate-regulated electric utility. Therefore, witness Hevert selected companies with at least 60 percent of consolidated net operating income derived from regulated operations in order to ensure that the proxy group companies had rate-regulated operations similar to the subject company. The threshold to eliminate companies with significant unregulated operations must balance the need to develop a group of companies that is fundamentally comparable to Tampa Electric with the need to develop a proxy group of sufficient size. In witness Hevert's view, the 60 percent threshold reasonably balances those objectives.

d. As noted on pages 13-14 of the direct testimony of Robert B. Hevert, witness Hevert's objective in selecting a proxy group is to select companies that are highly representative of the risks and prospects faced by Tampa Electric, which is a 100 percent rate-regulated electric utility. Because natural gas operations tend to be viewed as distinct operating segments, it is important to develop a group of proxy companies that are primarily regulated electric utilities. In Mr. Hevert's view, the 90 percent threshold accomplishes that objective while at the same time producing a proxy group of sufficient size.

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BATES STAMPED PAGE: 1783
FILED: JULY 5, 2013

55. Regarding Hevert at 10:21-22. Please provide all studies created or reviewed by Mr. Hevert prior to April 5, 2013 that discuss or analyze whether Tampa Electric's capital expenditures are "substantial" as compared to his proxy group.

A. Mr. Hevert has not created or reviewed any analysis to determine whether Tampa Electric's capital expenditures are "substantial" as compared to his proxy group.

**TAMPA ELECTRIC COMPANY
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HUA'S FIRST SET OF
INTERROGATORIES
INTERROGATORY NO. 26
PAGE 1 OF 1
FILED: JULY 5, 2013**

26. Regarding Hevert at 10:21-22. Please explain why Mr. Hevert believes Tampa Electric's capital expenditure plans are "substantial" and the benchmark by which he determined the plans as "substantial."

A. While Mr. Hevert does not employ a strict benchmark to determine "substantial" levels of capital expenditures, he notes that TECO Energy has included a discussion of Tampa Electric's capital expenditure plans in recent investor presentations. In Mr. Hevert's experience, investors consider the capital expenditures when assessing a given company's risk profile. Please refer to Hevert at 40:9-45:21, which discusses credit agencies' and equity investors' recognition of increased risk due to high levels of capital expenditures. Witnesses Hornick, Chronister, and Young describe the company's capital investment plans in their direct testimonies.

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BATES STAMPED PAGES: 1416 - 1417
FILED: JULY 5, 2013

30. Regarding Callahan at 9:23-25. Please provide all studies or other evidence that Ms. Callahan relies on for her assertion that Tampa Electric's capital spending program is "very substantial."

A. Please see attached 2012 10-K 2012 Cap Ex table. In addition, please see the Commission's Final Order granting determination of need for Polk 2-5 combined cycle conversion, issued on January 8, 2013.

http://www.floridapsc.com/library/filings/13/00136-13/00136-13.pdf

CAPITAL INVESTMENTS

Capital Investments

		Forecast			
(millions)	Actual 2012	2013	2014	2015-2017	2013 - 2017 Total
Tampa Electric[1]					
Transmission	$31	$30	$35	$70	$135
Distribution	103	105	115	325	545
Generation	153	165	170	395	730
New generation and transmission	5	50	210	345	605
Other	28	30	35	95	160
Other environmental	23	40	75	25	140
Tampa Electric total	343	420	640	1,255	2,315
Net cash effect of AFUDC, accruals and retentions[1]	19	--	--	--	--
Tampa Electric net	362	420	640	1,255	2,315
Peoples Gas	98	80	100	310	490
Unregulated companies	45	20	35	120	175
Total	$505	$520	$775	$1,685	$2,980

(1) Individual line items exclude AFUDC-debt and equity; however total AFUDC is a reconciling item in 2012.

TECO Energy's 2012 capital expenditures of $505 million included $362 million at Tampa Electric, including AFUDC debt and equity. Capital expenditures at PGS were $98 million in 2012. Tampa Electric's capital expenditures in 2012 included $17 million for a reclaimed water pipeline to serve the Polk Power Station, approximately $40 million to improve the Big Bend Station solid fuel handling and flue gas desulphurization systems reliability, for equipment and facilities to meet modest customer growth, generating equipment maintenance, and environmental compliance. Capital expenditures for PGS were approximately $70 million for system expansion, including $25 million for a 30-mile pipeline extension to convert a paperboard manufacturer from petroleum to natural gas; approximately $3 million to acquire a block propane system and extend the natural gas pipeline system to serve major commercial customers in a resort area of Southwest Florida; and approximately $27 million for maintenance of the existing system. TECO Coal's capital expenditures included $30 million primarily for normal mining equipment replacement, and $5 million for permitting and surface site preparation for new metallurgical coal reserves announced in November 2011.

TECO Energy estimates capital spending for ongoing operations to be $520 million for 2013 and approximately $2.5 billion during the 2014 – 2017 period. As described below, this forecast includes $610 million for Tampa Electric's next increment of generation expansion, including transmission system improvements to support the increased plant output.

For 2013, Tampa Electric expects to spend $420 million. For the transmission and distribution systems, Tampa Electric expects to spend $135 million in 2013, including approximately $95 million for normal transmission and distribution system expansion and reliability, and approximately $40 million for transmission and distribution system storm hardening. Capital expenditures for the existing generating facilities of $165 million include approximately $20 million for repair and refurbishments of CTs under long-term agreements with equipment manufacturers, approximately $70 million for generating unit outages in 2013 and advance purchases for 2014 unit outages, $35 million for a reclaimed water pipeline to eliminate ground water usage at the Polk Power Station, approximately $15 million to improve the Big Bend Station solid fuel handling system reliability and $25 million for other improvements and refurbishments to generating units. In addition, Tampa Electric expects to spend $40 million for environmental compliance programs and improvements to environmental control equipment in 2013.

In the 2014 – 2017 period, Tampa Electric expects to spend approximately $320 million annually to support normal system growth and reliability, environmental compliance and improvements to computer systems to serve customers better. This level of ongoing capital expenditures reflects the costs for materials and contractors, long-term regulatory requirements for storm hardening, and an active program of transmission and distribution system upgrades which will occur over the forecast period. These programs and requirements include: approximately $20 million annually for repair and refurbishments of CTs under long-term agreements with equipment manufacturers, average annual expenditures of more than $130 million to support generating unit availability and reliability, combustion by-product handling and storage, and coal-handling equipment replacement and refurbishment; average annual expenditures of more than $30 million for general infrastructure and facilities; average annual expenditures of approximately $30 million for transmission and distribution system storm hardening; approximately $115 million annually for transmission and distribution system

TAMPA ELECTRIC COMPANY
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DOCUMENT NO. 31
BATES STAMPED PAGES: 1418 - 1426
FILED: JULY 5, 2013

31. Regarding Callahan at 9:23-25. Please provide any documents comparing Tampa Electric's capital expenditures to those of other utilities.

A. The requested documents are attached.

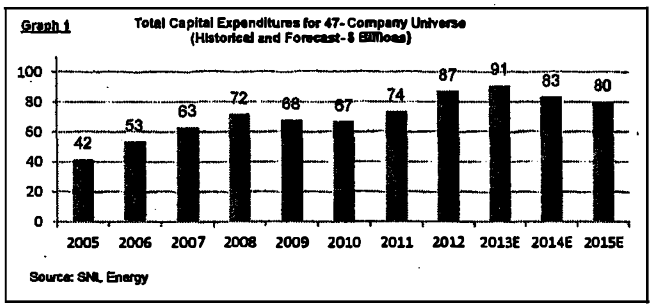
SNL Energy
FINANCIAL FOCUS

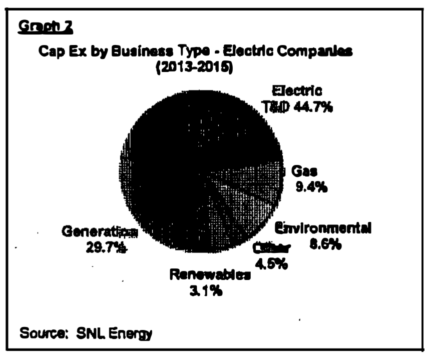
FINANCIAL FOCUS SPECIAL REPORT May 31, 2013

CAPITAL EXPENDITURE UPDATE

Spending headed higher in 2013

Capital spending throughout the U.S. power and gas sectors remains strong, driven by the need to replace an aging generation fleet, infrastructure upgrades to the transmission and distribution systems, coal-to-gas switching prompted by the economics of natural gas prices, and increasingly stringent environmental regulations. These factors, combined with utility initiatives to deploy new technologies and meet future customer demand growth, indicate that capital spending should remain elevated for the foreseeable future. An analysis of formal utility industry spending forecasts, as summarized in Graph 1 below, suggests that aggregate capital expenditure levels over the years 2013-2015, are in fact, expected to be considerably higher than previous spending levels. We note that the estimates included in this study are derived from formal company forecasts and, accordingly, reflect committed projects.





The trend toward new infrastructure investment is tied to the industry's now pervasive "back to basics" strategy – essentially investing in existing and ancillary energy businesses as a means of growing profits. After a most trying time in financial markets, stemming from intense uncertainty tied to the recession, financial measures in the group stabilized, and many companies returned to a more aggressive spending posture beginning in 2011, by initiating work on numerous new and/or postponed projects.

Much of the recent increase in spending by electric companies is tied to compliance with both a spectrum of guidelines issued by the Environmental Protection Agency (EPA) (aimed at more stringent environmental restrictions), and the ever-popular renewable portfolio requirements (resulting in new wind and solar facilities). Based on available forecasts, spending is headed substantially higher in 2013, but then drops off somewhat in the 2014 and 2015 timeframe. However, we believe capital expenditure levels will increase over time in order to comply with further governmental policy requirements. We note that over the past few years, many companies' initial capital spending forecasts for the current year have, by and large, been lower than forecasts provided at later dates. For instance, as displayed in Table 5, the average amount of spending forecasted in November 2012 for the full-year 2013 was 8.4% below the most recent forecasts. This latest instance could be due to the fact that companies now have a clearer picture of EPA guidelines and other governmental policy requirements.

In the wake of these developments, utilities have been forced to decide whether to make substantial capital investments in environmental upgrades or to retire plants. With an abundant supply of shale gas, U.S. gas prices fell to a 10-year low of $1.90 per MMBtu in 2012. Although gas prices have rebounded to more than $4, prices are still well below historic averages, and projections for shale gas reserves suggest prices will remain depressed for quite some time. As a result, many older coal plants have been slated for retirement, and many utilities have shifted from coal to natural gas to fill the capacity void. Despite the drop in sales growth throughout the economic downturn over the past several years, new capacity will still be needed to meet rising customer demand, thus exacerbating the need for increasing construction expenditures.

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Table 3	Total Capital Expenditures for 47 Companies (Historical and Forecast)									
								Capital Expenditure Estimate		
(Amount $ Millions)	2005	2006	2007	2008	2009	2010	2011	2012	2013E	2014E	2015E
ELECTRIC											
1 AES CORP.	826	1,460	2,425	2,850	2,520	2,310	2,430	2,236	1,380	1,285	1,900
2 ALLIANT ENERGY	538	399	542	679	1,203	867	673	1,158	835	860	990
3 AMEREN	835	992	1,381	1,896	1,710	1,042	1,030	1,240	1,540	[illegible]	1,738
4 AMERICAN ELECTRIC POWER*	2,404	3,528	3,556	3,800	2,792	2,345	2,669	3,025	3,578	3,800	3,800
5 CMS ENERGY	593	670	1,263	792	818	821	882	1,227	1,374	1,512	1,670
6 CONSOLIDATED EDISON	1,636	1,853	1,934	2,326	2,193	2,029	1,967	2,069	2,425	2,312	2,512
7 DOMINION RESOURCES	3,358	4,052	3,872	3,554	3,837	3,422	3,652	4,145	4,682	4,155	3,299
8 DTE ENERGY	1,086	1,403	1,299	1,373	1,035	1,099	1,484	1,820	2,175	1,879	1,761
9 DUKE ENERGY	2,413	3,470	3,216	4,533	4,435	4,855	4,413	5,507	6,066	5,713	6,050
10 EDISON INTERNATIONAL*	1,868	2,536	2,826	2,824	3,282	4,543	4,808	4,149	4,424	4,295	3,665
11 ENTERGY	1,458	1,633	1,578	2,212	1,931	2,074	2,040	2,875	2,360	2,094	2,191
12 EXELON CORP.	2,165	2,418	2,674	3,117	3,273	3,326	4,042	5,789	5,500	4,850	5,250
13 FIRSTENERGY	1,206	1,316	1,633	2,888	2,205	1,963	2,278	2,670	2,380	2,532	2,493
14 NEXTERA ENERGY	2,546	3,739	5,019	5,238	6,006	5,846	6,628	9,461	4,565	3,235	2,570
15 GREAT PLAINS ENERGY	327	476	512	1,024	841	618	457	610	725	711	716
16 IDACORP INC.	193	222	287	244	252	338	338	240	250	288	288
17 HAWAIIAN ELECTRIC INDUSTRIES	224	211	218	262	289	152	235	325	380	500	600
18 NORTHEAST UTILITIES	775	872	1,115	1,255	908	964	1,077	1,472	1,590	1,674	1,734
19 NORTHWESTERN CORP.	81	101	117	195	189	228	189	219	260	254	237
20 NV ENERGY	686	986	1,197	1,536	843	629	621	499	515	444	480
21 OGE ENERGY	297	487	558	1,185	809	848	1,221	1,123	1,245	760	565
22 PEPCO HOLDINGS	467	475	623	643	664	802	941	1,216	1,207	1,218	1,203
23 PG&E CORP.	1,804	2,402	2,769	3,628	3,958	3,802	4,038	4,624	5,100	5,000	5,250
24 PINNACLE WEST CAPITAL	661	738	980	936	765	748	884	890	1,121	1,033	1,188
25 PNM RESOURCES	211	321	456	345	285	281	327	309	493	586	490
26 PORTLAND GENERAL ELECTRIC	255	371	455	383	698	450	300	303	514	420	314
27 PPL CORP.	811	1,394	1,657	1,418	1,225	1,597	2,487	3,105	4,858	3,836	4,189
28 PUBLIC SRV. ENT. GROUP	1,063	1,015	1,348	1,771	1,794	2,160	2,083	2,574	2,535	2,085	1,515
29 SOUTHERN COMPANY	2,370	2,994	3,546	3,961	4,870	4,086	4,525	4,809	5,600	5,900	5,100
30 TECO ENERGY	295	456	494	590	640	490	454	505	520	775	562
31 UNS ENERGY CORP.	202	238	245	354	289	279	374	307	393	339	380
32 WESTAR ENERGY	213	345	748	937	558	540	697	810	892	803	842
33 WISCONSIN ENERGY	745	929	1,212	1,136	815	790	631	707	693	631	778
34 XCEL ENERGY	1,311	1,628	2,097	2,114	1,778	2,216	2,206	2,570	3,155	2,775	2,310
Total Electric ($ Millions)	35,997	46,127	53,933	62,145	59,498	58,492	63,280	74,397	74,858	70,290	67,736
GAS											
35 AGL RESOURCES	287	253	259	372	478	516	427	702	700	705	750
36 ATMOS ENERGY CORP.	333	425	392	472	509	543	623	733	780	710	735
37 CENTERPOINT ENERGY	693	1,007	1,114	1,020	1,160	1,509	1,303	1,212	1,614	1,423	1,173
38 INTEGRYS ENERGY	414	342	393	533	444	259	311	594	1,266	816	732
39 NISOURCE	590	627	787	1,300	777	804	1,125	1,499	1,615	1,589	1,573
40 ONEOK	250	376	884	1,473	791	583	1,336	1,866	2,956	1,919	1,928
41 PIEDMONT NATURAL GAS CO.	181	204	135	181	129	199	244	530	550	300	300
42 SCANA CORP.	385	527	725	904	914	878	884	1,077	1,639	1,631	1,497
43 SEMPRA ENERGY	1,377	1,907	2,010	2,061	1,912	2,062	2,844	2,956	3,300	2,540	2,340
44 SOUTHWEST GAS	294	345	341	300	217	215	361	396	340	330	330
45 QUESTAR CORP.	713	916	1,398	322	800	320	368	371	450	380	325
46 VECTREN CORP.	232	281	335	391	432	277	321	386	290	330	320
47 WGL HOLDINGS	113	180	165	135	139	130	202	251	368	381	359
Total Gas ($ Millions)	5,853	7,371	8,938	9,464	8,201	8,287	10,369	12,632	16,068	12,854	12,362
[illegible]											
Total ($ Millions)	41,850	53,498	62,871	71,609	67,699	66,779	73,649	87,029	90,926	83,144	80,098

Source: SNL Energy, company surveys, and RRA adjustments.

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Tampa Electric Discovery Responses
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TAMPA ELECTRIC COMPANY
DOCKET NO. 130040-EI
HUA'S SECOND REQUEST FOR PODS
FILED: JULY 5, 2013

Table 4

Utility Capital Expenditures by Category (2013-2015)

Generation

Companies with Segment Breakdown (Amount $ Millions)	Note	2013	2014	2015	2016	2017	% '13-'15 Total
Electric Companies							
ALLIANT ENERGY	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
CMS ENERGY		90	141	168	183	149	9%
CONSOLIDATED EDISON	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
DOMINION RESOURCES		2,394	1,868	1,267			46%
EXELON CORP	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
ENTERGY	6	1,214	915	984			47%
GREAT PLAINS ENERGY	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
HAWAIIAN ELECTRIC INDUSTRIES	3,6	38	108	130	152	152	19%
INTEGRYS ENERGY	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
NEXTERA ENERGY	4,6,9	1,985	1,955	1,525	1,285	1,095	53%
NORTHEAST UTILITIES	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
NORTHWESTERN CORP.	6,7	109	112	104	100	133	
NV ENERGY	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
OGE ENERGY		80	75	75	75	75	9%
PEPCO HOLDINGS	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
PNM RESOURCES	5,7	198	165	130	173	210	31%
PINNACLE WEST CAPITAL	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
PORTLAND GENERAL ELECTRIC	2,6	46	43	38	39	37	10%
PPL CORP	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
PUBLIC SRV. ENT. GROUP	4	330	295	290			15%
SOUTHERN COMPANY	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
TECO ENERGY	6,7	190	275	189	189	189	35%
UNS ENERGY CORP	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
WESTAR ENERGY	4,10	207	227	198			27%
WISCONSIN ENERGY	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
XCEL ENERGY	4	775	630	580	590	715	24%
Total - Electric ($ Millions)		14,991	13,308	11,921	[illegible]	[illegible]	[illegible]
Gas Companies							
AGL RESOURCES	[illegible]						
ATMOS ENERGY CORP.	7						
CENTERPOINT ENERGY	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
NISOURCE	8						
PIEDMONT NATURAL GAS CO.	[illegible]						
ONEOK	8						
SCANA CORP	[illegible]	1,200	1,162	1,031	[illegible]	[illegible]	[illegible]
SOUTHWEST GAS	7						
QUESTAR CORP	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
WGL HOLDINGS							
Total - Gas ($ Millions)							
Companies without Segment Breakdown ("Below the line")*							
AES CORP	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
AMERICAN ELECTRIC POWER*		647					
AMEREN	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
DTE ENERGY	8						
DUKE ENERGY	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
EDISON INTERNATIONAL*	1,8	576	546				9%
FIRSTENERGY	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
IDACORP INC.	7						
PG&E CORP	[illegible]	1,800	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
SEMPRA ENERGY	7						
VECTREN CORP	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Total - ($ Millions)							
Grand Total ($ Millions)		[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]

Electric T&D / **Environmental**

Company	T&D 2013	T&D 2014	T&D 2015	T&D 2016	T&D 2017	% '13-'15 Total	Env. 2013	Env. 2014	Env. 2015	Env. 2016	Env. 2017	% '13-'15 Total
Electric Companies												
ALLIANT ENERGY	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
CMS ENERGY	427	391	346	356	436	26%	331	314	247	154	97	20%
CONSOLIDATED EDISON	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
DOMINION RESOURCES	1,419	1,433	1,248			34%	64	98	114			2%
EXELON CORP	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
ENTERGY	964	984	1,010			44%						0%
GREAT PLAINS ENERGY	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
HAWAIIAN ELECTRIC INDUSTRIES	182	240	288	336	336	46%	67	98	70	82	82	13%
INTEGRYS ENERGY	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
NEXTERA ENERGY	745	795	745	770	795	22%						0%
NORTHEAST UTILITIES	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
NORTHWESTERN CORP.	67	64	64	64	64		47	41	32			
NV ENERGY	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
OGE ENERGY	655	390	235	275	265	50%	30	20	25	20	0	3%
PEPCO HOLDINGS	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
PNM RESOURCES	110	181	220	102	58	32%	120	193	118	52	0	27%
PINNACLE WEST CAPITAL	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
PORTLAND GENERAL ELECTRIC	209	185	164	170	159	45%	8	0	0	0	0	1%
PPL CORP	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
PUBLIC SRV. ENT. GROUP	1,900	1,605	1,150			76%	110	105	45			4%
SOUTHERN COMPANY	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
TECO ENERGY	160	255	189	189	189	33%	40	75	8	8	8	7%
UNS ENERGY CORP	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
WESTAR ENERGY	342	295	331			41%	311	240	93			28%
WISCONSIN ENERGY	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
XCEL ENERGY	1,525	1,395	1,175	1,170	1,315	50%	345	235	90	15	0	8%
Total - Electric ($ Millions)	20,863	20,139	19,479	[illegible]	[illegible]	[illegible]	4056	4365	3191	[illegible]	[illegible]	[illegible]
Gas Companies												
AGL RESOURCES												
ATMOS ENERGY CORP.												
CENTERPOINT ENERGY	720	677	557	534	512	[illegible]						
NISOURCE												
PIEDMONT NATURAL GAS CO.												
ONEOK												
SCANA CORP	[illegible]	[illegible]	[illegible]			[illegible]						
SOUTHWEST GAS												
QUESTAR CORP												
WGL HOLDINGS												
Total - Gas ($ Millions)	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Companies without Segment Breakdown ("Below the line")*												
AES CORP	[illegible]	[illegible]	[illegible]									
AMERICAN ELECTRIC POWER*	2,295						544					
AMEREN	[illegible]	[illegible]	[illegible]									
DTE ENERGY												
DUKE ENERGY												
EDISON INTERNATIONAL*	3,725	3,419				58%	103	311				3%
FIRSTENERGY	[illegible]	[illegible]	[illegible]			[illegible]	[illegible]	[illegible]				[illegible]
IDACORP INC.												
PG&E CORP	3,150	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]			
SEMPRA ENERGY												
VECTREN CORP	[illegible]	[illegible]	[illegible]			[illegible]	[illegible]	[illegible]	[illegible]			
Total - ($ Millions)												
Grand Total ($ Millions)	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]

Renewables / **Gas Pipeline/Storage/Distribution/and other**

Company	Ren. 2013	Ren. 2014	Ren. 2015	Ren. 2016	Ren. 2017	% '13-'15 Total	Gas 2013	Gas 2014	Gas 2015	Gas 2016	Gas 2017	% '13-'15 Total
Electric Companies												
ALLIANT ENERGY	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
CMS ENERGY	31	77	153	5	1	6%	398	501	678	552	367	35%
CONSOLIDATED EDISON	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	22%
DOMINION RESOURCES	73	0	0			1%	690	717	629			17%
EXELON CORP	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
ENTERGY						0%						0%
GREAT PLAINS ENERGY	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
HAWAIIAN ELECTRIC INDUSTRIES	67	98	70	82	82	13%						0%
INTEGRYS ENERGY	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
NEXTERA ENERGY	1215	220	10	5	5	14%	310	45	115	50	50	5%
NORTHEAST UTILITIES	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
NORTHWESTERN CORP.							38	38	38	38		
NV ENERGY	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
OGE ENERGY						0%	455	250	205	145	130	35%
PEPCO HOLDINGS	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
PNM RESOURCES	50	33	17	6	0	6%						0%
PINNACLE WEST CAPITAL	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
PORTLAND GENERAL ELECTRIC	23	28	28	1	0	6%	161	107	33	0	0	24%
PPL CORP	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
PUBLIC SRV. ENT. GROUP	150	40	0			3%						0%
SOUTHERN COMPANY	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
TECO ENERGY						0%	80	100	103	103	103	16%
UNS ENERGY CORP	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
WESTAR ENERGY	4	18	0			1%						0%
WISCONSIN ENERGY	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
XCEL ENERGY						0%	365	365	335	325	320	13%
Total - Electric ($ Millions)	2775	848	565	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Gas Companies												
AGL RESOURCES							[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
ATMOS ENERGY CORP.												
CENTERPOINT ENERGY							[illegible]	745	615	593	590	[illegible]
NISOURCE												
PIEDMONT NATURAL GAS CO.							[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
ONEOK												
SCANA CORP							[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
SOUTHWEST GAS												
QUESTAR CORP												
WGL HOLDINGS												
Total - Gas ($ Millions)	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Companies without Segment Breakdown ("Below the line")*												
AES CORP							[illegible]	[illegible]	[illegible]			
AMERICAN ELECTRIC POWER*							92					
AMEREN							[illegible]	[illegible]	[illegible]			
DTE ENERGY												
DUKE ENERGY												
EDISON INTERNATIONAL*	1	2				0%						0%
FIRSTENERGY	[illegible]	[illegible]	[illegible]			[illegible]						[illegible]
IDACORP INC.												
PG&E CORP							1,150					
SEMPRA ENERGY												
VECTREN CORP							[illegible]	[illegible]	[illegible]			
Total - ($ Millions)												
Grand Total ($ Millions)	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]

Corporate / Other / **Total**

Company	Corp. 2013	Corp. 2014	Corp. 2015	Corp. 2016	Corp. 2017	% '13-'15 Total	Total 2013	Total 2014	Total 2015	Total 2016	Total 2017	3 Year Total '13-'15
Electric Companies												
ALLIANT ENERGY	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	10%	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	2,685
CMS ENERGY	89	68	78	75	65	6%	1,374	1,512	1,670	1,327	1,157	4,556
CONSOLIDATED EDISON	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	2,425	2,312	2,512	[illegible]	[illegible]	7,249
DOMINION RESOURCES	42	39	41			1%	4,682	4,155	3,299			12,136
EXELON CORP	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	10%	5,500	[illegible]	5,250	[illegible]	[illegible]	15,600
ENTERGY	189	195	197			9%	2,367	2,094	2,191			6,652
GREAT PLAINS ENERGY	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	7%	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	2,151
HAWAIIAN ELECTRIC INDUSTRIES	27	35	42	49	49	7%	380	500	600	700	700	1,480
INTEGRYS ENERGY	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	2,814
NEXTERA ENERGY	330	220	175	195	190	7%	4,565	3,235	2,570	2,305	2,135	10,370
NORTHEAST UTILITIES	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	4,998
NORTHWESTERN CORP.							260	254	237	201	198	751
NV ENERGY	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	10%	515	[illegible]	[illegible]	[illegible]	[illegible]	1,439
OGE ENERGY	25	25	25	25	25	3%	1,245	760	565	540	495	2,570
PEPCO HOLDINGS	145	120	106	84	87	[illegible]	1,207	1,218	1,203	1,122	1,187	3,628
PNM RESOURCES	15	14	13	13	13	3%	493	586	498	346	281	1,577
PINNACLE WEST CAPITAL	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	1,121	1,033	[illegible]	[illegible]	[illegible]	3,342
PORTLAND GENERAL ELECTRIC	64	57	51	52	49	14%	514	420	314	263	245	1,248
PPL CORP	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	11,083
PUBLIC SRV. ENT. GROUP	45	40	30			2%	2,535	2,095	1,515			6,135
SOUTHERN COMPANY	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	5,600	5,800	5,100	[illegible]	[illegible]	16,600
TECO ENERGY	50	70	72	72	72	10%	520	775	562	562	562	1,857
UNS ENERGY CORP	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	10%	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	1,112
WESTAR ENERGY	29	24	20			3%	892	803	642			2,338
WISCONSIN ENERGY	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	2,102
XCEL ENERGY	155	150	160	155	150	6%	3,155	2,775	2,310	2,255	2,500	8,240
Total - Electric ($ Millions)	2,180	1,974	1,947	[illegible]	[illegible]	[illegible]	48,210	44,474	41,623	[illegible]	[illegible]	136,311
Gas Companies												
AGL RESOURCES							700	705	750	[illegible]	[illegible]	2,155
ATMOS ENERGY CORP.							780	710	735	820		2,225
CENTERPOINT ENERGY							[illegible]	1,423	1,173	1,127	1,102	4,210
NISOURCE							1,815	1,589	1,573			4,977
PIEDMONT NATURAL GAS CO.							[illegible]	[illegible]	[illegible]			[illegible]
ONEOK							2,956	1,919	1,928			6,803
SCANA CORP	[illegible]	[illegible]	[illegible]			[illegible]	[illegible]	[illegible]	[illegible]			[illegible]
SOUTHWEST GAS							340	330	330			1,000
QUESTAR CORP							[illegible]	[illegible]	[illegible]			[illegible]
WGL HOLDINGS							368	381	359	355	339	1,107
Total - Gas ($ Millions)							11,212	[illegible]	[illegible]	[illegible]	[illegible]	29,649
Companies without Segment Breakdown ("Below the line")*												
AES CORP							[illegible]	[illegible]	[illegible]			[illegible]
AMERICAN ELECTRIC POWER*							3,578	3,800	3,800			11,178
AMEREN							[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	5,016
DTE ENERGY							2,175	1,879	1,761			5,815
DUKE ENERGY							[illegible]	[illegible]	[illegible]			[illegible]
EDISON INTERNATIONAL*	19	15				0%	4,424	4,295	3,665			12,384
FIRSTENERGY	[illegible]	[illegible]	[illegible]			[illegible]	[illegible]	[illegible]	[illegible]			7,405
IDACORP INC.							250	288	288			825
PG&E CORP							5,100	5,000	5,250	5,250		15,350
SEMPRA ENERGY							3,300	2,340	2,340	2,340	2,340	7,980
VECTREN CORP							[illegible]	[illegible]	[illegible]			940
Total - ($ Millions)							30,605	29,199	29,604			89,306
Grand Total ($ Millions)							[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	254,168

Source: SNL Energy, company surveys, and RRA adjustments.

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<u>Notes to Table 4:</u>

1 RRA estimate for proportion related to environmental and/or renewable spending

2 Maintenance and growth capital expenditure apportioned to: generation 15%, T&D 65%, other 20%

3 Spending on fuel included in generation

4 Nuclear spending included in generation

5 Includes potential capital expenditures that may not be realized

6 Capital expenditures calculated and apportioned as per RRA adjustments

7 Average shown for any range provided by the company

8 FactSet estimates for years in which company has not provided data

9 Includes only capital expenditures that have been approved by NEE's board of directors

10 Includes the potential investment for the Praire Wind Transmission joint venture

* Classification by business type unavailable for some years, resulting in "below the line" listing
** Electric T&D includes Smart Metering/AMI
Percentages of three-year total shown next to each category

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23. Regarding Callahan at 12:12-13:24 and HUA Interrogatory No. 9. Please provide all documents prepared by or on behalf of Tampa Electric prior to April 5, 2013 that quantify or compare the costs and benefits of maintaining or enhancing Tampa Electric's "financial integrity."

A. The company has no documents that are responsive to this request.

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DOCUMENT NO. 33
BATES STAMPED PAGE: 1428
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33. Regarding Callahan at 13:9-12. Please provide all studies or documents prepared by or on behalf of Tampa Electric prior to April 5, 2013 that relate to whether "[m]aintaining a strong financial position allows the company to finance infrastructure investments at a lower cost than would otherwise be possible."

A. The company has no documents that are responsive to this request.

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DOCUMENT NO. 34
BATES STAMPED PAGE: 1429
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34. Regarding Callahan at 17:21-25 and 19:1-3. Please provide all studies or documents prepared by or on behalf of Tampa Electric prior to April 5, 2013 that discuss or analyze whether "Tampa Electric's current ratings provide a reasonable degree of assurance that ratings will not slip below investment grade in the event of a catastrophe, such as a hurricane or other unforeseen event."

A. The company has no documents that are responsive to this request.

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18. Regarding Gillete at 6:16-23. Please provide all documents created by or on behalf of Tampa Electric that discuss or analyze the costs or tradeoffs that Tampa Electric will or could incur in order to obtain the "best rate[]" for capital.

A. The company has no documents that are responsive to this request.

9. Regarding Callahan at 12:12-13:24. Please list and describe each cost associated with maintaining or enhancing Tampa Electric's "financial integrity."

A. The cost of maintaining financial integrity includes financing costs associated with maintaining committed credit facilities with financial institutions (liquidity) and the costs required to compensate long-term equity and debt capital providers.

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36. Regarding Callahan at 20:3-8 and SWC-1, Document No. 5. Please provide all documents that demonstrate the average cost of long term debt for electric utilities for each debt rating provided in Exh. No. SWC-1, Document No. 5 historically and projected into the future.

A. The company has no documents that are responsive to this request.

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HUA'S SECOND REQUEST FOR PRODUCTION OF DOCUMENTS
DOCUMENT NO. 37
BATES STAMPED PAGES: 1432 - 1439
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37. Regarding Callahan at 22:11-23. Please provide all documents explaining the ranking system utilized by Regulatory Research Associates.

A. The requested documents are attached.

Regulatory Research Associates
REGULATORY FOCUS

January 16, 2013

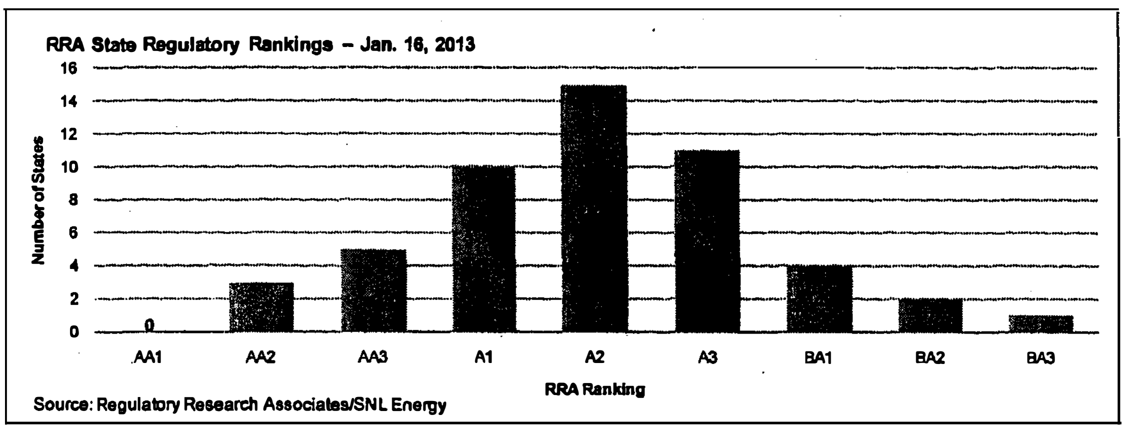
STATE REGULATORY EVALUATIONS

~ Including an Overview of RRA's ranking process ~

As part of RRA's regulatory research effort, we evaluate the regulatory climates of the 50 states and the District of Columbia on an ongoing basis. The evaluations are assigned from an investor perspective and indicate the relative regulatory risk associated with the ownership of securities issued by each jurisdiction's electric and gas utilities. Each evaluation is based upon our consideration of the numerous factors affecting the regulatory process in the state, and is changed as major events occur that cause us to modify our view of the regulatory risk accruing to the ownership of utility securities in that individual jurisdiction.

We also review our evaluations when we update our Commission Profiles, and when we publish this quarterly comparative evaluations report. The majority of factors that we consider are discussed in Focus Notes articles, Commission Profiles, or Final Reports. We also consider information obtained from contacts with commission, company, and government personnel in the course of our research. The final evaluation reflects our assessment of the probable level and quality of the earnings to be realized by the state's utilities as a result of regulatory, legislative, and court actions.

RRA maintains three principal rating categories, Above Average, Average, and Below Average, with Above Average indicating a relatively more-constructive, lower-risk regulatory environment from an investor viewpoint, and Below Average indicating a less-constructive, higher-risk regulatory climate from an investor viewpoint. Within the three principal rating categories, the numbers 1, 2, and 3 indicate relative position. The designation 1 indicates a stronger (more constructive) rating; 2, a mid-range rating; and, 3, a weaker (less constructive) rating. We endeavor to maintain about an equal number of ratings above the average and below the average. The graph below depicts the current distribution of our rankings. (***A more detailed explanation of our ratings process can be found in the Appendix that begins on page 3.***)



Our previous "State Regulatory Evaluations" report was published Oct. 12, 2012, at which time we noted no ratings changes. At this time we are making three ranking changes. As a result of recent constructive rulings, including an April 2012 rate case order for Southern Company subsidiary Gulf Power (see the Final Report dated 4/13/13), and especially the Commission's December 2012 adoption of a non-unanimous settlement in a base rate case for NextEra Energy subsidiary Florida Power & Light (see the RRA article dated 12/13/12), we are raising our rating of Florida regulation to Above Average/3 from Average/1. To our knowledge, this is the first time in the last 30 years that the Florida Public Service Commission has approved a settlement when faced with opposition by the Public Counsel. In addition, in light of certain constructive developments, including the implementation of an alternative regulation framework for each of the state's electric utilities, we are raising our rating of Hawaii regulation to Average/1 from Average/2. Also, in order to maintain a balance in our rankings, we are lowering our rating of West Virginia regulation to Below Average/1 from Average/3.

Appendix: Explanation of RRA ratings process

As noted above, RRA maintains three principal rating categories, Above Average, Average, and Below Average, with Above Average indicating a relatively more constructive, lower-risk regulatory environment from an investor viewpoint, and Below Average indicating a less constructive, higher-risk regulatory climate. Within the three principal rating categories, the numbers 1, 2, and 3 indicate relative position. The designation 1 indicates a stronger (more constructive) rating; 2, a mid-range rating; and, 3, a weaker (less constructive) rating within each higher-level category. Hence, if you were to assign numeric values to each of the nine resulting categories, with a "1" being the most constructive from an investor viewpoint and a "9" being the least constructive from an investor viewpoint, then Above Average/1 would be a "1" and Below Average/3 would be a "9."

The rankings are subjective and are intended to be comparative in nature. Consequently, we do not use a mathematical model to determine each state's ranking. However, we endeavor to maintain a "normal distribution" with an approximately equal number of rankings above and below the average. The variables that RRA considers in determining each state's ranking are largely the broad issues addressed in our State Regulatory Reviews/Commission Profiles and those that arise in the context of rate cases and are discussed in RRA Rate Case Final Reports. Keep in mind that the rankings reflect not only the decisions rendered by the state regulatory commission, but also take into account the impact of the actions taken by the governor, the legislature, the courts, and the consumer advocacy groups. The summaries below are intended to provide an overview of these variables and how each can impact a given regulatory environment.

Commissioner Selection Process/Membership--RRA looks at how commissioners are selected in each state. All else being equal, RRA attributes a greater level of investor risk to states in which commissioners are elected rather than appointed. Generally, energy regulatory issues are less politicized when they are not subject to debate in the context of an election. Realistically, a commissioner candidate who indicates sympathy for utilities and appears to be amenable to rate increases is not likely to be popular with the voting public. Of course, in recent years there have been some notable instances in which energy issues in appointed-commission states have become gubernatorial/senatorial election issues, with detrimental consequences for the utilities (e.g., Illinois, Florida, and Maryland, all of which were downgraded by RRA when increased politicization of the regulatory process became apparent.)

In addition, RRA looks at the commissioners themselves and their backgrounds. Experience in economics and finance and/or energy issues is generally seen as a positive sign. Previous employment by the commission or a consumer advocacy group is sometimes viewed as a negative indicator. In some instances, new commissioners have very little experience or exposure to utility issues, and in some respects, these individuals represent the highest level of risk, simply because there is no way to foresee what they will do or how long it will take them to "get up to speed."

Commission Staff/Consumer Interest--Most commissions have a staff that participates in rate proceedings. In some instances the Staff has a responsibility to represent the consumer interest and in others the Staff's statutory role is less defined. In addition, there may or may not be: additional state-level organizations that are charged with representing the interests of a certain class or classes of customers; private consortia that represent certain customer groups; and/or, large-volume customers that intervene directly in rate cases. Generally speaking, the greater the number of consumer intervenors, the greater the level of uncertainty for investors. The level of risk for investors also depends on the caliber and influence (political and otherwise) of the intervening parties and the level of contentiousness in the rate case process. RRA's opinion on these issues is largely based on past experience and observations.

Rate Case Timing/Interim Procedures--For each state commission, RRA considers whether there is a set time frame within which a rate case must be decided, the length of any such statutory time frame, the degree to which the commission adheres to that time frame, and whether interim increases are permitted. Generally speaking, we view a set time frame as preferable, as it provides a degree of certainty as to when any new revenue may begin to be collected. In addition, shorter time frames for a decision generally reduce the likelihood that the actual conditions during the first year the new rates will be in effect will vary markedly from the test period utilized (a discussion of test periods is provided below) to set new rates. In addition, the ability to implement all or a portion of a proposed rate increase on an interim basis prior to a final decision in a rate case is viewed as constructive.

Return on Equity--Return on equity (ROE) is perhaps the single most litigated issue in any rate case. There are two aspects RRA considers when evaluating an individual rate case and the overall regulatory environment: (1) how the authorized ROE compares to the average of returns authorized for energy utilities nationwide over the 12 months, or so, immediately preceding the decision; and, (2) whether the company has been accorded a reasonable opportunity to earn the authorized return in the first year of the new rates. (It is important to note that even if a utility is accorded a "reasonable opportunity" to earn its authorized ROE, there is no guarantee that the utility will do so.)

5. Regarding Gillete at 10:12-22 and 12:3-6. For each year from 1995 to 2012, please provide Tampa Electric's average annual growth in O&M expenses and debt costs, using the same methodology used for Mr. Gillette's calculation of customer growth.

A. The requested information is included in the following tables.

	Total O&M Expense Actual $(000)	
1994	251,118	
1995	220,592	-12.2%
1996	220,386	-0.1%
1997	234,718	6.5%
1998	248,797	6.0%
1999	242,469	-2.5%
2000	269,362	11.1%
2001	275,913	2.4%
2002	303,276	9.9%
2003	275,950	-9.0%
2004	258,062	-6.5%
2005	266,588	3.3%
2006	307,687	15.4%
2007	314,820	2.3%
2008	313,442	-0.4%
2009	353,316	12.7%
2010	335,516	-5.0%
2011	297,830	-11.2%
2012	313,178	5.2%
1995-2007		**2.1%**
2008-2012		**0.2%**

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	Total Debt Expense Actual ($)	
1994	36,950,033	
1995	38,210,213	3.4%
1996	39,243,518	2.7%
1997	43,412,365	10.6%
1998	44,126,223	1.6%
1999	44,886,647	1.7%
2000	44,862,411	-0.1%
2001	51,776,737	15.4%
2002	65,571,115	26.6%
2003	89,817,695	37.0%
2004	88,286,849	-1.7%
2005	86,442,349	-2.1%
2006	95,372,516	10.3%
2007	105,826,166	11.0%
2008	110,034,111	4.0%
2009	113,089,660	2.8%
2010	116,274,843	2.8%
2011	114,831,133	-1.2%
2012	105,389,196	-8.2%
1995-2007		**9.0%**
2008-2012		**0.0%**

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12. Regarding Callahan at 19:9-15. In Ms. Callahan's opinion, will Tampa Electric have higher than average customer growth in the future?

A. The level of customer growth in Tampa Electric's service territory is generally higher than that experienced by other electric utilities in the United States. This level of customer growth is expected to continue.

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52. Regarding Hevert at 31:8-24 and Exh. No. RBH-1, Document No. 3. Please explain why Mr. Hevert believes the companies included in Document No. 3 (*i.e.*, the S&P 500) provide an adequate estimate of "the required return on the market as a whole."

A. The S&P 500 is a commonly cited and relied upon benchmark for the overall United States stock market performance. As noted by Standard & Poor's, the S&P 500 is widely regarded as the best single gauge of large cap US equities. See http://www.spindices.com/indices/equity/sp-500.

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53. Regarding Hevert at 34:1-8. Please identify and describe the market used by Bloomberg and Value Line to calculate their Beta coefficients.

A. Bloomberg uses the S&P 500 Index to measure the market return, and Value Line uses the New York Stock Exchange Composite Index to measure the market return. The S&P 500 is a stock market index based on the 500 leading companies publicly traded in the United States. The New York Stock Exchange Composite Index is designed to measure the performance of all common stocks listed on the New York Stock Exchange.

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52. Regarding Hevert. Please provide Tampa Electric's actual historical capital structure from 2007 through 2012. Please provide all supporting workpapers and documentation.

A. The requested documents are attached.

Tampa Electric - Historical Capital Structure

	Common Equity	Debt
2012Q4	53.78%	46.22%
2012Q3	51.36%	48.64%
2012Q2	50.63%	49.37%
2012Q1	52.04%	47.96%
2011Q4	51.48%	48.52%
2011Q3	52.01%	47.99%
2011Q2	51.51%	48.49%
2011Q1	51.32%	48.68%
2010Q4	50.54%	49.48%
2010Q3	51.56%	48.44%
2010Q2	50.53%	49.47%
2010Q1	51.20%	48.80%
2009Q4	50.12%	49.88%
2009Q3	50.45%	49.55%
2009Q2	50.10%	49.90%
2009Q1	50.55%	49.45%
2008Q4	51.84%	48.18%
2008Q3	51.13%	48.87%
2008Q2	50.26%	49.74%
2008Q1	51.43%	48.57%
2007Q4	48.01%	51.99%
2007Q3	46.44%	53.56%
2007Q2	44.87%	55.13%
2007Q1	47.12%	52.88%

SNLTable

		Company Name	SNL Institution Key	Total Long-term Debt ($000)	Total Proprietary Capital ($000)	Preferred Stock Issued ($000)	Notes Payable ($000)	Notes Payable to Associated Companies ($000)
		201129	201136	201292	201284	201247	201304	201306
3010781	2012Q4	Tampa Electric Company	3010781	1,701,306	1,979,457	0	0	0
3010781	2012Q3	Tampa Electric Company	3010781	1,847,980	1,951,697	0	0	0
3010781	2012Q2	Tampa Electric Company	3010781	1,831,988	1,878,554	0	0	0
3010781	2012Q1	Tampa Electric Company	3010781	1,682,235	1,881,902	0	34,000	0
3010781	2011Q4	Tampa Electric Company	3010781	1,768,172	1,875,907	0	0	0
3010781	2011Q3	Tampa Electric Company	3010781	1,768,158	1,918,262	0	0	0
3010781	2011Q2	Tampa Electric Company	3010781	1,768,145	1,885,804	0	7,000	0
3010781	2011Q1	Tampa Electric Company	3010781	1,768,132	1,863,833	0	0	0
3010781	2010Q4	Tampa Electric Company	3010781	1,843,118	1,883,456	0	0	0
3010781	2010Q3	Tampa Electric Company	3010781	1,768,105	1,902,060	0	18,900	0
3010781	2010Q2	Tampa Electric Company	3010781	1,768,092	1,884,415	0	77,000	0
3010781	2010Q1	Tampa Electric Company	3010781	1,768,079	1,874,059	0	18,000	0
3010781	2009Q4	Tampa Electric Company	3010781	1,768,065	1,831,712	0	55,000	0
3010781	2009Q3	Tampa Electric Company	3010781	1,768,052	1,855,284	0	54,000	0
3010781	2009Q2	Tampa Electric Company	3010781	1,665,045	1,831,094	0	159,000	0
3010781	2009Q1	Tampa Electric Company	3010781	1,664,947	1,800,325	0	96,000	0
3010781	2008Q4	Tampa Electric Company	3010781	1,664,850	1,822,682	0	28,550	0
3010781	2008Q3	Tampa Electric Company	3010781	1,664,752	1,755,445	0	13,000	0
3010781	2008Q2	Tampa Electric Company	3010781	1,664,654	1,681,975	0	0	0
3010781	2008Q1	Tampa Electric Company	3010781	1,564,557	1,657,563	0	1,120	0
3010781	2007Q4	Tampa Electric Company	3010781	1,659,459	1,532,687	0	370	0
3010781	2007Q3	Tampa Electric Company	3010781	1,659,361	1,489,394	0	58,175	0
3010781	2007Q2	Tampa Electric Company	3010781	1,784,257	1,452,032	0	0	0
3010781	2007Q1	Tampa Electric Company	3010781	1,595,218	1,433,442	0	13,560	0

Source: SNL Financial

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

IN RE: PETITION FOR RATE INCREASE BY TAMPA ELECTRIC COMPANY	))	DOCKET NO. 130040-EI

EXHIBIT___(RAB-8)

OF

RICHARD A. BAUDINO

ON BEHALF OF THE

THE WCF HOSPITAL UTILITY ALLIANCE

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

TAMPA ELECTRIC COMPANY
ELECTRIC COMPANY COMPARISON GROUP
AVERAGE PRICE, DIVIDEND AND DIVIDEND YIELD

		Jun-13	May-13	Apr-13	Mar-13	Feb-13	Jan-13
American Electric Power	High Price ($)	46.490	51.600	51.500	48.680	47.030	45.340
	Low Price ($)	42.830	45.570	47.940	46.360	44.230	42.920
	Avg. Price ($)	44.660	48.585	49.720	47.520	45.630	44.130
	Dividend ($)	0.490	0.490	0.470	0.470	0.470	0.470
	Mo. Avg. Div.	4.39%	4.03%	3.78%	3.96%	4.12%	4.26%
	6 mos. Avg.	4.09%					
Black Hills Corp.	High Price ($)	49.350	50.530	46.950	44.320	41.900	40.970
	Low Price ($)	45.070	45.820	43.190	41.020	39.550	36.890
	Avg. Price ($)	47.210	48.175	45.070	42.670	40.725	38.930
	Dividend ($)	0.380	0.380	0.380	0.380	0.380	0.380
	Mo. Avg. Div.	3.22%	3.16%	3.37%	3.56%	3.73%	3.90%
	6 mos. Avg.	3.49%					
Cleco	High Price ($)	46.760	49.400	49.520	47.170	44.770	42.830
	Low Price ($)	43.750	44.810	46.240	43.570	42.360	40.390
	Avg. Price ($)	45.255	47.105	47.880	45.370	43.565	41.610
	Dividend ($)	0.362	0.338	0.338	0.338	0.338	0.338
	Mo. Avg. Div.	3.20%	2.87%	2.82%	2.98%	3.10%	3.25%
	6 mos. Avg.	3.04%					
CMS Energy	High Price ($)	27.720	29.980	29.940	27.950	26.790	25.740
	Low Price ($)	25.760	26.790	27.670	25.990	25.430	24.600
	Avg. Price ($)	26.740	28.385	28.805	26.970	26.110	25.170
	Dividend ($)	0.255	0.255	0.255	0.255	0.255	0.240
	Mo. Avg. Div.	3.81%	3.59%	3.54%	3.78%	3.91%	3.81%
	6 mos. Avg.	3.74%					
Consolidated Edison	High Price ($)	58.950	64.030	63.810	61.130	59.200	57.060
	Low Price ($)	55.420	56.850	60.440	58.330	56.260	54.950
	Avg. Price ($)	57.185	60.440	62.125	59.730	57.730	56.005
	Dividend ($)	0.615	0.615	0.615	0.615	0.615	0.605
	Mo. Avg. Div.	4.30%	4.07%	3.96%	4.12%	4.26%	4.32%
	6 mos. Avg.	4.17%					
Dominion Resources	High Price ($)	57.250	61.850	61.720	58.250	57.190	54.540
	Low Price ($)	53.790	56.550	57.940	55.450	53.900	51.920
	Avg. Price ($)	55.520	59.200	59.830	56.850	55.545	53.230
	Dividend ($)	0.563	0.563	0.563	0.563	0.563	0.527
	Mo. Avg. Div.	4.06%	3.80%	3.76%	3.96%	4.05%	3.96%
	6 mos. Avg.	3.93%					
Great Plains Energy	High Price ($)	23.210	24.440	24.140	23.200	22.470	21.410
	Low Price ($)	21.730	22.080	22.670	21.590	21.310	20.390
	Avg. Price ($)	22.470	23.260	23.405	22.395	21.890	20.900
	Dividend ($)	0.217	0.217	0.217	0.217	0.217	0.217
	Mo. Avg. Div.	3.86%	3.73%	3.71%	3.88%	3.97%	4.15%
	6 mos. Avg.	3.88%					

TAMPA ELECTRIC COMPANY
ELECTRIC COMPANY COMPARISON GROUP
AVERAGE PRICE, DIVIDEND AND DIVIDEND YIELD

		Jun-13	May-13	Apr-13	Mar-13	Feb-13	Jan-13
Hawaiian Electric	High Price ($)	26.290	28.240	28.300	27.800	27.920	27.000
	Low Price ($)	23.840	26.060	26.310	26.490	26.570	25.500
	Avg. Price ($)	25.065	27.150	27.305	27.145	27.245	26.250
	Dividend ($)	0.310	0.310	0.310	0.310	0.310	0.310
	Mo. Avg. Div.	4.95%	4.57%	4.54%	4.57%	4.55%	4.72%
	6 mos. Avg.	4.65%					
Otter Tail	High Price ($)	28.780	31.240	31.700	31.340	29.210	27.190
	Low Price ($)	26.500	27.090	29.840	28.270	26.760	25.170
	Avg. Price ($)	27.640	29.165	30.770	29.805	27.985	26.180
	Dividend ($)	0.298	0.298	0.298	0.298	0.298	0.298
	Mo. Avg. Div.	4.31%	4.09%	3.87%	4.00%	4.26%	4.55%
	6 mos. Avg.	4.18%					
Pepco	High Price ($)	21.000	22.720	22.670	21.430	20.490	20.450
	Low Price ($)	19.350	20.630	21.260	20.100	19.220	18.820
	Avg. Price ($)	20.175	21.675	21.965	20.765	19.855	19.635
	Dividend ($)	0.270	0.270	0.270	0.270	0.270	0.270
	Mo. Avg. Div.	5.35%	4.98%	4.92%	5.20%	5.44%	5.50%
	6 mos. Avg.	5.23%					
Pinnacle West	High Price ($)	58.130	61.890	61.090	57.960	56.010	53.620
	Low Price ($)	51.560	55.600	57.410	55.560	52.950	51.500
	Avg. Price ($)	54.845	58.745	59.250	56.760	54.480	52.560
	Dividend ($)	0.545	0.545	0.545	0.545	0.545	0.545
	Mo. Avg. Div.	3.97%	3.71%	3.68%	3.84%	4.00%	4.15%
	6 mos. Avg.	3.89%					
SCANA	High Price ($)	50.910	54.410	54.270	51.230	49.640	46.980
	Low Price ($)	47.220	50.070	50.980	48.490	46.700	45.570
	Avg. Price ($)	49.065	52.240	52.625	49.860	48.170	46.275
	Dividend ($)	0.507	0.507	0.507	0.507	0.495	0.495
	Mo. Avg. Div.	4.13%	3.88%	3.85%	4.07%	4.11%	4.28%
	6 mos. Avg.	4.05%					
UIL Holdings	High Price ($)	39.640	42.140	42.080	39.890	39.580	37.400
	Low Price ($)	36.320	38.630	39.090	38.350	36.760	35.860
	Avg. Price ($)	37.980	40.385	40.585	39.120	38.170	36.630
	Dividend ($)	0.432	0.432	0.432	0.432	0.432	0.432
	Mo. Avg. Div.	4.55%	4.28%	4.26%	4.42%	4.53%	4.72%
	6 mos. Avg.	4.46%					
UNS Energy	High Price ($)	47.670	51.540	51.330	49.130	47.300	45.350
	Low Price ($)	42.510	46.570	47.060	46.370	45.110	43.100
	Avg. Price ($)	45.090	49.055	49.195	47.750	46.205	44.225
	Dividend ($)	0.435	0.435	0.435	0.435	0.430	0.430
	Mo. Avg. Div.	3.86%	3.55%	3.54%	3.64%	3.72%	3.89%
	6 mos. Avg.	3.70%					

TAMPA ELECTRIC COMPANY
ELECTRIC COMPANY COMPARISON GROUP
AVERAGE PRICE, DIVIDEND AND DIVIDEND YIELD

		Jun-13	May-13	Apr-13	Mar-13	Feb-13	Jan-13
Westar Energy	High Price ($)	32.240	34.920	34.960	33.350	31.670	30.230
	Low Price ($)	30.130	31.260	32.850	31.010	30.080	28.590
	Avg. Price ($)	31.185	33.090	33.905	32.180	30.875	29.410
	Dividend ($)	0.340	0.340	0.340	0.340	0.330	0.330
	Mo. Avg. Div.	4.36%	4.11%	4.01%	4.23%	4.28%	4.49%
	6 mos. Avg.	4.25%					
Wisconsin Energy	High Price ($)	41.740	44.840	45.000	42.950	41.410	39.430
	Low Price ($)	39.040	40.560	42.310	40.790	39.360	37.030
	Avg. Price ($)	40.390	42.700	43.655	41.870	40.385	38.230
	Dividend ($)	0.340	0.340	0.340	0.340	0.340	0.300
	Mo. Avg. Div.	3.37%	3.19%	3.12%	3.25%	3.37%	3.14%
	6 mos. Avg.	3.24%					
Average Dividend Yield	4.00%						
Monthly Group Dividend Yields		4.11%	3.85%	3.80%	3.97%	4.09%	4.19%

Source: Yahoo! Finance

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

IN RE: PETITION FOR RATE INCREASE BY TAMPA ELECTRIC COMPANY	))	DOCKET NO. 130040-EI

EXHIBIT___(RAB-9)

OF

RICHARD A. BAUDINO

ON BEHALF OF THE

THE WCF HOSPITAL UTILITY ALLIANCE

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

TAMPA ELECTRIC COMPANY
ELECTRIC COMPANY COMPARISON GROUP
DCF Growth Rate Analysis

Company	(1) Value Line DPS	(2) Value Line EPS	(3) Value Line B x R	(4) Zacks	(5) Thomson Financial
American Electric Power Co.	4.00%	4.50%	4.00%	3.38%	3.84%
Black Hills Corporation	2.50%	11.50%	4.00%	6.00%	6.00%
Cleco Corp.	10.00%	5.50%	4.50%	8.00%	8.00%
CMS Energy Corporation	8.00%	5.50%	5.00%	5.85%	5.90%
Consolidated Edison, Inc.	1.50%	2.50%	3.50%	3.27%	2.27%
Dominion Resources, Inc.	5.50%	6.00%	5.00%	4.63%	7.27%
Great Plains Energy Incorporated	6.00%	6.50%	3.00%	5.07%	6.26%
Hawaiian Electric Industries, Inc.	2.00%	5.50%	2.50%	3.70%	2.40%
Otter Tail Corp.	1.50%	21.50%	4.00%	6.00%	6.00%
Pepco Holdings, Inc.	1.00%	6.00%	2.50%	6.00%	4.60%
Pinnacle West Capital Corp.	3.62%	5.00%	3.50%	4.13%	6.00%
SCANA Corporation	2.50%	4.50%	4.00%	4.65%	4.80%
UIL Holdings Corporation	0.00%	4.00%	3.00%	6.50%	8.06%
UNS Energy Corp.	5.50%	6.50%	4.50%	7.95%	8.00%
Westar Energy, Inc.	3.00%	6.00%	4.50%	5.13%	4.83%
Wisconsin Energy Corporation	12.00%	5.50%	5.00%	5.20%	4.93%
Averages*	4.29%	5.67%	3.91%	5.34%	5.57%
Median Values	3.31%	5.50%	4.00%	5.17%	5.95%

Sources: Zack's and Thomson Earnings Reports, retrieved June 25, 2013
Value Line Investment Survey, May 3, May 24, and June 21, 2013

* - The Value Line earnings growth estimate for Otter Tail Corp. was omitted from the group average.

RETURN ON EQUITY CALCULATION - ELECTRIC COMPANY COMPARISON GROUP
TAMPA ELECTRIC COMPANY

	(1) Value Line Dividend Gr.	(2) Value Line Earnings Gr.	(3) Zack's Earning Gr.	(4) Thomson Earning Gr.	(5) Average of All Gr. Rates
Method 1:					
Dividend Yield	4.00%	4.00%	4.00%	4.00%	4.00%
Growth Rate	4.29%	5.67%	5.34%	5.57%	5.22%
Expected Div. Yield	4.09%	4.11%	4.11%	4.11%	4.10%
DCF Return on Equity	***8.38%***	***9.78%***	***9.45%***	***9.68%***	***9.32%***
Midpoint of Results					***9.08%***
Method 2:					
Dividend Yield	4.00%	4.00%	4.00%	4.00%	4.00%
Median Growth Rate	3.31%	5.50%	5.17%	5.95%	4.98%
Expected Div. Yield	4.07%	4.11%	4.10%	4.12%	4.10%
DCF Return on Equity	***7.38%***	***9.61%***	***9.27%***	***10.07%***	***9.08%***
Midpoint of Results					***8.73%***

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

IN RE: PETITION FOR RATE INCREASE BY TAMPA ELECTRIC COMPANY	))	DOCKET NO. 130040-EI

EXHIBIT___(RAB-10)

OF

RICHARD A. BAUDINO

ON BEHALF OF THE

THE WCF HOSPITAL UTILITY ALLIANCE

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

TAMPA ELECTRIC COMPANY
Capital Asset Pricing Model Analysis
Comparison Group

20-Year Treasury Bond, Value Line Beta

Line No.			Value Line
1	Market Required Return Estimate		
2		Expected Dividend Yield	0.75%
3		Expected Growth	11.43%
4		Required Return	12.18%
5	Risk-free Rate of Return, 20-Year Treasury Bond		
6		Average of Last Six Months	2.77%
8	Risk Premium		
9		@ 6 Month Average RFR (Line 4 minus Line 6)	9.42%
10	Comparison Group Beta		0.71
11	Comparison Group Beta * Risk Premium		
12		@ 6 Month Average RFR (Line 10 * Line 9)	6.68%
13	CAPM Return on Equity		
14		@ 6 Month Average RFR (Line 12 plus Line 6)	9.44%

5-Year Treasury Bond, Value Line Beta

Line No.			Value Line
1	Market Required Return Estimate		
2		Expected Dividend Yield	0.75%
3		Expected Growth	11.43%
4		Required Return	12.18%
5	Risk-free Rate of Return, 5-Year Treasury Bond		
6		Average of Last Six Months	0.87%
8	Risk Premium		
9		@ 6 Month Average RFR (Line 4 minus Line 6)	11.31%
10	Comparison Group Beta		0.71
11	Comparison Group Beta * Risk Premium		
12		@ 6 Month Average RFR (Line 9 * Line 10)	8.02%
13	CAPM Return on Equity		
14		@ 6 Month Average RFR (Line 12 plus Line 6)	8.89%

TAMPA ELECTRIC COMPANY
Capital Asset Pricing Model Analysis
Comparison Group

Supporting Data for CAPM Analyses

20 Year Treasury Bond Data

	Avg. Yield
January-13	2.68%
February-13	2.78%
March-13	2.78%
April-13	2.55%
May-13	2.73%
June-13	3.07%
6 month average	2.77%

5 Year Treasury Bond Data

	Avg. Yield
January-13	0.81%
February-13	0.85%
March-13	0.82%
April-13	0.71%
May-13	0.84%
June-13	1.20%
6 month average	0.87%

Value Line Market Growth Rate Data:

Forecasted Data:	
Earnings	13.64%
Book Value	9.22%
Average	11.43%

Source: Value Line Investment Survey for Windows retreived June 25, 2013

Comparison Group Betas:	Value Line
American Electric Power Co.	0.65
Black Hills Corporation	0.80
Cleco Corporation	0.65
CMS Energy Corporation	0.75
Consolidated Edison, Inc.	0.60
Dominion Resources, Inc.	0,65
Great Plains Energy Incorporated	0.80
Hawaiian Electric Industries, Inc.	0.70
Otter Tail Corp.	0.90
Pepco Holdings, Inc.	0.75
Pinnacle West Capital Corp.	0.70
SCANA Corporation	0.65
UIL Holdings Corporation	0.70
UNS Energy Corp.	0.70
Westar Energy, Inc.	0.75
Wisconsin Energy Corporation	0.60
Average	0.71

Source: Value Line Investment Survey

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

IN RE: PETITION FOR RATE INCREASE BY TAMPA ELECTRIC COMPANY	))	DOCKET NO. 130040-EI

EXHIBIT___(RAB-11)

OF

RICHARD A. BAUDINO

ON BEHALF OF THE

THE WCF HOSPITAL UTILITY ALLIANCE

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

TAMPA ELECTRIC COMPANY
Capital Asset Pricing Model Analysis
Historic Market Premium

	Geometric Mean	Arithmetic Mean
Long-Term Annual Return on Stocks	9.80%	11.80%
Long-Term Annual Income Return on Long-Term Government Bonds	5.10%	5.10%
Historical Market Risk Premium	4.70%	6.70%
Comparison Group Beta, Value Line	0.71	0.71
Beta * Market Premium	3.33%	4.75%
Current 20-Year Treasury Bond Yield	2.77%	2.77%
CAPM Cost of Equity, Value Line Beta	**6.10%**	**7.52%**

Source: *Ibbotson SBBI 2013 Valuation Yearbook,* Morningstar, page 23

CERTIFICATE OF SERVICE
DOCKET NO. 130040-EI

I HEREBY CERTIFY that a copy of the prefiled Testimony and Exhibits of the WCF Hospital Utility Alliance ("HUA") has been furnished by electronic mail, U.S. Mail or Federal Express, this 15th day of July, 2013 to the following:

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