FILED SEP 10, 2013
DOCUMENT NO. 05340-13
FPSC - COMMISSION CLERK

BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

In the Matter of:

DOCKET NO. 130040-EI

PETITION FOR RATE INCREASE
BY TAMPA ELECTRIC COMPANY.
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VOLUME 5

Pages 738 through 959

PROCEEDINGS: HEARING

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

DATE: Monday, September 9, 2013

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

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

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

APPEARANCES: (As heretofore noted.)

I N D E X

WITNESSES

EXHIBITS

NUMBER:	ID.	ADMTD.

NO EXHIBITS MARKED OR ADMITTED IN THIS VOLUME

P R O C E E D I N G S

(Transcript follows in sequence from Volume 4.)

TAMPA ELECTRIC COMPANY
DOCKET NO. 130040-EI
FILED: 04/05/2013

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

WILLIAM R. ASHBURN

Q. Please state your name, business address, occupation and employer.

A. My name is William R. Ashburn. My business address is 702 North Franklin Street, Tampa, Florida 33602. I am the Director, Pricing and Financial Analysis for Tampa Electric Company ("Tampa Electric" or "company").

Q. Please provide a brief outline of your educational background and business experience.

A. I graduated from Creighton University with a Bachelor of Science degree in Business Administration. Upon graduation, I joined Ebasco Business Consulting Company where my consulting assignments included the areas of cost allocation, computer software development, electric system inventory and mapping, cost of service filings and property record development. I joined Tampa Electric in 1983 as a Senior Cost Consultant in the Rates and Customer Accounting Department. At Tampa Electric I have held a series of positions with responsibility for cost of service studies, rate filings, rate design, implementation of new conservation and marketing programs, customer surveys and various state and federal regulatory filings. In March 2001, I was promoted to my current position of Director, Pricing and Financial Analysis in Tampa Electric's Regulatory Affairs Department. I am a member of the Rate and Regulatory Affairs Committee of the Edison Electric Institute ("EEI") and the Rate Committee of the Southeastern Electric Exchange ("SEE").

Q. Have you previously testified before the Florida Public Service Commission ("FPSC" or "Commission")?

A. Yes. I have testified or filed testimony before this Commission in several dockets. Most recently I testified for Tampa Electric in Docket No. 000061-EI regarding the company's Commercial/Industrial Service Rider tariff, in Docket No. 020898-EI regarding a self-service wheeling experiment, and in Docket No. 080317-EI which was Tampa Electric's last base rate proceeding on the same topics I testify to in this case. In Docket Nos. 000824-EI, 001148-EI, 010577-EI and 020898-EI, I testified at different times for Tampa Electric and as a joint witness representing Tampa Electric, Florida Power & Light Company ("FP&L") and Progress Energy Florida, Inc. ("PEF") regarding rate and cost support matters related to the GridFlorida proposals. In addition, I have represented Tampa Electric numerous times at workshops and in other proceedings regarding rate, cost of service and related matters. I have also provided testimony and represented Tampa Electric before the Federal Energy Regulatory Commission ("FERC") in rate and cost of service matters.

Q. Please state the purpose of your direct testimony.

A. The purpose of my direct testimony is to present the proposed rates and service charges that will produce the company's proposed jurisdictional revenue requirement increase of $134,841,000. Specifically, I present the following information:

1) The development and application of billing determinants, the forecast of base revenues from the sale of electricity, revenues from service charges for the 2013 and 2014 projected periods using present rates and for 2014 under proposed rates to achieve proposed class revenues;
2) The Jurisdictional Separation Study and resultant

jurisdictional separation factors used for the 2012 historical period and the 2013 and 2014 projected periods that determine the portion of Tampa Electric's system rate base and operating expenses subject to the jurisdiction of the FPSC and form the basis for the company's proposed revenue requirement for the test year;

3) The 2014 projected period Retail Class Allocated Cost of Service and Rate of Return Studies that used a 12 Coincident Peak ("CP") and 50 Percent Average Demand ("AD") production capacity cost allocation methodology, which I will refer to as 12 CP and 50 Percent AD;

4) The methods employed, facts considered, and principles upon which the Jurisdictional Separation Study and Cost of Service Study were prepared;

5) Conclusions regarding the adequacy of the aforementioned studies and the reasonableness of the resulting costs being used to support the proposed rate design; and

6) Explanation of the company's proposed rate structure modifications, rate designs and rates, service charges and schedules to be implemented.

Q. Have you prepared an exhibit to support your direct testimony?

A. Yes, I am sponsoring Exhibit No._(WRA-1) consisting of four documents, prepared under my direction and supervision. These consist of:

Document No. 1	List Of Minimum Filing Requirement Schedules Sponsored Or Co-Sponsored By William R. Ashburn
Document No. 2	Development Of Proposed (Target) Base Revenue Increase By Rate Class
Document No. 3	IS Customer Billing Comparisons
Document No. 4	Summary Of Resultant Class Parity Ratios

Q. Are you sponsoring any sections of Tampa Electric's Minimum Filing Requirements ("MFRs")?

A. Yes. I am sponsoring or co-sponsoring the MFRs shown in Document No. 1 of my exhibit.

Q. Are Tampa Electric's billing determinants, forecast of base revenues from the sale of electricity and service charges, Jurisdictional Separation Study, Cost of Service Study, proposed rate design and rate schedules provided as part of Tampa Electric's MFRs?

A. Yes, they are provided within the portion of the MFRs designated Section E, "Rate Schedules". I have provided the Jurisdictional Separation Study and two sets of Cost of Service Studies as well as work papers in separate bound volumes due to their voluminous size. Volume I contains the Jurisdictional Separation Study and the Cost of Service Studies using the MFR-required 12 CP and 1/13 AD methodology without Minimum Distribution System ("MDS") concept with present and proposed rates. Volume II contains the Cost of Service Studies using the company's proposed 12 CP and 50 Percent AD methodology and employing the MDS concept with present and proposed rates and work papers. Volume III contains the company's Lighting Incremental Cost Study which is a supplement to MFR Schedule E-13d.

Q. What are the company's primary goals for the proposed cost of service and rate design changes in this case?

A. There are four primary goals that are reflected in the cost of service and rate design proposals of Tampa Electric in this case. First, is the use of the 12 CP and 50 Percent AD production capacity allocation methodology in the cost of service study. Second, is the use of the MDS within the cost of service study. Third, is to complete the transition of Interruptible Service ("IS") customers to the same General Service Demand ("GSD") rate schedules available to all other interruptible service customers. Fourth, is to better recognize in the rate design the cost of providing service to customers taking service at higher voltages.

BILLING DETERMINANTS

Q. Please explain the term billing determinants.

A. Billing determinants are the parameters to which prices are applied to derive billed revenues. They include 1) the number of customers (*i.e.,* bills) to which the customer charges are applied, 2) the amount of energy or kilowatt-hours ("kWh") sold to which the energy charges are applied, and 3) the amount of demand or kilowatts ("kW") to which the demand charges are applied. They also include the number of units to which any additional charges, discounts and/or penalties are applied. Some rate schedules are only billed using customer and kWh billing determinants, while others may include a kW billing determinant as well. Lighting schedules are billed based on lighting facility billing determinants (*e.g.*, poles and fixtures) along with kWh.

Q. Where are the billing determinants found in the company's filing?

A. Billing determinants for present and proposed rates are contained in MFR Schedules E-13c and E-13d.

Q. How were the billing determinants derived?

A. The basis for the billing determinants by rate schedule was historical billing data maintained by Tampa Electric's Customer Information System. Details of the derivation of these numbers are explained in MFR Schedule E-15. The foundation for the billing determinants was the company's customer, peak demand and energy sales forecasts for test year 2014, which are supported in Tampa Electric witness Lorraine L. Cifuentes' direct testimony. The forecasts produce the number of customers, energy consumption and demand by revenue classifications of residential, commercial, industrial, public street and highway lighting, and sales to public authorities. Witness Cifuentes also forecasts the expected requirements for phosphate industry load.

The forecasts of customers and kWh sales were then distributed to rate schedule classifications. This distribution was made in proportion to customer and sales relationships of revenue classifications to rate schedule classifications that were experienced in recent years by analyzing actual data for the most recent 12 months.

Historical customer and kWh sales relationships were also established for other billing units in each rate schedule. These relationships were applied to the apportioned number of customers and sales of each respective rate schedule to derive the various other billing units, including billing demands, time-of-day rate billing quantities, and metering and service voltage level distinctions, as well as various other billing quantities subject to additional charges or credits.

Q. How were these billing determinants used?

A. The forecasted billing determinants were applied to current rates to calculate the base revenues from the sale of electricity for the 2014 test year based on the company's present rate structure.

Q. Were these same billing determinants used to derive the base revenues from the sale of electricity for the 2014 test year based on the proposed rate structure?

A. Yes. The billing determinants are the same quantities as those used to derive present rate revenues but were distributed differently to reflect the proposed rate design, which combines certain current rate schedules and changes some charges. In addition, because of the proposed changes in rate design, certain customers were transferred from their current rate schedule to another new rate schedule, either because of schedule parameters or because of other rate options which were more economical for the customers.

Q. Will customers who are transferred or who may benefit from transfer under the proposed rate changes be informed of the proposed changes in order to assist them with making the appropriate rate choice?

A. Yes. Tampa Electric will use multiple means to inform customers of these changes and their options, depending on the size of the customer group being affected and the type of choices available. Company representatives will contact some customers directly by phone call or visit, as well as by bill inserts. The company will inform others through direct mail letters and bill inserts.

FORECAST OF BASE REVENUES AND SERVICE CHARGES

Q. Did the company prepare a forecast of base revenues from the sale of electricity for 2014? If so, how was the forecast of base revenues derived?

A. Yes. The base 2014 sales revenue forecast for present and proposed rates is summarized in MFR Schedule E-13a and calculated in detail in MFR Schedules E-13c and E-13d. The rates currently in effect were applied to the forecasted billing determinants to derive total annual base revenues forecasted for the 2014 test year before the proposed change in rates were considered.

Q. What is the projected retail billed electric revenue for 2014?

A. The projected retail billed electric revenue shown in MFR Schedule E-13a for 2014 is $907,769,000 under present rates and $1,041,409,000 under proposed rates, an increase of $133,640,000.

Q. The revenues you just described are for billed sales.

Does the company make a calculation for unbilled sales?

A. Yes. For the 2014 test period, an amount of unbilled revenues has been determined to be ($174,000) under present rates, and ($196,000) under proposed rates, resulting in a change of ($22,000) for unbilled sales.

Q. Did the company prepare a forecast of service charge revenues? If so, how was the forecast of service charge revenues derived?

A. Yes. The 2014 forecast of service charge revenues for present and proposed rates is presented in MFR Schedule E-13b. The current effective rates were applied to the forecasted billing determinants to derive service charge revenues. This represents the forecasted amount of service charge revenues before any proposed change to rates is considered.

Q. What is the projected billed service charge revenue for 2014?

A. The projected billed service charge revenue shown in MFR Schedule E-13b for 2014 is $21,593,000 under present rates and $22,787,000 under proposed rates, an increase of $1,194,000.

Q. What is the total amount of additional base revenues from the sale of electricity and service charges that are produced by the company's proposed rate design changes?

A. The total amount is $134,812,000 in additional revenues in 2014. This is comprised of $133,640,000 of additional billed electric base sales revenues, ($22,000) of additional unbilled electric base sales revenues, and $1,194,000 of additional service charge revenues. Thus, the company's proposed rate design changes results in an increase that is only $29,000 less than its proposed revenue requirement increase of $134,841,000.

JURISDICTIONAL SEPARATION STUDY

Q. What is a Jurisdictional Separation Study?

A. A Jurisdictional Separation Study allocates costs between the company's wholesale and retail customers or jurisdictions. While all costs are allocated, the allocation of joint costs is the focal point of the study. Joint or common costs are costs that are incurred to serve many customers at the same time. One example is a generating plant that provides power not only to one customer or one group of customers, but to the aggregate load requirements of all power customers on the company's system. The joint costs of the generating plant are recorded on the company's books and records in total, and the Jurisdictional Separation Study allocates the joint costs between retail and wholesale customers. Only the costs associated with retail customers are applicable in this proceeding.

The Jurisdictional Separation Study allocates revenue, rate base and operating expense items, whether jointly or specifically assigned to a single jurisdiction, to derive the company's retail jurisdiction cost of service for the test period. Costs are first functionalized, then classified, and finally allocated between the wholesale and retail jurisdictions. These allocations utilize load and other factors that best represent each jurisdiction's cost responsibility to achieve this purpose. A description of how costs are functionalized, classified and allocated is provided below. The overall methodology is the same in both the Jurisdictional Separation Study and the Retail Cost of Service Studies, which I will discuss later.

Q. Why is it necessary to prepare a Jurisdictional Separation Study for Tampa Electric?

A. Since early 1991, Tampa Electric has provided wholesale power sales and transmission service to some wholesale power purchasers in Florida at rates that are under the jurisdiction of the Federal Energy Regulatory Commission ("FERC"). Although the company operates in two regulatory jurisdictions, its investments, revenue, and expenses are maintained on a total company basis in accordance with the Uniform System of Accounts prescribed by the FERC and the FPSC. The Jurisdictional Separation Study is designed to directly assign or allocate total system costs to each jurisdiction.

Q. Is the Jurisdictional Separation Study provided in this proceeding consistent with Tampa Electric's previous Commission filings and industry practice?

A. Yes. Tampa Electric provided a Jurisdictional Separation Study in its last base rate proceeding that led to an approved methodology by the FPSC. That methodology has been used to produce separation factors for the annual projected surveillance reports, which are the same factors that have been used as separation factors for the 2012 and 2013 MFRs.

Q. What were the major steps followed in performing the Jurisdictional Separation Study?

A. There are several steps. First, the company's accounting information provided by FERC account, shown in the MFR Schedules B, C and D, is adjusted for the 2014 test period. The accounts are then functionalized into production, transmission, distribution, and general functions. Next, they are classified into demand, energy or customer groups. After classification, the groupings are allocated into the retail and wholesale jurisdictions using allocation factors. The allocation factors are predominantly based on demand data for the retail and wholesale jurisdictions during the time of the company's projected system monthly peaks, although other factors are used that directly allocate certain costs to the specific jurisdiction for which the costs are incurred. In addition, other metrics such as energy sales and number of customers are used.

Q. What wholesale power sales customers are included in the 2014 test year?

A. None. Currently and as forecasted for the 2014 test year, Tampa Electric is not providing long-term firm requirements electric power service to any wholesale customers.

Q. Does Tampa Electric currently provide transmission service to other Open Access Transmission Tariff ("OATT") customers?

A. Yes. Tampa Electric is providing long-term firm transmission service in the test year under the company's OATT to Seminole Electric Cooperative Inc., Auburndale Power Partners ("APP") and Calpine. However, pro forma adjustments, which are more fully described in the direct testimony of Tampa Electric witness Jeffrey S. Chronister, have been made to remove the load effects of the APP and Calpine transmission service agreements from the jurisdictional separation in 2014. The APP agreement terminates as of December 31, 2013 which puts it outside the 2014 test year. The Calpine Agreement terminates as of May 31, 2014. Removing these loads best reflects the appropriate jurisdictional separation effects on retail revenue requirement measurement for the test year and going forward. Each of these transmission customers has the option under FERC rules to request rollover of its existing contracts before they end but have not yet done so. If such a request is made and a new contract is created or the existing contract is extended during the pendency of this case, Tampa Electric is prepared to reflect that change, for whatever portion of their existing contracted capacity that they secure for extension, in revised transmission separation factors. With respect to the revenues that will be collected from the Calpine contract during the first portion of 2014, the retail portion of those 2014 revenues is proposed to be flowed back to retail customers through the retail fuel adjustment clause. This is described in greater detail in the testimony of witness Chronister.

Q. Please summarize the results of the Jurisdictional Separation Study.

A. In 2014, the retail business represents the vast majority of the electric service provided by Tampa Electric. As the results show in Volume I, Jurisdictional Separation Study, the retail business is responsible for all of production and distribution plant and 98.37 percent of transmission plant.

COST OF SERVICE STUDY

Q. What is a Retail Class Allocated Cost of Service and Rate of Return Study ("Cost of Service Study")?

A. The Cost of Service Study is an extension of the Jurisdictional Separation Study. It starts with the retail separated costs derived from the Jurisdictional Separation Study and further allocates and assigns costs to individual retail rate classes. These rate classes represent relatively homogeneous groups of customers having similar service requirements and usage characteristics. Typically, the prices charged for service to different rate classes vary based on cost of service as well as other factors. Allocations of costs to each of these groups, like the Jurisdictional Separation Study, are based upon the results of cost analysis. The Cost of Service Study results are considered, along with other factors described below, in the allocation of the revenue requirement among rate classes when designing rates. The study provides class rates of return at present and proposed rates, class revenue surplus or deficiency from full cost of service, and functional unit cost information for use in rate design. Thus, the study serves as an important guide in determining the revenue requirement by rate class, as well as the specific charges for each rate schedule.

Q. What retail rate classes were used in the preparation of the Cost of Service Study?

A. For purposes of preparing the Cost of Service Study using present rates, existing retail rate classes were used. The rate classes used are 1) Residential, 2) General Service Non-Demand, 3) General Service Demand, 4) Interruptible, and 5) Lighting Energy and Facilities. For purposes of preparing the proposed rates, the Cost of Service Study presents a different set of retail rate classes. They are 1) Residential, 2) General Service Non-Demand, 3) General Service Demand, and 4) Lighting Energy and Facilities.

Q. Why are there two columns of information presented under the present and proposed rates in the Cost of Service Studies for lighting service: Lighting Energy and Lighting Facilities?

A. Dividing the lighting rate class into the two components, Lighting Energy and Lighting Facilities, provides better unit cost information for designing the energy and facilities components of this rate class. The two components are distinct types of service and are not always provided as a bundled service by the company.

Q. Why is the IS rate class omitted in the proposed rates Cost of Service Study?

A. As mentioned earlier in my direct testimony, one of the company's rate design goals is to complete the transition of customers receiving service under the closed IS rate schedules to the applicable GSD rate schedules where, with interruptible service provided through the GSLM-2 and GSLM-3 rate riders, such service is available for all other interruptible service customers. This proposed elimination is reflected in part by the interruptible class being omitted in the proposed rates Cost of Service Study. This proposal is more fully explained later in my direct testimony.

Q. How is the Cost of Service Study used as a guide in rate design?

A. Cost of service studies are useful in the design of rates to help ensure that the prices customers pay for electric service bear a reasonable relationship to the costs of providing that service. Costing and pricing are two distinct and separate steps in the ratemaking process. Costing attempts to objectively determine costs incurred in rendering service to the rate classes.

While economic considerations and other subjective factors may be considered in the ultimate design of rates, cost of service should be the paramount consideration and the Cost of Service Study provides this information. I describe more fully the rate design process later in my direct testimony.

Q. After establishing the rate classes, what were the next steps in the Cost of Service Study process?

A. Similar to the Jurisdictional Separation Study, the development of cost of service studies consists of three steps: 1) grouping all costs by function (functionalization), 2) classifying the functionalized costs by causal service characteristics (classification), and 3) apportioning the resulting classified costs to rate classes (allocation).

Q. How were Tampa Electric's costs functionalized?

A. Tampa Electric functionalized costs in accordance with the Uniform System of Accounts by dividing utility plant costs into the broad functions of production, transmission, distribution, and general. O&M and other expenses were functionalized in a comparable manner.

Q. How were Tampa Electric's costs classified after they were functionalized?

A. Tampa Electric's operations are classified into three categories: demand, energy and customer cost. Demand cost is a function of the capacity of plant, which in turn depends on the maximum kW for power demanded by customers. Energy cost is a function of the kWh volume consumed by customers over time. Customer cost is a function of the number of customers served by the company.

Similarly, Tampa Electric's cost of service is measured by these same three cost categories: demand, energy, and customer. The three categories are appropriately called cost causations. The assignment of costs to these cost causation categories is called classification. Once classified, Tampa Electric's costs are then allocated to retail rate classes based upon cost behavior.

Q. Are all of the company's production plant facilities classified as demand-related in the cost of service studies?

A. No. For purposes of jurisdictional separation, all production plant facilities are classified as demand-related consistent with prior jurisdictional separation practices. However, there are portions of two production facilities that are classified as energy-related for purposes of allocating the FPSC jurisdictional component of these facilities on an energy basis. These facilities consist of the gasifier train equipment ("gasifier") for Polk Unit 1 and the scrubber portion of the environmental equipment for Big Bend Unit 4.

Polk Unit 1 is an Integrated Gasified Combined Cycle ("IGCC") plant which has two main sections - the power block, which produces the power through gas turbines and heat recovery steam generators, and the gasifier, which converts coal as the fuel feedstock into gas used in the power block. The gasifier performs a fuel conversion function that is completely associated with the provision of fuel to the unit and not the supply of capacity. The classification of the gasifier as energy-related was applied in Tampa Electric's last approved cost of service study.

The classification of the Big Bend Unit 4 scrubber as energy-related was applied in Tampa Electric's last two approved cost of service studies. This treatment remains appropriate because the main purpose of the plant investment is related to energy output. Since the decision to classify the scrubber investment as energy-related, additional scrubber and Selective Catalytic Removal ("SCR") investments made by the company have been recovered through the Environmental Cost Recovery Clause ("ECRC") where they have been classified and allocated on an energy basis. Customers benefit from lower energy costs as the result of these investments, not primarily because of their contribution to serve system peak demand.

Q. How are costs classified to the customer function?

A. Costs classified to the customer function are those generally independent of consumption. They have traditionally included the cost of service drops, meters, meter reading, billing and customer information. In addition, the company has reviewed and employed a costing methodology in this case that is described in the industry as the MDS method. This method determines the minimum size and respective cost of distribution transformers, poles, and conductors that would be required to connect customers to the company's power grid. This minimum cost is also classified as customer-related, and the remaining cost of these facilities is classified as capacity-related. The methodology is described in the NARUC cost allocation manual and has recently been employed by Gulf Power Company ("Gulf Power") in its cost of service study presented in Docket No. 110138-EI before this Commission and then accepted by the Commission in the settlement of rate and cost of service matters in that docket.

Q. Why does the company believe the MDS method is a more appropriate classification of these distribution costs than previously recognized?

A. Previously, the costs of distribution facilities (*i.e.*, transformers, poles, conductors, and cables, etc.) were classified as capacity-related and allocated to rate classes based on the maximum load imposition on the distribution system. The company now recognizes certain deficiencies in this classification and rate design treatment for distribution costs and seeks to remedy them in this proceeding. First, the company seeks to recognize in its costing treatment the obligation it fulfills to electrically connect any customer desiring to energize their premise, no matter how much load the customer may impose or energy the customer may use. This requires the company to incur the cost to install transformers, poles and conductors in place to simply connect the customer to its power grid. The previous treatment of classifying these costs as only capacity-related ignored an important cost-causative responsibility to be energized and ready to serve. Second, for rate schedules employing demand metering and billing, distribution costs are included and recovered in a demand charge. However, the Residential Service and General Service Non-Demand rate schedules do not employ a demand charge. As a result, all of the costs of these distribution facilities were being recovered through the Energy Charge for these classes. The company believes these classifications of cost and resulting recovery has been deficient and finds that a portion of such costs should more appropriately be classified as customer-related and then recovered as a component of the Customer Charge.

Q. Can you summarize the resultant classifications of distribution facilities that you have derived under the MDS concept and incorporated in the company's Cost of Service Study?

A. Yes. The resultant classifications by type of distribution facility are shown below:

	Percentage Cost Classification		
Facility	Customer	Capacity	Total
Poles	64%	36%	100%
Conductors	9%	91%	100%
Transformers	24%	76%	100%

Q. Does the employment of the MDS methodology result in cost support for a higher Customer Charge and lower Energy Charge and thus has a greater impact on the total bill for a low usage residential customer as compared to a high usage customer?

A. Yes. Many residential customers are low energy use by virtue of residing in apartments or condominiums, smaller homes, second homes, part-time occupancy, having alternative energy sources, etc. It is only appropriate and equitable for all customers that the company be able to recover its connection-related costs from these low energy use customers and not depend on recovering these costs based on usage which places the burden of their collection on higher energy usage customers.

Q. After costs were functionalized and classified, how were they allocated?

A. After determining the functionalization and classification of costs based upon causation, the tools for cost apportionment to classes were determined. These tools, called allocation factors, are used to measure demand, energy and customer cost responsibilities. The derivation of the allocation factors used in the 2014 Cost of Service Study is shown in MFR Schedule E-10.

Q. What are the principal considerations when allocating demand costs?

A. The principal considerations in allocating demand costs include 1) customer demand usage characteristics and their related responsibility for system coincident and non-coincident peaks, 2) the design and configuration of production, transmission and distribution facilities, and 3) unique customer service and/or reliability requirements and system operating data. These considerations provide guidance in determining what components should be used to derive the demand factor. CP demands, non-coincident peak demands ("NCP"), customer demands, and percentage of energy have been used to best represent those considerations.

Q. Please explain CP, NCP and customer peak demand.

A. Coincident Peak or CP demand reflects a class contribution to the total system monthly peak demand. For example, at the hour of the system peak in one particular month, the CP demand for the residential class would be that class's proportion of that hour's peak demand. NCP demand reflects the monthly peak demand of a class on its own as a group, regardless of when the system peak occurs. For example, a class may peak during the nighttime hours, while the system may peak during the late afternoon. The NCP for that class would be the demand during that nighttime hour. Customer peak demand is the aggregation of all individual customers' monthly peak demands, regardless of when they occur. These different measurements of demand are utilized to allocate different cost elements because those elements represent the best way of identifying what causes certain costs to be incurred.

Q. Why is the company proposing a change in this proceeding to the 12 CP and 50 Percent AD methodology for allocation of production demand classified costs?

A. The company believes that the 12 CP and 50 Percent AD methodology provides the most appropriate classification and allocation of production plant within the Cost of Service Study when considering how power plants are planned and operated in Florida in response to customer energy and demand needs. The appropriate percentage of production demand classified plant to be allocated on an energy basis has been a debated topic in Florida for many decades. The percentage in prior Commission-approved studies for Tampa Electric has ranged from 8 percent (derived using the 1/13 portion of the 12 CP and 1/13 AD methodology) to over 70 percent (derived from the Equivalent Peaker method approved in 1985) with 25 percent being approved for the company in its last base rate proceeding. The debate over what is the appropriate percent to be allocated is about how much of the fixed production plant cost is incurred to meet system peak demand and how much is incurred to reduce variable operating costs, primarily fuel, by running the plant beyond peak demand periods. The higher the percentage of average demand applied, the more cost responsibility is allocated to higher load factor classes that benefit more from the additional investment in types of generating plant that produce more efficient energy production.

Q. Is the type of generation installed important in the selection of the appropriate production demand allocation methodology?

A. Yes. The company has installed a significant amount of base- and intermediate-load generation which is more expensive to install than alternative peaking generation, but less expensive to operate over time. The base- and intermediate-load generators provide lower fuel costs for each unit of energy produced compared to peakers. In fact, Tampa Electric is in the process of converting four of its existing simple cycle peakers at the Polk Power Station to a combined cycle structure that will accomplish this as well. Investment in more expensive generating units and associated equipment to provide more efficient fuel conversion for the generation of electricity drives the need to use a greater energy allocation within the production demand classified cost allocator.

Q. The company presented these arguments in its last base rate proceeding and at that time proposed a 25 percent energy allocation as a balance between the prior percentages that had been approved by the Commission in the past. The Commission approved that 25 percent allocation in that case. Why is the company proposing to increase the percentage in this case?

A. The 25 percent represented an appropriate balance at that time and in those circumstances. Use of the 25 percent allocates production demand classified costs to classes in closer proportion to the energy-based benefits those classes receive from those costs. The 25 percent, together with the energy classification to certain investments such as the gasifier and Big Bend scrubber equipment described earlier, are essential in capturing the production cost impact of higher load factor customers who benefit from the lower variable costs of base- and intermediate-load units. As the Commission recognized in their final decision in the company's last rate proceeding, the increase in that case to 25 percent resulted in a reduced revenue requirement allocation to the residential and small commercial rate classes. Increasing the percentage to 50 percent will further reduce that allocation. While the support for a higher energy allocation based on cost causation principles is strong, the selection of a proper percentage to reflect that principle is more judgmental and case specific. In this case, in concert with the impact of the proposed implementation of the MDS methodology on cost allocation, an increase to 50 percent is appropriate to recognize cost causation principles and minimize revenue requirement impacts to the RS and GS rate classes.

Q. Would the adoption of the 12 CP and 50 Percent AD methodology have implications for other cost recovery mechanisms?

A. Yes. The costs classified as production capacity-related in the cost recovery clauses should also consistently be allocated on the basis of the 12 CP and 50 Percent AD methodology.

Q. Please explain the treatment of demand allocated transmission and distribution costs in the Cost of Service Study.

A. The transmission demand classified costs are allocated on a 12 CP basis while distribution demand classified costs are allocated on a mixture of NCP and customer demand bases. This is the same allocation methodology as was adopted and relied on in the company's last base rate proceeding.

RATE DESIGN CRITERIA AND OBJECTIVES

Q. What criteria and objectives were used in designing the new rate schedules and how were they used in the rate design?

A. The basic criteria used in designing Tampa Electric's new rate schedules included 1) cost to serve the various classes, 2) rate history, 3) public acceptance of rate structures, 4) customer understanding and ease of application, 5) consumption and load characteristics of the classes, and 6) revenue stability and continuity. This Commission has recognized these criteria as good ratemaking practices.

Cost to serve is a major consideration in rate design and in the preparation of the Cost of Service Study. The use of derived unit cost is a major tool in the design of the company's proposed rates. Rate history is another important tool. This includes understanding how Tampa Electric rates were designed in the past, whether they achieved their intended objectives and what rate structures have been successfully applied in Florida and around the country by other utilities. I have worked in the regulatory area at Tampa Electric for almost thirty years and am well aware of the company's rate history. In addition, I track rate decisions made by the Commission that affect other jurisdictional electric utilities and participate frequently in EEI and SEE rate committee meetings where alternative rate designs, as well as successes and failures of such rates, are discussed. Public acceptance of rate structures, customer understanding, and ease of application are important considerations. I obtain information from frequent contact with the company's customer service team members and interaction with some customers that I factor into my work. Class consumption and load characteristics are used both within the Cost of Service Study as well as in the proposed design in developing appropriate projected billing determinants to assure successful recovery of revenue requirements. Revenue stability and continuity are criteria that factor into the rate design when selection of appropriate billing units to apply under the rates is considered, as well as the appropriate forecast of those billing units.

Q. With these criteria in mind, did the company have specific objectives that were considered in the proposed rate design?

A. Yes. First and foremost, the rates should be designed for each rate schedule so that their application to the test year billing determinants produces the target class and the total required revenues. The company also had two other specific objectives for the rate design in this case: 1) to complete the transition of IS customers to GSD rate schedules available to all other interruptible service customers and 2) to reflect the appropriate cost responsibility of providing service to customers served at higher voltage levels.

Q. Did the company meet these objectives?

A. Yes. The proposed rates and tariffs incorporate both of the additional specific objectives previously described and produce the company's proposed revenue requirements.

PROPOSED SERVICE CHARGES

Q. What was the first step in designing rates and charges to produce the company's revenue requirement?

A. The first step was to determine revenues from service charges. Cost support for the development of service charges is provided in MFR Schedule E-7. This cost support formed the basis of the proposed changes in service charges that are shown on MFR E-13b. In total, the proposed changes produce $1,194,000 in additional revenue. These revenues serve as a credit to offset a portion of the revenue requirement that would otherwise increase the company's base rates.

Q. What changes are being proposed for the company's service charges?

A. The cost support that is presented in MFR Schedule E-7 indicated that certain service charges should be increased in price to better reflect the cost and best provide cost recovery for these services. The proposed service charge increases are shown on MFR Schedule E-13b column 2. No increase was proposed for the initial service connection charge even though an increase was cost supported given that this charge was substantially increased in the company's last base rate proceeding.

One change being proposed is to rename the current "Field Credit Visit" charge to "Field Visit" charge. This proposed change would permit this charge to apply in cases where the company has made an appointment with a customer to discuss or perform work at the customer premise and the customer does not meet the appointment or the work cannot be performed because the customer has not made the premise ready for work to be performed. While this does not happen often, when it does occur it results in company resources not being used elsewhere for other customers. The company believes that such a fee will serve as an incentive for customers to keep their appointments and minimize the cost burden on other customers.

PROPOSED (TARGET) CLASS REVENUES

Q. After setting prices for service charges, what was the next step in designing rates?

A. Next, the company designed base rates to meet the proposed (target) class revenues. In designing new rates, the company first attempted to move unit prices toward unit costs for the various classes to determine parity. Parity is the comparison of the rate of return of a class to the system average rate of return. The term is used interchangeably with the term rate of return index. Since parity is calculated by dividing the rate of return for a particular class by the system average rate of return, a class with parity of 100 percent would be earning the same rate of return as the system average, and a class with parity below 100 percent would be earning less than the system average. Parity is useful when determining the development of class revenue targets associated with the proposed base rate revenue increase.

Q. Please describe the procedure used to determine what portion of the company's proposed (target) base rate revenue increase was assigned to each rate class.

A. The focus in determining the portion of the company's proposed (target) base rate revenue increase to be assigned to each rate class is the Cost of Service Study. The Cost of Service Study using the 12 CP and 50 Percent AD methodology and employing the MDS concept at present rates was relied upon for this purpose. Ideally, the rates developed will produce revenues from each of the rate classes that equal the costs allocated to that class by the cost of service study. This will achieve full parity.

The first step in determining how much each rate class should share in the company's total revenue increase (*i.e.*, the shortfall between total revenue requirements and total revenues under current rates) is to determine for each rate class the shortfall between the costs allocated to that class and the revenues produced by applying current rates to the class's test year billing determinants. The next step is to determine how much of each class's revenue shortfall will be offset by additional revenues from any increase in Other Operating Revenues that will occur as part of the proceeding, meaning any increase in service charge revenues being proposed. Once the net revenue deficiency of each rate class has been determined, the final step is to identify whether any ratemaking policy considerations should limit the amount of any rate class's revenue increase. Where an increase limit is imposed on a rate class, the other rate classes must make up the deficiency. This deficiency is spread to those other rate classes in proportion to their respective cost of service requirement to the extent that this resultant increase does not exceed an imposed limit.

The completion of this three-step procedure produces what is referred to as the target revenues for each class, the term "target" being used as the revenues become the target which the rate designer attempts to hit as close as possible through the design of proposed rate charges as applied to test year billing determinants.

Q. Did you prepare a document that develops the proposed class target revenues using the procedure you have just described?

A. Yes. Document No. 2 of my exhibit was prepared for that purpose.

Q. Was it necessary to limit any class's rate increase from being set at the increase indicated by the cost of service study?

A. Yes. By adhering to the Commission's practice of limiting a rate class's increase to 1.5 times that of the system average increase (including recovery clause revenues) the increase to the Lighting Energy class was limited. Also, in adhering to the Commission's practice that no rate class receive a decrease in an overall rate increase proceeding, the revenue requirements of the Lighting Facilities class are being left unchanged.

Q. Have you combined the revenue requirements of the Residential ("RS") and General Service Non-Demand ("GS") rate classes for developing the target revenues for these rate classes?

A. Yes. This is shown in Document No. 2 of my exhibit. It has been the company's practice since 1982 to set the base rate energy charges of the rate schedules associated with these two rate classes to be at the same rate level, with the only change to this practice being instituted in the last company rate proceeding where an inverted energy rate design was adopted for the RS standard rate, while the Energy Planner time-differentiated rate maintained an energy rate at the same level as the GS standard energy rate. This practice has led to combining the revenue requirements of these two classes when apportioning target revenues in rate proceedings.

Q. Have you combined the revenue requirements of the General Service Demand ("GSD") and Interruptible Service ("IS") rate classes developing the target revenues for these rate classes?

A. Yes. The IS rate class has been combined with the GSD rate class to complete the transition of the customers on the IS rate schedules to the GSD rate schedules. In this way the combined group will receive its appropriate target revenues associated with the increase.

Q. Were you able to design proposed rates for each rate class in order to produce each class's targeted revenues and reflect the requested increase?

A. Yes. The result of this design is shown in Document No. 4 of my exhibit, which shows a comparison of each class's target revenues and those revenues produced by the application of the proposed charges. It shows that the company's proposed revenues are equal to or very close to target revenues for each class, and the company's proposed revenues in total are within $29,000 of its total target revenue requirement. The exhibit also shows a comparison of each class's proposed revenues to its revenue requirement from the company's cost of service study and each class's resultant rate of return under the proposed rates. The company believes this exhibit demonstrates that the company has designed its proposed rates based on cost of service to the extent practical.

RATE DESIGN

Q. Please summarize the rate design changes or revisions the company is incorporating in its proposed base rates.

A. In summary, the following changes are proposed:

a. Most base rate charges contained in the company's rate schedules are being revised in order to reflect the costs of providing service and produce the target revenue requirements.

b. The "Customer Charge" on all rate schedules is being renamed the "Basic Service Charge" to reflect a more appropriate description of the costs being recovered in this fixed monthly charge. The proposed charges appropriately reflect the cost of service.

c. The "closed to new business" IS rate schedules are proposed for elimination, and the affected metered accounts are being transferred to the otherwise applicable GSD rate schedules with interruptible credits provided through the GSLM-2 and GSLM-3 conservation rate riders. The affected metered accounts' credit for interruptible service remains the same as previously established under the IS rate schedule.

d. Credits for providing service at higher voltage are being recognized under the GSD and standby rate schedules to reflect full avoided distribution costs, and the name of these credits is proposed to be changed from

"Transformer Ownership Discount" to "Delivery Voltage Credit" to better recognize taking service at the higher voltage. Another proposed name change is to change "Metering Level Discount" to "Metering Voltage Adjustment." This is a name change only; no rate change is proposed for this adjustment.

Q. You indicated that you revised most base rate charges in the various rate schedules in order that the proposed charges would result in the target revenues. To accomplish this, did you make any rate restructuring changes to any of your rate schedules?

A. The company is not proposing any rate restructuring changes in this proposal. The company is proposing elimination of the closed IS rate schedules and the more appropriate cost-based recognition of delivery credits for higher voltage service, but these do not represent any true "restructuring" of rates. The fixed Basic Service Charge in each rate schedule has been set in each rate schedule at its unit cost from the cost of service study. The demand and energy charges have been revised in each rate schedule to produce the target revenues for each rate class. Prior Commission approved and prescribed practices have been continued in the development of (a) the RS inverted energy rate with a one cent inversion after the 1,000 kWh usage level, (b) establishing the GS energy rate at an effective RS average rate, (c) maintaining an optional GSD energy rate set at 120 percent of the GS energy rate, (d) establishing time of use energy and demand charges for the GST and GSDT rate schedules in the manner previously adopted, and (e) establishing the standby rates in the manner prescribed by the Commission for the design of standby rates.

Q. Why did the company change the method of determining delivery voltage credits for customers taking service at higher voltages under demand-metered rate schedules?

A. This change is being made to provide a consistent treatment in rates with the allocation of costs in the cost of service study. Customers that take delivery at higher voltages, (*i.e.*, subtransmission or primary) are not allocated any cost responsibility in the cost of service study for the lower voltage facilities on which they do not impose their loads. Since rates are designed for application at the company's lowest service voltage, (*i.e.*, secondary), any customer taking higher voltage service should be credited for the avoidance of lower voltage delivery costs which are embodied in those rates. In previous rate designs the avoidance of costs at lower voltages for higher voltage service customers was only partially recognized through a transformer ownership discount.

Q. Can you provide a brief history of the rate treatment afforded the IS customers and why the company no longer needs to recognize these customers as a separate rate class for establishing their base rate charges?

A. Yes. For many years Tampa Electric has established and designed IS rate schedules to have lower base rate charges than other customers to recognize their "interruptibility" value. In Docket No. 080317-EI, the company's last base rate proceeding, the Commission approved a rate restructuring for the closed IS rate schedules whereby an IS customer's "interruptibility" would be treated as a demand-side or load management program. As load management participants, IS base rates were no longer required to be set less than that of firm customers. Instead, the IS customers receive interruptible demand credits for their participation as load management customers, and these credits are recovered from all customers through the ECCR clause.

The interruptible demand credits were set in the last proceeding to be the same credits as had been previously established in Rate Schedules GSLM-2 and GSLM-3, which were also applicable to other general service demand customers desiring to be load management participants.

Q. Why did the Commission close the company's IS rate schedules to new customers?

A. Actually, the company's IS rate schedules were "closed to new business" even before the last base rate proceeding. The IS-1 rate schedules were " closed to new business" in 1985 and the IS-3 rate schedules were "closed to new business" in 2000 when the GSLM-2 and GSLM-3 conservation programs were opened. The Commission's decision in Docket No. 080317-EI was a continuation of such closure for the IS rate schedules. In that proceeding, the company sought to permanently eliminate the already "closed" IS rate schedules on the basis that they were no longer necessary since interruptible service was openly available to any customer under the company's GSD rate schedules who wished to subscribe to the GSLM-2 or GSLM-3 rider as load management program participants. However, the Commission chose to maintain an IS rate class and accompanying rate schedules for those remaining metered accounts being served under the IS schedules.

Q. How would you describe the company's proposal in this proceeding for treating customers being served under the IS rate schedules?

A. The company is again proposing to bring an interim transition approach to final closure by eliminating the IS rate schedules. The affected metered accounts can be transferred to the applicable GSD rate schedules and continue to participate in the company's GSLM-2 or GSLM-3 load management program riders and obtain the same credits for interruptible service that they are paid now. As with other GSD customers on the GSLM-2 and GSLM-3 riders, these transferred customers' loads will be included in the company's biannual filed assessment of need of non-firm electric service. The IS schedules are no longer necessary, and their elimination will resolve inequitable situations that exist between the grandfathered customers taking service under them and new customers seeking to take interruptible service. The company believes the IS metered account holders are fully aware that their grandfathered status has been extended for decades and should now expect to be treated comparable to any other general service demand eligible customer that is willing and able to incur interruptible service.

Q. Do the closed IS metered accounts pose more favorable load characteristics than the rate class consisting of all GSD customers, thereby translating to a lower level of cost of service deserving of rate recognition for these customers?

A. While the forty-three remaining IS metered accounts in the aggregate do have more favorable load characteristics than the aggregate of the fourteen thousand customers being served under the company's GSD rate schedules, the load characteristics of GSD customers are rather diverse, and it is not surprising to find that a small subset of forty-three metered accounts would have different aggregate characteristics than the aggregate of all the customers in a large class. No doubt, another group of existing GSD accounts could be put together that would have exactly the same aggregate load characteristics or perhaps more favorable characteristics. The existing IS metered accounts would favor preserving their cost supported rate advantage, however it had been created or maintained over many years.

Q. Can you quantify the rate advantage that an existing IS account presently enjoys as compared to that of a typical prospective GSD customer taking interruptible service under the GSLM-2 conservation program rider to demonstrate the inequity that you describe exists for this grandfathered class?

A. Yes. I have prepared a billing example that quantifies the rate advantage that exists currently for a typical GSD measured customer. This is provided on the first page of Document No. 3 of my exhibit. The example billing comparison shows the grandfathered IS customer is charged under present rates 7.24 percent less on the base rate costs than would be charged a comparable GSD customer. On a total billing basis, the IS customer realizes a 4.66 percent billing advantage under present rates. The company does not believe such a rate discrepancy should exist or is just.

Q. Instead of eliminating the IS rate class and its rate schedules, could the company have proposed to open up the IS rate schedules to any GSD customer who wants to take interruptible service and thus eliminate the inequity described above?

A. Although that would eliminate inequity, it would not be fair treatment for the other GSD customers that do not want to take interruptible service. The value of interruptibility has been established by the payment of the interruptible demand credits under GSLM-2 and GSLM-3. There should be no further differentiation in rate treatment for interruptible service than the payment of these credits. It would be inappropriate to establish cost of service and ratemaking treatment for just one subset of general service customers on top of that credit recognition. The company had been seeking over several rate proceedings, and the Commission has approved, a reduction in the number of rate schedules applicable to subsets of customers that could be created from its general service rate customers. The company has advocated that the fairest approach to cost of service and ratemaking for this diverse group of customers is to establish a single rate that recovers cost of service of GSD customers and to use rate design of that rate to minimize cost disparities that exist due to differences in load characteristics and that of the average load characteristic of the class as a whole.

Q. Have you prepared any billing comparisons of the effect on each of the forty-three remaining IS metered accounts by their transfer to the proposed GSD rate schedules?

A. Yes. On page 2 of Document No. 3 of my exhibit, a billing comparison is presented for each of the forty-three IS customer accounts under their present rate charges and under the proposed applicable GSD rate charges for which they would be transferred. I believe this billing comparison reveals even more supportive information for the elimination of the IS rate schedules at this time. First, there are nine of these accounts that do not impose any load requirement on the company and are simply being retained as an active service location presumably to preserve the grandfathered rate status of that particular delivery point. Second, there are seven of these accounts that would actually benefit by transferring to the company's proposed applicable GSD rate schedule, primarily as a result of the change the company is seeking in its GSD rates regarding higher voltage delivery service. Third, the document shows the total proposed increase from all IS accounts results in a relatively moderate increase of 5.9 percent.

Q. Other than the transfer of IS metered accounts to their applicable GSD rate schedule, will the company's proposed rate changes result in any other customer transfers from one rate schedule to another?

A. Yes. The company has analyzed all of its demand metered GSD customers and finds a number of low energy use customers, about 950 customers, who are presently taking service under the GS rate who would receive lower billings under the proposed GSD rates. This is due primarily to the change to a lower Basic Service Charge for GSD secondary customers under the proposed rates that now results in those customers finding the GSD rate to be more economically beneficial. The transfer of these customers has been taken into account in the development of the company's proposed revenues.

Q. What changes are being made to the facilities charges of Lighting Service Rate Schedule LS-1?

A. Because the Cost of Service Study shows the revenues from the Facilities part of the company's Lighting Service class recover more than its cost of service, no change is being made to any of the fixture, pole or maintenance charges of this rate schedule.

Q. Is the company proposing to add any new rate schedules to its tariff?

A. Yes. Tampa Electric is proposing that a Commercial/Industrial Service Rider ("CISR") tariff be reinstituted for the company in this proceeding. Tampa Electric had a CISR tariff previously, on an experimental basis, which was allowed to lapse in 2004. CISR tariffs are currently in effect for Progress Energy Florida, Inc. and for Gulf Power. CISR is an economic development mechanism used to attract new load or retain existing commercial or industrial load to the service territory with rate flexibility made available under the company's GSD rate schedules for special contract situations. The company believes that reinstituting the CISR now will provide a tool which can be used with speed to address special situations to assist in accommodating commercial or industrial economic development opportunities.

Q. Are there any other miscellaneous tariff changes being proposed?

A. Yes. The tariff includes a Facilities Rental Agreement that includes a monthly rental factor and annual termination factors applicable to facilities that the company may agree to lease to customers. New proposed factors have been derived reflecting the company's proposed cost of capital in this proceeding. The revisions would only apply to new Facilities Rental Agreements and, since the company enters into very few of these agreements, no additional revenues have been projected in the 2014 test year. Additionally, certain administrative changes have been proposed for legal language in certain tariff agreements to reflect changes that have been previously approved by the Commission for similar tariff agreements but were overlooked at that time.

Q. Where can the results of the company's total rate design be found?

A. The revenue distribution by rate schedule is shown on MFR Schedule E-13a, supported by the detailed billing calculations in MFR Schedules E-13c and E-13d. The effect on customers' typical bills is shown on MFR Schedule A-2 and a comparison of present and proposed charges is shown on MFR Schedule A-3.

PARITY RESULTS OF PROPOSED RATE DESIGN

Q. Does your proposed rate design move rates closer to parity from a cost of service standpoint?

A. Yes. Document No. 4 of my exhibit presents the achieved class revenue requirement indices. Overall, most rate classes are reasonably close to parity. An index ratio of 1.00 indicates rates are set exactly on the cost of service. A ratio of less than 1.00 indicates that class is served below cost, and a class ratio of more than 1.00 indicates that class is served above cost.

SUMMARY

Q. Please provide a summary of the company's proposed rates and Cost of Service Studies in this proceeding.

A. The support for and design of the proposed rates in the case as presented in the MFRs and proposed tariffs meet the company's primary goals as articulated previously in my direct testimony. These rates are cost-based and reflect appropriately measured changes from the present rates that also reflect rate history, public acceptance of rate structures, customer understanding and ease of application, consumption and load characteristics of the classes, and will result in revenue stability and continuity.

The use of the company's proposed 12 CP and 50 Percent AD production capacity allocation methodology in the cost of service study provides an appropriate allocation of costs to the classes of service by Tampa Electric plant and equipment in the service territory. The application of the MDS approach to the company's cost of service methodology is an improvement in reflecting cost causation for the investment in distribution equipment. The completion of the transition of the IS customer class to the GSD rate in this case is appropriate, and the company proposal achieves that last transitional step appropriately. The rate design proposals that better reflect the cost of providing service to customers taking service at higher voltages are appropriate and assure that such customer's rates best reflect the cost of service they receive at the higher voltage levels. Finally, the proposed revenue increase has been apportioned to achieve class parity to the extent practical.

Q. Does this conclude your direct testimony?

A. Yes, it does.

BEFORE THE PUBLIC SERVICE COMMISSION

REBUTTAL TESTIMONY

OF

WILLIAM R. ASHBURN

Q. Please state your name, business address, occupation and employer.

A. My name is William R. Ashburn. My business address is 702 North Franklin Street, Tampa, Florida 33602. I am the Director, Pricing and Financial Analysis for Tampa Electric Company ("Tampa Electric" or "company").

Q. Are you the same William R. Ashburn who filed direct testimony in this proceeding?

A. Yes, I am.

Q. Please state the purpose of your rebuttal testimony?

A. The purpose of my rebuttal testimony is to address the prepared direct testimony of witnesses Stephen J. Baron, testifying on behalf of the WCF Hospital Utility Alliance ("HUA"), Jeffrey Pollock, testifying on behalf of the Florida Industrial Power Users Group ("FIPUG") and

William B. McNulty testifying on behalf of Commission Staff ("Staff"). Additionally, in conjunction with the rebuttal testimony being provided by Tampa Electric Witness Jeffrey S. Chronister, I will be addressing Office of Public Counsel ("OPC") witness Donna Ramas' jurisdictional separation issue regarding the updated information for transmission service commitments of the wholesale customers, Calpine and Auburndale Power Partners ("APP").

Q. Have you prepared an exhibit to support your rebuttal testimony?

A. Yes, I am sponsoring Exhibit No.__ (WRA-2), consisting of four documents, which were prepared under my direction and supervision. These consist of:

Document No. 1	Illustration of Economic Generation Selection and Allocated Cost Determination
Document No. 2	Comparison of Class Cost Results by Production Capacity Allocation Method
Document No. 3	Adjustment for Cost Effects of Updating Wholesale Transmission Service Requirements
Document No. 4	Minimum Distribution System Analysis

Q. Please summarize the key concerns and disagreements you have regarding the substance of witness Baron's, witness Pollock's, and witness McNulty's testimonies and the jurisdictional separation issue of witness Ramas.

A. My key concerns and disagreements are in regard to the following arguments raised by these witnesses as follows:

1. Witness Pollock's request to maintain IS as a separate rate class.
2. Witness Pollock's and witness Baron's criticisms of the company's proposed 12 CP & 50 Percent AD method and their recommendations to employ the 12 CP and 1/13th AD method.
3. Witness Pollock's and witness Baron's criticisms of the design of demand and energy charges in the GSD and GSDT rate schedules.
4. Witness McNulty's criticisms of the company's MDS determinations and the level of impact MDS has on the resultant cost classifications.
5. Although not necessarily in disagreement with witness Ramas, I wish to provide the adjusted rate base and net operating income cost elements resulting from the Jurisdictional Separation Study that has been adjusted to reflect updated information regarding the company's provision of

firm wholesale transmission service to Calpine and APP.

RETAINING IS AS A SEPARATE RATE SCHEDULE AND COST OF SERVICE CLASS

Q. Witness Pollock testifies that the IS rate schedule should be retained and that it should be retained as a separate class of service within the retail Class Cost of Service Study ("CCOSS"). Are his arguments persuasive and does he provide any new evidence to support this proposal?

A. No, as explained below, while he identifies some differing characteristics of the small group of customers comprising the IS class, his arguments for its retention have no merit and are not persuasive.

Q. Does witness Pollock agree that the feature of "interruptibility" in the IS rate schedules was removed in Tampa Electric's last rate case?

A. Yes. Witness Pollock made such a statement in his direct testimony on Page 10, line 22. Therein, he stated further that this action transformed the IS rate schedules from interruptible to a set of separate cost-based firm service rate schedules.

Q. If "interruptibility" is no longer a feature of the base rate aspects of the IS rate schedules, as witness Pollock acknowledges, then what homogeneous features or characteristics exist among the remaining customers under the IS rate schedules that warrant IS being retained as a separate set of rate schedules and class within the CCOSS?

A. I do not believe there are any and witness Pollock presents none. Witness Pollock has presented data showing that the 43 remaining accounts taking service under the IS rate schedules have different "aggregate" load characteristics than the comparable "aggregate" load characteristics of accounts served under the GSD rate schedules, but not that those 43 accounts are homogeneous as a group. The remaining customers taking service under the IS rate schedules are rather diverse and are made up of schools, chemical plants, mining, manufacturing, and communications facilities. It is not surprising that any selection of 43 diverse customers from within the GSD rate class could pose aggregate characteristics different than that of the aggregate of the GSD class. Absent consideration of the "interruptibility" characteristic, which witness Pollock agrees is no longer an aspect of service under IS, I don't think there is any common thread among the remaining IS customers that warrant them to be treated as a separate set of rate schedules or class within the CCOSS.

Q. Witness Pollock observes, from the results of the company's CCOSS, that the presently existing IS rate class is already above parity under its present rates. Do you concur?

A. Although I agree that the company's CCOSS shows this to be the case, I am concerned as to the forecast of coincident peak load responsibility for the IS class as it is embodied in the CCOSS. Since much of the IS class's allocated cost is based on coincident peak ("CP") load responsibility, any variation in its CP forecast has a significant result on its parity position. Of all the rate classes presented in the company's CCOS, the determination of the IS class's CP load is probably the most difficult to ascertain. This is because of three factors: (1) its relatively small size with respect to number of accounts that are members (i.e., 43) (2) in recent years the IS class has had the largest change in its load requirements of any of the company's rate classes and (3) the IS class consists of a substantial amount of accounts taking service under a standby rate schedule, relative to the total membership, which usage can be very volatile as to its needs and deceiving when included in aggregate analysis.

Witness Pollock provided in his Direct Testimony data showing the IS class's CP load factor for the historic years' 2010, 2011, and 2012. He also showed the CP load factor that was embodied in the CCOSS. A summary of this data is shown below:

IS 12CP Load Factor

2010	2011	2012	2014 Test Year
94%	94%	95%	110%

As can be seen from this data, the 2014 Test Year's 12 CP load factor for IS does not appear to be in line with that experienced in recent historic years. If the 2014 Test Year's 12 CP load factor for IS was indeed over-forecasted, and if it were adjusted to a 12 CP load factor more in line with that which the class has historically experienced as shown above, the IS rate class would not have been shown to be above parity in the CCOSS I have presented.

Q. You mentioned the difficulties in forecasting CP loads for those standby rate customers that comprise a large portion of the IS class's requirements. Didn't the Commission's Standby Rate Order recognize the volatile usage of standby customers and require that standby rate charges be set on the basis of system costs?

A. Yes. In Order No. 17159 in Docket No. 850673-EU, the Commission recognized that serving standby load is a function of a customer's generation reliability, and that diversity exists among standby customers with respect to the times of their generator outages. For this reason, the Commission required that standby rate charges be developed on the basis of system coincident peak power supply unit costs, factored by a probability of occurrence of generation outage. The company has followed this prescription in the design of its proposed standby rate charges in this proceeding. As a result, standby load requirements should be recognized and treated apart from that of a class's full requirements for costing and pricing purposes.

Q. What is the billing effect of the company's proposed rate schedule SBF if it is applied to the existing IS standby customers?

A. The billing effect proposed by the company would reflect the elimination of the IS rate schedules, including SBI. The billing effect was previously shown in Document No. 3 of Exhibit No. ____ (WRA-1) of my Direct Testimony in this case. That document shows there to be six IS standby customers, numbers 38 through 43 on the document, which in aggregate make up approximately 25 percent of the IS class's total revenues. The billing comparison shows that each of these customers would actually realize a billing benefit under the company's rate proposal to transfer these SBI customers to service under SBF. I would expect these customers would want to support the company's proposal to eliminate the IS rate schedules.

Q. Witness Pollock criticizes Tampa Electric for having too few rate classes. Is his criticism warranted?

A. No. Tampa Electric is proud of its proposed rate classes and the rate structure they represent in that the company has reduced its number of rate classes over the years to four major rate classes: (1) Residential, (2) General Service Non-Demand, (3) General Service Demand, and (4) Lighting (for which the latter is considered two sub-groups: Lighting Energy and Lighting Facilities). The company has minimized the number of rate classes by incorporating rider schedules, optional rates, and recognizing various combinations of metering and delivery voltage applications within its rate schedules. The company believes that its general service rate designs should attempt to recognize costs based on load factor and not business type or size. It appears that witness Pollock puts forth his criticism on the basis that eliminating the IS rate class results in one fewer rate class as compared to the other Florida investor-owned utilities ("IOU's"), highlighting for example (in a table on page 18 of his testimony) the large number of rate classes for Florida Power & Light ("FP&L"). Although FP&L has a large number of rate classes in their CCOSS, many are differentiated only by delivery voltage or size, which Tampa Electric has accomplished within the same rate class.

Importantly, FP&L does not reflect its curtailable customers (comparable to Tampa Electric's IS customers) under separate rate classes. FP&L does have individual rate schedules for its curtailable service customers, but they are not treated as separate rate classes. Instead their base rate charges are set at the same base rate charges as non-curtailable customers with credits provided to recognize their curtailable service characteristic. This is the very approach being proposed by Tampa Electric in this case for the IS customers.

PRODUCTION COST ALLOCATION METHODOLOGY

Q. Witness Pollock and witness Baron have both raised a number of criticisms regarding the level of energy responsibility Tampa Electric proposes to include in the production capacity allocation methodology. Would you comment on their testimony?

A. Yes. These witnesses have raised a number of issues attempting to find fault with the 12 CP and 50 Percent AD methodology. However, I find that their testimony provides little, if any, support or persuasive rationale for the use of the 12 CP and $1/13^{th}$ AD methodology which they are advocating to replace it with, other than that the 12 CP and $1/13^{th}$ AD methodology has been the "traditional method" used by other utilities in Florida for many years.

Q. Do you think that serious class cost allocation inequities result from the use of the 12 CP and $1/13^{th}$ AD production capacity cost allocation methodology which is being advocated by witness Pollock and witness Baron?

A. Yes. I believe that utilizing the 12CP and 1/13th AD method does result in an inequitable allocation of costs to the company's retail rate classes. The method over-allocates cost responsibility to those rate classes having proportionally more peak usage (e.g., the residential class) and under-allocates cost responsibility to those rate classes that are relatively less peak intensive with their usage (e.g., the general service demand class).

Q. Have you prepared an exhibit that illustrates the inequity that can result from the use of a production cost allocation methodology which relies predominantly on peak demand with little or no recognition of energy responsibility?

A. Yes. I have prepared a simple generation planning and cost allocation illustration which is presented in Document No. 1 of my exhibit and is entitled "Illustration of Economic Generation Selection and Allocated Cost Determination." The exercise focuses on selecting the most economic generating unit to serve a system comprised of two types of load, (1) Peak Load and (2) Off-Peak Load, and the cost allocations that are applied.

Q. Please explain the Document No. 1 in your Exhibit.

A. The planning exercise assumes a generation planner has available two types of generating units which can be installed to serve a hypothetical system electric load profile. For this purpose, I have selected the same two types of generating units (with their respective costs) that HUA witness Baron employed in his testimony regarding a screening exercise which he performed. One type of unit, identified as Type A on Page 1 of Document No. 1 of my exhibit, is an advanced combustion turbine unit which has a relatively low fixed cost but a relatively high operating cost. The second type of unit, identified as Type B, is a conventional combined cycle generation plant which has a higher fixed cost but a lower operating cost. For simplicity, I have assumed that both types of generating units have 100 percent availability, thereby eliminating the need in this exercise to consider reserves. On Page 1 of Document No. 1 of my exhibit, the annual costs (i.e., both fixed and variable costs) are shown for each type of unit, and their respective total annual costs are shown in graphical form as a function of capacity factor. The graph shows that the Type A unit has the lowest total annual cost of operation when utilized at less than a

26.9 percent capacity factor, and the Type B unit has the lowest total cost of operation when utilized at a capacity factor greater than 26.9 percent. This represents the "breakeven point" upon which witness Baron (and also witness Pollock, with different input values) places such reliance.

Q. Please continue to the second page of your Document No. 1 of your exhibit.

A. On Page 2 of Document No. 1 of my exhibit, two electric system annual load requirements are presented as case studies. The system load requirements are presented in the form of an annual load duration curve ("ALDC"). An ALDC is used in power system planning studies as an aide for analyzing load data. It differs from a chronological hourly load profile in that an ALDC plots the system's hourly loads in a descending order of magnitude, ignoring the clock time they occurred during the year.

In the first case study, Case No. 1, the ALDC depicts a system peak load of 500 MW with an annual load duration occurring for 10 percent of the hours in the year. All the hourly loads are of the same peak magnitude and there are no lesser hourly loads or off-peak load requirements.

In other words, Case No. 1 is intended to depict an electric system comprised of only peak load hours occurring for 10 percent of the hours in the year.

In the second case study, Case No. 2, the ALDC depicts an electric system comprised of the same peak hourly loads of 500 MW during 10 percent of the hours, but it depicts the potential of serving off-peak load for the remaining 90 percent of the hours in the year. This potential for off-peak hourly loads is shown as the dashed line of the ALDC, and the area under the dashed line is the energy usage of the potential off-peak load.

The purpose of these two hypothetical cases is to present two different electric system loads: one system comprised solely of "Peak Load" requirements and the other system comprised of both "Peak Load" and "Off-Peak Load" requirements. The task of the generation planner is to select the Type A or Type B generating unit as the most economical to supply the load requirements of each. After the appropriate generating unit selection is made, a cost allocation analysis is performed on Page 3 of Document No. 1 my exhibit using the Peak Production Capacity Allocation Method ("Peak Method") to determine the allocated costs that would result under each case for serving the Peak Load and Off-Peak loads.

Q. What process would the planner use to make the most economic selection?

A. The planner would rely on the economic analysis performed on Page 1 of Document No. 1 of my exhibit. For the system electric load of Case No. 1 comprised solely of "Peak Load", a generating unit operating at a 10 percent capacity factor would be required. Since this capacity factor is less than the 26.9 percent capacity factor calculated on Page 1, the planner would choose generating unit Type A. For the system load of Case No. 2, a load comprised of both "Peak Load" and potential "Off-Peak Load", a generating unit operating at 100 percent capacity factor would be required. Since this capacity factor is greater than the 26.9 percent capacity factor calculated on Page 1, the planner would choose generating unit Type B.

Q. Using the Peak Method, would you summarize the results of the costing analyses that were performed for each of the two system load cases?

A. Yes. The resultant cost analyses are summarized below:

Case No. 1

System Load: 500 MW Peak Load

Generating Unit Selection: Type A

Allocation Method: Peak Method

		Rate Class	
	System	Peak	Off-Peak
Resultant Total Cost	$167.20	$167.20	N/A

Case No. 2

System Load: 500 MW Peak Load and Potential Off-Peak Load

Generating Unit Selection: Type B

Allocation Method: Peak Method

		Rate Class	
	System	Peak	Off-Peak
Resultant Total Cost	$63.63	$200.65	$48.40

Q. What are your observations as to the results of this cost allocation exercise that uses the Peak Method?

A. I believe this exercise provides a number of noteworthy observations or consequences. First, it makes the point that it is the anticipation of "Off-Peak Load" that supports the economic justification for the selection of the more capital intensive, yet more efficient Type B generating unit in Case No. 2. The overall system cost of electricity is reduced from a system cost of $167.20 per MWH by the selection of Type A generating unit in Case No. 1 to a system cost of $63.63 per MWH by the selection of Type B generating unit in Case No. 2. Second, however, by the selection of Type B generating unit in Case No. 2, the total cost of service allocated to serve the "Peak Load" using the Peak Method has increased from $167.20 per MWH to $200.65 per MWH - an amount significantly more than the cost of serving the "Peak Load" on a stand-alone basis as depicted in Case No. 1. Lastly, under the Peak Method, the "Off-Peak Load" does not get allocated any fixed capacity cost and gets the advantage of being assigned only the cost of Type B's more efficient operating cost of $48.40 per MWH.

Q. What conclusions are illustrated regarding the use of the Peak Method in this simple planning exercise?

A. I find and conclude from this exercise that the use of the Peak Method poses, in particular, two disconcerting outcomes that result in cost allocation inequities for a system comprised of rate classes having both "Peak Load" and "Off-Peak Load". First, I find it to certainly be an inequitable outcome that the "Peak Load" is allocated a greater amount of cost than that required to serve this load on a stand-alone basis. The addition of "Off-Peak" load to a system should rightfully result in lower system costs per MWH, as it did in Case No. 2, and this should afford some shared cost advantage, or at least pose no harm, to the "Peak Load". Second, I find it an inequitable outcome that the use of the Peak Method results in no fixed cost allocation to the "Off-Peak Load", while such load enjoys the benefits of the system's low operating costs. It is simply a matter of equity that the "Off-Peak Load" provide some contribution to the system's fixed costs, especially if the system is producing energy at lower operating costs by the selection of a more capital intensive unit as was selected in Case No. 2 of the planning exercise.

Q. Does a production cost allocation method like the one that the company proposes, one that includes a significant weighting of energy responsibility, help alleviate the inequities that you find by use of the Peak Method?

A. Yes, I think a significant consideration of energy responsibility accomplishes that. To demonstrate this, I have employed a method like that which Tampa Electric is proposing in this proceeding to the same system costs as presented in Case No. 2. This cost allocation is shown as Case No. 3 on page 4 of Document No. 1 of my exhibit which incorporates a capacity allocation weighting of peak load responsibility by 50 percent and energy (or average demand) responsibility by 50 percent (for purposes of this example, I will call this the Peak and 50 Percent AD Method).

Q. Would you compare the allocation results of employing the Peak and 50 Percent AD Method with that of the Peak Method for your planning and costing exercise?

A. Certainly. A summary of the comparative findings is shown below:

Case No. 1

System Load: 500 MW Peak Load

Generating Unit Selection: Type A

Allocation Method: Peak Method

		Rate Class	
	System	Peak	Off-Peak
Resultant Total Cost	$167.20	$167.20	N/A

Case No. 2

System Load: 500 MW Peak Load and Potential Off-Peak Load

Generating Unit Selection: Type B

Allocation Method: Peak Method

	Rate Class		
	System	Peak	Off-Peak
Resultant Total Cost	$63.63	$200.65	$48.40

Case No. 3

System Load: 500 MW Peak Load and Potential Off-Peak Load

Generating Unit Selection: Type B

Allocation Method: Peak and 50 Percent AD Method

	Rate Class		
	System	Peak	Off-Peak
Resultant Total Cost	$63.63	$132.14	$56.01

Q. Do the results of applying the Peak and 50 Percent AD Method in your planning and costing exercise alleviate the cost allocation inequities that you described were inherent in the Peak Method?

A. Yes. By employing the Peak and 50 Percent AD Method in Case No. 3 of this exercise, the costs for the "Peak Load" and "Off-Peak Load" groups are allocated amounts that I find more reasonable and which do alleviate the inequitable concerns that I had observed in the use of the peak method. First, the "Peak Load" group's resultant allocated cost of $132.14 per MWH is a lesser amount than its stand-alone cost of $167.20 per MWH, whereby such allocated cost was greater using the peak allocation method. And, secondly, this allocation method results in the "Off-Peak Load" being assessed an amount of $56.01 per MWH – an amount of $7.71 per MWH above the system's operating cost of $48.40 per MWH. I consider this to be a fair and reasonable contribution for the "Off-Peak Load" to make toward the system's fixed cost since they are receiving the benefits of the system's low operating cost.

Q. What can one conclude from your illustrative Exhibit?

A. Although my Exhibit is a simple illustration of a generation planning exercise and cost determination for serving two types of loads, i.e. "Peak" and "Off-Peak", I believe the results are meaningful and provide an inference to the impact of cost allocation on the rate classes in this proceeding. It is my conclusion that the exercise meaningfully demonstrates that a rather significant energy weighting for production capacity cost responsibility is warranted to alleviate inequities in the use of a predominately peak allocation method.

Q. Would witness Pollock and witness Baron concur with your simple generation planning analysis and the concept you have described of selecting the most economic resource?

A. Yes, I believe they would and I believe they do express agreement in their testimony with that aspect of my exercise. Witness Pollock makes the same type of point of economic selection by using rental cars as an illustration and witness Baron presents his screening selection analysis. We all seem to concur with the concept that the economic selection of a facility should be based on a consideration of total costs, both fixed and variable. I believe we are in agreement that the economic principle of capital substitution is exercised in the selection of the most economic facilities. We also concur that there is an economic break-even point for which one type of facility becomes more economic than the other.

Q. Then, what is the primary difference between you and witnesses' Pollock and Baron that gives rise to the argument over what is the most appropriate production cost allocation methodology that should be employed?

A. In spite of our common understandings, there is a major costing philosophy difference being posed by these witnesses that I strongly disagree with in the context of the Commission's rate-making practices and policies. What the Commission decides as the appropriate costing philosophy should dictate whether the predominately peak or heavily weighted energy methodology should be employed.

The costing philosophy difference relates to the discussion by witnesses Baron and Pollock as to their treatment for costing usage before and after the economic break-even point of generation selection. Both of them assert that energy usage beyond that of a break-even required amount of usage does not impose any additional capital costs on the system and therefore should not be assessed any cost responsibility.

Although their assertion may be mathematically correct, the assignment of all premium or capital substitution costs to usage less than that of a break-even point, and the corresponding lack of any assignment of costs to usage greater than the break-even point, is certainly not an equitable or realistic principle. It is only proper and good cost allocation and ratemaking to employ methods which attempt to match costs with benefits. Whether it is the first kWh used or the last, each kWh consumed (not just the ones prior to the break-even point) is a beneficiary of the system's lower operating cost that result from investment in these more efficient generating plants and should share equally in the cost of the premium or capital substitution investment that afforded the benefit.

Q. Do you have a simple example to demonstrate why it is more equitable that all energy use, not just the energy required for breakeven consideration, should bear capital substitution costs?

A. Yes. Consider the decision by a consumer to purchase a new high efficiency home air conditioning system for $2,000. Assume that this high efficiency system will have a 10-year life and it will result in $500 per year lower electric energy usage. Therefore, the purchase results in anticipated savings in electric energy usage of $5,000 over the life of the system. This is a good economic purchase because the $5,000 savings less the $2,000 cost produces a net benefit of $3,000. Using witness Pollock's and witness Baron's approach, they would take the $2,000 investment cost and divide it by the $500 annual savings to calculate the breakeven point of four years. They would then claim that during the first four years, the customer would realize no net savings; however, there would be $500 per year net savings in the six remaining years.

I do not believe witness Pollock's and witness Baron's approach represents an equitable or even realistic viewpoint. It does not recognize the Commission's ratemaking practice of matching costs with benefits. In this example, the $2,000 cost should correspond to the full usage period that savings are realized which is all 10 years, not just the first four years. This use of the full usage period results in an allocated cost of $200 per year compared to the annual energy usage savings of $500 for an annual net savings of $300 for each year of its 10-year life. This is the most equitable treatment of matching costs and savings.

The flaw in witness Pollock's and witness Baron's breakeven analysis can be demonstrated in another way using this same air conditioning system example. If the purchaser of the more efficient system were to sell his home after four years, he would expect a greater sales price for the home by virtue of having the more efficient air conditioning system as compared to a home without such a system. Likewise, a purchaser should be willing to pay more for this home with the expectation of lower electric energy costs. Under their concept, the seller should not expect to increase the value of his home because he would conclude that he has fully recovered the additional cost. However, the purchaser, without paying a premium for the house, would realize all the remaining electric energy savings. Costs and benefits are not matched. If a ratepayer were the seller in this case, he would not opt to adopt witness Pollock's and witness Baron's perspective.

Q. Witness Pollock and witness Baron both compare similarities of generation mix and planning by Tampa Electric to that of FP&L in support of the use of the 12 CP and $1/13^{th}$ AD method which has been employed by FP&L. Do you think their comparisons are appropriate?

A. No. Since witness Pollock and witness Baron seemingly are using this comparison as primary support for their endorsement of the 12 CP and $1/13^{th}$ AD for Tampa Electric in this proceeding, I will proffer a few observations regarding this method and its prior application to FP&L.

First, I recall that the Commission deviated from the 12

CP and 1/13th AD method for FP&L and applied a 100 Percent energy allocation to the fixed capacity costs associated with the initiation of operations of FP&L's nuclear units. Both witness Baron and witness Pollock fail to bring that fact into their praise of the purity of the 12 CP and 1/13th AD methodology in FP&L's case.

Second, I am not aware, other than in the proceeding described above, that the incorporation of energy weighting in the production cost allocation methodology was ever presented as an issue for discussion or consideration by the Commission for FP&L.

Q. Witness Pollock asserts that Tampa Electric's proposal to change its cost methodology in this proceeding is particularly dramatic and causes undue instability in both class revenue requirements and rate design. Do you agree?

A. No, although the company does believe a much greater weighting of energy responsibility in its cost allocation methodology is more appropriate today, I believe that witness Pollock has exaggerated the effect of this change, especially for the GSD/IS rate class that he represents. To make this point, I have prepared Document

No. 2 of my exhibit which compares the rate classes' allocated costs under various cost allocation methods. This exhibit shows that the allocated cost effect of the company's proposed change from the prior 25 percent energy weighting to the 50 percent energy weighting has the effect of only a 2.4 percent non-fuel cost increase on the GSD/IS rate class. I don't consider that to be such a "dramatic" effect in a rate increase proceeding that would cause undue rate instability for the customers that he represents.

Q. Witness Pollock and witness Baron in their testimonies recommended that the Commission reject the 12 CP and 50 Percent methodology as outcome oriented rather than cost-based. Witness Pollock in his testimony stated that the Commission's long-standing policy was to employ "cost-based pricing" rather than "price-based costing", and witness Baron in his testimony said that deciding to switch cost responsibility (i.e., increasing the energy allocation of production capacity costs) without a substantive link to cost causation was not good ratemaking policy. Would you agree with those views?

A. I can agree with the sentiment, but would remind them of the history in Florida regarding this element of cost allocation for production cost allocation. Beginning as far back as the early 1980's the Commission has wrestled with the issue of how much of production capacity cost should be allocated on an energy basis as opposed to a demand basis. I discussed this in my direct testimony on page 31. This debate has been as much a cost causation debate as it has been an outcome and equity debate. Initially it was driven by concern about how much production capacity cost should be allocated to interruptible customers, because the value of the interruptible service was derived at that time through cost allocation within the CCOSS and not by credits applied to standard firm service rates. Production demand cost was not allocated to the interruptible class of service (under the cost causation theory that their load was not included in the determination of need for production plant) however cost allocation experts and the Commission at the time believed that some cost recovery of their production demand costs should be recovered through interruptible rates to recognize those customer's use of the fleet of generation built to serve their energy needs at times when they were not interrupted for firm customer capacity needs. As a result of this debate, the 1/13th proportion of energy was determined an appropriate amount, based on the outcome being deemed reasonable at that time, and applied across all the utilities in Florida.

Since that time, the interruptible nature of service to these customers has been converted from a base rate delivery to a credit applied to the base rates and recovered under the conservation clause. Now the energy proportion of allocation of production demand costs has become a debate over matters such as witnesses Baron, Pollock and I have been discussing - proper recognition of investment in production plant and the benefits of such investment associated with the fuel benefits that accrue from such investment being applied to all customers. The Commission wrestled with this issue in the last Tampa Electric base rate proceeding and resolved that a change from the 1/13th (roughly 8 percent) energy proportion to a 25 percent energy proportion was justified and reasonable. In part the Commission made that decision based on cost causation and in part on outcome. Tampa Electric in this case has proposed to increase that proportion to 50 percent while witness Baron and witness Pollock oppose it in their testimony entirely on the basis of cost causation, and undoubtedly because the outcome of its acceptance by the Commission would result in an outcome detrimental to their client's bills. I would suggest that this issue has always been, and will continue to be resolved by the Commission on both bases - cost causation support and the outcome of the choice made.

GSD RATE DESIGN

Q. Witness Pollock and witness Baron have criticized the company's method of revising the demand and energy charges of its demand measured general service rate schedules by not establishing these charges from the cost of service unit cost results. Do you believe this criticism is warranted?

A. No. Witness Pollock and witness Baron's premise is that all functionally related and classified capacity costs (i.e. production capacity, transmission capacity, distribution primary capacity, and distribution secondary capacity) should be recovered in a demand charge in those general service rate schedules where a billing demand is measured and a separate demand charge is applied. Likewise, they opine that only those functionally related and classified energy costs should be recovered in an energy charge of those rate schedules.

Although this may sound like a logical approach to rate design, it is important to recognize that the demand that is measured for billing purposes is that of the customer's maximum 30-minute kW demand occurring during the billing period. Only one of the identified functionally related and classified capacity costs — that of distribution secondary capacity — is directly related to and bears direct cost responsibility for this particular demand measurement. And, as it turns out, the distribution secondary capacity costs are the least costly of these types of functional capacity costs to be recovered.

The cost causation and appropriate measurement for assessing cost responsibility for the other, relatively more costly functionally related and classified capacity costs are summarized as follows:

Cost Function	**Cost Responsibility**
50% Prod. Capacity - Demand	12 CP
50% Prod. Capacity - Energy	Energy Usage
Trans. Capacity	12 CP
Distribution Primary	NCP

Because of metering and billing constraints, measurement of a customer's demand at the time of the monthly system peaks or at time of its respective class peak is generally not feasible. Under the Commission's prescribed general service rate design, these functional costs are simply apportioned and recovered under some combination of an energy charge and a billing demand charge. Based on load research performed by the company a number of years ago for the general service demand rate class, it was found that there was as good or even better correlation of a customer's coincident demand with a customer's energy usage than with that of a customer's billing demand. Thus, the company does not believe that recovering all functionally related and classified capacity costs on the basis of a customer's billing demand is the most appropriate rate design. The company believes its proposed levels of demand and energy charges fairly recover costs from customers over a wide range of customer load factors. Witness Pollock's and witness Baron's rate design proposal simply is one that favors high load factor customers and does not necessarily recognize the coincident load characteristics of customers by load factor when such costs are simply recovered on the basis of a customer's maximum or billing demand.

Q. Witness Pollock and witness Baron have criticized the resulting large percent increase in the GSD's time of use ("TOU") rate schedule energy charge. In fact, witness Pollock describes the increase as "rate shock"? Do you disagree with his description of the impact of this charge?

A. Yes, I disagree. It appears that witness Pollock and witness Baron are not aware that the Commission prescribed a specific calculation for Tampa Electric to develop the energy charges for its Time of Use ("TOU") rate schedules. This was specified in Order No. 15451 of Docket No. 850050-EI. The company has followed the prescribed method in all of its rate cases since this rate order, including the present proceeding. The Commission intended that such rate design would result in relationships of on-peak and off-peak charges of a multiple ratio, which is a point of criticism by witness Baron and witness Pollock.

More importantly, however, I would have thought they would understand that the rate increase effect of the changes to the TOU energy charges should be viewed on a weighted or effective basis resulting from a customer's proportion of on-peak and off-peak usage – not from the on-peak or off-peak energy charge alone. The table below shows the present and proposed GSD standard and GSDT energy charges and the effective TOU energy charges when weighted by the class's on-peak and off-peak proportions.

GSD/GSDT

Base Energy Rates	Current $/MWh	Proposed $/MWh	% Change
Standard	15.83	18.29	15.54 %
TOU			
On-peak	28.98	39.99	37.99 %
Off-peak	10.46	9.60	(8.22)%
Effective TOU:			
On-peak	8.40 (29% x 28.98)	11.44 (28.6% x39.99)	
Off-peak	7.43 (71% x 10.46)	6.85 (71.4% x9.60)	
Weighted	15.83	18.29	15.54 %

The TOU rate offering is predicated on a revenue neutral rate design, whereby if the customer had the same proportion of energy usage during on-peak hours and off-peak hours as compared to that experienced by the rate class as a whole, the effective TOU energy charge would be the same as the standard rate energy charge. The prior directive of the Commission required the off-peak energy charge to be set at the unit cost for the energy function in the company's cost of service study. The on-peak charge would then be mathematically calculated such that the effective charge resulted in the standard rate energy charge.

It should be noted that a customer would not incur any greater effective energy charge than that shown for the standard rate. This is because only customers having lesser on-peak percent usage than the class's on-peak percentage would find TOU rates more beneficial and realize an effective lower energy charge. If a customer's on-peak percentage exceeded that of the class's, he would find the standard rate more economical.

Thus, the company's changes to its GSDT TOU energy charges would not create a "rate shock" impact for any GSDT customer as witness Pollock has described. When a GSDT customer maintains or improves his proportional energy usage, he will not realize any greater increase than that of the standard energy charge increase and may see even a lesser increase.

Q. Witness Pollock proposed an additional credit amount of $0.53 per kW over and above the company's proposed sub-transmission delivery voltage credit for the purpose of off-setting the increase that IS sub-transmission customers would incur in the event that the present IS rate schedules are eliminated. What is your reaction to witness Pollock's proposal?

A. I find such a proposal to be arbitrary, unsupported, discriminatory, self-serving, and certainly not a demonstration of good ratemaking practices as he professes to endorse. I would note that this proposal would subsidize only the subtransmission-served IS customers transferred, and provide no such subsidy to the primary-served customers. Such a proposal, which appears entirely outcome-based and with no cost causation support as he has previously indicated in his testimony was a critical element in rate design, is poor ratemaking policy and should be rejected without any consideration.

MINIMUM DISTRIBUTION SYSTEM METHODOLOGY (DSM) AND RATIONALE

Q. Can you summarize your areas of agreement or disagreement with Staff witness McNulty regarding Tampa Electric's employment of the Minimum Distribution System ("MDS") concept in its proposed allocated class cost of service study and the resulting impact on proposed rate design?

A. Yes. I generally agree with witness McNulty's testimony which discusses the pros and cons of implementing the MDS concept, with some reservations which I will discuss. In addition, I agree with certain aspects of his testimony where he proposes some improvement upon the company's proposed cost classifications, but disagree with certain other aspects of his findings. Witness McNulty appears to have the expectation that the MDS calculations should be a more precise determination than cost of service analysis can provide. Finally, I find his assessment of the positive and negative consequences of MDS to be rather over-stated as to their significance.

Q. Witness McNulty seems to suggest in the summary of his testimony that "doubt as to the extent there are misclassifications of distribution costs under traditional treatment" may be a basis for the Commission to not employ the MDS concept in cost of service studies. Do you agree with this assessment?

A. No. Witness McNulty appears to raise this "doubt" as a position that the Commission may rely on regarding whether to use MDS in this proceeding. Although he provides findings and support in his testimony that distribution costs do have at least a portion of costs that are customer-related as opposed to capacity-related, he states that the data is not available to make precise determinations of the extent of the misclassification.

"Precision" has never been a governing requirement with regard to adoption of a cost allocation or cost classification option being considered. For example, using coincident peaks to allocate power supply costs for future test periods or even historical test periods assures that accuracy in numbers is maintained, but the precision of using 12 coincident peaks versus 8, or summer/winter average, is not.

Q. Do you agree with witness McNulty that the company's determination of the classifications of distribution costs between customer and capacity is not a "precise" calculation?

A. Yes, most certainly. A great deal of costing work represents a best determination based on special analysis, judgment, data availability, costing theories, etc. There are few aspects of costing work, at least with regard to determination of proper classification of cost, that result in a precise calculation. I readily concede that the company's proposed MDS determinations in this proceeding are not a precise calculation. For example, the company purposely rounded its classification results to whole percentage points as opposed to setting forth the results out to a number of decimal places (i.e., 64 percent poles, 24 percent transformers, 9 percent conductors). The lack of precise information in cost work should not be a deterrent to the development of a concept that one believes is more appropriate.

Q. Did witness McNulty's testimony seem to find favor or disfavor with regard to the company's MDS calculations?

A. I think witness McNulty favored the company's use of the zero-intercept method, which it used for application to conductors and transformers. He seemed to credit the company for resolving data problems by using replacement cost data rather than embedded data, although he stated this was contrary to the NARUC cost manual. He expressed particular criticism on two aspects of the company's calculations: (1) the recognition of too few observations in its regression model for conductors; and (2) the use of the minimum size method for poles in lieu of the zero-intercept method.

Q. Have you evaluated witness McNulty's criticism for using too few observations in the regression model for conductors?

A. Yes. The company originally employed three observations that represented the predominant types and quantities of conductors used by the company for primary distribution purposes. I agree with witness McNulty's Exhibit No. ___ (WBM-4) that shows the use of only these three observations result in a rather wide band of statistical confidence. As a result, the company has added one more observation as the only additional observation of primary conductors in use today by the company. The result of the revised regression analysis employing four observations points is shown on page 1 of Document No. 4 of my exhibit. This document shows a resultant zero-intercept value of $0.45 per conductor foot with a significantly improved band of confidence. As shown on page 2 of Document No. 4 of my exhibit, the use of this revised zero-intercept value does not change the resultant customer classification of 9 percent for conductors that was derived previously by the company.

Q. What is your response to witness McNulty's second criticism, about the company's use of the minimum size system method rather than the zero-intercept method for determining the classifications for poles?

A. First, I believe the minimum size method is the only feasible method for applying MDS to poles. Poles are comparatively unique facilities compared to the other electrical facilities that MDS is applied. Pole cost is not as easily measured in terms of electrical capacity as is the case for conductors (wire size) or transformers (KVA size). The NARUC manual describes using height and class as the variable measure of pole cost. Height and class selection of poles are not just a function of load carrying capability, but a selection based on a number of additional considerations: construction standards (e.g. wind loading); safety codes (e.g., overhead clearances); the type of electrical equipment and the number of joint-user attachments installed on the pole; and locational requirements or restrictions.

Where pole size (height) is used as the variable function, the company finds rather unrealistic results are produced for the zero-intercept determination. This is shown on page 4 of my Document No. 4 of my exhibit where I used the same data values as witness McNulty did in his Illustration B of Exhibit No. WBM-3. My calculation shows an amount of -$190 as the zero-intercept value of pole cost, which obviously is not a realistic result. It should be noted that I do not agree with the mathematical presentation that witness McNulty employed in his zero-intercept calculation of data for poles since he did not properly recognize the variable x value as the actual pole size (height), but simply assigned equally spaced numbering to the data as the x value.

Secondly, I take issue with witness McNulty's concern that the company's use of its selected 30 ft. pole as the minimum size pole overstates the customer component classification of pole costs. The company does not consider 30 foot poles as having much capability in this regard. The company utilizes 30 foot poles only in situations requiring minimal electrical loads, such as for supporting a street light fixture or a secondary wire from a transformation, or a service cable. Where electrical load becomes a consideration, the company generally utilizes a 40 foot or higher pole.

Q. Are there any findings by witness McNulty that you believe should be cause for Tampa Electric to change its MDS determinations in this proceeding?

A. No, other than the revision to the number of observations for conductor sizes that I discussed previously that had no impact on the final results. Although this was Tampa Electric's first attempt to develop MDS classifications, the company does expect to make refinements and attempt to improve upon these calculations in the future. However, the current development has resulted in reasonable and appropriate application for use in this proceeding.

Q. Witness McNulty cites the revenue and bill impacts of Tampa Electric's implementation of MDS on its customers in his Exhibit No. WBM-5. Do you agree with the information presented in this Exhibit?

A. With the exception of the LS or Lighting Services' classes, I agree with the impacts of MDS on customers that witness McNulty shows in this Exhibit. With respect to the LS classes, I think that witness McNulty misinterpreted the number of "217" for lighting service customers in calculating his impact of MDS on lighting service customers. The impact should instead be shown on the basis of serving a total of 206,663 lighting fixtures. The number of "217" lighting customers that appears in the company's statistics represents those accounts that have only lighting services billed under that account. This measurement doesn't recognize the number of lighting fixtures for these accounts nor the number of fixtures being served under those other accounts having multiple services being billed. The more appropriate and meaningful impact for the LS class should be shown as follows:

Revenue Requirements MDS $(000)	Revenue Requirements DOCC $(000)	Revenue Requirements MDS-DOCC $(000)	Number of customers	Average Annual Bill Impact	Average Monthly Bill Impact
39,668	40,296	(628)	206,663	(43.03)	($0.25)

Q. Witness McNulty comments on some of the consequences that might result from ratemaking that recognizes the MDS concept in a utility's costing and pricing. Do you agree with his comments?

A. Yes, but to a lesser extent. Foremost, the company is proposing applying the results of implementing the MDS concept in the design of its rate structure because it believes this method represents the most equitable costing and pricing treatment to be afforded customers for the recovery of the company's distribution costs. In addition, I do agree with witness McNulty that MDS may pose certain price elasticity and revenue stability impacts as well. However, I think such additional effects are likely to be rather minimal and not have the significance of effect he implies.

For example, witness McNulty indicates that rates based on MDS would have lower energy charges and thus pose less of a price signal to customers thereby resulting in a disincentive for customers to pursue energy conservation. The lower energy charge resulting from MDS for a residential customer is a lesser amount of 0.36 cents per kWh (reflected in the company's proposed rate design) as compared to the full energy charge of about 10 cents per kWh. This amounts to about a 4 percent price impact, and it is questionable that this magnitude of difference would meaningfully affect a residential customer's consumption behavior.

Another example cited by witness McNulty as a result of the consequence of MDS is that rates based on MDS may provide utilities a more certain and steady stream of revenue by the application of higher customer charges and lower demand and energy charges. In the rate designs proposed to recover the company's proposed revenues in this proceeding, as a result of MDS an additional amount of about $49 million of base revenue has been designed to be recovered on the basis of customer charges rather than usage charges. The company's total proposed base revenue in the proceeding is over $1 billion. Thus, MDS results in less than 5 percent of the company's base revenues being recovered on a less risky or steadier basis than otherwise.

UPDATE OF WHOLESALE TRANSMISSION AGREEMENTS

Q. OPC witness Ramas discusses the adjustment made by Tampa Electric to remove any cost treatment in the jurisdictional separation study related to the provision of firm transmission service for the wholesale customers' Auburndale Power Partners ("APP") and Calpine. Does the company have an update as to the status of the needs of these wholesale customers?

A. Yes. Subsequent to the company's filing in this proceeding, Calpine made a commitment to extend a portion of its firm transmission service agreement under Tampa Electric's wholesale open access transmission tariff that reduces their commitment from 526 MW to 249 MW effective after May 31, 2014. As of the filing of this rebuttal testimony, APP has not made a commitment for transmission service in the future and there is no current expectation that APP will make any commitment for transmission service in the foreseeable future. As a result of this updated information, witness Ramas believes the company's Jurisdictional Separation Study should be updated to reflect this more current information for the 2014 test year.

The company agrees with witness Ramas's general discussion to reflect the effect of the updated Calpine transmission load requirement in its Jurisdictional Separation Study. In an effort to make it clear as to the effect of including the Calpine transmission service requirement in its Jurisdictional Separation Study, Document No. 3 of my exhibit delineates Calpine's updated cost effect on each component of rate base and net operating income in the Jurisdictional Separation Study. The effects shown on this document were determined by comparing the company's original filed Jurisdictional Separation Study with that of a revised Jurisdictional Separation Study that incorporates a wholesale transmission load responsibility of 249 MW for Calpine in all months of the test period. As witness Jeffrey S. Chronister has recommended, any revenues the company receives in the test period for firm transmission service in excess of that recognized in the Jurisdictional Separation Study would be credited to the fuel clause and spread over a 12 month period. This would apply to the excess (526 MW less 249 MW) of service revenues from Calpine occurring for the first five months of the test year.

With regard to APP, as indicated earlier there is no current expectation that APP will be seeking to roll over their current transmission contract. Therefore, no adjustment is being made to the proposed jurisdictional separation.

The effect of including the Calpine transmission load in the Jurisdictional Separation Study, of course, increases the wholesale jurisdictional cost and reduces the retail jurisdictional cost. It should follow that any revenues associated with this cost allocation to the wholesale jurisdiction is directly attributable and assignable to the wholesale jurisdiction. Witness Ramas, in her testimony, appears to have confused this point in the calculation of her proposed adjustment related to this jurisdictional separation issue and erroneously assigned the Calpine transmission service revenues to the retail jurisdiction.

SUMMARY OF REBUTTAL TESTIMONY

Q. Please summarize your rebuttal testimony.

A. My rebuttal testimony addresses the intervener witnesses' Pollock and Baron's position on the issues as follows:

1. <u>Retaining IS as a Separate Rate Schedule and Cost of Service Class</u>

Witness Pollock has not provided any good argument for sustaining the present IS customers as a separate rate class for base rate costing and rate design purposes. He concedes that, as a result of Tampa Electric's last rate proceeding, "interruptibility" is no longer a feature of the base rate aspects of the IS rate schedules. I urge the Commission to bring final closure to the IS rate schedules which are no longer necessary since interruptible service is otherwise available as an option under the company's GSD rates schedules. There are no remaining reasons for this select group to receive rate class or schedule treatment different than other customers electing to be served on an interruptible basis.

2. <u>Production Cost Allocation Methodology</u>

Neither witness Baron, nor witness Pollock provide any support for their recommended use of the 12 CP and $1/13^{th}$ AD method other than its use by the other Florida utilities. I demonstrate the inequity that results from the use of this predominately peak allocation method which is alleviated by the use of the company's proposed 12 CP and 50 Percent AD method that more substantially recognizes energy responsibility and provides a better match of costs and benefits.

3. GSD Rate Design

Both witness Baron and witness Pollock have misconstrued the cost causation of much of the company's capacity costs by claiming that all capacity related costs (i.e. production capacity, transmission, capacity, distribution primary capacity, and distribution secondary capacity) should be recovered on a billing kW demand basis and none of these costs on an energy basis. The company's GSD rate design fairly recognizes recovery of these costs on both a billing demand charge and an energy charge basis and I find that their assertions are not supported by load research correlations or any cost determinations by load factor.

Both witness Baron's and witness Pollock's criticisms of the company's calculation of TOU energy charges appear to result from a misunderstanding of the Commission's directive for designing TOU energy charges. The design is intended to create a multiple ratio, which witness Pollock specifically criticizes, between on-peak and off-peak energy charges in order to provide customers incentive to shift usage. Additionally, the company's proposed TOU energy charges do not pose a "rate shock" to TOU customers (as alleged by witness Pollock) in that the customer's energy charge is effectively a weighting of the on-peak and off-peak energy charges which is not likely to exceed the increase proposed for the energy charge of the standard rate.

The proposal by witness Pollock to arbitrarily increase the sub-transmission delivery credit, in order to mitigate certain customer's rate increase in this proceeding, should be rejected without consideration.

4. <u>Minimum Distribution System (MDS) Methodology and Rationale</u>

I am in general agreement with witness McNulty's testimony on MDS and his recognition that traditional distribution treatment has misclassified certain distribution costs. I do not believe his criticisms of the company's MDS determinations are warranted nor do they have an impact on the resultant cost classifications it has employed in adopting the MDS concept.

5. Update of Wholesale Transmission Agreements

The company agrees with OPC witness Ramas to recognize the most current information regarding wholesale transmission service in its Jurisdictional Separation Study.

Q. Does this conclude your rebuttal testimony?

A. Yes, it does.

DIRECT TESTIMONY

OF

Kevin W. O'Donnell, CFA

On Behalf of the Office of Public Counsel

Before the

Florida Public Service Commission

Docket No. 130040-EI

INTRODUCTION

Q. PLEASE STATE YOUR NAME, POSITION, AND BUSINESS ADDRESS FOR THE RECORD.

A. My name is Kevin W. O'Donnell. I am President of Nova Energy Consultants, Inc. My business address is 1350 Maynard Rd., Suite 101, Cary, North Carolina 27511.

Q. ON WHOSE BEHALF ARE YOU PRESENTING TESTIMONY IN THIS PROCEEDING?

A. I am testifying on behalf of the Florida Office of Public Counsel ("OPC"), which represents the interests of consumers in utility rate proceedings, before the Florida Public Service Commission ("PSC" or "Commission").

Q. PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND RELEVANT EMPLOYMENT EXPERIENCE.

A. I have a Bachelor of Science in Civil Engineering from North Carolina State University and a Master of Business Administration from the Florida State University. I earned the designation of Chartered Financial Analyst (CFA), which is a highly sought-after professional designation that measures a person's in-depth knowledge of portfolio finance and investment knowledge, in 1988. I have worked in utility regulation since September 1984, when I joined the Public Staff of the North Carolina Utilities Commission ("NCUC"). I left the NCUC Public Staff in 1991 and have worked continuously in utility consulting since that time, first with Booth & Associates, Inc. (until 1994), then as Director of Retail Rates for the North Carolina Electric Membership Corporation (1994-1995), and since then in my own consulting firm.

Q. HAVE YOU TESTIFIED AS AN EXPERT IN UTILITY MATTERS?

A. Yes, I have testified in utility matters as an expert witness on rate of return, cost of capital, capital structure, cost of service, and other regulatory issues in general rate cases, fuel cost proceedings, and other proceedings before the North Carolina Utilities Commission, the South Carolina Public Service Commission, the Virginia State Commerce Commission, the Minnesota Public Service Commission, and the Florida Public Service Commission. In 1996, I testified before the U.S. House of Representatives, Committee on Commerce and Subcommittee on Energy and Power, concerning competition within the electric utility industry. Additional details regarding my education and work experience are set forth in Exhibit KWO-12 to my direct testimony.

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

A. The purpose of my testimony is to present to the Commission my findings as to the proper capital structure for use in this proceeding.

Q. HOW DOES YOUR TESTIMONY RELATE TO THE TESTIMONY OF OTHER OPC WITNESSES?

A. Based on the capital structure that I recommend, OPC witness Dr. Randall Woolridge will develop and quantify the return on equity capital that reflects the risk of an investment in Tampa Electric Company ("Tampa Electric" or "Company"), including the financial risk associated with my recommended capital structure. Since the cost of equity is directly linked to the capital structure, Dr. Woolridge will also quantify the reduced return on equity that should be associated with the much higher equity ratio Tampa Electric has requested. I will then evaluate the impact of OPC's recommended capital structure, return on equity, and all other OPC adjustments on the financial integrity of Tampa Electric as measured and perceived by the investment community.

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS IN THIS CASE.

A. My conclusions and recommendations in this case are as follows:

- The proper capital structure to use in this proceeding is 50% common equity and 50% debt;
- The cost rate for long-term debt should be the Tampa Electric embedded cost of debt;
- The cost rate for short-term debt should be the Tampa Electric embedded cost of short-term debt;
- The overall rate of return that should be granted Tampa Electric in this case is 5.66%;
- The financial integrity of Tampa Electric is currently strong; and
- The OPC recommendations in this case will result in financial parameters that rating agencies associate with strong financial integrity.

Q. HOW IS YOUR TESTIMONY STRUCTURED?

A. My testimony is divided into sections as follows:

I. Economic and Legal Guidelines for a Fair Rate of Return

II. Capital Structure

III. Financial Integrity of OPC's Positions

IV. Summary

I. ECONOMIC AND LEGAL GUIDELINES FOR A FAIR RATE OF RETURN

Q. PLEASE BRIEFLY DESCRIBE THE ECONOMIC AND REGULATORY POLICY CONSIDERATIONS YOU HAVE TAKEN INTO ACCOUNT IN DEVELOPING YOUR RECOMMENDATION CONCERNING THE CAPITAL STRUCTURE THAT THE COMMISSION SHOULD EMPLOY FOR RATEMAKING PURPOSES IN THIS PROCEEDING.

A. The theory of utility regulation assumes that public utilities are natural monopolies. Historically, it was believed or assumed that it was more efficient for a single firm to provide a particular utility service in a specific geographic area rather than multiple firms. Even though deregulation for the procurement of natural gas and generation of electric power and energy is spreading, the delivery of these products to end-use customers will continue to be considered a natural monopoly for the foreseeable future. When a natural monopoly exists, the authorities will regulate the service areas of these utilities. For example, the regulatory authorities will assign exclusive franchised territories to the public utilities, or will determine territorial boundaries when disputes arise, which allows these utilities to provide service more efficiently and at the lowest possible cost. In exchange for the protection of its monopoly service area, the utility is obligated to provide adequate service at a fair, regulated price. Section 366.06(1), Florida Statutes, states in part, that ". . . the commission shall have the authority to determine and fix fair, just, and reasonable rates,. . ."

This naturally raises the question: What constitutes a fair price? The generally accepted answer is that a prudently managed utility should be allowed to charge prices that allow the utility the opportunity to recover the reasonable and prudent costs of providing utility service and the opportunity to earn a fair rate of return on invested capital. A fair rate of return on capital allows the prudently managed utility to provide adequate service and attract capital to meet future expansion needs in its service area. Obviously, since public utilities are capital-intensive businesses, the cost of capital is a crucial issue for utility companies, their customers, and regulators. If the allowed rate of return is set too high, then consumers are burdened with excessive costs, current investors receive a windfall, and the utility has an incentive to overinvest. If the return is set too low, adequate service is jeopardized because the utility will not be able to raise new capital on reasonable terms.

In the case of Federal Power Commission v. Hope Natural Gas Company, 320 U.S. 591 (1944), the U.S. Supreme Court recognized that utilities compete with other firms in the market for investor capital. Historically, this case has provided legal and policy guidance concerning the return which public utilities should be allowed to earn:

In the Hope case, the U.S. Supreme Court specifically stated that". . . the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise so as to maintain its credit and to attract capital." Id. at p. 603.

Q. PLEASE EXPLAIN HOW THE ECONOMIC PRINCIPLES AND COURT PRONOUNCEMENTS THAT YOU HAVE DESCRIBED RELATE TO CAPITAL STRUCTURE?

A. Succinctly stated, the choice of capital structure affects the risk of the enterprise, and the appropriate rate of return is a function of that risk. Since every equity investor faces a risk-return tradeoff, the issue of risk is an important element in determining the fair rate of return for a utility.

As I will develop in greater detail below, the risks that a regulated utility faces can be broadly categorized as financial risk and business risk. Financial risk refers to the possibility that the utility may not be able to meet its debt obligations. As the amount of debt relative to equity capital increases, the amount of money necessary to pay the interest on debt increases, and financial risk increases. Similarly, as the amount of debt relative to equity capital decreases, financial risk decreases. This is another way of saying that the relative amounts of equity and debt in the total capital raised by the utility bear directly on the risk perceived by investors, and thus to the rate of return that is commensurate with that risk. One of the tasks of the utility is to employ prudent and reasonable levels of debt and equity. The related task of the regulator is to review the utility's capital structure and adjust, when necessary, the requested levels of equity and debt for ratemaking purposes to prevent customers from paying rates that are unreasonably high.

Business risk is a measure of a company's ability to operate at a profit within its industry. Given that Tampa Electric operates in a monopoly industry with little-to-no competition, its business risk is relative

II. CAPITAL STRUCTURE

Q. WHAT IS A CAPITAL STRUCTURE AND HOW WILL IT IMPACT THE REVENUES THAT THE UTILITY IS SEEKING IN A RATE CASE?

A. The term "capital structure" refers to the relative percentage of debt, equity, and other financial components that are used to finance a company's investments.

Focusing first on obtaining financing from the capital market in the most simplistic terms, there are basically three financing methods. The first method is to finance an investment with common equity, which essentially represents ownership in a company and its investments. Common equity returns, which take the form of dividends to stockholders, are not tax deductible. This feature makes financing with equity about 40% more expensive than debt financing.

The second form of corporate financing is preferred stock, which is normally used to a much smaller degree in capital structures. Dividend payments associated with preferred stock also are not tax deductible.

Debt is the other major form of financing used by corporations. There are two basic types of corporate debt: long-term and short-term. Long-term debt is generally understood to be debt that matures in a period of more than one year. Short-term debt is debt that matures in less than one year. Both long- and short-term debt are liabilities on the company's books that must be repaid before common or preferred stockholders can receive a return on their investment.

Q. PLEASE DESCRIBE THE RELATIONSHIP BETWEEN A UTILITY'S CAPITAL STRUCTURE AND ITS TOTAL REVENUE REQUIREMENTS.

A. The overall rate of return that is applied to rate base to calculate revenue requirements is a function of the utility's capital structure. A utility's total return is developed by multiplying the percentage of each component of the capital structure relative to the total financing on the company's books, by the cost rates associated with each form of capital. For each component, the mathematical product is referred to as a weighted average. The sum of the components' weighted averages represents the weighted average overall cost of capital. When these percentage ratios are applied to the cost rates applicable to the respective components, a total after-tax rate of return is developed.

The regulatory rate setting process allows utilities the opportunity to recover all expenses, including interest and taxes. Rates will be set so that the utility has sufficient funds to pay its taxes as well as its common stock dividends. Therefore, the ratepayer pays additional costs for equity (higher capital cost rate and associated gross-up for taxes) than they do for debt (lower capital cost rate and a tax deduction).

Q. WHY SHOULD THE FLORIDA PUBLIC SERVICE COMMISSION BE CONCERNED ABOUT HOW TAMPA ELECTRIC FINANCES ITS RATE BASE INVESTMENT?

A. There are two reasons why the Commission should be concerned about how Tampa Electric finances its rate base investment. The first reason is that the cost of common equity is higher than the cost of long-term debt, so that a higher equity percentage will translate into higher costs to Tampa Electric's customers with no corresponding improvement in quality of service. Long-term debt is a contractual obligation of the company and is carried as a liability on the company's books. Common stock is ownership in the company. Due to the nature of equity investments, common stockholders require higher rates of return to compensate them for the extra risk involved in owning part of the company versus having a promissory note from the company.

The second reason why the Commission should be concerned about Tampa Electric's capital structure is related to the tax treatment of debt versus common equity. Public corporations, such as TECO Energy, Inc. ("TECO Energy"), can write-off interest payments associated with debt financing. Corporations are not, however, allowed to deduct common stock dividend payments for tax purposes. All dividend payments must be made with after-tax funds. As a result, the revenue requirement set in utility rate cases must be high enough to allow the utility to pay all of its taxes before a dividend is paid to stockholders. If a utility is allowed to use a capital structure that is top-heavy in common stock for ratemaking purposes, customers will be forced to pay the higher associated income tax burden, while giving no added value to the customer. Setting rates through the use of capital structure that is top-heavy in common equity violates the fundamental principles of utility regulation that rates must be fair but only high enough to support the utility's provision of safe, adequate, and reliable service at a fair price.

Q. MR. O'DONNELL, HAVE YOU REVIEWED THE CAPITAL STRUCTURE REQUESTED BY THE COMPANY IN THIS PROCEEDING?

A. Yes, I have.

Q. WHAT CAPITAL STRUCTURE IS TAMPA ELECTRIC SEEKING IN THIS CASE?

A. According to the testimony of Tampa Electric witness Callahan, when focusing solely on investor-provided sources of capital (debt and equity), the Company is seeking approval of a capital structure that consists of long-term and short-term debt of 45.8%

and common equity of 54.2%. The Company's requested capital structure also properly reflects additional non-investor sources of capital from deferred income taxes, investment tax credits, and customer deposits. When these items are taken into account and their associated cost rates are applied, the Company's requested overall rate of return is 6.74%. The Company's investor-supplied capital structure as proposed by Ms. Callahan and the final adjusted capital structure as requested by the Company can be found in Exhibit KWO-1.

Q. DO YOU BELIEVE THAT THE CAPITAL STRUCTURE BEING PROPOSED BY TAMPA ELECTRIC IN THIS CASE IS APPROPRIATE FOR RATEMAKING PURPOSES?

A. No. There are several flaws with Tampa Electric's requested capital structure. First, the capital structure is not indicative of the risk/return profile used by market investors in assessing the required rate of return and, as such, the cost of equity as requested by the Company in this proceeding is overstated. Tampa Electric is a subsidiary of TECO Energy. As such, an investor cannot buy stock in Tampa Electric but, instead, must buy stock in TECO Energy to have ownership in Tampa Electric. To truly match the risk/return profile as required in the marketplace, the TECO Energy capital structure should be used for setting rates. Secondly, the credit rating of Tampa Electric is inextricably linked to the credit rating of TECO Energy. Setting rates using a capital structure that is more equity-heavy than what the market uses as the basis for its analyses is simply improper and unfair to consumers of Tampa Electric.

Q. HOW DOES TAMPA ELECTRIC'S REQUESTED CAPITAL STRUCTURE IN THIS CASE COMPARE TO THE CAPITAL STRUCTURE OF ITS PARENT COMPANY, TECO ENERGY?

A. The TECO Energy consolidated capital structure is much less reliant on common equity than is Tampa Electric's. To be specific, according to Schedules D-1a and D-2 of the MFRs filed in this case in 2012, the TECO Energy equity ratio is 43.59% as opposed to the Tampa Electric equity ratio of 53.78%. Exhibit KWO-2, provides a side-by-side comparison between the Tampa Electric capital structure and the TECO Energy consolidated capital structure.

Q. WHY IS THERE SUCH A LARGE DIFFERENCE IN THE COMMON EQUITY RATIOS BETWEEN TAMPA ELECTRIC AND ITS PARENT COMPANY, TECO ENERGY?

A. TECO Energy is a large company that operates an electric utility (Tampa Electric), a Florida gas utility (Peoples Gas), a coal mining business (TECO Coal), and recently acquired a New Mexico gas utility (New Mexico Gas Company). Both Tampa Electric and Peoples Gas are regulated businesses with monopoly service territories and little-to-no competition for the services they provide. On the other hand, TECO Coal operates in an unregulated market that is subject to market forces and competition. Based on my analysis, it appears that TECO Energy is using the regulatory process in Florida to extract excess profits from its captive ratepayers to subsidize TECO Coal's unregulated operations.

Q. PLEASE EXPLAIN HOW TECO ENERGY IS USING THE REGULATORY PROCESS IN FLORIDA TO SUBSIDIZE ITS COAL MINING BUSINESS.

A. In my analysis of this case, I have found evidence that TECO Energy is using its holding company status to doubleleverage the capital structure of Tampa Electric, thereby creating excess profits at the expense of captive ratepayers in Florida.

Q. HOW ARE YOU USING THE TERM "LEVERAGE"?

A. I am using the term "leverage" in the context of the parent company, TECO energy, using the capital structure of its subsidiary, Tampa Electric, to extract excess profits.

Q. PLEASE EXPLAIN THE CONCEPT OF "DOUBLELEVERAGE" AND HOW TECO ENERGY CAN USE IT TO CREATE EXCESS PROFITS.

A. Tampa Electric is a wholly-owned subsidiary of TECO Energy. There are no market forces that influence the shape of the Tampa Electric capital structure. As a result, TECO Energy can issue long-term debt on its consolidated balance sheet and then invest the funds into Tampa Electric and treat this as common equity. Since the return on common equity for regulated utilities must be grossed up for taxes and the cost of equity is already twice the cost of debt, captive ratepayers in Florida are being asked to pay higher rates to support a portion of Tampa Electric's common equity that is, effectively, comprised of lower cost debt.

In essence, TECO Energy is using the Commission's regulatory process to effectively transform a debt investment that it obtained at low cost into higher-paying equity returns. If allowed to continue in this case, the Company will be allowed to charge Florida consumers roughly 18% in pre-tax equity costs for debt costs that cost TECO Energy less than 4%. I believe that the Commission should reject and prohibit such manipulation of the regulatory process in this and all future proceedings.

Q. PLEASE ANALYTICALLY SHOW HOW TECO CAN MANIPULATE THE REGULATORY PROCESS BY TURNING A 4% INVESTMENT INTO AN 18% RETURN?

A. If TECO Energy were to issue debt today, the Company would pay roughly 4% in interest for a long-term bond. Since TECO Energy owns Tampa Electric, the Company could then invest its debt proceeds into its regulated subsidiary as common equity. In this case, TECO Energy pays the bondholder 4% interest, but it receives an 11.25% ROE (TECO's requested return in this case). In this example, TECO Energy can almost triple (4% to 11.25%) the return on its debt investment by essentially re-categorizing debt as equity. Even utilizing OPC's recommended 9.0% ROE would result in more than double the return on its debt investment (4% to 9%).

This debt-to-equity situation gets even more attractive to the utility when one considers that the revenue requirement for the utility must allow for taxes to be paid before the net income is determined. When these tax payments are included, the pre-tax rate of return on equity investments rises to approximately 18.4% using Tampa Electric's 11.25% ROE, or 14.7% using OPC's 9.0% ROE. Hence, in this example, TECO Energy can turn an investment costing 4% into a 15-19% return simply by turning the debt at the holding company level into common equity at the regulated subsidiary level. While using OPC's 9% ROE lessens the impact of double leveraging, it does not eliminate it.

Q. DO YOU HAVE ANY EVIDENCE THAT TECO ENERGY IS DOUBLELEVERAGING IT'S REGULATED ASSET INVESTMENTS, THEREBY CREATING EXCESS PROFITS AT THE EXPENSE OF CAPTIVE RATEPAYERS IN FLORIDA?

A. Yes. In Exhibit KWO-3, I have provided the December 31, 2012 balance of common equity for TECO Energy as well as that of TECO Energy's three business lines: Tampa Electric; Peoples Gas; and the Company's unregulated business.

As illustrated in Exhibit KWO-3, Tampa Electric, Peoples Gas, and TECO Energy's unregulated business have approximately $365 million more equity on their books than TECO Energy has on its books. This exhibit clearly demonstrates that TECO Energy is using its debt proceeds to infuse common equity into its regulated subsidiaries. Thus, it can use the dividends from its holdings in the regulated utility's common equity to help subsidize its unregulated activities. Assuming that the average interest rate for this $365 million is 4% and the cost of common equity is 14.7% grossed-up for taxes; TECO Energy can use the regulatory process to create close to $39.1 million in excess profits from its captive customers of Tampa Electric and Peoples Gas.

Q. HOW HAS TAMPA ELECTRIC'S COMMON EQUITY RATIO CHANGED SINCE 2005 TO THE PRESENT?

A. In Exhibit KWO-4, I have provided the common equity ratio of Tampa Electric from 2005 through 2012. As can be seen in this exhibit, the Tampa Electric equity ratio has ranged from roughly 48% in 2006 and 2007 to its current high of 54%. Generally, the equity ratio of Tampa Electric has been trending upward over the past 8 years.

Q. PLEASE COMPARE THE EQUITY RATIO GRANTED IN THE 2008 RATE CASE, THE REQUESTED EQUITY RATIO IN THIS CASE VERSUS TAMPA ELECTRIC'S HISTORIC EQUITY RATIOS?

A. The equity ratio approved in Tampa Electric's 2008 rate case was 53.97% for the forecasted test year of 2009. Tampa Electric did not achieve the 53.97% equity ratio, but achieved an actual 2009 equity ratio of only 51%. In the current case, Tampa

Electric is requesting an equity ratio of 54.2%, even though the Company has not achieved an equity ratio close to that over the past 8 years.

One critical aspect of the graph found in Exhibit KO-4 is how Tampa Electric seems to ramp up its equity ratio in the year that the Company files a rate case. In 2006 and 2007, Tampa Electric's equity ratio was 48%. In 2008, Tampa Electric filed its last rate case and increased its equity ratio to 52%. Tampa Electric was then awarded an equity ratio of 53.97% in its 2008 rate case. In 2009, however, the Company's equity ratio fell to 51% and it remained there until 2012. The Company then ramped up its equity ratio to 54% in 2012 coinciding with its preparation for the current rate case.

I believe the mere fact that Tampa Electric's equity ratio changed from 51% in 2011 to 54% in 2012 is quite telling. When a utility files a petition for a rate increase, it is essentially claiming that its finances are getting weak and it needs to stabilize and/or reverse the financial downward movement. One would think that, in times of financial concern, a Company's equity ratio would not jump 3% in one year. However, such a jump is exactly what happened with Tampa Electric in the year 2012 before the Company filed the current rate case.

Q. WHY DO YOU BELIEVE THAT TAMPA ELECTRIC INCREASED ITS EQUITY RATIO FROM 51% TO 54% LAST YEAR?

A. I believe that management at TECO Energy knew that Tampa Electric would be filing a rate case in 2013, therefore, it increased the equity ratio in its utility subsidiary in order to use the regulatory process to generate excess profits from its captive ratepayers. A review of the Tampa Electric Federal Energy Regulatory Commission ("FERC") Form 1 for 2011 and 2012 shows the Company's equity balance increased by over $100 million from 2011 to 2012 as compared to an increase of only $53 million from 2008 through 2011.

Q. WHAT IS THE SIGNIFICANCE TO RATEPAYERS OF THIS INCREASE IN THE COMMON EQUITY RATIO OF TAMPA ELECTRIC?

A. In 2010, Tampa Electric's year-end common equity ratio was 50.5%. The Company's request in the current case is 54.2%. When this difference in equity ratios is applied to the rate base, the increase in annual revenue requirements in this case due to the higher common equity ratio of 2013 versus 2010 is $6.5 million.

In this case, Tampa Electric is seeking a rate increase of almost $135 million, which, according to Tampa Electric, equates to roughly a 10% rate increase to residential consumers and a 6% increase for commercial and industrial consumers. $13.5 million is approximately 10% of the requested $135 6 million rate increase. According to information obtained from the United States Energy Information Administration, the typical Tampa Electric customer spends $1,669 for electric service each year. A 10% rate increase would result in an extra $167 per year for electric service from the Tampa Electric customers. Of that amount, $18 per year would be directly attributable to the request of Tampa Electric to impose a higher common equity ratio in 2013 than it carried on its books in 2010. Given that the Tampa area has many individuals on fixed incomes and the current economic malaise, I believe that the extra $18 charge for an artificial equity ratio would be burdensome for Florida residents.

Q. DO YOU HAVE ANY OTHER EVIDENCE TO SHOW THAT TECO ENERGY IS USING THE FLORIDA REGULATORY PROCESS TO BENEFIT ITS STOCKHOLDERS AT THE EXPENSE OF RATEPAYERS?

A. Yes. In Exhibit KWO-5, I have presented the common equity ratios of Tampa Electric, Peoples Gas, and TECO's unregulated entities. As can be seen in this chart, the equity ratio of TECO's unregulated subsidiaries is 27.52%, which is significantly less than the equity ratio of both Tampa Electric and Peoples Gas. The fact that the more risky unregulated entities has significantly more financial risk while also having a much higher business risk than the regulated utilities is simply nonsensical.

Q. WHY DO YOU SAY THAT THE LOWER EQUITY RATIO FOR TECO'S UNREGULATED AFFILATES IS NONSENSICAL?

A. The unregulated affiliates of TECO Energy operate in non-regulated businesses such as coal mining without traditional monopoly markets. These entities face competition for market share and do not enjoy automatic cost recovery clauses or the ability to seek additional revenues through filed rate cases. The earnings of these unregulated affiliates are typically more volatile than those of regulated utilities. These businesses are therefore considered to be riskier than a regulated utility.

Q. IF THE UNREGULATED SUBSIDIARIES OF TECO ENERGY, INC. ARE RISKIER THAN TAMPA ELECTRIC, WHY ARE THEIR EQUITY/DEBT RATIOS THE INVERSE OF WHAT ONE WOULD EXPECT TO SEE, BASED ON CONSIDERATIONS OF RELATIVE RISK?

A. The parent holding company has an incentive to maximize the amount of its equity investment in the less risky utility, with the knowledge that the returns on that investment will be relatively safer and more certain. The parent can then use dividends from its equity investment in the utility to fund its unregulated ventures. While the reversal of the expected equity–to-debt relationship may make sense from the perspective of a profit-maximizing holding company perspective, it is irrational from the ratemaking standpoint that should appropriately correlating the risk of the utility to the return that will be paid by TECO's customers.

Q. HOW DO CREDIT RATING AGENCIES ADDRESS THE DIFFERENCES BETWEEN CAPITAL STRUCTURES OF THE PARENT HOLDING COMPANY AND ITS REGULATED SUBSIDIARIES?

A. Standard & Poors (S&P) is the pre-eminent bond rating agency in the world. Two years ago, S&P made the following statement in regard to the credit ratings of a utility subsidiary and its parent company:

> Utility subsidiaries' ratings are linked to the consolidated group's credit quality because of the financial linkage of the parent to the subsidiary and the likelihood that, in times of stress or bankruptcy, the parent will consider the utility subsidiary as a resource to be used. Accordingly, our base-case financial analysis primarily focuses on the performance, cash flow, and balance sheet of the consolidated group.
>
> Methodology: Differentiating The Issuer Credit Ratings Of A Regulated Utility Subsidiary And Its Parent, **Standard & Poors**, March 11, 2010 at p. 2.

Based on this statement from S&P, it is clear that the credit rating of Tampa Electric is inextricably linked to the capital structure of TECO Energy. Since ratepayers are already being subjected to incrementally higher interest costs due to the capital structure of TECO Energy as opposed to that of Tampa Electric, it is appropriate and fair for Tampa Electric consumers to receive some of the benefit of the lower equity ratio associated with the TECO Energy common equity ratio.

Q. PLEASE EXPLAIN HOW TECO ENERGY CAN USE THE RESOURCES OF TAMPA ELECTRIC TO SUSTAIN THE CONSOLIDATED GROUP DURING ROUGH ECONOMIC TIMES.

A. The most direct way in which TECO Energy can lean on the resources of Tampa Electric is to increase its cash withdrawals from the utility. As this Commission is aware, 2008 was the start of a significant economic recession in Florida as well as throughout the United States. TECO Energy did, in fact, lean on its subsidiary Tampa Electric to help sustain its operations in its non-regulated businesses. In Exhibit KWO-6 is a graph that shows the cash withdrawals TECO has made from

Tampa Electric over the past 10 years. I point to the rather large withdrawals TECO made from Tampa Electric from 2008 through 2010.

Q. WHAT HAPPENS TO A SUBSIDIARY'S CAPITAL STRUCTURE WHEN THE PARENT COMPANY MAKES WITHDRAWALS FROM THE SUBSIDIARY COMPANY?

A. The financial resources of the subsidiary weaken, which is the concern cited by S&P in the above quotation. The doubleleveraging process occurs when a parent holding company uses the regulatory process to effectively force ratepayers to subsidize the operations of non-regulated companies, thereby creating a perverse incentive to withdraw capital from the regulated utility even though it weakens the utility's financial resources.

Q. ARE YOU AWARE OF ANY OTHER STATE PUBLIC SERVICE COMMISSION THAT HAS MADE A DOUBLELEVERAGE ADJUSTMENT?

A. Yes, the Iowa Utilities Board. In its Final Decision and Order, issued January 10, 2011, in Docket No. RPU-2010-0001, at page 95, the Iowa Utilities Board stated the following:

> In looking at a rate-regulated utility's capital structure, the Board traditionally considers the capital structure of the utility company, which includes debt, or the first layer of leverage, as well as any debt at the parent holding company level that could be used for a capital infusion into the utility, which is the second layer of leverage. <u>Without the double leverage adjustment, a subsidiary utility company could</u>

> manipulate its debt levels at the parent and subsidiary levels to support a higher overall rate of return, as affected by the capital structure, than any utility company that is not in such a position, i.e., that does not have a parent company. (Emphasis added)

In several cases, the Iowa Utilities Board has implemented adjustments to prevent double leveraging, including Docket Nos. RPU-02-3, RPU-02-8, and ARU-02-1 in 2003. However, the Board in those cases decided that it would not apply double leverage mechanically in each case, but rather would examine the particular facts and circumstances in each case where the adjustment is proposed.

Q. WHAT IS THE AVERAGE COMMON EQUITY RATIO GRANTED BY OTHER STATE REGULATORS SINCE 2010?

A. As can be seen in Exhibit KWO-7, from 2010 through 2012, the average common equity ratio granted by state regulators was 49.19%. Exhibit KWO-8 provides the authorized common equity ratio, which is 49.64%, granted in 2013 to-date by state regulators.

Q. HOW IS THE COMMON EQUITY RATIO OF A COMPANY RELATED TO THE INVESTOR REQUIRED RETURN ON EQUITY?

A. The common equity ratio of a company is a measure of its financial risk. Simply put, the higher the common equity ratio, the less risk and the corresponding lower required rate of return needed for the company. Hence, the common equity ratio to be set in this proceeding is directly linked to the allowed return on equity set by this Commission.

Q. WHAT IS THE AVERAGE RETURN ON EQUITY GRANTED BY STATE REGULATORS IN 2012 AND TO-DATE IN 2013?

A. As can also be seen in Exhibit KWO-8 the average return on equity allowed by state regulators across the country to-date in 2013 has been 9.77%. It is important to note that I excluded the allowed returns on equity set in Virginia, which were set by the Legislature only for their revenue adjustment clauses and not in general rate cases where the ROE could be re-set.

Q. IN TERMS OF A RETURN ON EQUITY, WHAT IS THE PREMIUM FOR TAMPA ELECTRIC BY SETTING ITS COMMON EQUITY RATIO AT ITS REQUESTED 54.2% AS OPPOSED TO THE 49.19% AVERAGE EQUITY RATIO GRANTED BY STATE REGULATORS OVER THE PAST 3 YEARS?

A. The revenue requirement difference in this case between a 54.2% equity ratio and a 49.19% equity ratio is $21 million. The corresponding post-tax return on equity difference is 50 basis points. In essence, granting 9.0% return on equity with a 54.2% common equity ratio is equivalent to granting a 9.5% return on equity with a 49.19% common equity ratio.

Q. WHAT CAPITAL STRUCTURE DO YOU RECOMMEND FOR RATEMAKING PURPOSES IN THIS CASE?

A. I believe that the Company's requested capital structure is unreasonable and unnecessarily burdensome on ratepayers which equates to $16.7 million in higher revenue requirements to support Tampa Electric's requested common equity ratio. Thus, I recommend that the Commission find the middle ground between the Company's requested capital structure and the TECO Energy capital structure, upon which the assets of this case were financed. To be specific, I recommend that the Commission employ a capital structure of 50% common equity, 49.21% long-term debt, and 0.79% short-term debt. I will also accept the cost rates of long-term debt and short-term debt as proposed by the Company.

The 50% common equity ratio that I am recommending is reasonable for the following reasons: 1) it is slightly higher than the average common equity ratio granted by state regulators; 2) it is much higher than the common equity ratio in the TECO Energy capital structure: and 3) it is roughly halfway between Tampa Electric's request in this case and the TECO Energy capital structure. My recommended capital structure as well as the ROE recommended by OPC witness Woolridge can be seen in Exhibit KWO-9.

Q. WHAT IS THE REVENUE REQUIREMENT IMPACT ON THIS CASE IF THE COMMISSION ACCEPTS YOUR RECOMMENDATION TO EMPLOY

A CAPITAL STRUCTURE CONSISTING OF 50% EQUITY AND 50% DEBT IN THIS PROCEEDING?

A. If the Commission accepts my recommendation in this case and sets the ROE at 9.0%, as recommended by OPC witness Woolridge, the revenue requirement for Tampa Electric will be $13.2 million lower than it would be if the Commission accepts the Company's requested capital structure.

III. FINANCIAL INTEGRITY

Q. PLEASE DESCRIBE THE CONCEPT OF FINANCIAL INTEGRITY AND WHY IT IS AN IMPORTANT PART OF THE REGULATORY PROCESS.

A. Financial integrity is a measure of the ability of the company to make its financial payments and earn the market required rate of return. Utility regulation gives utilities the opportunity to earn a fair rate of return and recover its reasonable operating costs, including debt payments. As a result, financial integrity is central to utility regulation. However, it is important to note that financial integrity in the context of this general rate case must consider how Tampa Electric operates on its own as well as its interaction with its parent holding company and its sister companies.

Q. HAVE YOU REVIEWED TAMPA ELECTRIC'S CURRENT BOND RATINGS AND THE POSITIONS THAT THE CREDIT RATING AGENCIES HAVE ON THE COMPANY?

A. Yes, I have.

Q. WHAT ARE THE CURRENT RATINGS FOR TAMPA ELECTRIC?

A. The current S&P rating for Tampa Electric is BBB+ and the outlook is stable. The Moody's credit rating for Tampa Electric is Baa2.

Q. AS AN EXPERT, DO YOU RELY ON THE CREDIT AGENCIES' ANALYSES OF COMPANIES SUCH AS TAMPA ELECTRIC AS PART OF YOUR DETERMINATIONS REGARDING THE FINANCIAL INTERGRITY OF THOSE COMPANIES?

A. Yes, I do.

Q. ARE YOU FAMILIAR WITH THE PROCESSES THE CREDIT AGENCIES USE TO EVALUATE THE CREDIT RISK OF A COMPANY?

A. Yes, I am. I have worked in the area of utility regulation field for almost 30 years, and have worked as an investment analyst for the same amount of time. I have witnessed firsthand the changes that have occurred within the credit rating agencies, particularly after 2008.

Q. PLEASE DESCRIBE HOW CREDIT AGENCIES ANALYZE THE CREDITWORTHINESS OF MAJOR COMPANIES SUCH AS TAMPA ELECTRIC.

A. S&P, Moody's, and other rating agencies consider financial risk as well as business risk when analyzing the creditworthiness of companies. S&P and Moody's specifically develop guidelines to help the ratings analyst assess the credit position of the Company in question. However, it is important to note that the rating guidelines are general statements that are not strictly enforced.

Q. PLEASE DESCRIBE HOW THE RATING AGENCIES ASSESS THE BUSINESS RISKS OF THE COMPANIES BEING RATED.

A. Business risk measures the ability of a company to make a profit in day-to-day operations. Credit agencies such as S&P and Moody's will analyze issues such as 1) the country in which the rated company operates; 2) the relative risk of the industry in which it operates; 3) unique business situations involving the rated company, and 4) the profitability of the company relative to its peers. When analyzing utilities, the regulatory atmosphere in which the company operates is also a material factor in the rating process. The Commission is rated as "above average" by Regulatory Research Associates (RRA), which focuses on utility regulation around the country. An "above average" rating by RRA translates into low regulatory risk for utilities operating under the jurisdiction of the Florida Public Service Commission. However, Tampa Electric is a subsidiary of TECO Energy and, as noted previously in this testimony, credit rating agencies link parent holding companies and utility subsidiaries when performing credit analyses.

Q. WHAT IS THE BUSINESS RISK OF TAMPA ELECTRIC?

A. Given that Tampa Electric has a monopoly in the provision of electric service, which is a basic necessity in its service territory, and the Florida Public Service Commission is considered to be credit supportive, the utility would generally be considered to have low business risk. However, since Tampa Electric is owned by TECO Energy, which has riskier assets, the overall business risk must also be considered in light of its more risky unregulated subsidiaries. On May 6, 2009, S&P upgraded the credit rating of TECO Energy and Tampa Electric from BBB- to BBB and stated the following about business risk:

> Continued exposure to elevated business risk in ventures outside of Florida, including coal-mining operations in Appalachia and electric distribution and generation overseas, detract from credit quality. TECO's business profile is in the low end of the "excellent" range of Standard & Poor's corporate ratings matrix, and the financial profile is considered to be "aggressive".

On May 27, 2011, TECO Energy and its subsidiaries, including Tampa Electric, enjoyed another ratings upgrade by S&P when the ratings were raised from BBB to BBB+. In its report on this date, S&P again noted the company's business risk when it stated:

> The ratings on TECO Energy Inc. reflect the company's ongoing commitment to improving its credit quality by shedding some of its unregulated businesses, . . .

The fact that Tampa Electric's sister companies are involved in unregulated activities is clearly a detriment to sustaining a higher credit rating for the utility.

Q. PLEASE EXPLAIN WHY CREDIT AGENCIES EXAMINE SISTER COMPANY OPERATIONS WHEN CONSIDERING THE CREDIT RISK OF TAMPA ELECTRIC.

A. The May 27, 2011, S&P report on the upgrade of TECO Energy and Tampa Electric notes that 80% of the credit profile of TECO Energy consists of Tampa Electric. The ability of TECO Energy to generate cash from its regulated subsidiary, Tampa Electric, makes it such that one cannot examine the credit standing of Tampa Electric without also looking at the credit of the parent company, TECO Energy. The credit agencies understand that, if one of the unregulated subsidiaries got into financial trouble, TECO Energy would be free to draw down cash from Tampa Electric, thereby putting the utility at financial risk as well.

Q. PLEASE DESCRIBE HOW RATING AGENCIES DETERMINE FINANCIAL RISK.

A. Assessing financial risk involves a more analytical process than determining business risk. Credit agencies will examine issues such as liquidity, debt coverage ratios, cash flow, financial policy, and accounting policy.

Liquidity is measured by examining the cash flow of a company. A company cannot make its debt payments (principal and interest) without having sufficient cash and earnings to cover the payments. Analyzing the cash flow of a company allows the credit analyst to determine the ability of the company to meet its debt service obligations.

Debt coverage ratios stem, in part, from the cash flow analysis of a company. In essence, the debt coverage ratio provides a measure of how much earnings and cash the company has relative to its debt payments.

Capital structure is really another debt leverage measure. The more debt the company has in its capital structure, the more financial risk the company will carry. Of course, in utility regulation, capital structure should be analyzed in the context of not only the stand-alone utility, but also its parent holding company and sister subsidiaries, particularly its unregulated sister companies.

Financial policy relates to the amount of debt the company wishes to take on as well as issues such as how the parent company wishes to invest its own debt and equity into subsidiary companies.

Q. PLEASE PROVIDE SOME OF THE SPECIFIC ANALYTICAL CALCULATIONS USED BY THE CREDIT AGENCIES TO ANALYZE FINANCIAL RISK.

A. To measure liquidity and financial risk, S&P and Moody's use similar financial ratio analyses. For example, both rating agencies measure cash flow from operations relative to the debt outstanding. For S&P, this ratio as known as the Funds from Operations to Debt (FFO/Debt). Moody's calls this ratio the CFO/Debt ratio, which stands for Cash Flow from Operations relative to Debt.

Both credit rating agencies also examine pre-tax interest coverage ratios, which is a measure of the ability of the company to make debt payments. Moody's definition of pre-tax interest coverage is the sum of Cash Flow from Operations (CFO) and interest divided by interest expense.

Both rating agencies look at debt leverage by examining the total amount of debt in a capital structure relative to the total amount of capital employed by the company. This ratio is defined as Debt/Capital.

In Exhibit KWO-10 shows a summary of the above-stated financial metrics and the associated credit ratings.

To the extent that Tampa Electric's credit rating is lower than it would be if Tampa Electric were a stand-alone company, the utility's ratepayers are overpaying in interest costs due to the association with TECO Energy and its subsidiaries.

Q. HAVE YOU PERFORMED A FINANCIAL ANALYSIS OF TAMPA ELECTRIC TO DETERMINE HOW THE COMPANY FITS INTO THE ABOVE S&P CREDIT RATING MATRIX?

A. Yes. Based on the OPC's recommendations in this case, I have determined the following financial ratios: the FFO/Debt is 27.78%; the debt to total capital is 50%: and the interest coverage ratio, as measured by CFO/Interest, is 5.27. My calculations for these ratios can be seen in Exhibit KWO-11.

Q. WHAT IS YOUR CONCLUSION AS TO HOW OPC'S RECOMMENDATIONS IN THIS CASE WILL AFFECT THE PARAMETERS VIEWED BY RATING AGENCIES?

A. My analysis shows that the OPC's recommendations in this case would produce metrics that would place Tampa Electric at the border of a single A/Baa bond rating. As a result, I believe that the OPC's recommendations in this case will allow Tampa Electric to maintain its current credit ratings.

Q. HOW DO YOU BELIEVE THE CREDIT AGENCIES WILL REACT TO YOUR RECOMMENDATION OF USING A CAPITAL STRUCTURE CONSISTING OF 50% COMMON EQUITY AND 50% DEBT?

A. The credit agencies are most concerned with the <u>actual</u> capital structures of TECO Energy and Tampa Electric. As I have demonstrated above, TECO Energy has the ability to change the capital structure of Tampa Electric as it so chooses. I have no doubt that the credit agencies noticed the drop in Tampa Electric's ratio right after the issuance of the final order in the 2008 rate case. Similarly, I have no doubt that the credit agencies understand that the Company's current equity ratio of 54% is abnormally high relative to its equity ratio of the past eight years. Thus, I do not believe that my recommendation of employing a capital structure consisting of 50% equity and 50% debt will have any impact on how the credit agencies view Tampa Electric.

IV. SUMMARY

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. My analysis has revealed that Tampa Electric's requested capital structure unnecessarily burdens Florida ratepayers with an excessive amount of common equity. The cost of common equity is significantly more expensive than the cost of long-term debt. Moreover, the regulatory process in Florida allows utilities to recover their prudently incurred operating expenses. However, based on my analysis of the MFRs and Company responses in this case, I have found that TECO Energy is using debt proceeds to finance equity infusions into Tampa Electric and then is asking ratepayers to pay roughly $16.7 million in higher revenue requirements to support a common equity ratio that provides them little-to-no benefits.

In the capital markets, the cost of common equity is tied directly to the financial integrity of the company which, in part, is measured by the common equity ratio. One cannot buy stock in Tampa Electric. Instead, an investor interested in Tampa Electric must buy stock in TECO Energy. Hence, the price of common stock in TECO Energy is directly tied to the common equity ratio in the consolidated company. This equity ratio was 43.59% at year-end 2012. In this case, Tampa Electric is seeking approval of a hypothetical equity ratio of 54.2%. In my opinion, the Company's request in this case should be rejected. My recommendation is that the Commission split the difference between the heavily leveraged TECO Energy capital structure and the Tampa Electric capital structure and approve a capital structure that consists of 50% common equity and 50% debt.

My analysis reveals that Tampa Electric's financial integrity is inter-related to the integrity of TECO Energy and its subsidiaries. My review of the credit rating reports of TECO Energy and Tampa Electric reveal a concern regarding the unregulated activities of TECO Energy. To the extent that TECO Energy's unregulated activities are detracting from the possibility of Tampa Electric obtaining a higher stand-alone credit rating, TECO Energy's unregulated activities are causing ratepayers of Tampa Electric to pay higher interest costs today.

In reviewing the financial integrity of OPC's recommendations in this case, I have concluded, based on a review of business risk and financial risk parameters, that

OPC's recommendations in this case will allow Tampa Electric to retain its currently solid financial ratings.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

I. IDENTIFICATION OF WITNESS AND PURPOSE OF TESTIMONY

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

A. My name is J. Randall Woolridge, and my business address is 120 Haymaker Circle, State College, PA 16801. I am a Professor of Finance and the Goldman, Sachs & Co. and Frank P. Smeal Endowed University Fellow in Business Administration at the University Park Campus of the Pennsylvania State University. I am also the Director of the Smeal College Trading Room and President of the Nittany Lion Fund, LLC. A summary of my educational background, research, and related business experience is provided in Appendix A, which is attached in Exhibit JRW-16.

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

A. I have been asked by the Florida Office of Public Counsel ("OPC") to provide an opinion as to the appropriate return on equity ("ROE") for Tampa Electric Company ("Tampa Electric" or "Company") and to evaluate Tampa Electric's rate of return testimony submitted by witness Robert Hevert in this proceeding.

Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. First, I review my return on equity ("ROE") recommendation for Tampa Electric. Second, I provide an assessment of capital costs in today's capital markets. Third, I discuss the selection of a proxy group of electric utility companies ("Electric Proxy Group") for estimating the cost of capital for Tampa Electric. Fourth, I discuss the relationship between a utility's capital structure and the return on equity that should be associated with that capital structure. Fifth, I discuss the concept of the cost of equity capital, and then estimate the equity cost rate for Tampa Electric. Finally, I provide a critique of Tampa Electric's rate of return testimony.

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS REGARDING THE APPROPRIATE RATE OF RETURN FOR TAMPA ELECTRIC.

A. I initially show that capital costs as measured by interest rates are at historically low levels. With respect to this case, I show that interest rates on utility bonds have declined by more than 150 basis points since the Company's last rate case. To estimate an equity cost rate for Tampa Electric, I have applied the Discounted Cash Flow Model ("DCF") and the Capital Asset Pricing Model ("CAPM") to my Electric Proxy Group as well as Mr. Hevert's proxy group of companies ("Hevert Proxy Group"). My recommended ROE depends on the capital structure that is adopted by the Commission. If the Commission adopts OPC's recommended capital structure with a 50% common equity ratio that is presented in the testimony of OPC witness Kevin O'Donnell, I recommend an equity cost rate of 9.0% for Tampa Electric. If the Commission adopts the Company's recommended capital structure with a 54.2% common equity ratio, I recommend an equity cost rate of 8.75%. These findings are summarized in Exhibit JRW-1.

Q. PLEASE SUMMARIZE THE PRIMARY ISSUES REGARDING RATE OF RETURN IN THIS PROCEEDING.

A. The Company's recommended capital structure has a common equity ratio of 54.2%, which is above the average common equity ratio of publicly-traded electric utility companies. OPC's recommended capital structure is provided by Mr. Kevin O'Donnell and includes a common equity ratio of 50.0%. Mr. Hevert has attempted to justify Tampa Electric's proposed capital structure by comparing the 54.2% common equity ratio to the common equity ratios for the operating companies (and not the holding companies) for the companies in his proxy group.

Other than the capital structure, the Company's proposed rate of return is inflated primarily due to an overstated equity cost rate. Mr. Hevert provides a recommended return on equity in the range of 10.50%-11.50%, and within this range he has recommended an 11.25% return on equity. Mr. Hevert and I both rely predominantly on our DCF results in estimating an equity cost rate in this proceeding. We also both use the CAPM approach as a check on our DCF results. Mr. Hevert also employs a Bond Yield Plus Risk Premium ("RP") approach as a check on his equity cost rate estimate. We both applied our approaches to groups of companies that are similar to Tampa Electric.

In terms of the DCF approach, the major area of disagreement is the estimation of the expected growth rate. Mr. Hevert uses a constant-growth DCF model with 30, 90, and 180 day average dividend yields. Mr. Hevert relied on the forecasted earnings per share ("EPS") growth rates of Wall Street analysts and *Value Line*. There are two primary issues with the DCF results. First, he has ignored the mean low results because he believes that the equity cost rate results are too low. Second, he has relied exclusively on the EPS growth rate forecasts of Wall Street analysts and *Value Line* to measure the expected DCF growth rate. I provide empirical evidence that demonstrate the long-term earnings growth rates of Wall Street analysts are overly optimistic and upwardly-biased. I also show that the estimated long-term EPS growth rates of *Value Line* are overstated. In developing my DCF growth rate, I used both historic and projected growth rate measures and evaluated growth in dividends, book value, and EPS.

The CAPM approach requires an estimate of the risk-free interest rate, beta, and the equity risk premium. The major area of disagreement involves the measurement and magnitude of the market or equity risk premium. In short, Mr. Hevert's market risk premium is excessive and does not reflect current market fundamentals. As I highlight in my testimony, there are three procedures for estimating a market or equity risk premium – historic returns, surveys, and expected return models. Mr. Hevert used projected market risk premiums of 6.03%, 9.88%, and 9.81%. He used a very time-specific Sharpe model to develop his projected market risk premium of 6.03%; however, current measures suggest a much lower risk premium. His projected equity risk premiums of 9.88% and 9.81% use analysts' EPS growth rate projections to compute an expected market return and market risk premium. These EPS growth rate projections and resulting expected market returns and risk premiums include unrealistic assumptions regarding future economic and earnings growth and stock returns. I use an equity risk premium of 5.0%, which: (1) factors in all three approaches to estimating an equity premium; and (2) employs the results of many studies of the equity risk premium. As I note, my market risk premium reflects the market risk premiums: (1) discovered in academic studies by leading finance scholars; and (2) that result from surveys of companies, financial forecasters, financial analysts, and corporate CFOs.

In the end, the most significant areas of disagreement in measuring Tampa Electric's cost of capital are: (1) the Company's capital structure, and the ROE that is associated with the capital structure; (2) Mr. Hevert's excessive reliance on the earnings per share growth rate forecasts of Wall Street analysts and *Value Line* to measure expected DCF growth; and (3) the measurement and magnitude of the equity risk premium used in a CAPM approach and RP approaches.

II. <u>CAPITAL COSTS IN TODAY'S MARKETS</u>

Q. PLEASE DISCUSS CAPITAL COSTS IN U.S. MARKETS.

A. Long-term capital cost rates for U.S. corporations are a function of the required returns on risk-free securities plus a risk premium. The risk-free rate of interest is the yield on long-term U.S Treasury yields. The yields on ten-year U.S. Treasury bonds from 1953 to the present are provided on page 1 of Exhibit JRW-2. These yields peaked in the early 1980s and have generally declined since that time. These yields have fallen to historically low levels in recent years due to the financial crisis. In 2008, Treasury yields declined to below 3.0% as a result of the mortgage and subprime market credit crisis, the turmoil in the financial sector, the monetary stimulus provided by the Federal Reserve, and the slowdown in the economy. From

2008 until 2011, these rates fluctuated between 2.5% and 3.5%. In 2012, the yields on ten-year Treasuries declined from 2.5% to below 2.0%, as the Federal Reserve has continued to support a low interest rate environment and economic uncertainties have persisted. In the past month, these yields have increased to the 2.5% range as investors have speculated that the Federal Reserve's aggressive monetary policy in the form of its $85B per month bond buying program will be coming to end in the coming months.

Panel B on Exhibit JRW-2 shows the differences in yields between ten-year Treasuries and Moody's Baa-rated bonds since the year 2000. This differential primarily reflects the additional risk required by bond investors for the risk associated with investing in corporate bonds as opposed to obligations of the U.S. Treasury. The difference also reflects, to some degree, yield curve changes over time. The Baa rating is the lowest of the investment grade bond ratings for corporate bonds. The yield differential hovered in the 2.0% to 3.5% range until 2005, declined to 1.5% until late 2007, and then increased significantly in response to the financial crisis. This differential peaked at 6.0% at the height of the financial crisis in early 2009, due to tightening in credit markets, which increased corporate bond yields, and the "flight to quality," which decreased treasury yields. The differential subsequently declined and has been in the 2.5% to 3.5% range over the past three years.

The risk premium is the return premium required by investors to purchase riskier securities. The risk premium required by investors to buy corporate bonds is observable based on yield differentials in the markets. The market risk premium is the return premium required to purchase stocks as opposed to bonds. The market or equity risk premium is not readily observable in the markets (as are bond risk premiums) since expected stock market returns are not readily observable. As a result, equity risk premiums must be estimated using market data. There are alternative methodologies to estimate the equity risk premium, and these alternative approaches and equity risk premium results are subject to much debate. One way to estimate the equity risk premium is to compare the mean returns on bonds and stocks over long historical periods. Measured in this manner, the equity risk premium has been in the 5% to 7% range. However, studies by leading academics indicate the forward-looking equity risk premium is actually in the 4.0% to 5.0% range. These lower equity risk premium results are in line with the findings of equity risk premium surveys of CFOs, academics, analysts, companies, and financial forecasters.

Q. PLEASE DISCUSS INTEREST RATES AND THE FINANCIAL CRISIS.

A. The yields on Treasury securities decreased significantly at the onset of the financial crisis and have remained at historically low levels. In fact, these yields have declined to levels not seen since the 1940s. The decline in interest rates reflects several factors, including: (1) the "flight to quality" in the credit markets as investors sought out low risk investments during the financial crisis; (2) the very aggressive monetary actions of the Federal Reserve, which have been aimed at restoring liquidity and faith in the financial system as well as maintaining low interest rates to boost economic growth; and (3) the continuing slow recovery from the recession.

The credit market for corporate and utility debt experienced higher rates due to the credit crisis. The long-term corporate credit markets tightened during the financial crisis, but have improved significantly since 2009. Interest rates on utility and corporate debt have declined to historically low levels. These low rates reflect the monetary policy actions of the Federal Reserve and the weak economy.

Panel A of page 2 of Exhibit JRW-2 provides the yields on A- rated public utility bonds. These yields peaked in November 2008 at 7.75% and henceforth declined significantly. They hovered in the 4.0% area for most of the past year, until increasing to about 4.75% in the past two months. Panel B of page 2 of Exhibit JRW-2 provides the yield spreads between long-term A-rated public utility bonds relative to the yields on 20-year Treasury bonds. These yield spreads increased dramatically in the third quarter of 2008 during the peak of the financial crisis and have decreased significantly since that time. For example, the yield spreads between 20-year U.S. Treasury bonds and A-rated utility bonds peaked at 3.40% in November of 2008, declined to about 1.5% in the summer of 2012, and have since remained in that range.

Q. PLEASE DISCUSS THE FEDERAL RESERVE'S MONETARY POLICY AND INTEREST RATES.

A. Yes. On September 13, 2012, the Federal Reserve released its policy statement relating to Quantitative Easing III ("QE3"). In the statement, the Federal Reserve announced that it intended to expand and extend its purchasing of long-term securities to about $85B per month.[1] The Federal Open Market Committee ("FOMC") also indicated that it intends to keep the target rate for the federal funds rate between 0 to ¼ % through at least mid-2015. In addition, on December 12, 2012, the Federal

[1] Board of Governors of the Federal Reserve System, "Statement Regarding Transactions in Agency Mortgage-Backed Securities and Treasury Securities," September 13, 2012.

Reserve reiterated its continuation of its bond buying program and tied future monetary policy moves to unemployment rates and the level of interest rates. Specifically, the Committee decided to keep the target range for the federal funds rate at 0 to 1/4 percent and anticipates that this exceptionally low range for the federal funds rate will be appropriate at least as long as the unemployment remains above 6.5%.[2] Subsequently, at the March and April 2013 FOMC meetings, the Federal Reserve voted to continue its bond buying program policy and stick with its plan to keep interest rates at historically low levels until unemployment falls to 6.5%. In its policy statement, the Federal Reserve acknowledged that the U.S. job market has improved, and that consumer spending and business investments have increased and the housing market has improved; however, it also said it still did not expect unemployment to reach 6.5 percent until 2015.[3]

Subsequently, in the past two months, speculation has risen that the Federal Reserve's bond buying program is about to be reduced or eliminated in the coming months. This speculation has been fueled by more positive economic data on jobs and the economy as well as statements by FOMC members indicating that QE3 could be reduced later this calendar year. The markets reacted very quickly to the news. The yields on 30-year Treasury Bonds, which were about 3.0% in the first week of May, have increased to 3.60% as of early July. As such, capital costs have come off their bottoms but are still at historically low levels.

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[2] Board of Governors of the Federal Reserve System, FOMC Statement," December 12, 2012.

[3] Martin Crustinger, "Bernanke: Low interest-rate-policies benefit trade," Associated Press – Mon., Mar 25, 2013 4:20 PM EDT.

Q. HOW DO THE CAPITAL COST INDICATORS COMPARE TODAY TO THOSE AT THE TIME OF TAMPA ELECTRIC'S LAST RATE CASE

A. In Exhibit JRW-3, I provide the yields on ten-year Treasury bonds and thirty-year A-rated utility bonds for the following six month periods: Panel A - June 2008 to November 2008, and February 2013 to July 2013; and Panel B - June 2008 to November 2008, and January 2013 to June 2013. Current interest rates and capital costs are well below those at the time of Tampa Electric's last rate case. Panel A of Exhibit JRW-3 shows the yields on ten-year Treasury bonds. The average ten-year Treasury yields for these two periods are 3.84% and 2.05%, respectively. Panel B of page 1 of Exhibit JRW-3 shows the yields on thirty-year A-rated public utility bonds for the same six month periods. The average yields for these periods are 6.80% and 4.22%, respectively. These yields also indicate a decline in utility capital costs. In both cases, the decline in interest rates and capital costs is in excess of 150 basis points.

Q. OVERALL, WHAT DOES YOUR REVIEW OF THE CAPITAL MARKET CONDITIONS INDICATE ABOUT THE EQUITY COST RATE FOR UTILITIES TODAY?

A. The market data suggests that capital costs for utilities remain at historically low levels despite the recent increase in interest rates associated with speculation over the end of QE3. As shown on page 2 of Exhibit JRW-2, the yield on long-term A-rated utility bonds is about 4.75%. In addition, utility bond yields and capital costs are more than 150 basis points below their levels at the time of Tampa Electric's last rate case.

III. <u>PROXY GROUP SELECTION</u>

Q. PLEASE DESCRIBE YOUR APPROACH TO DEVELOPING A FAIR RATE OF RETURN RECOMMENDATION FOR TAMPA ELECTRIC.

A. To develop a fair rate of return recommendation for Tampa Electric, I evaluated the return requirements of investors on the common stock of a proxy group of publicly-held electric utility companies ("Electric Proxy Group"). In addition, I have also applied the DCF and CAPM equity cost rate approaches to the Hevert Proxy Group.

Q. PLEASE DESCRIBE YOUR PROXY GROUP OF COMPANIES.

A. My Electric Proxy Group consists of thirty-four electric utility companies. The selection criteria include the following:

1. Listed as Electric Utility by *Value Line Investment Survey* and listed as an Electric Utility or Combination Electric & Gas company in *AUS Utilities Report*;
2. At least 50% of revenues from regulated electric operations as reported by *AUS Utilities Report;*
3. An investment grade bond rating as reported by *AUS Utilities Report;*
4. Has paid a cash dividend for the past three years, with no cuts or omissions;
5. Not involved in an acquisition of another utility, and/or was not the target of an acquisition, in the past six months; and

6. Analysts' long-term EPS growth rate forecasts available from Yahoo, Reuters, and/or Zacks.

My Electric Proxy Group includes thirty-four companies. Summary financial statistics for the proxy group are listed in Panel A of page 1 of Exhibit JRW-4.[4] The median operating revenues and net plant for the Electric Proxy Group are $4,354.7 million (M) and $10,440.2 M, respectively. The group receives 84% of revenues from regulated electric operations, has an A-/BBB+ bond rating from Standard & Poor's, a current common equity ratio of 46.2%, and an earned return on common equity of 9.5%.

Q. PLEASE DESCRIBE THE "HEVERT PROXY GROUP."

A. Mr. Hevert's Proxy Group includes eleven electric utility companies. The median operating revenues and net plant for the Hevert Proxy Group are $14,799.0 M and $4,449.0 M, respectively. The group receives 95% of revenues from regulated electric operations, has a BBB+ bond rating from Standard & Poor's, a current common equity ratio of 50.3%, and a current earned return on common equity of 8.2%.

Q. HOW DOES TAMPA ELECTRIC COMPARE TO THE ELECTRIC AND HEVERT PROXY GROUPS?

A. I believe that bond ratings provide a reasonable measure of investment risk for utilities. Based on AUS Utilities Report, June 2013, Tampa Electric's parent company, TECO Energy, has S&P and Moody's bond ratings of BBB+ and A3,

[4] In my testimony, I present financial results using both mean and medians as measures of central tendency. However, due to outliers among means, I have used the median as a measure of central tendency.

respectively. My Electric Proxy Group has S&P and Moody's bond ratings of A-/BBB+ and A3, respectively; and the Hevert Proxy Group has S&P and Moody's bond ratings of BBB+ and Baa1, respectively. These ratings suggest that the risk level as measured by bond ratings is comparable to the two groups.

In addition, on page 2 of Exhibit JRW-4, I have assessed the riskiness of TECO Energy relative to the Electric and Hevert Proxy Groups using five different risk measures published by *Value Line*. These measures include Beta, Safety, Financial Strength, Earnings Predictability and Stock Price Stability. Whereas TECO Energy's Beta of 0.85 is above the Betas of the two groups (0.70 and 0.75), the other risk measures indicate that TECO is very similar in risk to the two proxy groups.

IV. <u>CAPITAL STRUCTURE RATIOS AND RETURN ON EQUITY</u>

Q. WHAT IS TAMPA ELECTRIC'S RECOMMENDED CAPITAL STRUCTURE FROM INVESTOR CAPITAL?

A. Tampa Electric's recommended capital structure from investor capital sources for ratemaking purposes includes 45.8% long-term debt and 54.2% common equity. This is provided in Panel A of Exhibit JRW-5.

Q. HOW DOES TAMPA ELECTRIC'S RECOMMENDED COMMON EQUITY RATIO COMPARE TO THAT OF ITS PARENT, TECO ENERGY, AS WELL AS THAT OF THE ELECTRIC AND HEVERT PROXY GROUPS?

A. The common equity ratios for TECO Energy and the Electric and Hevert Proxy Groups are provided on page 1 of Exhibit JRW-4. As reported in AUS Utilities Report, the common equity ratios are 43.6%, 46.2%, and 50.3% for TECO Energy and the Electric and Hevert Proxy Groups, respectively. These ratios show that Tampa Electric's common equity ratio is somewhat above those of TECO Energy and the Electric and Hevert Proxy Groups.

Q. WHY IS IT SIGNIFICANT THAT TAMPA ELECTRIC'S RECOMMENDED COMMON EQUITY RATIO IS ABOVE THAT OF TECO ENERGY AND THE ELECTRIC AND HEVERT PROXY GROUPS?

A. The common equity ratios in Exhibit JRW-4 are for the holding companies that trade in the markets that are used to estimate an equity cost rate for Tampa Electric. These ratios indicate that the Electric and Hevert Proxy Groups have, on average, a lower common equity ratio and a higher financial risk than Tampa Electric.

Q. PLEASE ELABORATE ON THE SIGNIFICANCE OF THE AMOUNT OF EQUITY THAT IS INCLUDED IN AN ELECTRIC UTILITY'S CAPITAL STRUCTURE.

A. An electric utility's decision as to the amount of equity capital it will incorporate in its capital structure involves fundamental trade-offs relating to the amount of financial risk the firm carries, the overall revenue requirements its customers are required to bear through the rates they pay, and the return on equity that investors will require.

Q. PLEASE DISCUSS A UTILITY'S DECISION TO USE DEBT VERSUS EQUITY TO MEET ITS CAPITAL NEEDS.

A. Utilities satisfy their capital needs through a mix of equity and debt. Because equity capital is more expensive than debt, the issuance of debt enables a utility to raise more capital with a given commitment of dollars than it could raise with just equity. Debt is therefore a means of "leveraging" capital dollars. However, as the amount of debt in the capital structure increases, its financial risk increases and the risk of the utility perceived by equity investors also increases. Significantly for this case, the converse is also true. As the amount of debt in the capital structure decreases, the financial risk decreases. The required return on equity capital is a function of the amount of overall risk that investors perceive, including financial risk in the form of debt.

Q. WHY IS THIS RELATIONSHIP IMPORTANT TO THE UTILITY'S CUSTOMERS?

A. Just as there is a direct correlation between the utility's authorized return on equity and the utility's revenue requirements (the higher the return, the greater the revenue requirement), there is a direct correlation between the amount of equity in the capital structure and the revenue requirements the customers are called on to bear. Again, equity capital is more expensive than debt. Not only does equity command a higher cost rate, it also adds more to the income tax burden that ratepayers are required to pay through rates. As the equity ratio increases, the utility's revenue requirements increase and rates paid by customers increase. If the proportion of equity is too high, rates will be higher than they need to be. For this reason, the utility's management must pursue a capital acquisition strategy that results in the proper balance in the capital structure.

Q. HOW HAVE ELECTRIC UTILITIES TYPICALLY STRUCK THIS BALANCE?

A. Due to regulation and the essential nature of its output, an electric utility is exposed to less business risk than other companies that are not regulated. This means that an electric utility can reasonably carry relatively more debt in its capital structure than can most unregulated companies. The utility should take appropriate advantage of its lower business risk to employ cheaper debt capital at a level that will benefit its customers through lower revenue requirements. Typically, one may see equity ratios for electric utilities range from the 40% to 50% range. As I stated earlier, the average amount of common equity in the average capital structure of the utilities in my proxy group is 46.2%.

Q. GIVEN YOUR VIEW THAT TAMPA ELECTRIC'S EQUITY RATIO IS HIGHER THAN THAT OF THE PROXY GROUP, WHAT SHOULD THE COMMISSION DO IN THIS RATEMAKING PROCEEDING?

A. When a regulated electric utility's actual capital structure contains too high an equity ratio, the options are: (1) to impute a more reasonable capital structure and reflect the imputed capital structure in revenue requirements; or (2) to recognize the downward impact that an unusually high equity ratio will have on financial risk of a utility and authorize a lower common equity cost rate.

Q. PLEASE ELABORATE ON THIS "DOWNWARD IMPACT."

A. As I stated earlier, there is a direct correlation between the amount of debt in a utility's capital structure and the financial risk that an equity investor will associate with that utility. A relatively lower proportion of debt translates into a lower required return on equity, all other things being equal. Stated differently, a utility cannot expect to "have it both ways." Specifically, a utility cannot maintain an unusually high equity ratio and not expect to have the resulting lower risk reflected in its authorized return on equity. The fundamental relationship between the lower risk and the appropriate authorized return should not be ignored.

Q. GIVEN THIS DISCUSSION, HOW ARE YOU EVALUATING THE CAPITAL STRUCTURE AND EQUITY COST RATE IN THIS PROCEEDING?

A. I have estimated an equity cost rate in the range of 9.0% based on my evaluation of the Electric and Hevert Proxy Groups. The average common equity ratios for the Electric and Hevert Proxy Groups are 46.2% and 50.3%, respectively. As such, the financial risks of both proxy groups are less than that of Tampa Electric. OPC witness O'Donnell has recommended a capital structure for Tampa Electric that includes a common equity ratio of 50.0%. To recognize the risk trade-off of the alternative proposed capital structures, I am recommending an equity cost rate of 8.75% if the Commission adopts Tampa Electric 54.2% equity capital structure. If the Commission adopts OPC's 50% debt and 50% equity capital structure, I recommend an equity cost rate of 9.0% for Tampa Electric.

V. THE COST OF COMMON EQUITY CAPITAL

A. OVERVIEW

Q. WHY MUST AN OVERALL COST OF CAPITAL OR FAIR RATE OF RETURN BE ESTABLISHED FOR A PUBLIC UTILITY?

A. In a competitive industry, the return on a firm's common equity capital is determined through the competitive market for its goods and services. Due to the capital requirements needed to provide utility services and to the economic benefit to society from avoiding duplication of these services, some public utilities are monopolies. It is not appropriate to permit monopoly utilities to set their own prices because of the lack of competition and the essential nature of the services. Thus, regulation seeks to establish prices that are fair to consumers and, at the same time, are sufficient to meet the operating and capital costs of the utility (i.e., provide an adequate return on capital to attract investors).

Q. PLEASE PROVIDE AN OVERVIEW OF THE COST OF CAPITAL IN THE CONTEXT OF THE THEORY OF THE FIRM.

A. The total cost of operating a business includes the cost of capital. The cost of common equity capital is the expected return on a firm's common stock that the marginal investor would deem sufficient to compensate for risk and the time value of money. In equilibrium, the expected and required rates of return on a company's common stock are equal.

Normative economic models of the firm, developed under very restrictive assumptions, provide insight into the relationship between firm performance or profitability, capital costs, and the value of the firm. Under the economist's ideal model of perfect competition, where entry and exit are costless, products are undifferentiated, and there are increasing marginal costs of production, firms produce up to the point where price equals marginal cost. Over time, a long-run equilibrium is established where price equals average cost, including the firm's capital costs. In equilibrium, total revenues equal total costs, and because capital costs represent investors' required return on the firm's capital, actual returns equal required returns, and the market value must equal the book value of the firm's securities.

In the real world, firms can achieve competitive advantage due to product market imperfections. Most notably, companies can gain competitive advantage through product differentiation (adding real or perceived value to products) and by achieving economies of scale (decreasing marginal costs of production). Competitive advantage allows firms to price products above average cost and thereby earn accounting profits greater than those required to cover capital costs. When these profits are in excess of that required by investors, or when a firm earns a return on equity in excess of its cost of equity, investors respond by valuing the firm's equity in excess of its book value.

James M. McTaggart, founder of the international management consulting firm Marakon Associates, described this essential relationship between the return on equity, the cost of equity, and the market-to-book ratio in the following manner:[5]

> Fundamentally, the value of a company is determined by the cash flow it generates over time for its owners, and the minimum acceptable rate of return required by capital investors. This "cost of equity capital" is used to discount the expected equity cash flow, converting it to a present value. The cash flow is, in turn, produced by the interaction of a company's return on equity and the annual rate of equity growth. High return on equity (ROE) companies in low-growth markets, such as Kellogg, are prodigious generators of cash flow, while low ROE companies in high-growth markets, such as Texas Instruments, barely generate enough cash flow to finance growth.
>
> A company's ROE over time, relative to its cost of equity, also determines whether it is worth more or less than its book value. If its ROE is consistently greater than the cost of equity capital (the investor's minimum acceptable return), the business is economically profitable and its market value will exceed book value. If, however, the business earns an ROE consistently less than its cost of equity, it is economically unprofitable and its market value will be less than book value.

As such, the relationship between a firm's return on equity, cost of equity, and market-to-book ratio is relatively straightforward. A firm that earns a return on equity above its cost of equity will see its common stock sell at a price above its book value. Conversely, a firm that earns a return on equity below its cost of equity will see its common stock sell at a price below its book value.

[5] James M. McTaggart, "The Ultimate Poison Pill: Closing the Value Gap," *Commentary* (Spring 1988), p. 2.

Q. PLEASE PROVIDE ADDITIONAL INSIGHTS INTO THE RELATIONSHIP BETWEEN RETURN ON EQUITY AND MARKET-TO-BOOK RATIOS.

A. This relationship is discussed in a classic Harvard Business School case study entitled "A Note on Value Drivers." On page 2 of that case study, the author describes the relationship very succinctly:[6]

> For a given industry, more profitable firms – those able to generate higher returns per dollar of equity ("ROE") – should have higher market-to-book ratios. Conversely, firms which are unable to generate returns in excess of their cost of equity ("K") should sell for less than book value.

Profitability	*Value*
If ROE > K	*then Market/Book > 1*
If ROE = K	*then Market/Book =1*
If ROE < K	*then Market/Book < 1*

To assess the relationship by industry, as suggested above, I performed a regression study between estimated return on equity ("ROE") and market-to-book ratios using natural gas distribution, electric utility and water utility companies. I used all companies in these three industries that are covered by *Value Line* and have estimated ROE and market-to-book ratio data. The results are presented in Panels A-C of Exhibit JRW-6. The average R-squares for the electric, gas, and water companies are 0.52, 0.71, and 0.77, respectively.[7] This demonstrates the strong positive relationship between ROEs and market-to-book ratios for public utilities.

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[6] Benjamin Esty, "A Note on Value Drivers," Harvard Business School, Case No. 9-297-082, April 7, 1997.

[7] R-square measures the percent of variation in one variable (e.g., market-to-book ratios) explained by another variable (e.g., expected ROE). R-squares vary between zero and 1.0, with values closer to 1.0 indicating a higher relationship between two variables.

Q. WHAT ECONOMIC FACTORS HAVE AFFECTED THE COST OF EQUITY CAPITAL FOR PUBLIC UTILITIES?

A. Exhibit JRW-7 provides indicators of public utility equity cost rates over the past decade. Page 1 shows the yields on long-term ‘A’ rated public utility bonds. These yields peaked in the early 2000s at over 8.0%, declined to about 5.5% in 2005, and rose to 6.0% in 2006 and 2007. They stayed in that 6.0% range until the third quarter of 2008 when they spiked to almost 7.5% during the financial crisis. They hovered in the 4.0% area for most of the past year, but have increased to the 4.75% range in the last two months.

Page 2 of Exhibit JRW-7 provides the dividend yields for the Electric Proxy Group over the past decade. The dividend yields for the Electric Proxy Group generally declined slightly over the decade until 2007. They increased in 2008 and 2009 in response to the financial crisis, but declined in the last three years and now are about 4.2%.

Average earned returns on common equity and market-to-book ratios for the group are on page 3 of Exhibit JRW-7. The average earned returns on common equity for the Electric Proxy Group were in the 9.0%-12.0% range over the past decade, and have hovered in the 10.0% range for the past three years. The average market-to-book ratio for the group has been in the 1.20X to 1.80X during the decade. The average declined to about 1.20X in 2009, but has since increased to 1.40X as of 2012.

Q. WHAT FACTORS DETERMINE INVESTORS' EXPECTED OR REQUIRED RATE OF RETURN ON EQUITY?

A. The expected or required rate of return on common stock is a function of market-wide as well as company-specific factors. The most important market factor is the time value of money as indicated by the level of interest rates in the economy. Common stock investor requirements generally increase and decrease with like changes in interest rates. The perceived risk of a firm is the predominant factor that influences investor return requirements on a company-specific basis. A firm's investment risk is often separated into business and financial risk. Business risk encompasses all factors that affect a firm's operating revenues and expenses. Financial risk results from incurring fixed obligations in the form of debt in financing its assets.

Q. HOW DOES THE INVESTMENT RISK OF UTILITIES COMPARE WITH THAT OF OTHER INDUSTRIES?

A. Due to the essential nature of their service as well as their regulated status, public utilities are exposed to a lesser degree of business risk than other, non-regulated businesses. The relatively low level of business risk allows public utilities to meet much of their capital requirements through borrowing in the financial markets, thereby incurring greater than average financial risk. Nonetheless, the overall investment risk of public utilities is below most other industries.

Exhibit JRW-8 provides an assessment of investment risk for 100 industries as measured by beta, which according to modern capital market theory, is the only relevant measure of investment risk. These betas come from the *Value Line*

Investment Survey and are compiled annually by Aswath Damodaran of New York University.[8] The study shows that the investment risk of utilities is very low. The average betas for electric, water, and gas utility companies are 0.73, 0.66, and 0.66, respectively. These are well below the *Value Line* average of 1.15. As such, the cost of equity for utilities is among the lowest of all industries in the U.S.

Q. HOW CAN THE EXPECTED OR REQUIRED RATE OF RETURN ON COMMON EQUITY CAPITAL BE DETERMINED?

A. The costs of debt and preferred stock are normally based on historical or book values and can be determined with a great degree of accuracy. The cost of common equity capital, however, cannot be determined precisely and must instead be estimated from market data and informed judgment. This return to the stockholder should be commensurate with returns on investments in other enterprises having comparable risks.

According to valuation principles, the present value of an asset equals the discounted value of its expected future cash flows. Investors discount these expected cash flows at their required rate of return that, as noted above, reflects the time value of money and the perceived riskiness of the expected future cash flows. As such, the cost of common equity is the rate at which investors discount expected cash flows associated with common stock ownership.

Models have been developed to ascertain the cost of common equity capital for a firm. Each model, however, has been developed using restrictive economic

[8] *Available* at http://www.stern.nyu.edu/~adamodar.

assumptions. Consequently, judgment is required in selecting appropriate financial valuation models to estimate a firm's cost of common equity capital, in determining the data inputs for these models, and in interpreting the models' results. All of these decisions must take into consideration the firm involved as well as current conditions in the economy and the financial markets.

Q. HOW DO YOU PLAN TO ESTIMATE THE COST OF EQUITY CAPITAL FOR THE COMPANY?

A. I rely primarily on the discounted cash flow ("DCF") model to estimate the cost of equity capital. Given the investment valuation process and the relative stability of the utility business, I believe that the DCF model provides the best measure of equity cost rates for public utilities. It is my experience that this Commission has traditionally relied on the DCF method. I have also performed a capital asset pricing model ("CAPM") study, but I give these results less weight because I believe that risk premium studies, of which the CAPM is one form, provide a less reliable indication of equity cost rates for public utilities.

B. DCF ANALYSIS

Q. DESCRIBE THE THEORY BEHIND THE TRADITIONAL DCF MODEL.

A. According to the DCF model, the current stock price is equal to the discounted value of all future dividends that investors expect to receive from investment in the firm. As such, stockholders' returns ultimately result from current as well as future dividends. As owners of a corporation, common stockholders are entitled to a *pro* *rata* share of the firm's earnings. The DCF model presumes that earnings that are not paid out in the form of dividends are reinvested in the firm so as to provide for future growth in earnings and dividends. The rate at which investors discount future dividends, which reflects the timing and riskiness of the expected cash flows, is interpreted as the market's expected or required return on the common stock. Therefore, this discount rate represents the cost of common equity. Algebraically, the DCF model can be expressed as:

$$P = \frac{D_1}{(1+k)^1} + \frac{D_2}{(1+k)^2} + \ldots \frac{D_n}{(1+k)^n}$$

where P is the current stock price, D_n is the dividend in year n, and k is the cost of common equity.

Q. IS THE DCF MODEL CONSISTENT WITH VALUATION TECHNIQUES EMPLOYED BY INVESTMENT FIRMS?

A. Yes. Virtually all investment firms use some form of the DCF model as a valuation technique. One common application for investment firms is called the three-stage DCF or dividend discount model ("DDM"). The stages in a three-stage DCF model are presented in Exhibit JRW-9. This model presumes that a company's dividend payout progresses initially through a growth stage, then proceeds through a transition stage, and finally assumes a steady-state stage. The dividend-payment stage of a firm depends on the profitability of its internal investments, which, in turn, is largely a function of the life cycle of the product or service.

1. Growth stage: Characterized by rapidly expanding sales, high profit margins, and abnormally high growth in earnings per share. Because of highly profitable expected investment opportunities, the payout ratio is low. Competitors are attracted by the unusually high earnings, leading to a decline in the growth rate.

2. Transition stage: In later years, increased competition reduces profit margins and earnings growth slows. With fewer new investment opportunities, the company begins to pay out a larger percentage of earnings.

3. Maturity (steady-state) stage: Eventually, the company reaches a position where its new investment opportunities offer, on average, only slightly attractive ROEs. At that time, its earnings growth rate, payout ratio, and ROE stabilize for the remainder of its life. The constant-growth DCF model is appropriate when a firm is in the maturity stage of the life cycle.

In using this model to estimate a firm's cost of equity capital, dividends are projected into the future using the different growth rates in the alternative stages, and then the equity cost rate is the discount rate that equates the present value of the future dividends to the current stock price.

Q. HOW DO YOU ESTIMATE STOCKHOLDERS' EXPECTED OR REQUIRED RATE OF RETURN USING THE DCF MODEL?

A. Under certain assumptions, including a constant and infinite expected growth rate, and constant dividend/earnings and price/earnings ratios, the DCF model can be simplified to the following:

$$P = \frac{D_1}{k - g}$$

where D_1 represents the expected dividend over the coming year and g is the expected growth rate of dividends. This is known as the constant-growth version of the DCF model. To use the constant-growth DCF model to estimate a firm's cost of equity, one solves for k in the above expression to obtain the following:

$$k = \frac{D_1}{P} + g$$

Q. IN YOUR OPINION, IS THE CONSTANT-GROWTH DCF MODEL APPROPRIATE FOR PUBLIC UTILITIES?

A. Yes. The economics of the public utility business indicate that the industry is in the steady-state or constant-growth stage of a three-stage DCF. The economics include the relative stability of the utility business, the maturity of the demand for public utility services, and the regulated status of public utilities (especially the fact that their returns on investment are effectively set through the ratemaking process). The DCF valuation procedure for companies in this stage is the constant-growth DCF. In the constant-growth version of the DCF model, the current dividend payment and stock price are directly observable. However, the primary problem and controversy in applying the DCF model to estimate equity cost rates entails estimating investors' expected dividend growth rate.

Q. WHAT FACTORS SHOULD ONE CONSIDER WHEN APPLYING THE DCF METHODOLOGY?

A. One should be sensitive to several factors when using the DCF model to estimate a firm's cost of equity capital. In general, one must recognize the assumptions under which the DCF model was developed in estimating its components (the dividend yield and expected growth rate). The dividend yield can be measured precisely at any point in time, but tends to vary somewhat over time. Estimation of expected growth is considerably more difficult. One must consider recent firm performance, in conjunction with current economic developments and other information available to investors, to accurately estimate investors' expectations.

Q. WHAT DIVIDEND YIELDS ARE YOU EMPLOYING IN YOUR DCF ANALYSIS FOR THE PROXY GROUPS?

A. The dividend yields on the common stock for the companies in the proxy groups are provided on page 2 of Exhibit JRW-10 for the six-month period ending June 2013. For the DCF dividend yields for the group, I normally use the median of the six-month and June 2013 dividend yields. However, as previously noted, interest rates and capital costs have changed in the last two months. This is reflected in the dividend yields for the Electric and Hevert Proxy Groups, which increased by 0.4% and 0.6%, respectively, over the May to June time period. As a result, I am using the June 2013 dividend yields for both proxy groups. Therefore, I am using dividend yields of 4.1% and 4.2% for the Electric and Hevert Proxy Groups, respectively.

Q. PLEASE DISCUSS THE APPROPRIATE ADJUSTMENT TO THE SPOT DIVIDEND YIELD.

A. According to the traditional DCF model, the dividend yield term relates to the dividend yield over the coming period. As indicated by Professor Myron Gordon, who is commonly associated with the development of the DCF model for popular use, this is obtained by: (1) multiplying the expected dividend over the coming quarter by 4, and (2) dividing this dividend by the current stock price to determine the appropriate dividend yield for a firm that pays dividends on a quarterly basis.[9]

In applying the DCF model, some analysts adjust the current dividend for growth over the coming year as opposed to the coming quarter. This can be complicated because firms tend to announce changes in dividends at different times during the year. As such, the dividend yield computed based on presumed growth over the coming quarter as opposed to the coming year can be quite different. Consequently, it is common for analysts to adjust the dividend yield by some fraction of the long-term expected growth rate.

Q. GIVEN THIS DISCUSSION, WHAT ADJUSTMENT FACTOR WILL YOU USE FOR YOUR DIVIDEND YIELD?

A. I will adjust the dividend yield by one-half (1/2) the expected growth so as to reflect growth over the coming year. This is the approach employed by the Federal Energy

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[9] *Petition for Modification of Prescribed Rate of Return*, Federal Communications Commission, Docket No. 79-05, Direct Testimony of Myron J. Gordon and Lawrence I. Gould at 62 (April 1980).

Regulatory Commission ("FERC").[10] The DCF equity cost rate ("K") is computed as:

$$K = [(D/P) * (1 + 0.5g)] + g$$

Q. PLEASE DISCUSS THE GROWTH RATE COMPONENT OF THE DCF MODEL.

A. There is much debate as to the proper methodology to employ in estimating the growth component of the DCF model. By definition, this component is investors' expectation of the long-term dividend growth rate. Presumably, investors use some combination of historical and/or projected growth rates for earnings and dividends per share and for internal or book value growth to assess long-term potential.

Q. WHAT GROWTH DATA HAVE YOU REVIEWED FOR THE PROXY GROUPS?

A. I have analyzed a number of measures of growth for companies in the proxy group. I reviewed *Value Line's* historical and projected growth rate estimates for earnings per share ("EPS"), dividends per share ("DPS"), and book value per share ("BVPS"). In addition, I utilized the average EPS growth rate forecasts of Wall Street analysts as provided by Yahoo, Reuters and Zacks. These services solicit five-year earnings growth rate projections from securities analysts and compile and publish the means and medians of these forecasts. Finally, I also assessed prospective growth as

[10] Opinion No. 414-A, *Transcontinental Gas Pipe Line Corp.*, 84 FERC ¶61,084 (1998).

measured by prospective earnings retention rates and earned returns on common equity.

Q. PLEASE DISCUSS HISTORICAL GROWTH IN EARNINGS AND DIVIDENDS AS WELL AS INTERNAL GROWTH.

A. Historical growth rates for EPS, DPS, and BVPS are readily available to investors and are presumably an important ingredient in forming expectations concerning future growth. However, one must use historical growth numbers as measures of investors' expectations with caution. In some cases, past growth may not reflect future growth potential. Also, employing a single growth rate number (for example, for five or ten years), is unlikely to accurately measure investors' expectations due to the sensitivity of a single growth rate figure to fluctuations in individual firm performance as well as overall economic fluctuations (i.e., business cycles). However, one must appraise the context in which the growth rate is being employed. According to the conventional DCF model, the expected return on a security is equal to the sum of the dividend yield and the expected long-term growth in dividends. Therefore, to best estimate the cost of common equity capital using the conventional DCF model, one must look to long-term growth rate expectations.

Internally generated growth is a function of the percentage of earnings retained within the firm (the earnings retention rate) and the rate of return earned on those earnings (the return on equity). The internal growth rate is computed as the retention rate times the return on equity. Internal growth is significant in determining long-run earnings and, therefore, dividends. Investors recognize the importance of internally generated growth and pay premiums for stocks of companies that retain earnings and earn high returns on internal investments.

Q. PLEASE DISCUSS THE SERVICES THAT PROVDE ANALYSTS' EPS FORECASTS.

A. Analysts' EPS forecasts for companies are collected and published by a number of different investment information services, including Institutional Brokers Estimate System ("I/B/E/S"), Bloomberg, FactSet, Zacks, First Call and Reuters, among others. Thompson Reuters publishes analysts' EPS forecasts under different product names, including I/B/E/S, First Call, and Reuters. Bloomberg, FactSet, and Zacks publish their own set of analysts' EPS forecasts for companies. These services do not reveal: (1) the analysts who are solicited for forecasts; or (2) the identity of the analysts who actually provide the EPS forecasts that are used in the compilations published by the services. I/B/E/S, Bloomberg, FactSet, and First Call are fee-based services. These services usually provide detailed reports and other data in addition to analysts' EPS forecasts. Thompson Reuters and Zacks do provide limited EPS forecasts data free-of-charge on the internet. Yahoo finance (http://finance.yahoo.com) lists Thompson Reuters as the source of its summary EPS forecasts. The Reuters website (www.reuters.com) also publishes EPS forecasts from Thompson Reuters, but with more detail. Zacks (www.zacks.com) publishes its summary forecasts on its website. Zack's estimates are also available on other websites, such as msn.money (http://money.msn.com).

Q. PLEASE PROVIDE AN EXAMPLE OF THESE EPS FORECASTS.

A. The following example provides the EPS forecasts compiled by Reuters for Alliant Energy Corp. (stock symbol "LNT"). The figures are provided on page 2 of Exhibit JRW-9. The top line shows that five analysts have provided EPS estimates for the quarter ending September 30, 2013. The mean, high and low estimates are \$1.42, \$1.74, and \$1.29, respectively. The second line shows the quarterly EPS estimates for the quarter ending December 31, 2013 of 0.50 (mean), 0.63 (high), and 0.20(low). Lines three and four show the annual EPS estimates for the fiscal years ending December 2013 of 3.13 (mean), 3.20 (high), and 3.08 (low) and December 2014 of 3.30 (mean), 3.35 (high), and 3.25 (low). The quarterly and annual EPS forecasts in lines 1-4 are expressed in dollars and cents. As in the LNT case shown here, it is common for more analysts to provide estimates of annual EPS as opposed to quarterly EPS. The bottom line shows the projected long-term EPS growth rate, which is expressed as a percentage. For LNT, four analysts have provided long-term EPS growth rate forecasts, with mean, high and low growth rates of 5.93%, 7.00%, and 4.70%, respectively.

Q. WHICH OF THESE EPS FORECASTS IS USED IN DEVELOPING A DCF GROWTH RATE?

A. The DCF growth rate is the long-term projected growth rate in EPS, DPS, and BVPS. Therefore, in developing an equity cost rate using the DCF model, the projected long-term growth rate is the projection used in the DCF model.

Q. WHY ARE YOU NOT RELYING EXCLUSIVELY ON THE EPS FORECASTS OF WALL STREET ANALYSTS IN ARRIVING AT A DCF GROWTH RATE FOR THE PROXY GROUPS?

A. There are several issues with using the EPS growth rate forecasts of Wall Street analysts as DCF growth rates. First, the appropriate growth rate in the DCF model is the dividend growth rate, not the earnings growth rate. Nonetheless, over the very long-term, dividend and earnings will have to grow at a similar growth rate. Therefore, consideration must be given to other indicators of growth, including prospective dividend growth, internal growth, as well as projected earnings growth. Second, a recent study by Lacina, Lee, and Xu (2011) has shown that analysts' long-term earnings growth rate forecasts are not more accurate at forecasting future earnings than naïve random walk forecasts of future earnings.[11] Employing data over a twenty year period, these authors demonstrate that using the most recent year's EPS figure to forecast EPS in the next 3-5 years proved to be just as accurate as using the EPS estimates from analysts' long-term earnings growth rate forecasts. In the authors' opinion, these results indicate that analysts' long-term earnings growth rate forecasts should be used with caution as inputs for valuation and cost of capital purposes. Finally, and most significantly, it is well known that the long-term EPS growth rate forecasts of Wall Street securities analysts are overly optimistic and upwardly biased. This has been demonstrated in a number of academic studies over the years. This issue is discussed at length in Appendix B, which is attached in

[11] M. Lacina, B. Lee & Z. Xu, *Advances in Business and Management Forecasting (Vol. 8)*, Kenneth D. Lawrence, Ronald K. Klimberg (ed.), Emerald Group Publishing Limited, pp.77-101.

Exhibit JRW-16 of this testimony. Hence, using these growth rates as a DCF growth rate will provide an overstated equity cost rate. On this issue, a study by Easton and Sommers (2007) found that optimism in analysts' growth rate forecasts leads to an upward bias in estimates of the cost of equity capital of almost 3.0 percentage points.[12]

Q. IS IT YOUR OPINION THAT STOCK PRICES REFLECT THE UPWARD BIAS IN THE EPS GROWTH RATE FORECASTS?

A. Yes, I do believe that investors are well aware of the bias in analysts' EPS growth rate forecasts, and therefore, stock prices reflect the upward bias.

Q. HOW DOES THAT AFFECT THE USE OF THESE FORECASTS IN A DCF EQUITY COST RATE STUDY?

A. According to the DCF model, the equity cost rate is a function of the dividend yield and expected growth rate. Since stock prices reflect the bias, it would affect the dividend yield. In addition, the DCF growth rate needs to be adjusted downward from the projected EPS growth rate to reflect the upward bias.

Q. PLEASE DISCUSS THE HISTORICAL GROWTH OF THE COMPANIES IN THE PROXY GROUPS AS PROVIDED BY *VALUE LINE*.

A. Page 3 of Exhibit JRW-10 provides the 5- and 10-year historical growth rates for the companies in the two proxy groups, as published in the *Value Line Investment Survey*.

[12] Peter D. Easton & Gregory A. Sommers, *Effect of Analysts' Optimism on Estimates of the Expected Rate of Return Implied by Earnings Forecasts*, 45 J. ACCT. RES. 983–1015 (2007).

As shown in Panel A, the historical growth measures in EPS, DPS, and BVPS for the Electric Proxy Group, as measured by the medians, range from 2.5% to 4.5%, with an average of 3.5%. For the Hevert Proxy Group in Panel B, the historical growth measures in EPS, DPS, and BVPS, as measured by the medians, range from -0.5% to 4.5%, with an average of 2.3%.

Q. PLEASE SUMMARIZE *VALUE LINE'S* PROJECTED GROWTH RATES FOR THE COMPANIES IN THE PROXY GROUPS.

A. *Value Line's* projections of EPS, DPS, and BVPS growth for the companies in the proxy groups are shown on page 4 of Exhibit JRW-10. As above, due to the presence of outliers, the medians are used in the analysis. For the Electric Proxy Group, as shown in Panel A, the medians range from 3.8% to 4.5%, with an average of 4.1%. For the Hevert Proxy Group, as shown in Panel B, the medians range from 3.5% to 5.0%, with an average of 4.2%.

Also provided on page 4 of Exhibit JRW-10 is prospective sustainable growth for the companies in the proxy groups as measured by *Value Line*'s average projected retention rate and return on shareholders' equity. As noted above, sustainable growth is a significant and primary driver of long-run earnings growth. For the Electric and Hevert Proxy Groups, the median prospective sustainable growth rates are 3.9% and 3.8%, respectively.

Q. PLEASE ASSESS GROWTH FOR THE PROXY GROUPS AS MEASURED BY ANALYSTS' FORECASTS OF EXPECTED 5-YEAR EPS GROWTH.

A. Yahoo, Zacks, and Reuters collect, summarize, and publish Wall Street analysts' long-term EPS growth rate forecasts for the companies in the proxy groups. These forecasts are provided for the companies in the proxy groups on page 5 of Exhibit JRW-10. The median of analysts' projected EPS growth rates for the Electric and Hevert Proxy Groups are 5.0% and 5.4%, respectively. Since there is considerable overlap in analyst coverage between the three services, and not all of the companies have forecasts from the different services, I have averaged the expected five-year EPS growth rates from the three services for each company to arrive at an expected EPS growth rate by company.

Q. PLEASE SUMMARIZE YOUR ANALYSIS OF THE HISTORICAL AND PROSPECTIVE GROWTH OF THE PROXY GROUPS.

A. Page 6 of Exhibit JRW-10 shows the summary DCF growth rate indicators for the proxy group.

The historical growth rate indicators for the Electric Proxy Group imply a baseline growth rate of 3.5%. The high end of the range for the Electric Proxy Group is 5.0%, which is the projected EPS growth rate of Wall Street analysts. The average of the historic, sustainable, and projected growth rate indicators is 4.1%, and the average of the sustainable and projected EPS growth rates is 4.3%. Focusing primarily on the sustainable and projected growth rate measures, and giving more weight to the projected EPS growth rates, I believe that an expected growth rate of 4.5% is appropriate for the Electric Proxy Group.

The historical growth rate indicators for the Hevert Proxy Group imply a baseline growth rate of 2.3%. The average of the projected EPS, DPS, and BVPS growth rates from *Value Line* is 4.2%. The average of the projected EPS growth rate of Wall Street analysts is 5.4% for the group. The average of the sustainable and projected growth rate indicators is 4.4%. Focusing primarily on the sustainable and projected growth rate measures, and giving more weight to the projected EPS growth rates, I believe that an expected growth rate of 4.5% to 5.0% is appropriate for the Hevert Proxy Group. Given these figures, I will use the mid-point of this range, 4.75%, as the DCF growth rate for the Hevert Proxy Group.

Q. BASED ON THE ABOVE ANALYSIS, WHAT ARE YOUR INDICATED COMMON EQUITY COST RATES FROM THE DCF MODEL FOR THE GROUP?

A. My DCF-derived equity cost rates for the groups are summarized on page 1 of Exhibit JRW-10. The results for my Electric Proxy Group is the 4.1% dividend yield, times the 1 and ½ growth adjustment of 1.0225, and the DCF growth rate of 4.50%, results in an Equity cost rate of 8.7%. The results for my Hevert Proxy Group is the 4.2%, dividend yield, times the 1 and ½ growth adjustment of 1.02375, and the DCF growth rate of 4.75% results in an Equity cost rate of 9.0%.

C. CAPM

Q. PLEASE DISCUSS THE CAPITAL ASSET PRICING MODEL ("CAPM").

A. The CAPM is a risk premium approach to gauging a firm's cost of equity capital. According to the risk premium approach, the cost of equity is the sum of the interest rate on a risk-free bond (R_f) and a risk premium (RP), as in the following:

$$k = R_f + RP$$

The yield on long-term Treasury securities is normally used as R_f. Risk premiums are measured in different ways. The CAPM is a theory of the risk and expected returns of common stocks. In the CAPM, two types of risk are associated with a stock: firm-specific risk or unsystematic risk, and market or systematic risk, which is measured by a firm's beta. The only risk that investors receive a return for bearing is systematic risk.

According to the CAPM, the expected return on a company's stock, which is also the equity cost rate (K), is equal to:

$$K = (R_f) + ß * [E(R_m) - (R_f)]$$

Where:

- K represents the estimated rate of return on the stock;
- $E(R_m)$ represents the expected return on the overall stock market. Frequently, the 'market' refers to the S&P 500;
- (R_f) represents the risk-free rate of interest;
- $[E(R_m) - (R_f)]$ represents the expected equity or market risk premium—the excess return that an investor expects to receive above the risk-free rate for investing in risky stocks; and
- *Beta*—(ß) is a measure of the systematic risk of an asset.

To estimate the required return or cost of equity using the CAPM requires three inputs: the risk-free rate of interest (R_f), the beta (ß), and the expected equity or market risk premium $[E(R_m) - (R_f)]$. R_f is the easiest of the inputs to measure – it is represented by the yield on long-term Treasury bonds. ß, the measure of systematic risk, is a little more difficult to measure because there are different opinions about what adjustments, if any, should be made to historical betas due to their tendency to regress to 1.0 over time. And finally, an even more difficult input to measure is the expected equity or market risk premium ($E(R_m) - (R_f)$). I will discuss each of these inputs below.

Q. PLEASE DISCUSS EXHIBIT JRW-11.

A. Exhibit JRW-11 provides the summary results for my CAPM study. Page 1 shows the results, and the following pages contain the supporting data.

Q. PLEASE DISCUSS THE RISK-FREE INTEREST RATE.

A. The yield on long-term U.S. Treasury bonds has usually been viewed as the risk-free rate of interest in the CAPM. The yield on long-term U.S. Treasury bonds, in turn, has been considered to be the yield on U.S. Treasury bonds with 30-year maturities.

Q. WHAT RISK-FREE INTEREST RATE ARE YOU USING IN YOUR CAPM?

A. As shown on page 2 of Exhibit JRW-11, the yield on 30-year Treasury bonds has been in the 2.5% to 4.0% range over 2012 – 2013 time period. These rates are currently in the 3.60% range. Given the recent range of yields, and the prospect of higher rates in the future, I will use 4.0%, as the risk-free rate, or R_f, in my CAPM.

Q. WHAT BETAS ARE YOU EMPLOYING IN YOUR CAPM?

A. Beta (ß) is a measure of the systematic risk of a stock. The market, usually taken to be the S&P 500, has a beta of 1.0. The beta of a stock with the same price movement as the market also has a beta of 1.0. A stock whose price movement is greater than that of the market, such as a technology stock, is riskier than the market and has a beta greater than 1.0. A stock with below average price movement, such as that of a regulated public utility, is less risky than the market and has a beta less than 1.0. Estimating a stock's beta involves running a linear regression of a stock's return on the market return.

As shown on page 3 of Exhibit JRW-11, the slope of the regression line is the stock's ß. A steeper line indicates the stock is more sensitive to the return on the overall market. This means that the stock has a higher ß and greater than average market risk. A less steep line indicates a lower ß and less market risk.

Several online investment information services, such as Yahoo and Reuters, provide estimates of stock betas. Usually these services report different betas for the same stock. The differences are usually due to: (1) the time period over which the ß is measured; and (2) any adjustments that are made to reflect the fact that betas tend to regress to 1.0 over time. In estimating an equity cost rate for the proxy group, I am using the betas for the companies as provided in the *Value Line Investment Survey*. As shown on page 3 of Exhibit JRW-11, the median beta for the companies in the Electric and Hevert Proxy Groups are 0.70 and 0.75, respectively.

Q. PLEASE DISCUSS THE ALTERNATIVE VIEWS REGARDING THE EQUITY RISK PREMIUM.

A. The equity or market risk premium - $(E(R_m) - R_f)$ - is equal to the expected return on the stock market (e.g., the expected return on the S&P 500 (E(R_m) minus the risk-free rate of interest (R_f)). The equity premium is the difference in the expected total return between investing in equities and investing in "safe" fixed-income assets, such as long-term government bonds. However, while the equity risk premium is easy to define conceptually, it is difficult to measure because it requires an estimate of the expected return on the market.

Q. PLEASE DISCUSS THE ALTERNATIVE APPROACHES TO ESTIMATING THE EQUITY RISK PREMIUM.

A. Page 4 of Exhibit JRW-11 highlights the primary approaches to, and issues in, estimating the expected equity risk premium. The traditional way to measure the equity risk premium was to use the difference between historical average stock and bond returns. In this case, historical stock and bond returns, also called ex post returns, were used as the measures of the market's expected return (known as the ex ante or forward-looking expected return). This type of historical evaluation of stock and bond returns is often called the "Ibbotson approach" after Professor Roger Ibbotson who popularized this method of using historical financial market returns as measures of expected returns. Most historical assessments of the equity risk premium suggest an equity risk premium of 5-7 percent above the rate on long-term U.S. Treasury bonds. However, this can be a problem because: (1) ex post returns are not the same as ex ante expectations; (2) market risk premiums can change over time, increasing when investors become more risk-averse and decreasing when investors become less risk-averse; and (3) market conditions can change such that ex post historical returns are poor estimates of ex ante expectations.

The use of historical returns as market expectations has been criticized in numerous academic studies as discussed later in my testimony. The general theme of these studies is that the large equity risk premium discovered in historical stock and bond returns cannot be justified by the fundamental data. These studies, which fall under the category "Ex Ante Models and Market Data," compute ex ante expected returns using market data to arrive at an expected equity risk premium. These studies have also been called "Puzzle Research" after the famous study by Mehra and

Prescott in which the authors first questioned the magnitude of historical equity risk premiums relative to fundamentals.[13]

In addition, there are a number of surveys of financial professionals regarding the equity risk premium. There have been several published surveys of academics on the equity risk premium. *CFO Magazine* conducts a quarterly survey of CFOs which includes questions regarding their views on the current expected returns on stocks and bonds. Usually over 300 CFOs usually participate in the survey.[14] Questions regarding expected stock and bond returns are also included in the Federal Reserve Bank of Philadelphia's annual survey of financial forecasters which is published as the *Survey of Professional Forecasters*.[15] This survey of professional economists has been published for almost 50 years. In addition, Pablo Fernandez conducts occasional surveys of financial analysts and companies regarding the equity risk premiums they use in their investment and financial decision-making.[16]

Q. PLEASE PROVIDE A SUMMARY OF THE EQUITY RISK PREMIUM STUDIES.

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[13] Rajnish Mehra & Edward C. Prescott, *The Equity Premium: A Puzzle*, J. MONETARY ECON. 145 (1985).

[14] *See*, www.cfosurvey.org.

[15] Federal Reserve Bank of Philadelphia, *Survey of Professional Forecasters*, (February 15, 2013). The *Survey of Professional Forecasters* was formerly conducted by the American Statistical Association ("ASA") and the National Bureau of Economic Research ("NBER") and was known as the ASA/NBER survey. The survey, which began in 1968, is conducted each quarter. The Federal Reserve Bank of Philadelphia, in cooperation with the NBER, assumed responsibility for the survey in June 1990.

[16] Pablo Fernandez, Javier Auirreamalloa, and Javier Corres, "Market Risk Premium and Risk Free Rate used for 51 countries in 2013: a survey with 6,237 answers," June 26, 2013.

A. Derrig and Orr (2003), Fernandez (2007), and Song (2007) have completed the most comprehensive reviews to date of the research on the equity risk premium.[17] Derrig and Orr's study evaluated the various approaches to estimating equity risk premiums as well as the issues with the alternative approaches and summarized the findings of the published research on the equity risk premium. Fernandez examined four alternative measures of the equity risk premium – historical, expected, required, and implied. He also reviewed the major studies of the equity risk premium and presented the summary equity risk premium results. Song provides an annotated bibliography and highlights the alternative approaches to estimating the equity risk summary.

Page 5 of Exhibit JRW-11 provides a summary of the results of the primary risk premium studies reviewed by Derrig and Orr, Fernandez, and Song, as well as other more recent studies of the equity risk premium. In developing page 5 of Exhibit JRW-11, I have categorized the studies as discussed on page 4 of Exhibit JRW-11. I have also included the results of the "Building Blocks" approach to estimating the equity risk premium, including a study I performed, which is presented in Appendix C, which is attached in Exhibit JRW-16. The Building Blocks approach is a hybrid approach employing elements of both historical and *ex ante* models.

Q. PLEASE DISCUSS PAGE 5 OF EXHIBIT JRW-11.

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[17] *See* Richard Derrig & Elisha Orr, "Equity Risk Premium: Expectations Great and Small," Working Paper (version 3.0), Automobile Insurers Bureau of Massachusetts, (August 28, 2003); Pablo Fernandez, "Equity Premium: Historical, Expected, Required, and Implied," IESE Business School Working Paper, (2007); Zhiyi Song, "The Equity Risk Premium: An Annotated Bibliography," CFA Institute, (2007).

A. Page 5 of JRW-11 provides a summary of the results of the equity risk premium studies that I have reviewed. These include the results of: (1) the various studies of the historical risk premium; (2) *ex ante* equity risk premium studies; (3) equity risk premium surveys of CFOs, Financial Forecasters, analysts, companies and academics; and (4) the Building Block approaches to the equity risk premium. There are results reported for over thirty studies and the median equity risk premium is 4.39%.

Q. PLEASE HIGHLIGHT THE RESULTS OF THE MORE RECENT RISK PREMIUM STUDIES AND SURVEYS?

A. The studies cited on page 5 of Exhibit JRW-11 include all equity risk premium studies and surveys I could identify that were published over the past decade and that provided an equity risk premium estimate. Most of these studies were published prior to the financial crisis of the past two years. In addition, some of these studies were published in the early 2000s at the market peak. It should be noted that many of these studies (as indicated) used data over long periods of time (as long as fifty years of data) and so they were not estimating an equity risk premium as of a specific point in time (e.g., the year 2001). To assess the effect of the earlier studies on the equity risk premium, on page 6 of Exhibit JRW-11, I have reconstructed page 5 of Exhibit JRW-11, but I have eliminated all studies dated before January 2, 2010. The median for this subset of studies is 4.51%.

Q. GIVEN THESE RESULTS, WHAT MARKET OR EQUITY RISK PREMIUM ARE YOU USING IN YOUR CAPM?

A. Much of the data indicates that the market risk premium is in the 4.5% to 5.5% range. I use the midpoint of this range, 5.0%, as the market or equity risk premium.

Q. IS YOUR *EX ANTE* EQUITY RISK PREMIUM CONSISTENT WITH THE EQUITY RISK PREMIUMS USED BY CFOS?

A. Yes. In the June, 2013 CFO survey conducted by *CFO Magazine* and Duke University, the expected 10-year equity risk premium was 4.2%.

Q. IS YOUR *EX ANTE* EQUITY RISK PREMIUM CONSISTENT WITH THE EQUITY RISK PREMIUMS OF PROFESSIONAL FORECASTERS?

A. Yes. The financial forecasters in the previously referenced Federal Reserve Bank of Philadelphia survey project both stock and bond returns. In the February, 2013 survey, the median long-term expected stock and bond returns were 6.13% and 3.83%, respectively. This provides an *ex ante* equity risk premium of 2.30% (6.13%-3.83%).

Q. IS YOUR *EX ANTE* EQUITY RISK PREMIUM CONSISTENT WITH THE EQUITY RISK PREMIUMS OF FINANCIAL ANALYSTS AND COMPANIES?

A. Yes. Pablo Fernandez recently published the results of a 2013 survey of academics, financial analysts and companies.[18] This survey included over 6,000 responses. The median equity risk premium employed by U.S. analysts and companies was 5.7%.

[18] Pablo Fernandez, Javier Auirreamalloa, and Javier Corres, “Market Risk Premium Used in 51 Countries in

Q. WHAT EQUITY COST RATE IS INDICATED BY YOUR CAPM ANALYSIS?

A. The results of my CAPM study for the proxy groups is summarized on page 1 of Exhibit JRW-11. For the Electric Proxy Group, the risk-free rate of 4.0% plus the beta of 0.70 times the equity risk premium of 5.0% results in 7.5% equity cost rate. For the Hevert Proxy Group, the risk-free rate of 4.0% plus the beta of 0.75 times the equity risk premium of 5.0% results in 7.8% equity cost rate.

D. EQUITY COST RATE SUMMARY

Q. PLEASE SUMMARIZE YOUR EQUITY COST RATE STUDY.

A. My DCF analyses for the Electric and Hevert Proxy Groups indicate equity cost rates of 8.7% and 9.0%, respectively. My CAPM analyses for the Electric and Hevert Proxy Groups indicate equity cost rates of 7.5% and 7.8%, respectively.

Q. GIVEN THESE RESULTS, WHAT IS YOUR ESTIMATED EQUITY COST RATE FOR THE GROUP?

A. Given these results, I conclude that the appropriate equity cost rate for companies in the Electric and Hevert Proxy Groups is in the 7.5% to 9.0% range. However, since I rely primarily on the DCF model, and given the recent upward movement in interest rates, I am using the upper end of the range as the equity cost rate. Therefore, I conclude that the appropriate equity cost rate, as determined by the companies in the proxy groups, is in the 8.7% to 9.0% range at this time.

2013: A survey with 6,237 Answers," June 26, 2013.

Q. GIVEN THIS RANGE, WHAT IS YOUR RECOMMENDED ROE FOR TAMPA ELECTRIC?

A. Given this range, I am recommending 9.0% as the equity cost rate for Tampa Electric using OPC's recommended capital structure of 50% long-term debt and 50% common equity. If the Commission adopts Tampa Electric's capital structure with a 54.2% common equity ratio, I recommend a ROE of 8.75% for Tampa Electric.

Q. PLEASE INDICATE WHY A 9.0% RETURN IS APPROPRIATE FOR TAMPA ELECTRIC AT THIS TIME.

A. There are several reasons why a 9.0% return on equity is appropriate for the Company in this case. First, as shown on in Exhibit JRW-8, the electric utility industry is *Value Line*'s one of the lowest risk industries in the U.S. as measured by beta. As such, the cost of equity capital for this industry is amongst the lowest in the U.S. according to the CAPM. Second, as shown in Exhibit JRW-3, capital costs for utilities, as indicated by long-term bond yields, are still at historically low levels, even given the increase in these rates over the past two months. Third, while the markets have recovered significantly over the past four years, the growth in the economy is tepid and unemployment is still at 7.6%. The slow economic growth is a major reason that interest rates and inflation are at relatively low levels, and hence the expected returns on financial assets remain low. Therefore, in my opinion, a 9.0% return is appropriate for a regulated electric utility.

VI. <u>CRITIQUE OF TAMPA ELECTRIC'S RATE OF RETURN TESTIMONY</u>

Q. PLEASE SUMMARIZE TAMPA ELECTRIC'S OVERALL RATE OF RETURN RECOMMENDATION.

A. Tampa Electric's return on equity recommendation is provided by Mr. Robert Hevert. Tampa Electric's overall rate of return recommendation is summarized on page 1 of Exhibit JRW-12. The Company's recommended capital structure from investor sources consists of 45.8% long-term debt and 54.2% common equity.

Q. WHAT ISSUES DO YOU HAVE WITH THE COMPANY'S COST OF CAPITAL POSITION?

A. The primary areas of disagreement in measuring Tampa Electric cost of capital are: (1) the Company's capital structure, and the ROE that is associated with the capital structure; (2) Mr. Hevert's excessive reliance on the earnings per share growth rate forecasts of Wall Street analysts and *Value Line* to measure expected DCF growth; and (3) the measurement and magnitude of the equity risk premium used in a CAPM approach and RP approaches.

A. CAPITAL STRUCTURE

Q. PLEASE REVIEW THE CAPITAL STRUCTURE ISSUE.

A. Tampa Electric has recommended a capital structure that includes a common equity ratio of 54.2%. Such a capital structure includes more equity and less debt than the capital structures of other electric utilities and Tampa Electric and its parent, TECO

Energy. As shown on page 1 of Exhibit JRW-4, the average common equity ratios for the Electric Proxy Group and TECO Energy are 46.2% and 43.6%, respectively. These ratios highlight the fact that proxy companies and TECO Energy have a higher degree of financial risk than Tampa Electric.

Q. HOW HAS MR. HEVERT ATTEMPTED TO DEFEND THE COMPANY'S PROPOSED EQUITY-HEAVY CAPITAL STRUCTURE?

A. Mr. Hevert has attempted to justify Tampa Electric's capital structure by computing the capital structure ratios for the operating companies (and not the holding companies) for the companies in his proxy group.

Q. PLEASE DISCUSS MR. HEVERT'S ANALYSIS OF THE CAPITALIZATIONS OF THE OPERATING COMPANIES OF HIS PROXY GROUP.

A. In Exhibit No. __ (RBH-1), Document No. 13, Mr. Hevert computes the capitalization ratios for the operating subsidiaries of the companies in his utility group. He claims that this analysis supports the Company's proposed capital structure with a 54.2% common equity ratio.

The major issue with Mr. Hevert's analysis is that the capital structure ratios that he uses are for the operating subsidiaries and not for the parent companies. The stocks of the parent companies trade in the markets. Mr. Hevert and I used the data for the parent companies to estimate an equity cost rate for the Company. The investment and financial risks of the parent companies that trade in the markets are a function of the overall capitalization of the parent companies, not the subsidiaries. As such, it is their capitalization ratios, which are indicative of the financial risk they are exposed to, that is relevant when making capitalization comparisons, not the operating subsidiaries.

B. EQUITY COST RATE

Q. PLEASE REVIEW MR. HEVERT'S EQUITY COST RATE APPROACHES.

A. Mr. Hevert estimates an equity cost rate for Tampa Electric using a proxy group of eleven electric utility companies and employs DCF, CAPM, and RP equity cost rate approaches.

Q. PLEASE SUMMARIZE MR. HEVERT'S EQUITY COST RATE RESULTS.

A. Mr. Hevert's equity cost rate estimates for Tampa Electric are summarized in Exhibit JRW-13. Based on these figures, he concludes that the appropriate equity cost rate is in the range of 10.5% to 11.5%. He has recommended an 11.25% as an equity cost rate in its rate filing.

Q. PLEASE DISCUSS YOUR ISSUES WITH MR. HEVERT'S REQUESTED EQUITY COST RATE.

A. Mr. Hevert's requested return on common equity is too high primarily due to: (1) his asymmetric elimination of low-end DCF results; (2) the DCF growth rate, and in particular the use of (a) the earnings per share growth rates of Wall Street analysts and *Value Line*; and (3) the measurement and magnitude of the market risk premium used in CAPM and RP approaches.

Q. PLEASE INITIALLY REVIEW MR. HEVERT'S PROXY GROUP.

A. Mr. Hevert has used a group of eleven electric utility companies. My Electric Proxy Group includes all of the companies with the exception of Empire District ("EDE") and Otter Tail ("OTTR"). I have excluded EDE because the company, in response to tornadoes in its service territory, suspended its dividend in 2011 and cut its dividend when it subsequently reinitiated the dividend in 2012. I have excluded OTTR because the Company has bonds with below investment grade ratings. Nonetheless, I have included and used an analysis of the Hevert Proxy Group in my equity cost rate analysis.

1. DCF Approach

Q. PLEASE SUMMARIZE MR. HEVERT'S DCF ESTIMATES.

A. On pages 21-27 of his testimony and in Document No. 2 of Exhibit No. ___ (RBH)-1, Mr. Hevert develops an equity cost rate by applying the DCF model to his group of electric companies. Mr. Hevert's DCF results are summarized in Panel A of Exhibit JRW-13. Mr. Hevert uses three dividend yield measures (30, 90, and 180 days) and reports DCF equity cost rates using the Mean and Median Low, Mean/Median, and High DCF results. He adjusts his dividend yield by ½ the expected growth rate. Mr. Hevert has relied on the forecasted EPS growth rates of Zacks, First Call, and *Value Line*.

Q. WHAT ARE THE ERRORS IN MR. HEVERT'S DCF ANALYSES?

A. The primary issues in Mr. Hevert's DCF analyses are: (1) The asymmetric elimination of low-end DCF results - he has ignored the mean low DCF results for his three different DCF model applications; and (2) The use of the EPS growth rate forecasts of Wall Street analysts and *Value Line* - the DCF growth rates in all three models employ the overly optimistic and upwardly-biased EPS growth rate estimates of Wall Street analysts and *Value Line.*

Q. PLEASE ADDRESS MR. HEVERT'S ASYMMETRIC ELIMINATION OF DCF RESULTS.

A. A significant error with Mr. Hevert's DCF equity cost rate analyses is that he has ignored the mean low DCF results because he claims they are too low. In other words, he has ignored 1/3 of his DCF results in establishing a range of equity cost rates for his proxy group. Mr. Hevert claims that his DCF approach produces a ROE range of 10.6% to 13.19%. By eliminating so-called low-end outliers and not also eliminating the same number of high-end outliers, Mr. Hevert biases his DCF equity cost rate study and reports a higher DCF equity cost rate than the data indicate. I have used the median as a measure of central tendency so as to not give outlier results too much weight while not ignoring the impact of low and/or high results in determining a measure of central tendency.

Q. PLEASE REVIEW MR. HEVERT'S DCF GROWTH RATE.

A. In his DCF model, Mr. Hevert's DCF growth rate is the average of the projected EPS growth rate forecasts: (1) Wall Street analysts as compiled by Zacks and First Call; and (2) *Value Line.*

Q. WHY IS IT ERRONEOUS TO RELY EXCLUSIVELY ON THE EPS FORECASTS OF WALL STREET ANALYSTS IN ARRIVING AT A DCF GROWTH RATE?

A. A very significant issue with Mr. Hevert's DCF analysis is his sole reliance on the EPS growth rate forecasts of Wall Street analysts and *Value Line*. There are several issues with using these forecasts as DCF growth rates. First, the relevant cash flows are dividends in the DCF model. Therefore, the appropriate growth rate in the DCF model is the dividend growth rate, not the earnings growth rate. Hence, in my opinion, consideration must be given to other indicators of growth, including prospective dividend growth, internal growth, as well as projected earnings growth. Second, and most significantly, it is well-known that the long-term EPS growth rate forecasts of Wall Street securities analysts are overly optimistic and upwardly biased. This has been demonstrated in a number of academic studies over the years. In addition, I demonstrate that *Value Line*'s EPS growth rate forecasts are consistently too high. Hence, using these growth rates as a DCF growth rate will provide an overstated equity cost rate.

Q. PLEASE DISCUSS MR. HEVERT'S RELIANCE ON THE PROJECTED GROWTH RATES OF WALL STREET ANALYSTS AND *VALUE LINE.*

A. It seems highly unlikely that investors today would rely excessively on the EPS growth rate forecasts of Wall Street analysts and ignore other growth rate measures in arriving at expected growth. As I previously indicated, the appropriate growth rate in the DCF model is the dividend growth rate, not the earnings growth rate. Hence, consideration must be given to other indicators of growth, including historic growth prospective dividend growth, internal growth, as well as projected earnings growth. In addition, a recent study by Lacina, Lee, and Xu (2011) has shown that analysts' long-term earnings growth rate forecasts are not more accurate at forecasting future earnings than naïve random walk forecasts of future earnings.[19] As such, the weight given to analysts' projected EPS growth rate should be limited. And finally, and most significantly, it is well-known that the long-term EPS growth rate forecasts of Wall Street securities analysts are overly optimistic and upwardly biased. Hence, using these growth rates as a DCF growth rate produces an overstated equity cost rate. A recent study by Easton and Sommers (2007) found that optimism in analysts' growth rate forecasts leads to an upward bias in estimates of the cost of equity capital of almost 3.0 percentage points.[20] These issues are addressed in more detail in Appendix B, which is attached in Exhibit JRW-16 of this testimony.

2. CAPM Approach

[19] M. Lacina, B. Lee and Z. Xu, *Advances in Business and Management Forecasting (Vol. 8),* Kenneth D. Lawrence, Ronald K. Klimberg (ed.), Emerald Group Publishing Limited, pp.77-101.

[20] Easton, P., & Sommers, G. (2007). Effect of analysts' optimism on estimates of the expected rate of return implied by earnings forecasts. *Journal of Accounting Research*, 45(5), 983–1015.

Q. PLEASE DISCUSS MR. HEVERT'S CAPM.

A. On pages 27-36 of his testimony and in Documents Nos. 3-5 of Exhibit No. ___ (RBH)-1, Mr. Hevert estimates an equity cost rate by applying a CAPM model to his proxy group of electric utility companies. The CAPM approach requires an estimate of the risk-free interest rate, beta, and the equity risk premium. Mr. Hevert uses three different measures of the risk-free interest rate (a current rate of 3.12%, a near-term projected rate of 3.25%, and a long-term projected rate of 5.10%), two different Betas (an average Bloomberg Beta of 0.714 and an average *Value Line* Beta of 0.718) and three market risk premium measures (a Bloomberg, DCF-derived market risk premium of 9.88%, a Capital IQ, DCF-derived market risk premium of 9.81%, and a Sharpe ratio premium of 6.03%). Based on these figures, he finds a CAPM equity cost rate range from 7.42% to 12.15%.

Q. WHAT ARE THE ERRORS IN MR. HEVERT'S CAPM ANALYSIS?

A. There are three primary errors: (1) he has effectively ignored the low-end results of his CAPM; (2) his long-term projected 30-year Treasury yield of 5.10% is about 200 basis points above current rates and is unrealistic; and (3) the measurement and magnitude of the three market risk premium measures.

Q. PLEASE ASSESS MR. HEVERT'S MARKET RISK PREMIUM DERIVED FROM APPLYING THE DCF MODEL TO THE S&P 500.

A. For his Bloomberg and Capital IQ market risk premiums, Mr. Hevert computes market risk premiums of 9.88% and 9.81% by: (1) calculating an expected market return by applying the DCF model to the S&P 500; and (2) subtracting the current 30-year Treasury bond yield. Mr. Hevert's estimated expected market returns from these approaches of 12.93% (using Bloomberg long-term EPS growth rate estimates) and of 12.87% (using Capital IQ long-term EPS growth rate estimates), are not realistic. He uses (1) a dividend yield of 1.93% and an expected DCF growth rate of 10.44% for Bloomberg and (2) a dividend yield of 2.02% and an expected DCF growth rate of 10.76% for Capital IQ. The primary error is that the expected DCF growth rate is the projected 5-year EPS growth rate from Wall Street analysts as reported by these two services. As explained below, this produces an overstated expected market return and equity risk premium.

Q. WHAT EVIDENCE CAN YOU PROVIDE THAT MR. HEVERT'S GROWTH RATES ARE ERRONEOUS?

A. Mr. Hevert's expected long-term EPS growth rates of 10.88% for Bloomberg and 10.93% for Capital IQ represent the forecasted 5-year EPS growth rates of Wall Street analysts. The error with this approach is that the EPS growth rate forecasts of Wall Street securities analysts are overly optimistic and upwardly biased. This is detailed at length in Appendix B, which is attached in Exhibit JRW-16 of this testimony.

Q. ARE EPS GROWTH RATES OF 10.88% AND 10.93% CONSISTENT WITH THE HISTORIC AND PROJECTED GROWTH IN EARNINGS AND THE ECONOMY?

A. No. Long-term EPS growth rates of 10.88% and 10.93% are not consistent with historic as well as projected economic and earnings growth in the U.S for several reasons: (1) long-term growth in EPS is far below Mr. Hevert's projected EPS growth rates; (2) more recent trends in GDP growth, as well as projections of GDP growth, suggest slower long-term economic and earnings growth in the future; and (3) over time, EPS growth tends to lag behind GDP growth.

The long-term economic, earnings, and dividend growth rate in the U.S. has only been in the 5% to 7% range. I performed a study of the growth in nominal GDP, S&P 500 stock price appreciation, and S&P 500 EPS and DPS growth since 1960. The results are provided on page 1 of Exhibit JRW-14, and a summary is provided for 1960 to present: nominal GDP of 6.74%; S&P 500 stock price of 6.35%; S&P 500 EPS of 6.96%; S&P 500 DPS of 5.39%; with an average of 6.36%. The results are presented graphically on page 2 of Exhibit JRW-14. In sum, the historical long-run growth rates for GDP, S&P EPS, and S&P DPS are in the 5% to 7% range. By comparison, Mr. Hevert's long-run growth rate projections of 10.88% and 10.93% are vastly overstated. These estimates suggest that companies in the U.S. would be expected to: (1) increase their growth rates of EPS by over 50% in the future and (2) maintain that growth indefinitely in an economy that is expected to grow at about one-half of his projected growth rates.

Q. DO MORE RECENT DATA SUGGEST THAT THE U.S. ECONOMY GROWTH IS FASTER OR SLOWER THAN THE LONG-TERM DATA?

A. The more recent trends suggest lower future economic growth than the long-term historic GDP growth. The historic GDP growth rates for 10-, 20-, 30-, 40- and 50-years, as presented in Panel A of page 3 of Exhibit JRW-14, clearly suggest that nominal GDP growth in recent decades has slowed to the 4.0% to 5.0% area.

Q. WHAT LEVEL OF GDP GROWTH IS FORECASTED BY ECONOMISTS AND GOVERNMENT AGENCIES?

A. As shown in Panel B of page 3 of Exhibit JRW-14, forecasts of annual GDP growth from the *Survey of Professional Forecasters* (4.8%), the Energy Information Administration (4.5%), and the Congressional Budget Office (4.6%), suggests GDP growth in the range of 4.0% to 5.0% is more appropriate today for the U.S. economy.

Q. WHY IS GDP GROWTH RELEVANT IN YOUR DISCUSSION OF MR. HEVERT'S USE OF THE LONG-TERM EPS GROWTH RATES IN DEVELOPING A MARKET RISK PREMIUM FOR HIS CAPM?

A. Because, as indicated in recent research, the long-term earnings growth rates of companies are limited to the growth rate in GDP.

Q. PLEASE HIGHLIGHT THE RECENT RESEARCH ON THE LINK BETWEEN ECONOMIC AND EARNINGS GROWTH AND EQUITY RETURNS.

A. Brad Cornell of the California Institute of Technology recently published a study on GDP growth, earnings growth, and equity returns. He finds that long-term EPS growth in the U.S. is directly related GDP growth, with GDP growth providing an upward limit on EPS growth. In addition, he finds that long-term stock returns are determined by long-term earnings growth. He concludes with the following observations:[21]

> The long-run performance of equity investments is fundamentally linked to growth in earnings. Earnings growth, in turn, depends on growth in real GDP. This article demonstrates that both theoretical research and empirical research in development economics suggest relatively strict limits on future growth. In particular, real GDP growth in excess of 3 percent in the long run is highly unlikely in the developed world. In light of ongoing dilution in earnings per share, this finding implies that investors should anticipate real returns on U.S. common stocks to average no more than about 4–5 percent in real terms.

Given current inflation in the 2% to 3% range, the results imply nominal expected stock market returns in the 7% to 8% range. As such, Mr. Hevert's projected earnings growth rates and implied expected stock market returns and equity risk premiums are not indicative of the realities of the U.S. economy and stock market. As such, his expected CAPM equity cost rate is significantly overstated.

Q. PLEASE PROVIDE A SUMMARY ASSESSMENT OF MR. HEVERT'S PROJECTED EQUITY RISK PREMIUM DERIVED FROM EXPECTED MARKET RETURNS.

A. Mr. Hevert's market risk premium derived from his DCF application to the S&P 500 is inflated due to errors and bias in his study. Investment banks, consulting firms, and CFOs use the equity risk premium concept every day in making financing, investment,

[21] Bradford Cornell, "Economic Growth and Equity Investing," *Financial Analysts Journal* (January-February, 2010), p. 63.

and valuation decisions. On this issue, the opinions of CFOs and financial forecasters are especially relevant. CFOs deal with capital markets on an ongoing basis since they must continually assess and evaluate capital costs for their companies. They are well aware of the historical stock and bond return studies of Ibbotson. The CFOs in the June 2013 *CFO Magazine* – Duke University Survey of over almost 350 CFOs shows an expected return on the S&P 500 of 6.7% over the next ten years. In addition, the financial forecasters in the February 2013 Federal Reserve Bank of Philadelphia survey expect an annual market return of 6.15% over the next ten years. As such, with a more realistic equity or market risk premium, the appropriate equity cost rate for a public utility should be in the 8.0% to 9.0% range and not in the 10.0% to 11.0% range.

Q. PLEASE REVIEW MR. HEVERT'S SECOND MARKET RISK PREMIUM.

A. Mr. Hevert's second market risk premium of 6.03% uses the Sharpe Ratio, and calculates the expected market risk premium based on a comparison of historical and expected market volatility. The Sharpe Ratio is computed as:

$$S(X) = (R_x - R_f)/Std\ Dev\ (X)$$

where:

X = the investment;
R_x = the average return of X;
R_f = the best available rate of return of a risk free security; and
$Std\ Dev$ = the standard deviation of r_x.

Mr. Hevert defines the constant Sharpe Ratio as the ratio of the historical market risk premium of 6.60% and the historical market volatility of 20.30%. These figures are computed using the Morningstar historical stock and bond market data and use arithmetic mean returns. He then calculates the expected market risk premium as the product of the Sharpe Ratio and the expected market volatility. Mr. Hevert computes the expected market volatility as the thirty-day average of the Chicago Board Options Exchange's ("CBOE") three-month volatility index (*i.e.*, the VXV) and the same thirty-day average of settlement prices of futures on the CBOE's one-month volatility index (*i.e.*, the VIX) for July 2013 through September 2013. Mr. Hevert used a "VIX" volatility measure of 18.54.

Q. PLEASE DISCUSS THE VIX.

A. The VIX is the stock ticker symbol for the Chicago Board Options Exchange Market Volatility Index. The VIX, which is quoted as a percentage, is a measure of the implied volatility of S&P 500 index options for the next 30 day period. Higher levels of the VIX imply that investors expect larger market upward or downward movements in the next 30 days.

Panel A of page 1 of Exhibit JRW-15 shows the historic levels of the VIX since 1990. The data indicate that the current level of the VIX, about 16.0, is lower than historic norms. Panel B of page 1 of Exhibit JRW-15 shows the VIX over the past year. The VIX peaked at about 22 at year-end 2012 during the debate over the fiscal cliff. The VIX has increased in the past month in response to concerns about prospective Federal Reserve monetary policy. Panel C of page 1 of Exhibit JRW-15 shows the VXV over the past year. The VXV movement has mirrored the VIX movement, and the current level is also about 18.0.

Q. WHAT IS THE ISSUE OF USING THE VIX TO ESTIMATE A MARKET RISK PREMIUM?

A. The primary issue with this approach is the use of the VIX in the context of long-term stock market volatility. The VIX is a measure of short-term stock market volatility. Mr. Hevert has used the Sharpe ratio and developed a market risk premium comparing the VIX or short-term volatility measure with the long-term standard deviation of the market. The error is in the comparison of the short-term volatility measure (VIX) with the long-term standard deviation of the market. The VIX is too-short-term of a measure to estimate a long-term expected risk and return.

Q. WHAT DO THE CURRENT LEVELS OF THE VIX IMPLY ABOUT THE MARKET RISK PREMIUM AND CAPM EQUITY COST RATE USING MR. HEVERT'S SHARPE RATIO APPROACH?

A. As shown on page 1 of Exhibit JRW-15, the current levels of the VIX and the VXV are about 16.0 and 18.0. Panel A of page 2 of Exhibit JRW-15 shows Mr. Hevert's market risk premium and CAPM equity cost rate calculations using a VIX level of 18.54. In Panel B of page 2 of Exhibit JRW-15, I have replicated Mr. Hevert's market risk premium and CAPM equity cost rate calculations using the current VIX level of 16.44. The range of the CAPM equity cost rates using the updated VIX levels are 6.94% to 8.94%. Hence, current VIX levels support an equity cost rate that is even lower than the equity cost rate of 9.0% that I recommend.

3. RP Approach

Q. PLEASE REVIEW MR. HEVERT'S RP ANALYSIS.

A. On pages 36-39 of his testimony and in Document No. 6 of Exhibit No. ___ (RBH)-1, Mr. Hevert estimates an equity cost rate using a RP model. Mr. Hevert develops an equity cost rate by: (1) regressing the authorized returns on equity from electric utility companies from January 1, 1980 to February 27, 2013 time period on the thirty-year Treasury Yield; and (2) adding the appropriate risk premium established in (1) to the on three different thirty-year Treasury yields (a) a current yield of 3.12%, a near-term projected yield of 3.25%, and a long-term projected yield of 5.10%. Mr. Hevert's RP results are provided in Panel C of Exhibit JRW-13**.** He reports RP equity cost rates ranging from 10.23% to 10.76%.

Q. WHAT ARE THE ERRORS IN MR. HEVERT'S RP ANALYSIS?

A. There are two primary errors: (1) his long-term projected 30-year Treasury yield of 5.10% is about 150 basis points above current rates and is unrealistic; and (2) his measurement and magnitude of the risk premium.

Q. WHAT ARE THE ISSUES WITH MR. HEVERT'S RISK PREMIUM?

A. The risk premium is inflated as a measure of investor's required risk premium. Mr. Hevert's approach is a study of *Commission* behavior, not a study of *investor* behavior. It does not make sense to find the cost of equity in a new proceeding like this one by studying the outcomes of other cases. Such an approach is circular. It tends to perpetuate any past errors, and over time could become entirely disconnected from financial market realities. Evidence of such errors is demonstrated by the market-to-book ratios for electric utility companies. Electric utility companies have been selling at market-to-book ratios in excess of 1.0 for many years. This indicates that the authorized rates of return have been greater than the return that investors require. Therefore, the risk premium produced from the study is overstated as a measure of investor return requirements and produced an inflated equity cost rate.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

STATE OF FLORIDA)
: CERTIFICATE OF REPORTER
COUNTY OF LEON)

I, LINDA BOLES, CRR, RPR, Official Commission Reporter, do hereby certify that the foregoing proceeding was heard at the time and place herein stated.

IT IS FURTHER CERTIFIED that I stenographically reported the said proceedings; that the same has been transcribed under my direct supervision; and that this transcript constitutes a true transcription of my notes of said proceedings.

I FURTHER CERTIFY that I am not a relative, employee, attorney or counsel of any of the parties, nor am I a relative or employee of any of the parties' attorney or counsel connected with the action, nor am I financially interested in the action.

DATED THIS 10th day of September 2013.

Linda Boles

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