BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

In the Matter of:

DOCKET NO. 140025-EI

APPLICATION FOR RATE INCREASE BY FLORIDA PUBLIC UTILITIES COMPANY.
_________________________/

VOLUME 2
Pages 228 through 483

PROCEEDINGS: HEARING

COMMISSIONERS PARTICIPATING: COMMISSIONER LISA POLAK EDGAR
COMMISSIONER EDUARDO E. BALBIS
COMMISSIONER JULIE I. BROWN

TIME: Commenced at 1:03 p.m.
Concluded at 1:45 p.m.

DATE: Monday, September 15, 2014

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 1.)

Q. Please state your name and business address.

A. My name is Robert J. Camfield, and my business address is 800 University Bay Drive, Suite 400, Madison, Wisconsin 53705.

Q. By whom are you employed and what is your position?

A. I hold the position of Vice President with Christensen Associates Energy Consulting, LLC, located in Madison, Wisconsin.

Q. What is the purpose of your testimony?

A. My testimony covers two major areas. In the first section of my testimony, I present the recommended billing determinants of Florida Public Utilities Company (FPUC, Company) for the test year, October 2014–September 2015. I then present the Company's expected test-year revenues, which are based on the projections of test-year sales quantities. In the second section of my testimony, I address the expected rate of cost inflation facing Florida Public Utilities Company during the 2014 and 2015 period, including the projected test year. This section of the testimony begins by defining the notion of general inflation and discussing the macroeconomic forces that drive cost and price inflation within regional and national economies. The testimony briefly reviews methods for measuring expected inflation over the near-term future—methods which are applied within this immediate rate filing of Florida Public Utilities Company. The testimony then turns to the empirical analysis, reviewing the study results that are presented in an exhibit. The testimony concludes with a summary of findings along with accompanying recommendations.

Q. Would you please provide a brief overview of your professional background?

A. Yes. My professional work is focused on the energy industry and includes regulatory economics, cost of capital and valuation, cost analysis including cost allocation, and analysis of energy demand and forecasting. For over thirty-five years, I have been involved in numerous technical and policy issues facing the energy services industry, including electric and gas utilities. Before regulatory authorities, I have made appearances on behalf of consumer advocacy groups, transmission and distribution companies, RTOs, integrated electric utilities, generation companies, regulatory agencies, and utility associations. I have provided testimony on a variety of topics, including power supply contracts, transmission congestion, cost allocation and marginal costs, tariff design and rate phase-in plans, corporate performance and cost benchmarking, and load and energy forecasts. My consulting assignments include wholesale market restructuring, and the management of power procurement processes. I have contributed materials to noted industry journals such as *The Electricity Journal* and *IEEE Transactions on Power Systems*, and presented papers before the *Council on Large Electric Systems*. I served as Program Director for the Edison Electric Institute's *Market Design and Transmission Pricing School*, 1999–2008. I have held the positions of chief economist for a regulatory agency, and system economist for a large, integrated electric service provider. I hold a master's degree in economics from Western Michigan University, and I am a graduate of Interlochen Arts Academy.

Q. Have you previously testified before the Florida Public Service Commission?

A. Yes, I have represented Florida Public Utilities Company in fuel and non-fuel related dockets of the Florida Public Service Commission (Florida PSC) in previous years.

Q. Have you previously testified with respect to cost analysis and revenue requirements?

A. Yes, I have conducted and been involved in numerous public and private cost studies and various analyses regarding electric, gas, and water utilities, and I have testified with respect to various cost and revenue requirements issues, including sales forecasts.

I. Billing Determinants and Test-Year Revenues

Q. Please identify how your testimony regarding test-year billing determinants and revenues is organized.

A. The first section of my testimony is organized as follows:

- History and Forecast of Billing Determinants, starting on page 6.
- Approach to Load and Energy Forecasting, starting on page 8.
- Preparation and Development of Data, starting on page 14.
- Review of Forecast Models, starting on page 24.
- Estimating Test-Year Billing Determinants, starting on page 26.

- Discussion of Key Issues, including Population, Personal Income, and End-Use Technologies, starting on page 28.
- Presentation of Forecast Test-Year Revenues, starting on page 36.

Q. Are you sponsoring exhibits to accompany this section of your testimony?

A. Yes, I am sponsoring the following exhibits in this section:

RJC-1: *Summary of Historical Energy Sales, Northeast and Northwest Divisions*

RJC-2: *Summary Statistics of Estimated Forecast Equations*, shown on separate pages for the Northeast and Northwest Divisions (2 pages)

RJC-3: *Predicted vs. Actuals*, with Number of Customers and Use per Customer shown separately for each of the four major rate classes (RS, GS, GSD, GSLD) for the Northeast and Northwest Divisions (8 pages)

RJC-4: *Changes in Population of Rural Counties, United States and the State of Florida* (2 pages)

RJC-5: *Global Factors Affecting Residential Energy Use: Real Personal Income, Electricity Prices, and the Stock of Energy-Using Technology* (3 pages)

RJC-6: *Projections of Test-Year Revenues*, shown by customer class and month. This exhibit shows the projected revenues for each of the two divisions as well as for the Company's combined electric operations (3 pages).

Q. Please describe billing determinants and the role of billing determinants in the Company's rate proceeding.

A. Billing determinants refer to billing quantities, and include energy sales (kWh), number of customers served, billing demands (kW) for demand-metered customers, and reactive demand for a subset of demand-metered classes. Billing determinants are specific to the Company's customer classes, which include Residential (RS), General Service (GS), General Service Demand (GSD), General Service Large Demand (GSLD), and General Service Large Demand 1 (GSLD1), as well as Outdoor Lighting (OL) and Street Lighting (STL). The Company's larger commercial classes, including GSD, GSLD, and GSLD1, are demand-metered; kilovolt-amperes reactive (kVAR) are recorded and used for billing purposes in the case of GSLD1.

Test-year billing determinants are major elements of the Company's application for a change in tariff prices. First, test-year billing determinants form the basis for estimating test-year revenues. In addition, billing determinants serve as allocators within the process of cost allocation, and the sales basis for the Company's proposed retail tariffs. Also, billing determinants (number of customers, energy sales, and billing demands) are used by the Company to develop cost projections through and including the test-year period.

Q. Can you please review the Company's electricity sales experience over recent years?

A. The Company's electricity sales have declined over recent years, which has also been the experience of many utilities nationally. Moreover, some electric companies have experienced declines in the number of customers served over recent years. The Company's declining sales over recent years are attributable to a slowing growth—if not outright declines—in electricity usage on a per-customer basis.

The Company's sales experience reflects the combined impacts from declines in household incomes during the deep recession of late 2007 through mid-2009, the subsequent extended recovery from abnormally mild weather of selected years including 2013, and the sharp rise in real electricity prices during the 2009–2010 timeframe. The increase in prices is a direct result of the Company's formerly highly favorable power contracts evolving to new terms that reflect the contemporary market expectations of late 2005 through and including 2008. At that time, the demand for electricity was advancing rapidly as a result of the U.S. economy operating somewhat beyond sustainable full employment. These high demand conditions, coupled with tight supply margins and disruptions in fuel transport, precipitated expectations of comparatively high prices for generation services.

Exhibit RJC-1, *Summary of Historical Energy Sales and Billing Determinants, Northeast and Northwest Divisions*, presents the Company's sales over the years 2008–2013, along with the projected sales in the test year, shown without weather normalization of historical data. In the Northeast Division, residential sales are expected to decline from 186 GWh during 2008 to 178 GWh during the 2014/2015 test year, seven years later. Similarly, sales for the GSD class also decline, by 1.3% annually. Sales for the combined GS and GSLD classes rise modestly, by 1.1% annually. For the Northeast Division as a whole, the net result—without accounting for the nearly fourfold decline in GSLD1 sales—amounts to a decline of about 0.5% annually for the seven years shown, from 326.7 GWh in 2008 to 315.4 GWh in the 2014/2015 test year.

Similar historical experience is shown for the Northwest Division, where residential sales decline from 144 GWh during 2008 to an expected 127 GWh for the test year, a decline of 1.8% annually over these seven years. For the business classes within the Northwest Division, only GSLD sales are predicted to rise—by 0.3% annually over seven years. Taken as a whole, sales in the Northwest Division are expected to decline by 1.0% annually for the 2008 through 2014/2015 period.

Q. How can projections of test-year billing determinants be estimated?

A. Billing determinants (sales) can be estimated in several ways. First, sales trends over historical years can be extrapolated over future years. Second, time series methods, such as autoregressive moving averages (ARMA), are useful for determining short-term forecasts—three to six months forward. Third, structural models, estimated using conventional and well-founded statistical methods, constitute a proven and often-applied approach. In selected cases, time series components can be integrated within structural models.

Generally speaking, trend-based methods are appropriate when the data series (sales, number of customers, and demands) change over time in smooth and easily predictable patterns. Trend-based forecasts also provide a means to check and verify the forecast results obtained through other means.

Q. For the immediate proceeding, how are the Company's test-year billing determinants estimated?

A. Billing determinants are estimated from structural models, using a statistical methodology commonly referred to as regression analysis. Structural models are particularly well suited to the task of estimating electricity demand.

Q. How are structural models applied? Please describe the framework used for determining billing determinants.

A. The methodology underlying the Company's forecast of test-year billing determinants is referred to as a *Use per Customer-Number of Customers* (UPC) approach. This approach recognizes that the decisions and choices of economic agents (households, private firms, and public institutions) driving electricity sales are twofold and separable: first, the decisions on location and facility siting (e.g., new sub-divisions built to satisfy the demand for single-family dwellings); and second, the decisions regarding the consumption of electricity, which are derivative to consumer and business valuations of electricity-using technologies. These valuations are essentially assessments of whether the net benefits are sufficient to warrant the expenditure for the purchase and operation of residential appliances and business technologies.

The UPC approach can be applied with monthly frequency, thus allowing for estimation over more contemporary timeframes. For purposes of analysis, the reliance on recent experience (2004–2013), in isolation from the longer-term history, is important if the underlying relationships between energy consumption and causal factors are evolving gradually over time. Additionally, the UPC approach with monthly frequency captures the composition of regional electricity markets in more depth. In so doing, the UPC approach allows for better diagnostics, thus facilitating an improved understanding of the underlying relationships among sales, demands, and explanatory factors.

For the purpose of developing the Company's load and energy forecast models, specific features of a UPC approach include the following:

- Marginal real price of electricity.
- Weather factors, constructed as the weighted combination of daily heating degree days (HDDs) and cooling degree days (CDDs) over the 60 days of current and previous months covered within billed energy for the current month.
- Monthly identifier variables (binaries), covering eleven months.
- Real personal income and its components (population and per capita income).
- Other factors correlated with electricity consumption. These factors may be orthogonal within the data set, and thus prove to be statistically significant, but may not be inherent causal drivers within the context of a regional economy. Examples include various employment metrics and housing starts for the relevant region.

Q. Are there specific concerns and issues regarding the estimation of the Company's test-year billing determinants and revenues?

A. Yes, there are two overarching concerns. First, the estimation process should not reach back too far historically, if the underlying relationships among the variables in the data set are evolving gradually. Second, forecasts covering small regions are less able to account for the risk associated with random events within small, regional economies.

For sales forecasting, the appropriate starting point is an understanding of the fundamental factors that determine electricity demand, and the particular characteristics and features of the Company's markets. To the degree possible, the sales forecast should take account of the generic structural factors that drive sales/billing determinants, including the underlying forces taking place within the relevant regional economies as well as expected electricity prices and weather conditions. A major factor within the residential class is the technological advancement of electricity-using household products, inducing corresponding gains in energy efficiency. Moreover, in the immediate case, the forecasting process must take account of the directional change of the Company's energy sales—from rising to declining sales—within the estimation period, 2004–2013. This sales trend appears to be a combined result of a contraction in economic activity (the recession in Florida and the Southeast U.S.) and rising electricity prices, as mentioned above. However, a long-term secular trend of declining sales appears to be setting in within the

Company's Northwest Division.

Q. Would you please describe the forecast process for estimating the Company's test-year billing determinants and revenues?

A. Yes. The estimation of billing determinants and revenues involves a five-step process.

Step 1: *Identify the likely factors that determine electricity sales*. As alluded to above, the relevant factors for consideration include *demographic and related factors,* such as population and civilian labor force participation; *economic factors,* such as the income of households (often referred to as personal income) and total employment; *weather factors* represented by CDDs and HDDs; *marginal prices of electricity*; and the *timeframe*, including month specificity (monthly binary variables) and time trends.

Step 2: *Gather and prepare data associated with the factors identified in Step 1*. The identified factors can be referred to as *energy sales drivers* (drivers). For the task at hand, the estimation of billing determinants for the test year, historical data that may serve as relevant sales drivers are gathered and organized into a billing determinants data set.

Step 3: *Estimate forecast models*. The data set assembled in Step 2 serves as the basis to estimate the Company's sales forecast models. The models are linear equations developed to capture the underlying statistical relationships between billing determinants (number of customers, use per customer, and billing demands) and the identified explanatory factors.

Step 4: *Determine test-year sales*. Using the forecast models estimated in Step 3, test-year billing determinants are projected based on the energy sales drivers, as forecasted for the test period (October 2014–September 2015).

Step 5: *Incorporate appropriate adjustments and calculate test-year revenues*. Projections of sales for the test year are adjusted downward for 1) expected conservation within the residential class; 2) the expected natural gas penetration within the residential class served by the Northeast Division; and 3) the change in tariff prices, as filed for, within the Company's petition for an increase in tariff rates.

Q. Does the process outlined above align with contemporary industry practices for sales forecasting?

A. Yes, the forecast process and general approach conform to current practices, industry-wide. That is, linear and non-linear statistical methods are commonly used by electric and gas service providers to develop near-term projections of billing determinants, and also long-term sales forecasts used within resource planning processes.

For the purposes here, the Company's projections of electricity billing determinants are estimated in monthly frequency over the 2004–2013 timeframe, and consist of number-of-customers and use-per-customer models for the four major rate classes (RS, GS, GSD, and GSLD). In addition, statistical models are also used to estimate billing demands for the GSD and GSLD classes. At a class and division level, the historical data for number of customers and use per customer are drawn from the

Company's billing records. Forecast billing determinants for the GSLD1 and lighting classes (OL, STL) are determined by applying trend-based methods, where historical trends are used to project sales in the future. Historical data for GSLD1 and the lighting classes are also drawn from the Company's billing records.

Q. Please elaborate on Step 1, identifying the factors used to estimate the statistical models, for forecasting the Company's test-year billing determinants.

A. As implied above, the demand for electricity within defined service territories of utilities is driven by key explanatory factors, including the size of the underlying regional economy, as reflected in well-known measures such as personal income and regional gross product, and descriptive metrics such as population and civilian employment, including private and public sector employment. Personal income covers the income available to households in a region, and includes wages and salaries, interest on savings and investment, and transfers including social security and unemployment insurance payments. As mentioned, weather factors consist of CDDs and HDDs but can also include other metrics such as the level of humidity and, in some locales, wind velocity. Finally, the price of electricity measured in real terms is found to be an important explanatory factor.

Q. Please discuss the gathering and preparation of data under Step 2.

A. Once the factors have been identified, the forecast process involves the collection, organization, and preparation of data, including key transformations. This Step 2 work is discussed below for each of the several data types.

Regional Demographic and Macroeconomic Factors: The Company's number-of-customers and use-per-customer forecast models incorporate monthly estimates of the population of the counties relevant to the Company's Northeast and Northwest electric service territories. The Bureau of the Census estimates county population annually. The Census Bureau's population estimates for the relevant counties provide the basis for determining the monthly change in population over the course of the year.

For personal income, the forecast process draws upon two main sources of data: the Bureau of Economic Analysis county-level personal income and its components; and the Bureau of Labor Statistics quarterly estimates of average weekly wages and salaries (earned income), and employment. The annual estimates of personal income at the county level reach back several decades, although the immediate work utilizes the more contemporary period, 2001 through 2012, and our preliminary estimates for 2013 are based on trend experience. As mentioned, the annual, county-level personal income metrics are based on earned income and other elements, including transfers and the interest on financial holdings (return to financial assets). For small areas such as rural counties, earned income, driven by both wages and employment, varies over the course of the year as a result of seasonal and macroeconomic forces. As a consequence, the analysis varies the earned income component of personal income, observed annually, according to the monthly experience in wages and salary income, while holding the other components constant across all months. The net result is a proxy for monthly personal income.

Monthly estimates of county population are obtained by interpolating the annual population estimates, as mentioned above. This approach implicitly assumes that the underlying population evolves at a fairly steady and consistent rate of change over the course of individual years.

The monthly proxy for personal income is divided by estimates of monthly population in order to obtain monthly per capita income, stated in nominal dollars. Finally, monthly per capita income, which serves as a proxy for the true underlying level of income available to individuals and households (which is unobserved within official data) is converted to real terms using the Consumer Price Index for the U.S. economy. In short, per capita income is a main macroeconomic driver within the use-per-customer equations, essentially accounting for leftward and rightward shifts over time in the underlying demand for electricity. The historical experience within Duval County, not Nassau County, is used for model estimation for the Northeast Division.

Q. Is it possible that measures of macroeconomic activity, other than real per capita income at the local level, also explain variation in electricity demand?

A. Yes. The level of monthly employment and proxies for monthly gross product may potentially be constructed and utilized for explaining electricity demand. Along this line of thought, the most relevant issue is one of discovery—finding macroeconomic metrics that are conceptually appropriate and also "fit" in a statistically significant way within the larger set of explanatory variables. Second, even if alternative orthogonal data vectors (time series) are discovered, it is highly likely that, in the context of macroeconomic data, new proxies as constructed, are highly correlated with other macroeconomic time series. As an example, at the national level, personal income and gross domestic product (GDP) move nearly in lock step, demonstrating strikingly high correlation. In brief, it may be of little value to construct gross product metrics (e.g., measures of regional product) with monthly frequency, either in lieu of or in addition to personal income.

Q. Please discuss the development of weather data.

A. *Weather Factors*, including CDDs and HDDs, are drawn from temperature data observed and collected by the National Weather Service (NWS). In the case of the Northeast Division, weather data are culled from the NWS data banks for the Jacksonville Naval Air Station and Fernandina Beach. In the case of the Northwest Division, weather data are drawn from NWS data for the Municipal Airport for the City of Marianna in Jackson County as well as for the City of Tallahassee.

The Company's forecast models utilize weather experience for the period 1999–forward, observed daily. For the four weather stations (Jacksonville Naval Air Station, Fernandina Beach, Municipal Airport for the City of Marianna, and the City of Tallahassee), the historical record of the maximum and minimum temperatures (with daily frequency) includes missing data points, a typical occurrence. As a consequence, it is necessary to fill in the missing data with the weather data for the alternate locations for the Northeast and Northwest Divisions, respectively. The analysis includes an assessment of the correlation and level differences between the weather experiences for the main and alternate locations. The substitute data points, which essentially serve as weather proxies, are adjusted for level differences between the main and substitute locations; the differences are quite small.

The daily temperature data are then converted to CDDs and HDDs using the commonly recognized weather benchmark: 65 degrees Fahrenheit. Alternative CDD and HDD benchmarks have not yet been explored. However, my experience suggests that, for plausible alternative temperature benchmarks, such as 60° F or 70° F, the differences in the estimated effects of CDD and HDD weather metrics on use per customer range from small to vanishingly small. Nonetheless, the possible use of alternative temperature benchmarks is a topic for further exploration.

As with all variables utilized in Step 3, the model's weather metrics (CDDs and HDDs) are converted to monthly frequency. Monthly billed energy reflects energy consumption during the current and previous month. Due to the timing of bills, as determined by bill-cycle practices, a progressively larger share of billed energy for a current month is consumed during the latter days of the previous month, and the early days of the current month. Accordingly, for a current billing month, the daily CDDs and HDDs of the current and previous months (approximately 60 days total) are triangle-weighted, where the central point (greatest weight) is the last day of the previous month and first day of the current month. The monthly normal weather CDDs and HDDs are equal to the average CDDs and HDDs for the respective month, for the period 1999–forward. In the case of the Northeast Division—but less so for the Northwest Division—the analysis has discovered a clear upward trend in temperatures, for both winter and summer periods. This is not unusual; warming trends in weather patterns can be observed in various areas of the North American continent, notwithstanding recent El Nino and La Nina episodes. As a consequence, the observed trends in weather for the Northeast and Northwest Divisions, though small, are incorporated into the projections of normal CDDs and HDDs for the individual months of 2014–2015, with increases in CDDs and decreases in HDDs. Accordingly, the trends in weather are incorporated into the projected billing determinants for the test year, October 2014–September 2015. It goes without saying, the rising long-term trend in temperatures has slowed more recently, and may assume a fairly moderate pace following the rapid pace of rising temperatures over recent decades.

Q: Would you please describe the role of electricity price factors?

A: *Electricity Price Factors* are developed from observed class billing records of the Company's Northeast and Northwest Divisions. Like all normal goods, the demand for electricity services is sensitive to the "own" price of electricity. For the purpose of estimating use per customer, the most relevant—though not exclusive—

price measure is the marginal usage price. Accordingly, estimates of the monthly revenue attributable to customer charges are removed from total monthly revenue, thus isolating revenue attributable to the consumption of electricity. Dividing this volumetric revenue by energy usage obtains estimates for the marginal usage price that, over the sample historical period (2004–2013), is then converted to real terms using the Consumer Price Index for the U.S. economy. This monthly real electricity price incorporates a finite lag process, where the weighting scheme assigns greater weight to near-term months and reduced weight to later months (e.g., the eleventh month) over a twelve-month period.

The procedure just discussed is followed for each customer class (RS, GS, GSD, and GSLD) and both divisions. To summarize, use per customer is a function of the weighted combination of electricity prices over the previous twelve months as well as the several other factors discussed above.

Q. Is electricity demand sensitive to the prices of alternative, substitute forms of energy?

A. Yes, in the very long term, particularly with the rising availability of natural gas supply within areas where, over decades, gas was not previously accessible. It is common for long-run electricity demand studies using panel data to find that electricity demand is sensitive to natural gas prices; essentially, there is a "cross-price" effect. More generally, electricity demand is sensitive to substitute forms of energy in the very long run, under the condition of ready availability of the energy substitutes.

However, energy consumers will take a "whole package view," thus internalizing any incremental capital charges associated with the conversion to alternative energy sources. For example, industrial customers often adopt natural gas-fueled generating technologies for the purpose of on-site power supply, which appears to be currently taking place in Germany. Second, it is to be expected that, in the long term, many residential and commercial customers will select natural gas for space conditioning where natural gas is available.

The Company has recently introduced natural gas within the Northeast Division service territory and, as a consequence, residential and commercial customers may selectively utilize natural gas for space conditioning, prospectively. Also, within the near term, natural gas may be used for power supply at the wholesale level.

At this point, we have not as yet explored the potential inclusion (through imputation) of the prices of alternative energy forms within the use-per-customer models. However, we have incorporated a trace amount of natural gas substitution over electricity within test-year residential sales of the Northeast Division.

Q. Would you please describe the role of other explanatory factors?

A. *Other explanatory factors* are selectively incorporated within the data set analysis, including monthly binary variables, a time trend, and shift factors (which are also represented by binary variables). Shift factors make allowances for abrupt and sometimes transitory changes in dependent variables that are not captured by other explanatory variables incorporated within the model.

Q. Please discuss *Forecast Model Estimation*, Step 3 of the Billing Determinants process.

A. The forecast models are estimated using the data set developed in Step 2. As implied above, the data consists of the "left-hand-side" (LHS) dependent variables, including number of customers, use per customer, and non-coincident demands of the GSD and GSLD classes; and the "right-hand-side" (RHS) explanatory variables consisting of the macroeconomic metrics, weather factors (CDDs and HDDs), the marginal price of electricity, monthly binaries, and other variables such as trend, utilized selectively. The models are estimated in levels, although double-log estimation (for non-binary variables) was also briefly explored.

A levels approach is generally most appropriate—indeed, arguably necessary—when weather factors are included in the RHS data set because electricity consumption is generally linear with respect to weather data over *much of the relevant range* of the variables. As alluded to above, the analysis is conducted with monthly frequency over the years 2004 through 2013, and is based on well known, conventional econometric practices (regression analysis) including appropriate test statistics. In general, the period of estimation should be fairly contemporary but no shorter than ten years, recognizing that relationships among the LHS and RHS variables may evolve prospectively—outside the historical sample period used for estimation.

Q. What are the appropriate criteria for assessing model performance?

A. A primary performance measure is conceptual: forecast models should conform to a plausible explanation of the underlying behavior of electricity demand. Second, the coefficients for the explanatory (RHS) variables should have appropriate directional signs. Third, the magnitude of the coefficients should not stray far from the plausible, as revealed by elasticity calculations. Fourth, overall predictive performance, as technically revealed in the "root mean square error" statistic and visually observed in predicted vs. actual graphs, should be acceptable for the purpose at hand. Fifth, continuous RHS variables preferably should be statistically significant but they may remain within models even if they fail commonly recognized tests of significance. Also, other statistical tests can be drawn into the assessments of models but are not determining.

Q. Please describe key analysis issues and impacts on model performance.

A. The Step 3 analysis, in the form of time series regression models, consists of twenty models. Summary statistics of the estimated equations for number of customers and use per customer, covering the four main classes of the Company's two divisions, are shown in Exhibit RJC-2, pages 1 and 2. Reported performance metrics for each of the estimated equations include *Adjusted* R^2 (the share of variation in the dependent variable explained by the estimated equation, adjusted for degrees of freedom); *RMSE* (root mean square error, a metric for the size of model error); *F Statistic* (*a measure of goodness of fit*); and *# of Observations* (number of data observations over which each equation is estimated). Not reported are the four models for non-coincident demands for the GSD and GSLD classes—two models for each of the Company's two electricity divisions. Not reported but calculated is the increasingly utilized *Akaike Information Criteria* (AIC).

The historical set of data used for model estimation is characterized by random variation within selected data series, an inherent property of small-area forecasting—in this case, the Company's Northeast and Northwest Divisions. Specifically, the Northeast Division serves Amelia Island situated in the northeast corner of Florida and comprises a share of Nassau County. Similarly, the Northwest Division serves areas within Calhoun, Liberty, and Jackson counties in north central Florida. Small area forecasts confront two informational issues. First, observed data regarding historical experience is generally limited or of reduced frequency when compared to that which is available for larger territories such as multiple, integrated county regions or large metropolitan areas. Second, small area forecasting faces random variation, particularly within the underlying number-of-customer and use-per-customer data, where the variation is attributable to unobservable events and thus cannot be easily attributable, through analysis, to causal factors.

Q. Would you please briefly describe the realized performance of the Company's forecast models?

A. Generally speaking, the Company's forecast models are conceptually plausible, obtaining results which are uniformly consistent and reasonable. In the case of the use-per-customer models for the residential class, the macroeconomic metric of household incomes is negatively related to use per customer. This topic requires further explanation, which I will take up later on in this testimony.

The forecast equations in full detail are reported in Minimum Filing Requirement (MFR) Schedule F8 of the Company's filing. As shown, the continuous RHS variables along with the shift factors (captured by binary variables) have the correct signs and provide adequate levels of statistical significance.

Exhibit RJC-2 presents a summary of the performance statistics for the various forecast equations used to provide estimates for the two main dimensions of billing determinants, *number of customers* and *use per customer*. The number-of-customers equations for the Residential and General Service customer classes report Adjusted R^2 results within the 0.90 to 0.95 range, and F Statistics with adequate levels of significance. As expected, the performance metrics for the number-of-customers forecast equations, for the larger business customers, GSD and GSLD, are lower, with Adjusted R^2 results within the 0.62 to 0.70 range, and similarly lower values for the F Statistics. The reduced performance, at least measured in terms of overall fit, is a result of the small sample count for large customers (GSD and GSLD) within each of the Company's two divisions. Note that, for the Northwest Division, the number of customers for the GS and GSD classes is estimated together (GS plus GSLD), and then "shared out" between these two rate classes over time via trend.

The use-per-customer equations for the Residential and General Service classes have Adjusted R^2 values of 0.91 to 0.93, along with adequate F Statistics. For the reasons mentioned above, the GSD and GSLD customer class equations have lower Adjusted

R^2 values, ranging from 0.53 to 0.92, along with correspondingly lower F Statistics. As shown, the use-per-customer models for GSLD in the two divisions have considerable estimation error, a result of the small number of customers taking service under the Company's GSLD tariff. Nonetheless, the forecast results reside well within the realm of the plausible.

Forecast performance can also be gauged through a graphical comparison of the model-based predicted and actual values over the historical sample period, often referred to as *predicted vs. actuals*. These comparisons are presented in Exhibit RJC-3, pages 1–8 and ordered according to the Northeast Division (pages 1–4) and the Northwest Division (pages 5–8), with the number-of-customer and use-per-customer comparisons for each class shown on a single page. Several observations regarding the model performance for the two divisions are as follows:

1) The use-per-customer models appear to capture well the month-by-month and long-term variation in electricity consumption.
2) GSLD use per customer in the Northeast Division is unusually high during 2005 and 2007, with the model-based predicted values for early 2005 understating actual experience (page 4).
3) The number of customers served over the ten-year historical period has considerable random variation, which can be difficult to capture analytically, at least without resorting to extensive use of event variables (binaries).
4) Anomalous customer count experience in the GS and GSD classes of the

Northwest Division is managed with event variables; the models appear to perform well overall.

5) Similarly anomalous customer count experience appears in these two classes (GS and GSD) within the Northeast Division.

6) The small number of customers for the GSLD class, in both the Northeast and Northwest Divisions, inherently make for rather lumpy model performance (pages 4 and 8). The number of GSLD customers, in both the Northeast and Northwest Divisions, is held constant over the forecast test year.

Q. Please explain Step 4, *Determine Test-Year Sales*.

A. Test-year billing determinants (sales) are estimated by applying projections of the forecast drivers within the RHS of the various forecast models. Projections of drivers are, in the case of the binary variables, determined by definition (0, 1). The weather variables, CDDs and HDDs, are based on normal weather and incorporate a slight trend in recognition of steadily warming weather within recent historical years. The real price of electricity is the variable price during each of the months of the final historical year (2013), adjusted downward over time according to the expected rate of inflation (2.20% for 2014 and 2.23% for 2015). (The purchased power price is expected to remain unchanged in real terms.) The test-year macroeconomic drivers including personal income and per capita income, both stated in real terms, reflect the expected near-term change in macroeconomic variables for the small county areas relevant to the Company's Northeast and Northwest Divisions. For the Northeast

Division, projections for the rate of change in real per capita income for the U.S. economy are used as a proxy for Amelia Island (Fernandina Beach) and, when combined with the projected change in population for the area, provide the basis to construct the area proxy for real personal income.

Q. Please explain Step 5, *Incorporate Appropriate Adjustments and Calculate Test-Year Revenues.*

A. As mentioned above, the test-year billing determinants (sales) estimated in Step 4 are adjusted in three ways. First, the estimates of residential use per customer are adjusted downward by 2% in order to capture the expected further declines in use per customer beyond the test year. In view of the ongoing efficiency gains in residential electricity-using technologies, these changes are not only expected but virtually certain, thus constituting known and measurable changes.

Second, we incorporate a comparatively small effect in residential sales resulting from the availability of natural gas for space conditioning and water heating. The working assumption is that 20% of new residential customers in the Northeast Division will select natural gas in lieu of electricity for cooking and water heating. In the case of electric space heating, the assumption is 10%. Using the forecasts of new customers and the assumed shares selecting natural gas (20% for cooking and water heating, 10% for space heating), the residential sales are adjusted according to the residential energy attributable to these end-use applications.

The third adjustment accounts for the sales compression as a consequence to the

Company's filed for change in electricity prices.

Q. You have indicated that further discussion is warranted on two issues: (1) including changes in population trends, and (2) the impact of personal income on electricity use within the residential class. Please elaborate.

A. As mentioned, the historical timeframe over which the forecast models have been estimated is somewhat difficult in view of mid-course changes in key explanatory factors such as regional population. Regarding population, rural areas of the U.S. have been experiencing declines in population for some time, even as the overall U.S. population has been growing and the national economy has been advancing. This history reflects several factors, including, in particular, more robust employment and income opportunities in urban areas for young adults. As shown on Exhibit RJC-4, page 2, the number of U.S. rural counties experiencing declining population during the 2001–2008 period averaged 825, while the number of counties experiencing positive population growth during the same timeframe averaged 779. Florida was exceptional, insofar as typically only one of Florida's rural counties would have a decline in population in any single year during the 2001–2008 period.

By this metric—positive or negative growth in population—the outlook for rural counties has changed markedly for the worse more recently, 2009–2013. For the U.S., and for Florida in particular, a rising number of rural counties appear to be experiencing major, and in some cases chronic, decreases in population. For the U.S., the average number of counties with declining population has risen to 906—an increase of approximately 10% over the previous time period. In Florida, declining population has set in for an average of nine of Florida's sixteen rural counties. While I anticipate that few of Florida's rural counties will experience declining population over the long term, decreasing population for several rural areas will likely continue for a number of forward years. In brief, the abrupt break from rising to declining population for the rural territory served by the Company's Northwest Division is not altogether uncommon. And while the current trends in population may turn positive, it is not likely to reassume the comparatively robust growth of the earlier era, the decade prior to the deep recession of '07–'09.

Q. Please turn to the second issue, personal income and the efficiency of electricity end uses in the residential sector.

A. Historically, increases in real personal income have translated into rising electricity sales, though at a progressively slower rate of change. Evidence demonstrates that the relationship between income and electricity consumption has changed significantly, beginning in the 2006–2008 timeframe. Since that time, rising incomes, overall and on a per capita basis, appear to be negatively related to electricity sales. Exhibit RJC-5, page 1, graphically presents residential energy usage, on a kWh/$1,000 of personal income basis, for the U.S. as whole. Energy use per unit of income rose rapidly through the late 1970s and has subsequently declined by approximately 15%. Residential electricity usage increased, however, as real personal income since the late 1970s increased by approximately 25%.

An equally interesting story regarding the relationship between residential electricity usage and personal income is presented on page 2 of Exhibit RJC-5, subtitled *Residential Electricity Use and Income, stated on a Per Capital Basis*. Here, indexes of per capita electricity use (April and November) and real income are compared. For the years 1990–2006, baseline electricity use on a per capita basis rose by 17% (1.171 for 2006), while real income per capita increased by 38% (1.383 for 2006). Since 2006, however, electricity use per capita has declined by 0.73% annually, while per capita income has risen by 0.43% annually (with the marked slowdown in real income resulting from the deep recession and slow recovery of '09–'12 and continuing). As shown, this experience constitutes a sizable gap between the growth rates for electricity consumption and income: 1.16% and 1.38% during the 2006–2012 and 2008–2012 time periods, respectively. While correlation may not necessarily imply causality, this near-term historical review suggests that the negative relationship between income and electricity usage on a per capita basis, captured in the residential use-per-customer models, is plausible and certainly consistent with the larger experience base of the U.S. overall.

Q. Can you explain how increases in real per capita and personal income translate into declining electricity use per customer within the residential sector?

A. Modern durable consumer goods are increasingly attractive in view of their modern and innovative design features. As discussed further below, rising incomes appear to be associated with a more rapid adoption of modern and much more efficient electricity-using durable goods, including major and minor appliances as well as lighting.

While not conclusive, this reasoning provides an explanation of the negative relationship between real incomes and residential electricity consumption. The end result, under rising incomes, is observable declines in electricity use, stated on both a per capita and a per customer basis.

Q. You have described the workings of rising incomes and declining electricity consumption per capita. Clearly, the apparent advances in electricity-using technologies are central to this analysis. Please elaborate on the attractions of modern end-use equipment within the residential sector and electricity efficiency. If true, this trend could be a major structural factor driving electricity sales.

A. Electricity-using household technologies are undergoing rapid changes, often including major product innovations regarding design, features and controls, and technology. Referred to as durable goods, the most common household energy-consuming technologies include air conditioning, heating, lighting, cooking, water heating, and major appliances, including televisions, washers, and dryers. These end-use technologies have experienced—and are continuing to experience—overall product improvements and dramatic gains in energy efficiency. As mentioned above, modern residential end-use technologies are in demand and have been adopted by consumers fairly rapidly in recent years.

The rate of adoption can be inferred from Indexes of Industrial Production for the Appliance/Electrical Equipment Sectors, when compared to Occupied Housing over recent years. Occupied Housing constitutes the "in-use" housing stock, and can serves as an appropriate basis of comparison. Both sets of data series are presented on Exhibit RJC-5, page 3. As shown, the average rate of production of electricity-using durable goods has declined modestly during the years of the housing slowdown, 2009–2013, when compared to the 2002–2008 period, a time of rapid increases in the U.S. housing stock. In comparison, the average gains in the Occupied Housing metric have slowed by nearly 45% during the more current period (2009–2013), when compared to the 2002–2008 period.

Notwithstanding the effects of the increasing living space of residential dwellings, the net result of product advances within these consumer durable goods is declining individual household energy consumption, as earlier vintage technologies, which constitute the existing capital stock, are replaced with more contemporary units.

Q. Isn't it true that the stock of electricity-using devices is expanding? If true, does not the increased saturation of these devices imply that residential use per customer could rise, as the expanded use of these technologies offsets the reduced energy use for the more conventional applications of residential electricity services that you mention?

A. Without doubt, the smaller electricity-using household appliances/devices cause the electricity usage per residential customer to be higher than otherwise at the national level (and, as I expect, for virtually all regions), as there are only small substitute effects from the major categories of residential electricity consumption. As suggested, the range of electricity-powered devices includes an expanded array of equipment over recent years. These new technologies include audio home entertainment equipment, ceiling fans, desktop and laptop computers, computer monitors, dehumidifiers, DVD players, external power chargers, modems and routers, portable electric spas, pool and pool pumps, security systems, and set-top boxes. Also, we should not forget the expanded array of electricity-using kitchen equipment.

Moreover, studies suggest that household saturation for these smaller-scale devices will likely rise prospectively. And while the annual energy consumption of many of these devices is comparatively small, when taken together the energy usage for this miscellaneous category of energy-consuming technologies is sizable.

Survey-based assessments of the small electricity-using devices provide a more complete view of the underlying markets for these devices and the likely impact on residential electricity consumption. That is, because of the energy-efficiency gains, when stated on a per-device basis, the net overall result is a decline in electricity use per residential customer. Stated annually, the Energy Information Administration's estimates of the changes in electricity use (kWh) between 2011 and 2015 are as follows: for audio home entertainment equipment (from 88 kWh to 83 kWh), for ceiling fans (from 77 to 71), for computers including desktops and laptops (from 280 to 215), for computer monitors (from 99 to 75), for dehumidifiers (from 710 to 620), for DVD players (from 27 to 23), for external power chargers (from 6.5 to 5.6), for modems and routers (from 51 to 44), for portable electric spas (from 2,050 to 2,040), for pool and pool pumps (from 2,460 to 2,060), for security systems (from 45 to 44), and for set-top boxes (from 127 to 107).

To summarize, overall energy consumption for miscellaneous technologies is expected to decline much like the experience for the major residential end-use technologies, despite steady increases in saturation. Indeed, the energy consumption for these smaller electricity-using devices is expected to decline by over 2.5% annually for 2011 through 2015. In brief, the smaller devices as a whole are contributing to the decline in residential use-per-customer electricity demand, despite rising saturation.

Q. Is the rate of adoption of new household technologies related to household income? Also, how does income, through the impact on adoption of contemporary technology, affect energy use per customer? Please discuss.

A. The rate of adoption of new energy-using technologies is positively related to, and driven by, the incomes available to households. While income can be measured in several ways, increases in personal income will give rise to an increase in the rate of adoption of new technologies within the residential sector.

Q. What are the implications for energy use per customer, within the residential class, as a result of long-run increases in household income over time?

A. At least over near-term forward years, rising household incomes, stated in real terms, will likely cause declines in energy use per customer within the residential class. The exception is larger homes; if the average size of homes were to again assume a clear upward trend, it is possible that progressively larger space, stated on a per capita basis, may more than offset the efficiency gains obtained through the adoption of more contemporary-vintage end-use technologies within the residential class.

As alluded to above, residential durable goods, in the form of electricity-using technologies, are undergoing major design improvements, including innovations and expanded features covering a number of dimensions. These improvements make contemporary electricity-using durable goods increasingly attractive. As a consequence, rising household incomes will precipitate increased demand for these good, which will be manifested in a faster rate of obsolescence, as new products are brought into the capital stock of equipment more quickly. Because of the large gains in energy efficiency associated with these modern residential electricity-using technologies, the faster rate of adoption of new products translates into outright reductions in energy use. In brief, electricity use per customer is negatively associated with increasing household income, thus explaining the negative sign on the RHS income variable within the use-per-customer equations for the residential class.

I should also mention that the declining use per customer within the residential class is not unique to FPUC. As presented earlier in my discussion of Exhibit RJC-5, pages 1and 2, the contemporary experience reveals continued declines in residential electricity consumption per unit of personal income. So, even with rising real personal income, stated on a per capita basis, electricity usage per customer will likely continue to decline within near-term years.

Q. Do you anticipate that the negative relationship between residential use per customer and household income will be stationary over an extended future?

A. No. We can expect that, over the long term, the relationship may reverse as energy efficiency gains are exhausted. Second, electric vehicles and robotics will likely assume an increasingly prominent share of use per customer within the residential class. Nonetheless, we can anticipate that the apparent negative relationship may hold over the next few years, though a follow-up review involving the combined experience of several utilities may also be appropriate.

Q. Projected test-year billing determinants translate into revenues for the test year, calculated at current tariff prices. Please discuss.

A. Exhibit RJC-6 presents the Company's test-year revenues, shown monthly by class. Test-year revenues are shown on page 1 for the Northeast Division, and on page 2 for the Northwest Division. Additionally, test-year revenues are shown for the Company's combined electric operations on page 3. The test-year revenues are calculated monthly, obtained by multiplying the billing determinants—number of customers, monthly energy sales, non-coincident demands (GSD, GSLD, and GLSD1), and kVAR (GSLD1)—by the Company's applicable tariff prices.

<u>II. Expected Rate of Inflation</u>

Q. Please provide a summary of your testimony with regard to the expected rate of inflation.

A. With few exceptions, ongoing price inflation has been a feature of contemporary business conditions and over the long term. As a consequence, inflation expectations factor into the decisions of buyers and sellers within markets. It is thus necessary to account for the impact of broadly defined inflation expectations within the costs incurred by Florida Public Utilities Company to provide retail electricity services.

My assessment of inflation expectations covers the years 2014 and 2015, and is based on the combined results of four measures of inflation expectations. These measures include observed *Interest Rate Differentials*, which reveal expectations held by investors, and three surveys, including the *Livingston Survey* of business economists, the University of Michigan/Thompson Reuters *Survey of Consumers*, and the *Survey of Professional Forecasters* conducted by the Philadelphia Federal Reserve Bank.

The assessment leads me to conclude that broad-based inflation expectations held during 2013, for the years 2014 and 2015, were 2.20% and 2.23%, respectively. I recommend that the Florida Public Service Commission adopt these estimates of expected inflation (2.20%, 2.23%) for test-year cost escalation factors in the Company's immediate rate case filing, covering the October 2014–September 2015 test period.

Q. Let's begin by focusing on general inflation. Please describe the notion of

price inflation and the reasons for it.

A. Price inflation (inflation) refers to the change over time in the prices of goods and services. Inflation is expressed in growth rates over time, usually as annual rates of change.

As with virtually all economies, the U.S. macroeconomy continues to experience ongoing price inflation. Broadly defined, price inflation is a common feature of all regions, and permeates all sectors of the U.S. economy over the long term, including electricity services. As alluded to above, expectations of future inflation have become implicitly embedded in the actions of private companies, households, and public institutions.

The causes of price inflation are several. First, both expected and unanticipated increases in the demand for (or decreases in supply of) goods and services across macroeconomies (e.g., that of the U.S. or other sovereign regions) imply upward pressures on prices. Second, changes in the exchange value of sovereign currencies on international currency markets can cause domestic prices to rise or decline.

Third, and importantly, changes in the monetary policy of central banks can often impact price levels across the macroeconomy. This is because the key function of fiat money is the accommodation and facilitation of economic transactions, the purchase/sale of goods and services. Holding other factors constant—in particular, the velocity of money supply and its equivalents, and the demand for asset liquidity—an unanticipated expansion in money supply can cause a corresponding rise in prices, or for prices to rise more rapidly (i.e., for inflation to accelerate). Similarly, a slower rate of change in money supply or the monetary base will correspondingly cause prices to rise more slowly (i.e., a decline in the rate of price inflation). Monetary policy can be implemented by central banks in several ways, including changes in the reserve requirements of commercial banks, changes in the interest rates paid on commercial bank reserves held by central banks, and the purchase and sale of widely held debt securities such as Treasury bonds or other broadly held debt securities (e.g., mortgage-backed securitized debt and commercial paper within wholesale capital markets).

Of the various monetary policy options listed above, the third approach (purchase and sale of debt securities) has been applied extensively by the U.S. Federal Reserve Board in the most recent years. That is, liquidity, in the form of large increases in the monetary base, has been expanded greatly beginning in September 2008, and then extended during early 2011 and 2013. While the expanded monetary base has not precipitated substantial increases in the general price level—because the Federal Reserve pays interest on the accounts held by banks with the Federal Reserve—such policy has caused expected inflation to rise selectively during recent months.

Q. How is inflation measured historically?

A. Inflation is measured as the rate of price change per unit of time. Inflation metrics (indexes of inflation) are based on in-depth monthly and quarterly surveys of prices, and are generally stated as annual rates of change. Inflation indexes, including the consumer price index (CPI) and the producer price index (PPI), are calculated and released monthly by the Bureau of Labor Statistics. The published inflation indexes include price changes for individual wholesale commodities, narrowly defined retail goods or services, and broadly defined sector composites. The CPI metric of inflation is available for both urban consumers and urban wage earners, and for core components. The CPI is also measured for several large, metropolitan areas, including Miami.

The PPI is computed for numerous economic sectors and production stages (commodity, intermediate, and final demand for specific sectors), and for specific commodities, product lines, and services. The PPI includes some 10,000 price series. In addition, price indexes are also estimated by the Bureau of Economic Analysis for the main components of U.S. national income (Gross Domestic Product or GDP), including Personal Consumption Expenditure (PCE) deflators.

Q. Is historical inflation, captured by various price indexes, the same as inflation expectations?

A. By definition, historical inflation refers to observed changes in the various metrics of inflation, such as the indexes described above. In contrast, inflation expectations refer to the estimates of inflation prospectively—the expectations harbored by economic agents (households, business firms, and government entities) regarding the change, or trend, in prices over future periods. Expectations of future inflation are rationally driven by expected levels of demand and supply within specific sectors of the broad macroeconomy, expected money supply, and expected interest rates to the degree that interest rates affect currency exchange rates. Importantly, inflation expectations are influenced by observed historical inflation, and the prices and price changes that parties to transactions actually experience. Price experience covers the gamut of transactions, including, in the case of households, changes in the prices of groceries and apartment rents; in the case of business entities, changes in the invoice prices for rail transport services and components of labor contracts; or in the case of public authorities such as a municipal services department, changes in the prices paid for repair services to reactivate a large water pump used for water supply.

Q. Please describe the methods that you use and recommend for measuring inflation expectations.

A. The task at hand is to estimate expectations of inflation over the near-term future, including the test period, October 2014–September 2015. As mentioned above, the issue of expected inflation is approached by applying two methods: 1) observed interest rate differentials within capital markets, and 2) surveys of expected inflation. These methods are defined as follows:

Interest Rate Differentials: Interest rate/yield differentials between two types of Treasury securities: Nominal and Treasury Inflation-Protected Securities (TIPS). The *Interest Rate Differentials* approach provides estimates of the inflation expectations of investors.

<u>*Survey Methods*</u>:

Projected Rates of Inflation: The consensus view of professional forecasters, as reported in the Philadelphia Federal Reserve Bank's *Survey of Professional Forecasters* (SPF).

Survey of Households: Expectations of future inflation as reported by sampled households included in the *Survey of Consumers* conducted monthly by the Survey Research Center, University of Michigan/Thomson Reuters.

Expectations of Inflation by Economists: Inflation expectations held by academic and business economists, as reported in the *Livingston Survey*, as conducted by the Philadelphia Federal Reserve Bank.

In brief, the approach underlying my assessment of expected inflation draws upon observed market yields on securities of equivalent risks, as well as three surveys. Such an approach is sufficiently broad, capturing the expectations of investors, forecasters, consumers, and business and academic economists.

Q. Would you please elaborate on the *Interest Rate Differentials-* and *Survey-*based methods for measuring inflation expectations?

A. Yes. The *Interest Rate Differentials* method focuses on the inflation expectations of investors, where the term "investors" is interpreted broadly to mean any party that holds, and thus purchases and sells, financial assets, including equities and debt obligations. Transacting parties can thus include individual households, retirement funds, or investment banks trading on behalf of their own accounts.

The market value of financial assets can rise or fall with respect to changes in expected inflation. Some types of assets, such as equities, are less sensitive to expected inflation than others. In the case of debt securities, *yield to maturity* refers to the expected rate of return on the outstanding principle (the securities themselves). Precisely because the face yields on debt securities such as corporate or Treasury bonds are generally held constant at the time of origination, the market value, and thus the net yield, on outstanding debt obligations either decline as expected inflation increases or rise as expected inflation decreases. Changes in market yield account for changes in expected inflation for the investment community as a whole. As a consequence, the *expected real return* on outstanding debt—realized net return after accounting for expected inflation—at a point in time is predominantly, though not exclusively, a function of perceived risks.

This is a natural result of efficient capital market processes, where expected inflation is capitalized within market yields. Debt securities with equivalent risks and terms can be expected to trade at nearly equivalent yields, given expected inflation. This result also means that, for debt obligations of common risk attributes, obligations that fully compensate for (i.e., *are protected from*) inflation should trade at market yields below the yields for obligations with nominal yields, where the difference is approximately equal to expected inflation.

This is the case for selected bond issues of the U.S. Treasury. The U.S. Treasury issues both debt securities with nominal yields, and other bonds that include provisions for inflation compensation. As mentioned, this latter type of Treasury bonds, *Treasury Inflation-Protected Securities*, referred to as TIPS, insulates investors from inflation risk.

Accordingly, this metric for expected inflation, the *Interest Rate Differentials* method, reveals investor expectations by examining the yield differences between nominal and TIPS obligations. For these analyses, nominal and TIPS yield differentials for 5-year U.S. Treasury obligations are calculated monthly for each month of 2013, and then averaged.

Q: Would you please describe the three surveys of inflation expectations listed above?

A. As mentioned, we draw upon the results of three surveys of inflation expectations. Each is described below.

Projections of Inflation are predominantly model-based forecasts of inflation, as reported in the *Survey of Professional Forecasters* (SPF) and organized by the Philadelphia Federal Reserve Bank. This survey dates to 1968 and is carried out quarterly. This survey's results present the consensus view of forecasters, covering the usual macroeconomic metrics of interest but with considerable density—a selection of thirty-two variables altogether. Of particular technical interest is that, for selected variables, SPF reports the dispersion and range of expectations of survey respondents.

Consumer Expectations of Inflation are captured by the *Survey of Consumers,* conducted by the Survey Research Center at the University of Michigan in collaboration with the Thomson Reuters News Service. This survey consists of approximately 500 telephone interviews with randomly selected households, where the question categories include personal finances, business conditions, and purchasing plans. The *Survey of Consumers* was initiated during the late 1940s.

Expectations of Inflation of Economists are based on the survey results gathered and reported semi-annually by the *Livingston Survey*, as mentioned above. This third survey is compiled from the results provided by some fifty respondents, and covers eighteen survey items, such as economic output (real and nominal GDP, corporate profits, business fixed investment, industrial production, retail sales, and auto sales), price inflation (CPI and the PPI), labor markets (unemployment rate, average earnings of wage earners), and capital markets (prime interest rate, 10-year U.S. Treasury bond rate, and the S&P 500 Index).

Q. Please summarize the methods for determining the inflation factor which you describe above.

A. The basis for the inflation factors, for determining cost escalation for the Company's test year, is the annual rates of expected inflation over the period. The overall measure of expected inflation is derived from four estimates involving two methods as I have discussed. The four estimates are expectational in nature: estimates of the expected rate of inflation harbored by four categories of economic actors, including investors, professional forecasters, consumers, and economists.

As discussed above, the first of the two methods, *Interest Rate Differentials*, is the observed interest rate gap between nominal and TIPS yields for U.S. Treasury securities. The second method draws on the expressed views of the identified constituent groups, as gathered through the three formal surveys (*Survey of Professional Forecasters*, *Survey of Consumers* (University of Michigan/Thomson Reuters), and the *Livingston Survey*). The results of these four measures of expected inflation form the basis for the Company's proposed inflation factor, for cost escalation. For this reason, for the purpose of determining future cost escalation, I recommend that the Florida PSC utilize measures for *expectations of inflation* rather than metrics of observed historical inflation.

Q. What are the overall results for the four selected metrics of inflation expectations?

A. Based on the above analyses, I project overall inflation of 2.20% and 2.23% per year for 2014 and 2015, respectively. These results are summarized in the column entitled *Summary Results* in Exhibit RJC-7. This exhibit shows estimates of inflation expectations for each of the four methods: *Nominal-TIPS Yield Differentials (1)*, *Survey of Professional Forecasters (2)*, *Survey of Consumers* (U of M/Thompson Reuters) (3), and the *Livingston Survey (4)*.

Exhibit RJC-7 presents 2013 inflation expectations for 2014 and 2015. Shown from left to right, Exhibit RJC-7 defines the *Forward Year*, details the timeframe for the S*amples of Inflation Expectations* (1st half, 2nd half, or December of 2013), and provides the results for each of methods 1 through 4. The results are summarized for each year in the far right column: expected rates of inflation (during 2013) for 2014 and 2015 are equal to 2.20% and 2.23%, respectively. The average accounts for the four methods. The sample frequency of methods 1 and 3 is higher than for methods 2 and 4.

Q. In your view, is it useful to consider observed historical inflation in order to develop projections of inflation for the near term future?

A. Yes, a useful perspective can be obtained from a review of historical inflation measures, in order to benchmark and assess the reasonableness of projections of inflation. Certainly, historical experience tailors and, to a substantial degree, also drives the expectations of inflation harbored by private companies, households, and other economic actors. In other words, historical inflation experience is implicitly accounted for in expectations of inflation for forward periods.

However, presuming that future price inflation essentially replicates that of historical timeframes, however defined, will likely result in inflation projections that do not align with the expectations held by the economy as a whole. As an example, expectations of inflation measured by interest rate differentials rose by 40 basis points between mid-2012 and March-April 2013, largely as a consequence of changes in the expected impact of the Federal Reserve's monetary policy (i.e., a slowing rate of purchase of financial assets). The expectation of considerably higher inflation, as held by investors, subsequently eased and has remained largely unchanged since early 2013.

Q. Can you please provide examples of expectations of inflation, estimated historically?

A. Historical expectations of inflation refer to expectations held at various timeframes historically. Interest rate differentials between nominal and TIPS yields for the 2003-2013 timeframe have averaged 1.95% and 2.19% for Treasury securities with 5- and 10-year terms, respectively. Similarly, the University of Michigan/Thomson Reuters monthly Survey of Consumers reveals inflation expectations of 3.10% and 3.07% for the same timeframes, 2003–2013 and 2009–2013, respectively. It is important to distinguish between historical samples of expected inflation and actual inflation, measured using various price indexes over historical periods.

Q. Does the rate of inflation within regions of the U.S., such as the Florida Peninsula, vary from the rate of inflation across the U.S?

A. Yes. First of all, it is essential to distinguish between price level and price inflation. Measured in terms of levels, prices across regions can vary greatly. Measured in terms of rates of changes through time, prices across regions appear to evolve in remarkably similar patterns over the long term.

Nonetheless, inflation for specific regions may deviate from the rate of inflation for the U.S. as a whole, over selected timeframes. Regional differences in price inflation are largely attributable to differences in growth in aggregate economic demand for goods and services. A contemporary example is the economic expansion within North Dakota's western region, a result of the vast and sudden expansion of oil and gas production within the Bakken formation. Prices, including labor costs, have risen fast within western North Dakota. Similarly, prices in southeastern Florida, including the Miami Metropolitan Statistical Area (MSA), have outpaced general price inflation for the U.S. during the 2000–2013 period, particularly during 2000–2007. Over recent years, however, it appears that price inflation in this large Florida region has slowed and, prospectively, is likely to closely approximate that of the U.S. In view of the comparative rise in economic activity in South Florida recently, I anticipate that, prospectively, price inflation in South Florida and the U.S. will maintain a similar path. In summary, with few exceptions, projections of inflation expectations for the U.S. as a whole provide an appropriate basis for inflation within various regions of the U.S., including Florida.

Q. Can you please provide a brief summary of the findings of your study of inflation expectations and your recommended inflation factors for cost escalation?

A. Yes. I have conducted an assessment of expected rates of inflation as the basis for estimating the inflation factors, for determining the escalation in costs incurred by Florida Public Utilities Company in providing electricity services during 2014 and 2015. My assessment utilizes the four methods described above. My findings indicate that the appropriate inflation factors for 2014 and 2015 are 2.20% and 2.23%, respectively.

Q. Does this conclude your testimony?

A. It does.

DIRECT TESTIMONY OF PAUL R. MOUL

INTRODUCTION AND SUMMARY OF RECOMMENDATION

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

A. My name is Paul Ronald Moul. My business address is 251 Hopkins Road, Haddonfield, New Jersey 08033-3062. I am Managing Consultant at the firm P. Moul & Associates, an independent financial and regulatory consulting firm.

Q. Please describe your educational background and prior experience.

A. I have a Bachelor of Science in Business Administration from Drexel University. I have a long history of experience in this subject area with years of study and testimony before state commissions around the country. My educational background, business experience, and qualifications are provided in Appendix A, which follows my direct testimony.

Q. What is the purpose of your testimony?

A. My testimony presents evidence, analysis, and a recommendation concerning the appropriate rate of return that the Florida Public Service Commission (the "Commission") should recognize in the determination of the revenues that Florida Public Utilities Company ("FPU" or the "Company") should realize as a result of this proceeding. My analysis and recommendation are supported by the detailed financial data contained in Exhibit PRM-1, which is a multi-page document divided into thirteen (13) schedules.

Q. Was this exhibit prepared by you or under your direction or supervision?

A. Yes, it was.

Q. Are you responsible for any of the Company's Minimum Filing Requirements

(MFRs)?

A. Yes. I am sponsoring MFR Number D-1a.

Q. Based upon your analysis, what is your conclusion concerning the appropriate cost of common equity and rate of return for the Company?

A. My conclusion is that the Commission should find that the Company's rate of return on common equity is 11.25%. With this return, I have presented on page 1 of Schedule 1 the weighted average cost of capital of 8.60% that is based on investor-provided capital. In addition, cost of capital components for customer deposits and deferred income taxes also play a role in the rate of return that is applicable to the rate base. The resulting overall cost of capital that will be used to establish rates, which is the product of weighting the individual capital costs by the proportion of each respective type of capital, should, if adopted by the Commission, establish a compensatory level of return for the use of capital and provide the Company with the ability to attract capital on reasonable terms.

Q. What background information have you considered in reaching a conclusion concerning the Company's cost of capital?

A. FPU is a combination electric and natural gas distribution utility. The Company is a wholly-owned subsidiary of Chesapeake Utilities Corporation ("Chesapeake" or "CUC"), which is a diversified energy company that has regulated gas distribution operations in Florida, Delaware, and Maryland, as well as interstate transmission of natural gas on the Delmarva Peninsula and non-regulated propane delivery operations. CUC also has other non-regulated businesses. FPU is a very small electric delivery utility that provides service to approximately 31,066 customers, in two divisions, i.e., Marianna and Fernandina Beach. The Company obtains all of the energy needs for its customers from purchases from JEA, Gulf Power Company, and other marketers. The Company's sales are primarily made to residential and commercial customers, although there are two major industrial customers engaged in the manufacturing of paper that represents approximately 9% of kWh sales.

Q. How have you determined the cost of common equity in this case?

A. The cost of common equity is established using capital market and financial data relied upon by investors to assess the relative risk, and hence the cost of equity, for an electric utility, such as FPU. In this regard, I relied on four well-recognized measures of the cost of equity: The Discounted Cash Flow ("DCF") model, the Risk Premium ("RP") analysis, the Capital Asset Pricing Model ("CAPM"), and the Comparable Earnings ("CE") approach. The results of a variety of approaches indicate that the Commission should find that the Company's rate of return on common equity is 11.25%.

Q. In your opinion, what factors should the Commission consider when determining the Company's cost of capital in this proceeding?

A. The Commission's rate of return allowance must be set to cover the Company's interest and dividend payments, provide a reasonable level of earnings retention, produce an adequate level of internally generated funds to meet capital requirements, be commensurate with the risk to which the Company's capital is exposed, assure confidence in the financial integrity of the Company, support reasonable credit quality, and allow the Company to raise capital on reasonable terms. The return that I propose fulfills these established standards of a fair rate of return set forth by the landmark Bluefield and Hope cases.[1] That is to say, my proposed rate of return is commensurate with returns available on investments having corresponding risks.

Q. What factors have you considered in measuring the cost of equity in this case?

A. The models that I used to measure the cost of common equity for the Company were applied with market and financial data developed from my proxy group of eleven (11) electric companies. The criteria that I used to assemble the proxy group will be described later in my testimony. The companies in the electric proxy group are identified on page 2 of Schedule 3. I will refer to these companies as the "Electric Group" throughout my testimony.

Q. How have you performed your cost of equity analysis with the market data for the Electric Group?

A. I have applied the market-based models (i.e., DCF, RP, and CAPM) for estimating the cost of equity using the average data for the Electric Group. By employing group average data, rather than individual Company's analysis, I have helped to minimize the effect of extraneous influences on the market data for an individual company.

Q. Please summarize your cost of equity analysis.

A. My cost of equity determination was derived from the results of the

[1] Bluefield Water Works & Improvement Co. v. P.S.C. of West Virginia, 262 U.S. 679 (1923) and F.P.C. v. Hope Natural Gas Co., 320 U.S. 591 (1944).

methods/models identified above, and is revealed on page 2 of Schedule 1. In general, the use of more than one method provides a superior foundation to arrive at the cost of equity. At any point in time, reliance on a single method can provide an incomplete measure of the cost of equity. The specific application of these methods/models will be described later in my testimony. The following table, taken from the model results presented on page 2 of Schedule 1, provides a summary of the indicated costs of equity using each of these approaches and recognizing flotation costs.[2]

DCF	9.59%
RP	12.19%
CAPM	10.84%
Comparable Earnings	13.30%
Average	11.48%
Median	11.52%
Mid-point	11.45%

From all measures of the cost of equity, I recommend that the Company's rate of return on common equity be set at 11.25%. The result of the Risk Premium and Comparable Earnings methods indicate that my recommended equity return of 11.25% is conservative. Even the average, median and midpoint of my analyses suggest my recommendation is conservative. To accommodate the Commission's

[2]Flotation costs are defined as the out-of-pocket costs associated with the issuance of common stock. Those costs typically consist of the underwriters' discount and company issuance expenses.

preference for a range of the cost of equity, I propose a range of 10.25% to 12.25%, which includes the one percentage point band on each side of the midpoint often employed by the Commission. I also believe my recommended cost of equity is appropriate in this case because it makes no provision for the prospect that the rate of return may not be achieved due to unforeseen events that could occur during the rate effective period.

ELECTRIC UTILITY RISK FACTORS

Q. Please identify some of the risk factors that impact the electric utility industry today.

A. Today, electric utilities face meaningful changes in the fundamentals that affect their operations, but cost of service pricing continues to dominate much of their business profile. On the national level, the passage of the National Energy Policy Act ("EPACT") and the issuance of FERC Order Nos. 888 and 889 and Order No. 2000 initiated sweeping changes that fundamentally altered the structure of the electric utility business.

Q. Will you please elaborate on the risk factors that affect electric utilities today?

A. Yes. Aside from the obligation to serve and the responsibility to maintain reliability, electric utilities are faced with risks associated with demand uncertainty, investment cost uncertainty, and regulatory uncertainty. In addition, the risk of distributed generation will continue to be a concern, and could have an increasing influence on the business of electric delivery utilities. With technological advances in micro-turbines, potential commercialization of fuel cells, development of wind and solar power, and the creation of micro-grids, utilities face the potential for bypass and the resulting declines in transmission and distribution revenues. At the same time, an electric utility retains the obligation to provide reliable delivery service. Utilities must make new investment to provide continuity of quality service, keep rates reasonable, while promoting conservation.

Moreover, regulatory risks include the overall framework of ratesetting, cost allocation, and rate design issues, and the level of return that will be allowed. With increased emphasis on market-determined prices, a new dimension exists in the electric utility business. A pricing structure restricted by regulation or politics diminishes management's ability to adjust its business strategy quickly to changing market conditions to respond to broadening competition.

Q. Are there specific risk issues facing the Company?

A. Yes. Energy deliveries to one commercial and two industrial customers, which represent approximately 42,064,300 of kWh sales, are usually thought to be of higher risk than to residential customers. Success in this segment of the Company's market is subject to the business cycle and pressures from self-generation. Moreover, external factors also can influence deliveries to these customers, which face competitive pressure on their own operations from other facilities outside the utility's service territory.

Q. Please indicate how the Company's risk profile is affected by its construction program.

A. The Company is faced with the requirement to undertake investment to maintain and upgrade existing facilities in its service territory and to meet growth. Over the next five years (i.e., 2014 through 2018), the Company's total capital expenditures are expected to be approximately \$32.6 million, as described in the testimony of Company witness Mark Cutshaw. These expenditures will represent approximately 52% (\$32.6 million ÷ \$63.0 million) of the net utility plant at December 31, 2013.

A fair rate of return for the Company represents a key to a financial profile that will provide the Company with the ability to raise the capital, in all market conditions to meet its needs, and to satisfy investor requirements at reasonable cost. In the situation where significant additional capital is required, as shown by the construction expenditures indicated above, the regulatory process must establish a return on equity that provides a reasonable opportunity for the Company to actually achieve its cost of capital. This is especially important for FPU due to its small size.

FUNDAMENTAL RISK ANALYSIS

Q. Is it necessary to conduct a fundamental risk analysis to provide a framework for a determination of a utility's cost of equity?

A. Yes. It is necessary to establish a company's relative risk position within its industry through a fundamental analysis of various quantitative and qualitative factors that bear upon investors' assessment of overall risk. The qualitative factors that bear upon the Company's risk have already been discussed. The quantitative risk analysis follows. The items that influence investors' evaluation of risk and their required returns were described above. For this purpose, I compared FPU to the S&P Public Utilities, an industry-wide proxy consisting of various regulated businesses, and to the Electric Group.

Q. What are the components of the S&P Public Utilities?

A. The S&P Public Utilities is a widely recognized index that is comprised of electric power and natural gas companies. These companies are identified on page 3 of Schedule 4.

Q. What criteria did you employ to assemble the Electric Group?

A. The Electric Group companies have the following common characteristics: they are engaged in similar business lines, have publicly-traded common stock, are reported in The Value Line Investment Survey, operate within the southeastern and south central regions of the U.S., and are not currently the target of a merger or acquisition. It would be inappropriate to include a company that is a target of a takeover in a proxy group because the stock price of that company reflects the acquisition price of the target company. The Electric Group includes American Electric Power Company, CenterPoint Energy, Inc., Cleco Corporation, Dominion Resources, Inc., Duke Energy Corp., Entergy Corp., NextEra Energy, Inc., OGE Energy Corp., SCANA Corp., Southern Company, and TECO Energy. The Electric Group members are identified on page 2 of Schedule 3.

Q. Is knowledge of a utility's bond rating an important factor in assessing its risk and cost of capital?

A. Yes. Knowledge of a company's credit quality rating is important because the cost of each type of capital is directly related to the associated risk of the firm. So while a company's credit quality risk is shown directly by the rating and yield on its bonds, these relative risk assessments also bear upon the cost of equity. This is because a firm's cost of equity is represented by its borrowing cost plus compensation to recognize the higher risk of an equity investment compared to debt.

Q. Does FPU have a bond rating from the major credit rating agencies?

A. No. There is no public rating on the debt of FPU. Rather, I have reviewed the credit quality rating of CUC, which provides the basis for the debt component of FPU's rate of return. The CUC's long-term debt carries a designation of "1" from the National Association of Insurance Commissioners ("NAIC"). The NAIC is a non-profit organization that is comprised of the chief insurance regulators of the fifty states, the District of Columbia, and four U.S. territories. Essentially, it is a trade association of insurance regulators much like the National Association of Regulatory Utility Commissioners ("NARUC") is for state economic regulators. NAIC conducts analysis that aids the state regulators in performing their oversight of the insurance companies. As the NAIC has stated:

> The quality of the assets of an insurance company has long been a key concern to state insurance regulators. As the chief public officials charged with the responsibility for monitoring the financial condition of insurers, state regulators must keep a close watch on both the credit quality and the value of those assets.

As noted, the valuation of the assets of insurance companies has been a matter of concern to the NAIC for a very long period of time. The NAIC recognized the need for the standardization of securities valuation across the U.S.

and published its first volume of *Valuation of Securities* in 1908. Later, in 1949, the NAIC set up the Securities Valuation Office ("SVO") to perform analytical valuations of the growing number of securities owned by insurance companies that were acquired through private placement. Privately placed securities owned by insurance companies typically do not have credit quality ratings from Moody's and S&P. The mission of the SVO is to provide state insurance regulators and insurance companies with a uniform source of prices and quality ratings for securities holdings in the portfolios of insurance companies. These prices and quality ratings form what are known as "Association Values" that are used by insurance companies in their Annual Statements filed with state insurance regulators. For many years, the SVO used four bond rating categories: "Yes" (investment grade), "No*" (average quality), "No**" (below average quality), and "No" (in or near default). In September 1986, NAIC Valuation of Securities Task Force began to consider revising its bond rating system that had been used previously to provide a more discriminating set of bond categories. After 2-1/2 years of study, the NAIC established a six-category system that is in use today.

Q. Are NAIC designations comparable to S&P and Moody's?

A. Yes. The NAIC designations provide credit quality ratings for privately placed debt securities that are not rated by Moody's and S&P. The chart below summarizes the alignment between the different ratings by S&P, Moody's and NAIC:

S&P	Moody's	NAIC	
AAA	Aaa	1	
AA+	Aa1	1	
AA	Aa2	1	
AA-	Aa3	1	
A+	A1	1	Investment
A	A2	1	Grade
A-	A3	1	
BBB+	Baa1	2	
BBB	Baa2	2	↑
BBB-	Baa3	2	
BB+	Ba1	3	↓
BB	Ba2	3	
BB-	Ba3	3	
B+	B1	4	Non-
B	B2	4	Investment
B-	B3	4	Grade
CCC	Caa	5	
CC	Ca	5	
C	C	5	
D	D	6	

Q. How do the ratings compare for CUC, the Electric Group, and the S&P Public Utilities?

A. Due to the size of the debt issued by CUC, private placement is the most cost effective way of issuing debt. As noted above, CUC has an NAIC designation of 1, which is equivalent to an A-bond rating and above. For the Electric Group, the average LT issuer rating is Baa1 from Moody's Investors Service ("Moody's") and the average CCR is BBB+ from Standard & Poor's Corporation ("S&P"). The LT issuer rating by Moody's and the CCR designation by S&P focuses upon the credit quality of the issuer of the debt, rather than upon the debt obligation itself. Many of the financial indicators that I will subsequently discuss are considered during the rating process.

Q. How do the financial data compare for FPU, the Electric Group, and the S&P Public Utilities?

A. The broad categories of financial data that I will discuss are shown on Schedules 2, 3, and 4. The data cover the five-year period 2008-2012. The analysis covering the years 2011 and 2012 for FPU relate to its electric operations exclusively. The amounts that I used were taken from the Company's FERC Form No. 1 and are not prepared in a rate case format. That is to say, all of the Company's capitalization is represented by proprietary capital for the purpose of the FERC Form No. 1 presentation. Prior years, i.e., 2008, 2009 and 2010, cover both the Company's electric and natural gas distribution operations. The important categories of relative risk may be summarized as follows:

Size. In terms of capitalization, FPU is very much smaller than the average size of the Electric Group and the S&P Public Utilities. All other things being equal, a smaller company is riskier than a larger company because a specific numerical change in revenue and expense has a proportionately greater impact on a small firm. As I will demonstrate later, the size of a firm can impact its cost of equity. This is the case for FPU.

Market Ratios. Market-based financial ratios provide a partial indication of the investor-required cost of equity. If all other factors are equal, investors will require a higher rate of return on equity for companies that exhibit greater risk, in order to compensate for that risk. That is to say, a firm that investors perceive to have higher risks will experience a lower price per share in relation to expected earnings. For example, two otherwise similarly situated firms each reporting $1.00 in earnings per share would have different market prices at varying levels of risk (i.e., the firm with a higher level of risk will have a lower share value, while the firm with a lower risk profile will have a higher share value).

There are no market ratios available for FPU because the Company's stock is not traded. The five-year average price-earnings multiple for the Electric Group was somewhat below that of the S&P Public Utilities. The five-year average dividend yield was the same for the Electric Group and the S&P Public Utilities. The average market-to-book ratio for the Electric Group was fairly similar to the S&P Public Utilities.

<u>Common Equity Ratio.</u> The level of financial risk is measured by the proportion of long-term debt and other senior capital that is contained in a company's capitalization. Financial risk is also analyzed by comparing common equity ratios (the complement of the ratio of debt and other senior capital). That is to say, a firm with a high common equity ratio has lower financial risk, while a firm with a low common equity ratio has higher financial risk. The five-year average common equity ratios, based on permanent capital, were 43.0% for the Electric Group and 45.0% for the S&P Public Utilities. The capital structure for the FPU Electric Division is not meaningful because the CUC capital structure is used for rate of return purposes for FPU.

<u>Return on Book Equity.</u> Greater variability (i.e., uncertainty) of a firm's earned returns signifies relatively greater levels of risk, as shown by the coefficient of variation (standard deviation ÷ mean) of the rate of return on book common equity. The higher the coefficients of variation, the greater degree of variability. For the five-year period, the coefficients of variation were 0.873 (5.5% ÷ 6.3%) for FPU, 0.132 (1.6% ÷ 12.1%) for the Electric Group, and 0.104 (1.1% ÷ 10.6%) for the S&P Public Utilities. The earnings variability was much higher for FPU than the Electric Group and the S&P Public Utilities, indicating that the Company has higher risk. Moreover, the Company's generally poor historical earnings performance only adds to its risk.

<u>Operating Ratios.</u> I have also compared operating ratios (the percentage of revenues consumed by operating expense, depreciation and taxes other than income taxes).[4] The complement of the operating ratio is the operating margin which provides a measure of profitability. The higher the operating ratio, the lower the operating margin. The five-year average operating ratios were 94.6% for FPU, 80.9% for the Electric Group, and 82.3% for the S&P Public Utilities. These comparisons show significantly higher operating risk for FPU as compared to the Electric Group and the S&P Public Utilities. FPU's higher operating ratio can be traced to the significant role that purchased power has on its operations. With a majority of its energy requirements provided by other utilities, the Company must rely upon JEA and Gulf Power Company to provide the majority of the energy

[4]The complement of the operating ratio is the operating margin which provides a measure of profitability. The higher the operating ratio, the lower the operating margin.

needs for its customers. In the hierarchy of claims on the Company's revenues, JEA and Gulf Power Company (i.e., the wholesalers) obtain recovery of their fixed costs prior to the realization of a return for FPU (i.e., the retailer).

Coverage. The level of fixed charge coverage (i.e., the multiple by which available earnings cover fixed charges, such as interest expense) provides an indication of the earnings protection for creditors. Higher levels of coverage, and hence earnings protection for fixed charges, are usually associated with superior grades of creditworthiness. The five-year average interest coverage (excluding Allowance for Funds Used During Construction ("AFUDC")) was 2.95 times for FPU, 3.23 times for the Electric Group, and 3.12 times for the S&P Public Utilities. The lower interest coverage for FPU can be traced to its lower earnings rate on its common equity. The Company's lower interest coverage adds to its risk.

Quality of Earnings. Measures of earnings quality usually are revealed by the percentage of AFUDC related to income available for common equity, the effective income tax rate, and other cost deferrals. These measures of earnings quality usually influence a firm's internally generated funds because poor quality of earnings would not generate high levels of cash flow. Quality of earnings has not been a significant concern for FPU, the Electric Group, and the S&P Public Utilities.

Internally Generated Funds. Internally generated funds ("IGF") provide an important source of new investment capital for a utility and represent a key measure of credit strength. Historically, the five-year average percentage of IGF to capital expenditures was 126.5% for FPU, 82.3% for the Electric Group, and 91.1% for the S&P Public Utilities. The higher IGF percentage indicates a lower risk factor for FPU.

Betas. The financial data that I have been discussing relate primarily to company-specific risks. Market risk for firms with publicly-traded stock is measured by beta coefficients. Beta coefficients attempt to identify systematic risk, i.e., the risk associated with changes in the overall market for common equities. Value Line publishes such a statistical measure of a stock's relative historical volatility to the rest of the market. As computed by Value Line, the beta coefficient is derived from a regression analysis of the relationship between weekly percentage changes in the price of a stock and weekly percentage changes in the NYSE Index over a period of five years. The betas are adjusted for their long-term tendency to converge toward 1.00. A common stock that has a beta less than 1.0 is considered to have less systematic risk than the market as a whole and would be expected to rise and fall more slowly than the rest of the market. A stock with a beta above 1.0 would have more systematic risk. A comparison of market risk is shown by the Value Line beta of .73 as the average for the Electric Group (see page 2 of Schedule 3), and .75 as the average for the S&P Public Utilities (see page 3 of Schedule 4).

Q. Please summarize your risk evaluation of the Company and the Electric Group.

A. FPU is much smaller than the average size of the Electric Group and its earnings are much more variable. The Company also has a high operating ratio. These factors indicate that the Company has a higher risk profile. The Company's relatively high IGF percentage is an offsetting risk factor. Since several of these risk factors balance out, the cost of equity derived from the Electric Group provides a reasonable basis for measuring the Company's cost of equity.

CAPITAL STRUCTURE RATIOS

Q. Please explain the selection of capital structure ratios for FPU.

A. CUC provides all the permanent capital, both debt and equity, for FPU. There is some legacy debt that remains outstanding that was issued prior to FPU's acquisition by CUC. This debt remains outstanding because it is not callable without a make-whole provision to the lender. The Company has determined that it is uneconomic to redeem this debt and make the call premium payment. For this case, CUC's capital structure ratios have been employed for rate of return purposes after assigning the legacy debt directly to FPU. Details of the Company's proposed capital structure are provided in the D-Schedules and are summarized on my Schedule 1.

Q. Why is it appropriate to assign the legacy debt to the Company's weighted average cost of capital with the remainder represented by the Parent Company capitalization?

A. As noted above, there is one series of long-term debt that remains outstanding, which was issued prior to the acquisition of FPU by CUC. When rates were set for the Company prior to the acquisition, this issue of debt was part of the capital structure of FPU for rate of return purposes. As this one issue remains outstanding, it should be included in the Company's capital structure, which is consistent with previous rate cases. The direct assignment of this debt to FPU will avoid having customer rates in other jurisdictions carry the cost of this debt (i.e., Delaware, Maryland, and FERC jurisdictional customers do not benefit from this debt). That is to say, FPU customers have benefited from the assets constructed with the legacy debt, and should continue to carry the cost associated with it. As to the remainder of the Company's capital structure, it should be represented by the relative proportions of the CUC capitalization. This procedure is appropriate because CUC refinanced the other debt previously issued by FPU prior to the acquisition, and CUC will provide all of the new capital needs of FPU on a going forward basis.

Q. Please explain the justification for removing the accumulated Other Comprehensive Income ("OCI") from the capital structure ratios proposed for this case.

A. The accumulated OCI must be eliminated from the capital structure for ratesetting purposes. OCI arises from a variety of sources, including: minimum pension liability ("MPL"), foreign currency hedges, unrealized gains and losses on securities available for sale, interest rate swaps, and other cash flow hedges. The accumulated OCI has its roots in the MPL. None of the accounting entries that affect accumulated OCI have anything to do with financing the rate base (i.e., they do not generate or consume any cash). A MPL entry must be recorded on the balance sheet when the present value of the pension benefit earned by employees exceeds the market value of trust fund assets. As such, MPL arises from a decline in stock market values and a decline in interest rates, which reduces the value of the trust fund assets and increases the present value calculation of the pension benefit obligation. SFAS 87 requires that the MPL be recognized as a pension expense over future periods, as long as the MPL continues to exist. When stock market improves and when interest rates rise from recent low levels, the MPL will reverse and not impact future pension expense. Hence, the accumulated OCI must be excluded from the common equity.

Q. As shown on Schedule D-1a, the capital structure ratios that the Company proposes for the projected test year 2015 include 41.79% combined legacy debt, long-term debt and short-term debt, and 58.21% common equity based on investor provided capital. Are these ratios reasonable for the Company?

A. Yes. These ratios conform with the Company's capital structure objectives stated on Schedule D-8. Further justification for these ratios rests with the market capitalization capital structure ratios for the Electric Group shown on Schedule 8. Since we are using market-based models (i.e., DCF, RP and CAPM) with data obtained from the Electric Group, then the capital structure ratios derived from the market capitalization of the Electric Group is relevant for comparative purposes. There, the average common equity ratio for the Electric Group is 57.58% based on the market capitalization, which is close to the 58.21% common equity ratio proposed by the Company for ratesetting purposes. Moreover, the Company's common equity ratio is clearly within the range of common equity ratios for the Electric Group based on their market capitalization. Further, the small size of

FPU/CUC requires more conservative financial policies as compared to the Electric Group. The capital structure proposed by the Company will allow it to invest in order to grow its business and take advantage of other opportunities.

COST OF SENIOR CAPITAL

Q. Please explain the cost of debt for FPU.

A. Consistent with the capital structure ratios for the Company, the embedded cost rates of FPU's legacy debt and the cost of CUC's debt must be employed. The determination of the cost of debt is essentially an arithmetic exercise and is provided in the D-Schedules.

Q. The Company has forecast new issues of long-term debt for CUC in September 2014 and in 2015. Are the rates of interest on the new long-term debt financings that the Company has forecast reasonable?

A. Yes. For the September 2014 new issue by CUC, the Company has forecast a rate of 4.50%. For the 2015 issue, the Company has forecast a rate of 5.00%. The Company is proposing a fifteen year term for its proposed new issues of long-term debt. These rates are reasonable based upon the forecast contained in the Blue Chip Financial Forecasts, which I will describe below. According to Blue Chip, the consensus yield on thirty-year Treasury bonds is forecast to be 4.1% for the third quarter of 2014 (see page 2 of Schedule 12). Adding to that yield the interest rate spread of 1.00% related to A-rated public utility bonds that I will describe below, the Blue Chip derived yield would be 5.1% (i.e., 4.1% + 1.0% = 5.1%). This shows that the Company's forecast of 4.5% is reasonable and recognizes that the term for its issue (i.e., 15 years) is shorter than a 30-year issue. Likewise for the 2015 issue, the Blue Chip issue dated December 1, 2013 provides the long-range forecasts of interest rates, which reveals 4.3% yield for 30-year Treasury bonds. Here, the Blue Chip derived yield for A-rated public utility bonds would be 5.3% (4.3% + 1.0% = 5.3%). Again, the Company's forecast is reasonable in light of its shorter 15-year maturity.

Q. Are the projections of future interest rates regarding short-term debt that the Company has proposed in this case reasonable?

A. Yes. The Company has reflected the general trend toward higher interest rates as part of its forecasts in this case. According to the Blue Chip issue that forecasts long-range interest rates, the LIBOR rate that forms the basis for CUC's short-term borrowings are shown below:

Year	LIBOR
2015	0.90%
2016	2.20%
2017	3.30%
2018	4.00%
Average	2.60%

The Company has proposed the use of a four-year average for its short-term borrowings. Therefore, the forecast interest rate for short-term debt would be 3.7% (2.6% + 1.1%), which reflects the 1.10% margin that the Company is required to pay under its short-term credit facility that exceeds LIBOR.

COST OF EQUITY – GENERAL APPROACH

Q. Please describe the process you employed to determine the cost of equity for FPU.

A. Although my fundamental financial analysis provides the required framework to establish the risk relationships among FPU, the Electric Group, and the S&P Public Utilities, the cost of equity must be measured by standard financial models that I identified above. Differences in risk traits, such as size, business diversification, geographical diversity, regulatory policy, financial leverage, and bond ratings must be considered when analyzing the cost of equity.

It is also important to reiterate that no one method or model of the cost of equity can be applied in an isolated manner. Rather, informed judgment must be used to take into consideration the relative risk traits of the firm. It is for this reason that I have used more than one method to measure FPU's cost of equity. As I describe below, each of the methods used to measure the cost of equity contains certain incomplete and/or overly restrictive assumptions and constraints that are not optimal. Therefore, I favor considering the results from a variety of methods. In this regard, I applied each of the methods with data taken from the Electric Group to arrive at a cost of equity of 11.25%.

DISCOUNTED CASH FLOW ANALYSIS

Q. Please describe your use of the Discounted Cash Flow approach to determine the cost of equity.

A. The DCF model seeks to explain the value of an asset as the present value of future expected cash flows discounted at the appropriate risk-adjusted rate of return. In its simplest form, the DCF return on common stock consists of a current cash (dividend) yield and future price appreciation (growth) of the investment. The dividend discount equation is the familiar DCF valuation model and assumes future dividends are systematically related to one another by a constant growth rate. The DCF formula is derived from the standard valuation model: $P = D/(k-g)$, where P = price, D = dividend, k = the cost of equity, and g = growth in cash flows. By rearranging the terms, we obtain the familiar DCF equation: $k = D/P + g$. All of the terms in the DCF equation represent investors' assessment of expected future cash flows that they will receive in relation to the value that they set for a share of stock (P). The DCF equation is sometimes referred to as the "Gordon" model. My DCF results are provided on page 2 of Schedule 1 for the Electric Group. The DCF return is 9.59%.

Among other limitations of the model, there is a certain element of circularity in the DCF method when applied in rate cases. This is because investors' expectations for the future depend upon regulatory decisions. In turn, when regulators depend upon the DCF model to set the cost of equity, they rely upon investor expectations that include an assessment of how regulators will decide rate cases. Due to this circularity, the DCF model may not fully reflect the true risk of a utility.

Q. Please explain the dividend yield component of a DCF analysis.

A. The DCF methodology requires the use of an expected dividend yield to establish the investor-required cost of equity. The monthly dividend yields for the twelve months ended December 2013, are shown on Schedule 5 and capture an adjustment to the month-end prices to reflect the buildup of the dividend in the price that has occurred since the last ex-dividend date (i.e., the date by which a shareholder must own the shares to be entitled to the dividend payment – usually about two to three weeks prior to the actual payment).

For the twelve months ended December 2013, the average dividend yield was 4.01% for the Electric Group based upon a calculation using annualized dividend payments and adjusted month-end stock prices. The dividend yields for the more recent six- and three-month periods were 4.04% and 4.03%, respectively. I have used, for the purpose of the DCF model, the six-month average dividend yield of 4.04% for the Electric Group. The use of this dividend yield will reflect current capital costs, while avoiding spot yields. For the purpose of a DCF calculation, the average dividend yield must be adjusted to reflect the prospective nature of the dividend payments, i.e., the higher expected dividends for the future. Recall that the DCF is an expectational model that must reflect investor anticipated cash flows for the Electric Group. I have adjusted the six-month average dividend yield in three different, but generally accepted, manners and used the average of the three adjusted values as calculated in the lower panel of data presented on Schedule 5. This adjustment adds eleven basis points to the six-month average historical yield, thus producing, the 4.15% adjusted dividend yield for the Electric Group.

Q. Please explain the underlying factors that influence investor's growth

expectations.

A. As noted previously, investors are interested principally in the future growth of their investment (i.e., the price per share of the stock). Future earnings per share growth represent the DCF model's primary focus because under the constant price-earnings multiple assumption of the model, the price per share of stock will grow at the same rate as earnings per share. In conducting a growth rate analysis, a wide variety of variables can be considered when reaching a consensus of prospective growth, including: earnings, dividends, book value, and cash flows stated on a per share basis. Historical values for these variables can be considered, as well as analysts' forecasts that are widely available to investors. A fundamental growth rate analysis is sometimes represented by the internal growth ("b x r"), where "r" represents the expected rate of return on common equity and "b" is the retention rate that consists of the fraction of earnings that are not paid out as dividends. To be complete, the internal growth rate should be modified to account for sales of new common stock. This is called external growth ("s x v"), where "s" represents the new common shares expected to be issued by a firm and "v" represents the value that accrues to existing shareholders from selling stock at a price different from book value. Fundamental growth, which combines internal and external growth, provides an explanation of the factors that cause book value per share to grow over time.

Growth also can be expressed in multiple stages. This expression of growth consists of an initial "growth" stage where a firm enjoys rapidly expanding markets, high profit margins, and abnormally high growth in earnings per share. Thereafter, a firm enters a "transition" stage where fewer technological advances and increased product saturation begin to reduce the growth rate and profit margins come under pressure. During the "transition" phase, investment opportunities begin to mature, capital requirements decline, and a firm begins to pay out a larger percentage of earnings to shareholders. Finally, the mature or "steady-state" stage is reached when a firm's earnings growth, payout ratio, and return on equity stabilizes at levels where they remain for the life of a firm. The three stages of growth assume a step-down of high initial growth to lower sustainable growth. Even if these three stages of growth can be envisioned for a firm, the third "steady-state" growth stage, which is assumed to remain fixed in perpetuity, represents an unrealistic expectation because the three stages of growth can be repeated. That is to say, the stages can be repeated where growth for a firm ramps-up and ramps-down in cycles over time.

Q. What investor-expected growth rate is appropriate in a DCF calculation?

A. Investors consider both company-specific variables and overall market sentiment (i.e., level of inflation rates, interest rates, economic conditions, etc.) when balancing their capital gains expectations with their dividend yield requirements. I follow an approach that is not rigidly formatted because investors are not influenced by a single set of company-specific variables weighted in a formulaic manner. In my opinion, all relevant growth rate indicators using a variety of techniques must be evaluated when formulating a judgment of investor-expected growth.

Q. What data for the proxy group have you considered in your growth rate analysis?

A. I have considered the growth in the financial variables shown on Schedules 6 and 7. The historical growth rates were taken from the Value Line publication that provides this data. As shown on Schedule 6, the historical growth of earnings per share was in the range of 3.60% to 5.23% for the Electric Group.

Schedule 7 provides projected earnings per share growth rates taken from analysts' forecasts compiled by IBES/First Call, Zacks, Morningstar, SNL, and Value Line. IBES/First Call, Zacks, Morningstar, and SNL represent reliable authorities of projected growth upon which investors rely. The IBES/First Call, Zacks, and SNL growth rates are consensus forecasts taken from a survey of analysts that make projections of growth for these companies. The IBES/First Call, Zacks, Morningstar, and SNL estimates are obtained from the Internet and are widely available to investors. First Call probably is quoted most frequently in the financial press when reporting on earnings forecasts. The Value Line forecasts also are widely available to investors and can be obtained by subscription or free-of-charge at most public and collegiate libraries. The IBES/First Call, Zacks, Morningstar, and SNL forecasts are limited to earnings per share growth, while Value Line makes projections of other financial variables. The Value Line forecasts of dividends per share, book value per share, and cash flow per share have also been included on Schedule 7 for the Electric Group.

Q. What specific evidence have you considered in the DCF growth analysis?

A. As to the five-year forecast growth rates, Schedule 7 indicates that the projected earnings per share growth rates for the Electric Group are 4.99% by IBES/First

Call, 5.27% by Zacks, 5.68% by Morningstar, 5.13% by SNL, and 4.70% by Value Line. The Value Line projections indicate that earnings per share for the Electric Group will grow prospectively at a more rapid rate (i.e., 4.70%) than the dividends per share (i.e., 4.64%), which translates into a declining dividend payout ratio for the future. As noted earlier, with the constant price-earnings multiple assumption of the DCF model, growth for these companies will occur at the higher earnings per share growth rate, thus producing the capital gains yield expected by investors.

Q. What conclusion have you drawn from these data regarding the applicable growth rate to be used in the DCF model?

A. A variety of factors should be examined to reach a conclusion on the DCF growth rate. However, certain growth rate variables should be emphasized when reaching a conclusion on an appropriate growth rate.

First, historical and projected earnings per share, dividends per share, book value per share, cash flow per share, and retention growth represent indicators that could be used to provide an assessment of investor growth expectations for a firm. However, although history cannot be ignored, it cannot receive primary emphasis. This is because an analyst, when developing a forecast of future earnings growth, would first apprise himself/herself of the historical performance of a company. Hence, there is no need to count historical growth rates separately, because historical performance already is reflected in analysts' forecasts.

Second, from the various alternative measures of growth identified above, earnings per share should receive greatest emphasis. Earnings per share growth are the primary determinant of investors' expectations regarding their total returns in the stock market. This is because the capital gains yield (i.e., price appreciation) will track earnings growth with a constant price earnings multiple (a key assumption of the DCF model). Moreover, earnings per share (derived from net income) are the source of dividend payments and are the primary driver of retention growth and its surrogate, i.e., book value per share growth. As such, under these circumstances, greater emphasis must be placed upon projected earnings per share growth. In this regard, it is worthwhile to note that Professor Myron Gordon, the foremost proponent of the DCF model in rate cases, concluded that the best measure of growth in the DCF model is a forecast of earnings per share growth.[5] Hence, to follow Professor Gordon's findings, projections of earnings per share growth, such as those published by IBES/First Call, Zacks, Morningstar, and Value Line, represent a reasonable assessment of investor expectations.

The forecasts of earnings per share growth, as shown on Schedule 7, provide a range of average growth rates of 4.70% to 5.68%. Although the DCF growth rates cannot be established solely with a mathematical formulation, it is my opinion that an investor-expected growth rate of 5.25% is within the array of earnings per share growth rates shown by the analysts' forecasts. The stellar performance of the stock market in 2013 points to an improving economy, as it is one of the leading

[5] Gordon, Gordon & Gould, "Choice Among Methods of Estimating Share Yield," The Journal of Portfolio Management (Spring 1989).

economic indicators compiled by The Conference Board.[6] In fact, the Leading Economic Index, whose financial components include the stock market, has increased for five consecutive months through November 2013. Moreover, "…the strengths among the leading indicators have become more widespread." according to The Conference Board. This improving economic growth argues for a higher DCF growth rate in the future.

Q. Are the dividend yield and growth components of the DCF adequate to explain the rate of return on common equity when it is used in the calculation of the weighted average cost of capital?

A. Only if the capital structure ratios are measured with the market value of debt and equity. In the case of the Electric Group, those average capital structure ratios are 42.16% long-term debt, 0.26% preferred stock, and 57.58% common equity, as shown on Schedule 8. These capital structure ratios are quite close to the ratios that the Company proposes in this case.

Q. How have you measured the flotation cost allowance as part of the DCF return?

A. The flotation cost adjustment adds 0.19% (9.59% - 9.40%) to the rate of return on common equity for the Electric Group as shown by the calculations provided on page 2 of Schedule 1. In my opinion, this adjustment is reasonable and supported by the analysis of natural gas utility stock issue shown on Schedule 9. On that

[6] The Conference Board U.S. Business Cycle Indicators -The Conference Board Leading Economic Index (LEI) for the U.S. and Related Composite Economic Indexes for November 2013 [Press Release].Retrieved from http://www.conference-board.org/data/bci.cfm dated December 19, 2013.

schedule, I show that the average underwriters' discount and commission and company issuance expenses are 3.3% for the twenty-six issues of common stock shown there for the Electric Group. Since I apply the flotation cost to the entire DCF result, I have utilized a flotation cost adjustment factor of 1.02 on page 2 of Schedule 1.

RISK PREMIUM ANALYSIS

Q. Please describe your use of the Risk Premium approach to determine the cost of equity.

A. With the Risk Premium approach, the cost of equity capital is determined by corporate bond yields plus a premium to account for the fact that common equity is exposed to greater investment risk than debt capital. The result of my Risk Premium study is shown on page 2 of Schedule 1. That result is 12.19% including the adjustment for flotation costs. As with other models used to determine the cost of equity, the Risk Premium approach has its limitations, including potential imprecision in the assessment of the future cost of corporate debt and the measurement of the risk-adjusted common equity premium.

Q. What long-term public utility debt cost rate did you use in your Risk Premium analysis?

A. In my opinion, a 5.50% yield represents a reasonable estimate of the prospective yield on long-term A-rated public utility bonds.

Q. What forecasts of interest rates have you considered in your analysis?

A. I have determined the prospective yield on A-rated public utility debt by using the

Blue Chip Financial Forecasts ("Blue Chip") along with the spread in the yields that I describe below. The Blue Chip is a reliable authority and contains consensus forecasts of a variety of interest rates compiled from a panel of banking, brokerage, and investment advisory services. In early 1999, Blue Chip stopped publishing forecasts of yields on A-rated public utility bonds because the Federal Reserve deleted these yields from its Statistical Release H.15. To independently project a forecast of the yields on A-rated public utility bonds, I have combined the forecast yields on long-term Treasury bonds published on January 1, 2014, and a yield spread of 1.00%, derived from historical data.

Q. What historical data have you analyzed?

A. I have analyzed the historical yields on the Moody's index of long-term public utility debt as shown on page 1 of Schedule 10. For the twelve months ended December 2013, the average monthly yield on Moody's index of A-rated public utility bonds was 4.48%. For the six and three-month periods ended December 2013, the yields were 4.75% and 4.76%, respectively. During the twelve-months ended December 2013, the range of the yields on A-rated public utility bonds was 4.00% to 4.81%. Page 2 of Schedule 10 shows the long-run spread in yields between A-rated public utility bonds and long-term Treasury bonds. As shown on page 3 of Schedule 10, the yields on A-rated public utility bonds have exceeded those on 30-year Treasury bonds by 1.03% on a twelve-month average basis, 0.99% on a six-month average basis, and 0.97% on a the three-month average basis. From these averages, 1.00% represents a reasonable spread for the yield on A-rated public utility bonds over Treasury bonds.

Q. How have you used these data to project the yield on a-rated public utility bonds for the purpose of your Risk Premium analyses?

A. Shown below is my calculation of the prospective yield on A-rated public utility bonds using the building blocks discussed above, i.e., the Blue Chip forecast of Treasury bond yields and the public utility bond yield spread. For comparative purposes, I also have shown the Blue Chip forecasts of Aaa-rated and Baa-rated corporate bonds. These forecasts are:

		Blue Chip Financial Forecasts				
		Corporate		30-Year	A-rated Public Utility	
Year	Quarter	Aaa-rated	Baa-rated	Treasury	Spread	Yield
2014	First	4.7%	5.5%	3.9%	1.00%	4.90%
2014	Second	4.8%	5.6%	4.0%	1.00%	5.00%
2014	Third	4.9%	5.7%	4.1%	1.00%	5.10%
2014	Fourth	5.0%	5.8%	4.2%	1.00%	5.20%
2015	First	5.1%	5.9%	4.3%	1.00%	5.30%
2015	Second	5.2%	6.0%	4.4%	1.00%	5.40%

Q. Are there additional forecasts of interest rates that extend beyond those shown above?

A. Yes. Twice yearly, Blue Chip provides long-term forecasts of interest rates. In its December 1, 2013 publication, Blue Chip published longer-term forecasts of interest rates, which were reported to be:

	Blue Chip Financial Forecasts		
	30-Year	Corporate	
Averages	Treasury	Aaa-rated	Baa-rated
2015-19	5.0%	5.7%	6.7%
2020-24	5.5%	6.3%	7.0%

Given these forecasted interest rates, a 5.50% yield on A-rated public utility bonds represents a reasonable expectation.

Q. What equity Risk Premium have you determined for this case?

A. To develop an appropriate equity risk premium, I analyzed the results from Stocks, Bonds, Bills and Inflation ("SBBI") 2014 Classic Yearbook published by Ibbotson Associates that is part of Morningstar. My investigation reveals that the equity risk premium varies according to the level of interest rates. That is to say, the equity risk premium increases as interest rates decline and it declines as interest rates increase. This inverse relationship is revealed by the summary data presented below and shown on page 1 of Schedule 11.

Common Equity Risk Premiums

Low Interest Rates	7.60%
Average Across All Interest Rates	5.79%
High Interest Rates	3.98%

Based on my analysis of the historical data, the equity risk premium was 7.60% when the marginal cost of long-term government bonds was low (i.e., 3.01%, which was the average yield during periods of low rates). Conversely, when the yield on long-term government bonds was high (i.e., 7.28% on average during periods of high interest rates) the spread narrowed to 3.98%. Over the entire spectrum of interest rates, the equity risk premium was 5.79% when the average government bond yield was 5.15%. With the recent upward movement of interest rates that I described above from historically low levels, I have utilized a 6.50% equity risk premium. This equity risk premium is between the 7.60% premium related to periods of low interest rates and the 5.79% premium related to average interest rates across all levels.

.

CAPITAL ASSET PRICING MODEL

Q. What are the features of the CAPM as you have used it?

A. The CAPM uses the yield on a risk-free interest bearing obligation plus a rate of return premium that is proportional to the systematic risk of an investment. As shown on page 2 of Schedule 1, the result of the CAPM is 10.84% including flotation costs. To compute the cost of equity with the CAPM, three components are necessary: a risk-free rate of return ("Rf"), the beta measure of systematic risk ("β"), and the market risk premium ("Rm-Rf") derived from the total return on the market of equities reduced by the risk-free rate of return. The CAPM specifically accounts for differences in systematic risk (i.e., market risk as measured by the beta) between an individual firm or group of firms and the entire market of equities.

Q. What betas have you considered in the CAPM?

A. For my CAPM analysis, I initially utilized the Value Line betas. As shown on page 2 of Schedule 3, the average beta is 0.73 for the Electric Group.

Q. What risk-free rate have you used in the CAPM?

A. As shown on page 1 of Schedule 12, I provided the historical yields on Treasury notes and bonds. For the twelve months ended December 2013, the average yield on 30-year Treasury bonds was 3.45%. For the six- and three-months ended

December 2013, the yields on 30-year Treasury bonds were 3.76% and 3.79%, respectively. During the twelve-months ended December 2013, the range of the yields on 30-year Treasury bonds was 2.93% to 3.89%.

The low yields that existed during recent periods can be traced to the financial crisis and its aftermath commonly referred to as the Great Recession. The resulting decline in the yields on Treasury obligations was attributed to a number of factors, including: the sovereign debt crisis in the euro zone, concern over a possible double dip recession, the potential for deflation, and the Federal Reserve's large balance sheet that was expanded through the purchase of Treasury obligations and mortgage-backed securities (also known as QEI, QEII, and QEIII), and the reinvestment of the proceeds from maturing obligations and the lengthening of the maturity of the Fed's bond portfolio through the sale of short-term Treasuries and the purchase of long-term Treasury obligations (also known as "operation twist").

Essentially, low interest rates were the product of the policy of the FOMC in its attempt to deal with stagnant job growth, which is part of its dual mandate. Recently, there has been an increase in Treasury bond yields from their trough that can be attributed to the slow reduction in its bond purchasing program of the FOMC. The term commonly used to describe this reduction in bond purchases is called "tapering." This represents the beginning of the wind-down of the latest quantitative easing by the FOMC, and has put upward pressure on interest rates.

There is a strong indication that the recent increase in interest rates will continue, and indeed there is the significant prospect that further increases in interest rates will occur. As shown on page 2 of Schedule 12, forecasts published by Blue Chip on January 1, 2014 indicate that the yields on long-term Treasury bonds are expected to be in the range of 3.9% to 4.4% during the next six quarters. The longer term forecasts described previously show that the yields on 30-year Treasury bonds will average 5.0% from 2015 through 2019 and 5.5% from 2020 to 2024. For the reasons explained previously, forecasts of interest rates should be emphasized at this time in selecting the risk-free rate of return in CAPM. Hence, I have used a 4.50% risk-free rate of return for CAPM purposes, which considers not only the Blue Chip forecasts, but also the recent trend in the yields on long-term Treasury bonds.

Q. What market premium have you used in the CAPM?

A. As shown in the lower panel of data presented on page 2 of Schedule 12, the market premium is derived from historical data and the Value Line and S&P 500 returns. For the historically based market premium, I have used the arithmetic mean obtained from the data presented on page 1 of Schedule 11. On that schedule, the market return was 12.17% on large stocks during periods of low interest rates. During those periods, the yield on long-term government bonds was 3.01% when interest rates were low. As I describe above, interest rates have been trending upward. To recognize that trend, I have given weight to the average returns and yields that existed across all interest rate levels. As such, I carried over to page 2 of Schedule 12 the average large common stock returns of 12.11% (12.17% + 12.05% = 24.22% ÷ 2) and the average yield on long-term government bonds of 4.08%

(3.01% + 5.15% = 8.16% ÷ 2). These financial returns rest between those experienced during periods of low interest rates and those experienced across all levels of interest rates. The resulting market premium is 8.03% (12.11% - 4.08%) based on historical data, as shown on page 2 of Schedule 12. For the forecast returns, I calculated an 8.68% total market return from the Value Line data and a DCF return of 11.69% for the S&P 500. With the average forecast return of 10.19% (8.68% + 11.69% = 20.37% ÷ 2), I calculated a market premium of 5.69% (10.19% - 4.50%) using forecast data. The market premium applicable to the CAPM derived from these sources equals 6.86% (5.69% + 8.03% = 13.72% ÷ 2).

Q. Are there adjustments to the CAPM that are necessary to fully reflect the rate of return on common equity?

A. Yes. The technical literature supports an adjustment relating to the size of the company or portfolio for which the calculation is performed. As the size of a firm decreases, its risk and required return increases. Moreover, in his discussion of the cost of capital, Professor Brigham has indicated that smaller firms have higher capital costs than otherwise similar larger firms.[7] Also, the Fama/French study (see "The Cross-Section of Expected Stock Returns"; The Journal of Finance, June 1992) established that the size of a firm helps explain stock returns. In an October 15, 1995 article in Public Utility Fortnightly, entitled "Equity and the Small-Stock Effect," it was demonstrated that the CAPM could understate the cost of equity significantly according to a company's size. Indeed, it was demonstrated in the

[7]See Fundamentals of Financial Management, Fifth Edition, at 623.

SBBI Yearbook that the returns for stocks in lower deciles (i.e., smaller stocks) had returns in excess of those shown by the simple CAPM. In this regard, the market-based equity capitalization of CUC is $578 million (9,638,230 shares x $60.02 price per share) according to the Value Line the Small & Mid-Cap Survey.[8] For my CAPM analysis, I have adopted the mid-cap adjustment of 1.14%, as revealed on page 3 of Schedule 12.

COMPARABLE EARNINGS APPROACH

Q. How have you applied the Comparable Earnings approach in this case?

A. The Comparable Earnings approach determines the equity return based upon results from non-regulated companies. It is the oldest of all rate of return methods, having been around for about one century. Because regulation is a substitute for competitively determined prices, the returns realized by non-regulated firms with comparable risks to a public utility provide useful insight into a fair rate of return. In order to identify the appropriate return, it is necessary to analyze returns earned (or realized) by other firms within the context of the Comparable Earnings standard. The firms selected for the Comparable Earnings approach should be companies whose prices are not subject to cost-based price ceilings (i.e., non-regulated firms) so that circularity is avoided.

There are two avenues available to implement the Comparable Earnings approach. One method involves the selection of another industry (or industries) with comparable risks to the public utility in question, and the results for all

[8] Value Line report dated December 6, 2013.

companies within that industry serve as a benchmark. The second approach requires the selection of parameters that represent similar risk traits for the public utility and the comparable risk companies. Using this approach, the business lines of the comparable companies become unimportant. The latter approach is preferable with the further qualification that the comparable risk companies exclude regulated firms in order to avoid the circular reasoning implicit in the use of the achieved earnings/book ratios of other regulated firms. The United States Supreme Court has held that:

> A public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding risks and uncertainties.... The return should be reasonably sufficient to assure confidence in the financial soundness of the utility and should be adequate, under efficient and economical management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties. [Bluefield Water Works and Improvement Co. v. Public Service Comm'n., 262 U.S. 679, 692 (1923)].

It is important to identify the returns earned by firms that compete for capital with a public utility. This can be accomplished by analyzing the returns of non-regulated firms that are subject to the competitive forces of the marketplace.

Q. How have you implemented the Comparable Earnings Approach?

A. In order to implement the Comparable Earnings approach, non-regulated companies were selected from <u>The Value Line Investment Survey</u> for Windows that have six categories of comparability designed to reflect the risk of the Electric Group. These screening criteria were based upon the range as defined by the rankings of the companies in the Electric Group. The items considered were: Timeliness Rank, Safety Rank, Financial Strength, Price Stability, Value Line betas, and Technical Rank. The definitions for these parameters are provided on page 3 of Schedule 13. The identities of the companies comprising the Comparable Earnings group and their associated rankings within the ranges are identified on page 1 of Schedule 13.

Value Line data was relied upon because it provides a comprehensive basis for evaluating the risks of the comparable firms. As to the returns calculated by Value Line for these companies, there is some downward bias in the figures shown on page 2 of Schedule 13, because Value Line computes the returns on year-end rather than average book value. If average book values had been employed, the rates of return would have been slightly higher. Nevertheless, these are the returns considered by investors when taking positions in these stocks. Because many of the comparability factors, as well as the published returns, are used by investors in selecting stocks, and the fact that investors rely on the Value Line service to gauge returns, it is an appropriate database for measuring comparable return opportunities.

Q. What data have you used in your Comparable Earnings analysis?

A. I have used both historical realized returns and forecasted returns for non-utility companies. As noted previously, I have not used returns for utility companies in order to avoid the circularity that arises from using regulatory-influenced returns to determine a regulated return. It is appropriate to consider a relatively long measurement period in the Comparable Earnings approach in order to cover conditions over an entire business cycle. A ten-year period (five historical years and five projected years) is sufficient to cover an average business cycle. Unlike the DCF and CAPM, the results of the Comparable Earnings method can be applied directly to the book value capitalization. In other words, the Comparable Earnings approach does not contain the potential misspecification contained in market models when the market capitalization and book value capitalization diverge significantly. A point of demarcation was chosen to eliminate the results of highly profitable enterprises, which the Bluefield case stated were not the type of returns that a utility was entitled to earn. For this purpose, I used 20% as the point where those returns could be viewed as highly profitable and should be excluded from the Comparable Earnings approach. And to minimize the effect of a skewed distribution, I removed from the average the returns that were less than 8%. The historical rate of return on book common equity was 13.3% using only the returns that were less than 20% and above 8%, as shown on page 2 of Schedule 13. The forecast rates of return as published by Value Line are shown by the 13.3% also using values less than 20% and above 8%, as provided on page 2 of Schedule 13. Using these data my Comparable Earnings result is 13.30%, as shown on page 2 of Schedule 1.

CONCLUSION ON COST OF EQUITY

Q. What is your conclusion regarding FPU's cost of common equity?

A. Based upon the application of a variety of methods and models described previously, it is my opinion that a reasonable cost of common equity for FPU is

11.25%. My cost of equity recommendation is obtained from a range of results and should be considered reasonable in the context of FPU's risk characteristics as compared to the Electric Group. It is essential that the Commission employ a variety of techniques to measure the FPU's cost of equity because of the limitations/infirmities that are inherent in each method. And equally important, the Commission should recognize the proposed capital structure of FPU in order to provide the Company with a financial profile that will both accommodate the Company's unique risks, as well as provide it with the wherewithal to attract the capital it needs to complete its large construction program.

Q. Does this conclude your direct testimony at this time?

A. Yes, it does.

DIRECT TESTIMONY

OF

DONNA RAMAS

On Behalf of the Office of Public Counsel

Before the

Florida Public Service Commission

Docket No. 140025-EI

<u>INTRODUCTION</u>

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

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

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

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

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

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

Q. ON WHOSE BEHALF ARE YOU APPEARING?

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

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

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

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

A. Yes. Dr. Randall Woolridge presents Citizens' recommended capital structure, short and long-term debt rates and rate of return on equity in this case. Dr. Woolridge also presents an alternative capital structure for the Commission's consideration should Citizens' primary capital structure and cost rate recommendation not be adopted by the Commission.

Q. HOW WILL YOUR TESTIMONY BE ORGANIZED?

A. I first present the overall financial summary for the base rate change, showing the primary revenue requirement recommended by Citizens. This is based on Dr. Woolridge's primary capital structure recommendation and the adjustments sponsored in this testimony. I then present my proposed adjustments which impact the test year revenue requirements. Exhibit DMR-2 presents the schedules and calculations in support of this section of my testimony.

Next, I present the outcome of the revenue requirement calculations using the alternative capital structure presented by Dr. Woolridge. The calculations of the alternative revenue requirement are presented in Exhibit DMR-3. I have also attached Exhibit DMR-4, which is an excerpt of the Chesapeake Utilities Corporation ("CUC" or "Chesapeake") 2014 Proxy Statement.

OVERALL FINANCIAL SUMMARY

Q. PLEASE DISCUSS THE EXHIBIT YOU PREPARED IN SUPPORT OF YOUR TESTIMONY.

A. Exhibit DMR-2, totaling 24 pages, consists of Schedules A-1, B-1 through B-3, C-1 through C-16, and D.

Schedule A-1 presents the revenue requirement calculation, giving effect to all of the adjustments I am recommending in this testimony, along with the impacts of the capital structure, debt and equity cost rates, and overall rate of return recommended by Citizens' witness Dr. Woolridge. Schedule B-1 presents OPC's adjusted rate base and identifies each of the adjustments impacting rate base that I am recommending in this case. Schedules B-2 and B-3 provide supporting calculations for several of the rate base adjustments addressed in this testimony. OPC's adjustments to net operating income are listed on Schedule C-1. Schedules C-2 through C-16 provide supporting calculations for the adjustments I am sponsoring to net operating income, which are presented on Schedule C-1.

Q. WOULD YOU PLEASE DISCUSS SCHEDULE D?

A. Schedule D presents Citizens' recommended capital structure and overall rate of return, based on the revisions to FPUC's proposed capital structure recommended by Dr. Woolridge and the rate of return on equity and debt rates recommended by Dr. Woolridge. The capital structure ratios are based on the ratios recommended by Dr. Woolridge. On Schedule D, I then applied Dr. Woolridge's recommended cost rates to the recommended capital ratios, resulting in OPC's overall recommended rate of return of 5.56%.

Q. WHAT IS THE RESULTING REVENUE REQUIREMENT FOR FLORIDA PUBLIC UTILITIES COMPANY?

A. As shown on Exhibit DMR-2, Schedule A-1, OPC's recommended adjustments in this case result in a recommended revenue increase for FPUC's electric operations of $1,996,096. This is $3,825,113 less than the $5,821,209 base rate increase requested by FPUC in its filing.

<u>RECOMMENDED ADJUSTMENTS</u>

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

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

<u>eCIS Project Included in CWIP Balance</u>

Q. WHAT IS THE ECIS PROJECT AND WHAT AMOUNT IS INCLUDED IN THE COMPANY'S PROJECTED TEST YEAR RATE BASE FOR THE PROJECT?

A. The Direct Testimony of Cheryl Martin describes the eCIS plus system as a corporate-wide billing system project that is an upgrade from the current billing system. Ms.

Martin indicates that the eCIS plus project is allocated from the corporate CWIP account to each business unit's CWIP based on the number of customers at each business unit that will use the new system. The response to OPC Interrogatory No. 3 indicates that the total budgeted cost of the project is $13.6 million with 19.6% of the costs, or $2,665,600, to be allocated to the FPUC electric operations. MFR Schedule B-13 shows the total projected cost to be allocated to FPUC electric operations of $2,665,600, with $2,385,647 of that amount included in the average projected test year rate base. MFR Schedule C-13 also identifies a project start date of May 6, 2010 and a projected completion date of October 1, 2016. Based on these dates, the project would span over six years.

Q. WHAT AMOUNT HAS BEEN EXPENDED ON THE PROJECT TO DATE?

A. The responses to OPC Interrogatory No. 3 and OPC Interrogatory No. 93 indicate that, as of May 12, 2014, $6,042,120 had been expended on the project. Using the 19.6% FPUC electric allocation factor, the amount expended to date on a FPUC's electric basis would be $1,184,226 ($6,042,120 x 19.6%).

Q. DO THE BUDGETS AND PROJECT REQUISITIONS PROVIDED BY THE COMPANY FOR THE ECIS PLUS PROJECT SUPPORT THE $13.6 MILLION COST ESTIMATE THAT IS USED IN DETERMINING THE AMOUNT INCLUDED IN CWIP IN THE COMPANY'S FILING?

A. No, they do not. The Company provided capital requisition documents, emails and other budget information in support of the project in response to OPC Production of Document Request ("POD") No. 7 (File Name: FPU RC-0904 – OPC FIRST POD 7 Schedule B support 1 of 2 - eCIS.pdf) and OPC Interrogatory No. 93. Several places in the responses identify the total projected capital cost of the project as $8,519,385 (Document FPU RC-

1911 and FPU RC-1923). Additionally, a document provided with the responses titled "Chesapeake Utilities Corp Budget 2013-2023 – ECIS" (Document FPU RC-001915) identifies the total projected ECIS Plus capital cost as $8.5 million, with amortization of the project beginning in April 2015. The capital requisitions provided for the project identify approximately $6 million approved for the project, and an email provided with the responses indicates that the board approved an additional $2.5 million for the project in the 2014 budget process for which there is no capital requisition. Combined, the actual project requisitions and additional board-approved budget total $8.5 million.

Q. WHAT INFORMATION HAS THE COMPANY PROVIDED IN SUPPORT OF THE HIGHER PROJECTED COST OF $13.6 MILLION?

A. As part of its responses to OPC POD No. 7 and OPC Interrogatory No. 93, the Company provided a stream of emails in which an estimated cost of the eCIS plus was requested associated with work on the electric rate case. In an email response dated February 24, 2014, an email from an employee of Bravepoint (an affiliated company) stated, in part: ". . . based on what you need, we feel the 5 Point estimate of $85/meter is accurate. This would total out to be $13.6m based on 160k meters." A subsequent email on the same date which included Cheryl Martin as a recipient indicated: "So to get your Electric rate case ECIS+ costs, take the number of electric customers times $85 to get ECIS+ costs projection. Don't use the total amount of $ $13.6M [sic] for electric." (Document FPU RC-001917). The response to OPC Interrogatory No. 96 indicated that the $85 per meter identified in the email was calculated incorrectly based on 160,000 meters, and that "The correct number of meters and corresponding cost per meter is 170,000 meters at $80/meter."

In response to OPC Interrogatory No. 94, the Company indicated that the eCIS project team estimated that the total project costs, including costs beyond 2014, would be $13.6 million, and that the estimate was provided by ". . . the Consultant, Five Point Partners, LLC." The response also provided a very high level total project estimate totaling $13.6 million; however, it did not detail how the projected remaining costs were determined.

Q. DID THE COMPANY SUBMIT A REQUEST FOR PROPOSAL FOR THE NEW INFORMATION SYSTEM OR SEEK BIDS FROM POTENTIAL VENDORS?

A. No. OPC POD No. 86 asked for a copy of the request for proposal that went to potential bidders for the eCIS system and for a list of potential vendors that received the request for proposal. In response, the Company indicated that there were no documents responsive to the question. In response to OPC POD No. 9, the Company indicated that it did not have any documents that would constitute a cost benefit analysis for the project. Based on the response to OPC Interrogatory No. 98, the eCIS system was in use within FPUC and the eCIS plus system was considered an upgrade with the current vendor. As part of the project, the eCIS plus system is being implemented with the various Florida regulated operations as well as for the CUC regulated operations in Delaware and Maryland.

Q. HAVE THERE BEEN ISSUES WITH THE IMPLEMENTATION OF THE ECIS PLUS SYSTEM?

A. Yes. Based on the review of the information provided by the Company in support of the project, there have been many delays in the project implementation. As previously indicated, MFR Schedule B-13 identifies an initial project start date of May 6, 2010, which is over four years ago. The initial capital requisition provided in response to OPC

Interrogatory No. 93, which was signed in April 2010, identified an expected project end date of May 2012. The various project timelines and revised timelines from the project vendor, Vertex, provided in response to discovery have project in-service or “Go Live” dates for FPUC as early as September 2011. The implementation dates changed to various dates in 2012 and 2013. An email provided in response to OPC POD No. 7 dated February 25, 2014 identifies an install date of April 2015 for the system, which falls within the projected test year (Document FPU RC-001921). When questioned on the in-service date, in response to OPC Interrogatory No. 97, the Company indicates that at the time of the rate case filing the projected in service date was updated and revised to October 2016. The response also states: “The Company is still working through the process to establish the final implementation target date, and key project milestone dates; however, at this time the Company is working towards an October 2016 implementation date.” Clearly, there have been numerous project delays and changes to the projected in service date. The extent to which the delays have negatively impacted the overall project cost are not clear from the information provided by FPUC in this case.

Additionally, the response to OPC Interrogatory No. 99 shows that during 2013 and 2014 legal costs were incurred associated with the project. The Company initially recorded some of the legal costs as part of the project capital costs, but subsequently removed the legal costs from the capital costs. The response indicates that the charges from Baker & Hostetler LLP identified as “Vertex Matters” related to “. . . legal review and advices associated with administrative contract matters with a vendor in this project . . .” Apparently, there have been issues with the project that have prompted CUC to seek legal review and advice on the project.

Q. ARE YOU RECOMMENDING ANY REVISIONS TO THE AMOUNT INCLUDED IN CWIP FOR THE ECIS PLUS PROJECT?

A. Yes. The Company has not adequately supported the $13.6 million total project cost upon which the amount it included in CWIP of $2,385,647 is based. Additionally, it is not clear from the information provided by the Company in support of the project in this case and the frequent extensions to the projected in-service date that the project has been prudently and cost effectively managed. I recommend that at this time the amount to be included in the projected test year CWIP balance for eCIS plus be limited to FPUC electric operation's portion of the $8,519,385 that has been supported by the various capital requisitions and internal project budgets. As shown on Exhibit DMR-2, Schedule B-2, the recommended CWIP allowance for the project is $1,669,799 based on a total amount of $8,519,385 times the FPUC electric operation portion of the costs of 19.6%. As shown on the schedule, CWIP should be reduced by $715,848 in order to limit the amount in rate base in this case to the amount supported by the Company.

I also recommend that, at the time of the Company's next rate case proceeding, the Commission require a full review and investigation of the total in-service project costs as well as the amount that is allocated to the various Florida regulated operations to ensure that ratepayers are not harmed by potential project mismanagement resulting in cost over-runs. In other words, prior to allowing the full project cost as part of plant in service in rate base, a prudence review should be performed on the project.

<u>Correction of Accumulated Depreciation Error</u>

Q. ARE YOU AWARE OF ANY ERRORS IN THE ACCUMULATED DEPRECIATION BALANCES INCORPORATED IN THE COMPANY'S FILING?

A. Yes. OPC Interrogatory No. 48 asked the Company to provide a revised version of the monthly depreciation reserve balances schedule, MFR Schedule B-10, replacing projected amounts for the period September 2013 through April 2014 with actual balances. The interrogatory also asked FPUC to explain any amounts that differ from the original projections by more than $50,000. The response showed a fairly large variance in the accumulated depreciation (or depreciation reserve) balance for transportation equipment. According to the response, the variance in sub-account 3923 – Transportation Equip-Heavy Duty Trucks was ". . . caused by a retirement made in December being duplicated in the forecast." The amount included in the filing on MFR Schedule B-10, at page 4 of 6, for accumulated depreciation on transportation equipment as of December 2013 is $1,513,910. The actual balance as of December 2013, based on the response to OPC Interrogatory No. 48, was $1,777,201, which is $263,291 higher than the balance incorporated in the filing. Thus, the error or duplication of the vehicle retirements causes the accumulated depreciation balance to be understated. Since the balances in accumulated depreciation are built up from the historic levels in the filing into the projected test year ending September 30, 2015, the duplication error reflected in December 2013 carries forward into the projected test year.

Q. HAS THE COMPANY PROVIDED ADDITIONAL INFORMATION REGARDING THE DUPLICATION ERROR?

A. Yes. In response to OPC Interrogatory No. 101, the Company indicated that the duplication of the retirement for Transportation Equipment-Heavy Duty Trucks in the MFRs for the projected test year was $260,834. The response also agrees that rate base is overstated by this amount.

Q. WERE THE PLANT IN SERVICE BALANCES ASSOCIATED WITH VEHICLES ALSO IMPACTED BY THE DUPLICATION OF THE VEHICLE RETIREMENTS CONTAINED IN FPUC'S FORECASTS?

A. No, apparently not. Based on a comparison of the actual transportation equipment plant in service balances provided in response to OPC Interrogatory No. 47 to the balance contained in FPUC's filing on MFR Schedule B-8, the December 2013 balances are the same. Thus, the duplication of the retirements in FPUC's forecast incorporated in the MFRs only impacted the accumulated depreciation (or depreciation reserve) balances and not the plant in service balances.

Q. WHAT ADJUSTMENT DO YOU RECOMMEND TO CORRECT THE DUPLICATION ERROR CONTAINED IN THE FILING?

A. As shown on Exhibit DMR-2, Schedule B-1, page 2 of 2, accumulated depreciation should be increased by $260,834 in order to remove the impacts of the duplication of the December 2013 vehicle retirements incorporated in FPUC's forecast. This results in a $260,834 reduction to rate base.

<u>Working Capital – Deferred Rate Case Expense</u>

Q. DID FPUC INCLUDE THE PROJECTED TEST YEAR BALANCE OF UNAMORTIZED RATE CASE EXPENSE IN ITS WORKING CAPITAL REQUEST?

A. Yes. MFR Schedule B-3, at page 11 of 12, shows that FPUC included 50% of the projected 13-month average test year balance of unamortized rate case expense. The total projected test year 13-month average unamortized balance is $692,056, with 50%, or $346,028, removed from working capital.

Q. SHOULD THE COMPANY BE PERMITTED TO INCLUDE 50% OF THE UNAMORTIZED RATE CASE EXPENSE BALANCE IN RATE BASE?

A. No, it should not. While the Commission did allow 50% of FPUC's unamortized rate case expense in working capital in its order in FPUC's prior electric rate case, Order No. PSC-08-0327-FOF-EI, issued May 19, 2008, it is my understanding that the Commission has consistently disallowed the inclusion of unamortized rate case expense in working capital for electric utilities. This long-standing Commission policy was reaffirmed in Commission Order No. PSC-10-0131-FOF-EI involving Progress Energy Florida. At pages 71 – 72 of that Order, the Commission stated the following with regard to unamortized rate case expense:

> We have a long-standing policy in electric and gas rate cases of excluding unamortized rate expense from working capital, as demonstrated in a number of prior cases. The rationale for this position was that ratepayers and shareholders should share the cost of a rate case: i.e., the cost of the rate case would be included in the O&M expenses, but the unamortized portion would be removed from working capital. It espouses the belief that customers should not be required to pay a return on funds expended to increase their rates.
>
> While this is the approach that has been used in electric and gas cases, water and wastewater cases have included unamortized rate case expense in working capital. The difference stems from a statutory requirement that water and wastewater rates be reduced at the end of the amortization period (Section 367.0816, F.S.). While unamortized rate case expense is not allowed to earn a return in working capital for electric and gas companies, it is offset by the fact that rates are not reduced after the amortization period ends.
>
> We agree with the long-standing policy that the cost of the rate case should be shared, and therefore find that the unamortized rate case expense amount of $2,787,000 shall be removed from working capital. (footnote 33 omitted)

At page 71 of the Order, in footnote 33, the Commission identified the following cases that confirm and validate its long-standing policy of excluding the unamortized rate case expense from working capital in electric and gas cases:

> Order No. 23573, issued October 3, 1990, in Docket No. 891345-EI, In re: Application of Gulf Power Company for a rate increase; Order No. PSC-09-0283-FOF-EI, issued April 30, 2009; in Docket No. 08317-EI, In re: Petition for rate increase by Tampa Electric Company; Order No. PSC-09-0375-PAA-GU, issued May 27, 2009, in Docket No. PSC-09-0375-PAA-GU, In re: Petition for rate increase by Florida Public Utilities Company.

In addition, in Order No. PSC-10-0153-FOF-EI involving Florida Power & Light Company, dated March 17, 2010, at page 164, the Commission stated in part:

> We do not agree with the Company that the unamortized balance of rate case expense should be included in rate base. Historically, the unamortized balance of rate case expense has been excluded from rate base to reflect a sharing of the rate case cost between the ratepayers and the shareholders. Rate case expenses are recovered from ratepayers through the amortization process as a cost of doing business in a regulated environment. However, the unamortized balance of rate case expense has been excluded from rate base to reflect that an increase in rates is a benefit to the shareholders.
> (footnote omitted)

This policy was again affirmed in Commission Order No. PSC-12-0179-FOF-EI involving Gulf Power Company, dated April 3, 2012, where the Commission stated at pages 30 and 31:

> . . . [w]e have a long-standing practice in electric and gas rate cases of excluding unamortized rate case expense from working capital, as demonstrated in a number of prior cases. The rationale for this position is that ratepayers and shareholders should share the cost of a rate case; i.e., the cost of the rate case would be included in O&M expense, but the unamortized portion would be removed from working capital. This practice underscores the belief that customers should not be required to pay a return on funds spent to increase their rates.
>
> . . .
>
> For the foregoing reasons, we find that the unamortized rate case expense of $2,450,000 shall be removed from working capital consistent with our long standing practice.
> (footnote 17 omitted)

In footnote 17 on page 30 of the same Gulf Power Company Order, the Commission identified the same cases referenced in the footnote and also included the Florida Power

& Light Order and Order No. PSC-10-0131-EI-FOF, issued March 5, 2010, in Docket No. 090079-EI, In re: Petition for increase in rates by Progress Energy Florida, Inc., at pages 71-72.

FPUC has provided no compelling reasons in this case for receiving special or different treatment from the other Florida electric utilities with regards to the treatment of unamortized rate case expense in working capital.

Q. WAS THIS ISSUE ADDRESSED FOR FPUC SUBSEQUENT TO THE PRIOR ELECTRIC RATE CASE?

A. Yes. In Docket No. 080366-GU, FPUC included 50% of its projected rate case costs in working capital for its natural gas division. In Order No. 09-0375-PAA-GU, issued May 27, 2009, the Commission stated at page 22 of the Order that ". . . none of the unamortized rate case expense shall be included in working capital for the projected test year." At page 21 of the Order, the Commission indicated that while it had allowed one half of the balance of unamortized rate case expense to be included in working capital in previous cases involving FPUC, it's long-standing policy in electric and gas rate cases is to exclude unamortized rate case expense from working capital. Thus, the Commission rejected FPUC's request to include rate case expense in working capital.

Q. DO YOU RECOMMEND THAT THE UNAMORTIZED RATE CASE EXPENSE BE EXCLUDED FROM RATE BASE IN THIS CASE?

A. Yes. I recommend that the Commission continue following its long-standing policy in electric and gas cases to exclude the unamortized rate case expense from rate base. Consistent with the Commission's findings in past Progress Energy Florida, Gulf Power

Company and Florida Power & Light Company base rate cases, as well as the previous FPUC natural gas rate case, it would be unfair for customers to pay a return on the rate case costs incurred by the Company in this case when the costs are being used to increase customer rates. On Exhibit DR-2, Schedule B-1, page 2, I have removed the remaining 50% of unamortized rate case expense from working capital in this case, reducing rate base by $346,028. This adjustment is necessary to ensure that none of the rate case costs are included in the rate base upon which a return is applied.

Working Capital – Reduction to Cash Balance

Q. HOW DOES THE OVERALL WORKING CAPITAL REQUEST IN THIS CASE COMPARE TO THE AMOUNT APPROVED BY THE COMMISSION IN THE PRIOR FPUC RATE CASE?

A. In the current case, FPUC included working capital of $2,213,542 in projected test year rate base. In the Commission's Order in the prior rate case, Order No. 08-0327-FOF-EI, the Commission-adjusted working capital allowance in rate base was a negative balance of ($4,246,823).

Q. WHAT AMOUNT IS INCLUDED IN FPUC'S WORKING CAPITAL REQUEST FOR CASH?

A. MFR Schedule B-3, at page 3 of 12, shows that the 13-month average historic test year ended September 30, 2013 balance in Account 1310 – Depository Account - Cash included in working capital was $501,251. The same schedule at page 11 of 12 shows the balance was increased to $504,312 for the projected test year ending September 30, 2015. In addition to the $504,312 included for Account 1310 - Depository Account – Cash, FPUC also included $8,000 for Account 1350 – Working Funds – Petty Cash. This results in $512,312 being included in working capital for both cash accounts.

Q. HOW DOES THE $512,312 INCLUDED FOR CASH IN WORKING CAPITAL IN THE CURRENT CASE COMPARE TO THE BALANCE IN FPUC'S PRIOR RATE CASE?

A. The balance has increased significantly. The Commission's Order in the prior rate case, Order No. 08-0327-FOF-EI, at page 25, indicates that the Company included projected cash balances in working capital for the electric operations of $70,678 in the 2008 projected test year in that case. The $512,312 included in this case is a $441,634 or 625% increase from the level included in the prior rate case.

Q. HAS THE COMPANY SUPPORTED THE SIGNIFICANT INCREASE IN THE CASH BALANCE IT SEEKS TO INCLUDE IN WORKING CAPITAL?

A. No, it has not. The Company has not supported the significant increase in the level of cash it seeks to include in working capital, nor has it demonstrated that its working cash needs have increased so significantly from the amount requested in the prior rate case. The acquisition by CUC should not cause such a large increase in the working cash needs of the FPUC electric operations.

Q. WHAT ADJUSTMENT DO YOU RECOMMEND?

A. As shown on Exhibit DMR-2, Schedule B-3, I recommend that the amount of cash included in working capital be limited to $100,000. This allows for a 41.5% increase above the $70,678 included for cash in the prior rate case. FPUC has not justified the 625% increase in the cash balance reflected in this case as compared to the prior rate case. As shown on Schedule B-3, working capital should be reduced by $412,312.

<u>Forfeited Discounts / Late Payment Fee Revenues</u>

Q. ARE YOU RECOMMENDING ANY ADJUSTMENTS TO TEST YEAR REVENUES?

A. Yes, I recommend that the amount of revenues included in Account 450 – Forfeited Discounts for late payment fee revenues be increased by $55,349. The calculation of this adjustment is provided on Exhibit DMR-2, Schedule C-2. As shown on Schedule C-2, the amount is based on increasing the historic test year late payment fee revenues by $55,000 with the applications of the revenue growth factors that were applied by FPUC to Account 450 for 2014 and 2015.

Q. WHY SHOULD THE AMOUNT OF LATE PAYMENT FEE REVENUES BOOKED DURING THE HISTORIC TEST YEAR BE INCREASED BY $55,000 BEFORE THE REVENUE GROWTH FACTORS ARE APPLIED IN DETERMINING THE PROJECTED TEST YEAR REVENUE LEVEL?

A. FPUC provided several budget variance reports in response to OPC POD No. 10. According to the March 2013 variance report, there was a $55,891 unfavorable variance in fees and other service charges when comparing the amount booked in March 2013 to the amount booked in March 2012. The year-to-year monthly variance explanation stated: "Approximately 40K Credit refund was given to the customers for Jan and Feb issues with the lockbox causing a late fees variance vs last march of ($55K)". Similarly, the same file indicated that in March 2013 fees and other service charges were $55,744 under budget. The budget variance explanation stated: "Primarily a decrease in late fees due to a mail forwarding issue all late fees from January and February were reversed in March ($55K)". (FPU RC-11068 – OPC FIRST POD 10 FE Analytics 03-2013 WIP.pdf) Thus, the historic test year late payment fee revenues were apparently understated by $55,000 as a result of a problem with mail being forwarded from a lockbox. Presumably, the issue has been remedied and should not recur in the future test year.

Q. IS THERE ANY ADDITIONAL INFORMATION THAT WOULD INDICATE THAT THE PROBLEM WITH THE MAIL FORWARDING ISSUE AND SUBSEQUENT REFUNDS CAUSED THE HISTORIC TEST YEAR LATE PAYMENT FEE REVENUES TO NOT BE REPRESENTATIVE OF A NORMAL RECURRING LEVEL?

A. Yes. In response to Staff Interrogatory No. 47, the Company indicated that the amounts booked in Account 450 – Forfeited Discounts represent late payment fees. As shown on Exhibit DMR-2, Schedule C-2, lines A.1 through A.3, the Forfeited Discounts for the Company during 2011 and 2012 were $437,000 and $434,000, respectively, and declined substantially to $380,000 during the historic test year ended September 30, 2013. Additionally, the response to OPC Interrogatory No. 159(d) indicates that the late payment fees for the first six months of 2014 were $220,000. On an annualized basis, the amount for 2014 would be $440,000. MFR Schedule C-5, page 3, shows that the projected test year Forfeited Discounts, or late payment fees, which are based on an escalation of the historic test year amount, are $381,931. Clearly, the amount recorded during the historic test year was inconsistent with the prior year levels and the amount realized subsequent to the historic test year to date. Thus, as shown on Exhibit DMR-2, Schedule C-2, I recommend that the projected test year late payment fee revenues be increased by $55,349. This results in projected test year late payment fee revenues of $437,280, which is consistent with the amount realized by FPUC in 2011, 2012 and for 2014 to date.

Remove Non-Recurring Severance Costs

Q. DO HISTORIC TEST YEAR AND PROJECTED TEST YEAR EXPENSES INCLUDE COSTS FOR EMPLOYEE SEVERANCE PAYOUTS?

A. According to the Florida Public Utility Electric Division variance reports provided in response to OPC POD No. 10 for July 2013 (Document FPU RC-11076) and September 2013 (Document FPU RC-11080), test year payroll and benefit costs included costs for one-time severance payouts associated with employees accepting the Voluntary Exit Program. The September 2013 variance report identifies the costs as ". . . $120,000 in Severance." The workpapers provided in response to OPC POD No. 21 in support of the adjustments made to the filing do not show that the severance payments were removed from historic test year expenses prior to the labor costs being escalated to the projected test year level. Thus, the costs apparently remain in the projected test year at the historic test year level plus escalation.

In response to OPC Interrogatory No. 108, the Company stated that "[t]he Company included $0 in the projected test year for severance to employees." However, as indicated above, the variance reports provided by the Company for July 2013 and September 2013 indicate that severance costs were incurred during the historic test year. Additionally, the severance payments that were recorded during the historic test year were not removed in the various adjustments made by the Company in its filing prior to escalating the labor costs to the projected test year levels.

Q. DID THE COMPANY REVISE ITS POSITION REGARDING SEVERANCE COSTS INCLUDED IN THE PROJECTED TEST YEAR?

A. Yes. In a subsequent response to OPC Interrogatory No. 151, the Company indicated that the historic test year ended September 30, 2013 included $108,204.50 in severance costs for direct electric employees and $11,464.61 for FPUC common employees allocated to the electric operations. This resulted in a total severance expense of $119,669.11 on an FPUC electric operations basis included the historic test year. The attachment to the interrogatory shows that the $119,669 was escalated to $127,628 in the projected test year. The response to Interrogatory No. 151 also stated:

> In preparing the MFR's the Company assumed that the severance costs in the historic year offset the lack of payroll and related benefits expenses while the positions were vacant in the same historic year. Therefore, in projecting the test year ended 9/30/15, the assumption was made that severance costs were excluded, only salaries and related benefits for the replacements of positions remain.

Q. IS IT A VALID ASSUMPTION THAT THE SEVERANCE COSTS INCORPORATED IN THE TEST YEAR ARE OFFSET BY THE LACK OF PAYROLL AND RELATED BENEFIT EXPENSES FOR THE PERIOD THE POSITIONS WERE VACANT IN THE COMPANY'S FILING?

A. No, it is not. In the attachment to the response to OPC Interrogatory No. 151, the Company presented a calculation showing that if each of the positions that accepted the severance were vacant for 2 ½ months, the impact on expenses for filling those positions for the 2 ½ months would be $89,364 when escalated to the projected test year, which is $38,264 less than the impact of the severance expense on the projected test year. The response also indicates that "The estimated salary and benefits during the historic year were lower than the severance payments by $38,264."

However, in the "Over and Under" adjustments made by FPUC on MFR Schedule C-7, the Company accounted for employee changes that occurred during the historic test year.

At page 46 of her direct testimony, Ms. Martin states: "Due to new hires, organization changes, or revised employee allocations made during the historic test year, expenses were adjusted to reflect costs for a full year."

Q. WILL THE SEVERANCE COSTS ASSOCIATED WITH THE VOLUNTARY EXIT PROGRAM BE INCURRED BY FPUC IN THE PROJECTED TEST YEAR?

A. No. The response to OPC Interrogatory No. 16 states: ". . . the Company does not anticipate any further work force reduction, attrition or early retirement programs during the next three years." The response also states: "All planned work force reduction programs since FPUC was acquired by Chesapeake Utilities Corporation have been implemented." Thus, FPUC should not incur additional severance costs in the projected test year.

Q. DO YOU RECOMMEND THAT THE SEVERANCE COSTS BE REMOVED FROM THE PROJECTED TEST YEAR?

A. Yes. As shown on Exhibit DMR-2, Schedule C-3, projected test year expenses should be reduced by $127,628 to remove the non-recurring severance costs charged to the FPUC electric division. These severance costs will not be realized by FPUC in the projected test year.

<u>Remove Marianna Litigation Bonus Payout</u>

Q. PLEASE DISCUSS YOUR ADJUSTMENT ON EXHIBIT DMR-2, SCHEDULE C-4, TITLED "REMOVE MARIANNA LITIGATION BONUS PAYOUT".

A. According to the Florida Public Utility Electric Division variance report provided in response to OPC POD No. 10, at FPU RC-11076 for July 2013, test year payroll and benefit costs include $24,000 ". . . due to the Marianna Bonus payout to employees for help with Litigation and referendum. . ." After the payroll escalation factor is applied, projected test year expenses include $25,462 associated with the special bonus payouts. I recommend that these costs be removed from the projected test year, reducing expenses by $25,462.

Q. WHY DO YOU RECOMMEND THESE COSTS BE REMOVED FROM THE PROJECTED TEST YEAR?

A. Ratepayers should not be asked to fund the special bonuses that the Company decided to pay out to employees who assisted on the Marianna litigation and referendum. Additionally, these one-time special bonuses are non-recurring and not reflective of costs that will be realized in the projected test year.

<u>Stock-Based Compensation Expense</u>

Q. ARE ANY COSTS INCLUDED IN THE TEST YEAR FOR STOCK-BASED COMPENSATION?

A. Yes. The response to OPC Interrogatory No. 14 identifies a total of $97,287 included in projected test year expenses on an FPUC Electric Division basis for stock-based compensation. The confidential attachment to the response identifies four individuals as projected to receive the stock-based compensation during the projected test year, with the total amount for the four individuals combined totaling $97,287. The individuals include the President of FPUC and three CUC executives.

Q. WHAT IS THE STOCK-BASED INCENTIVE COMPENSATION BASED UPON?

A. The Company's long-term incentive compensation plan, which is a stock and incentive compensation plan, is described in CUC's proxy statement that was issued March 31, 2014. In the 2014 Proxy Statement, CUC provides a detailed description of the executive compensation design and components, which includes the stock-based compensation. According to the 2014 Proxy Statement, at page 34, "The equity incentive awards are designed to reward executives for improving stockholder value by achieving growth in earnings while investing in the future growth of both our regulated and unregulated businesses." According to page 35 of the 2014 Proxy Statement, there are three performance components in the 2013 to 2015 performance period under the plan. See Exhibit DMR-4 CUC 2014 Proxy Statement Excerpt.

Q. WHAT ARE THE THREE PERFORMANCE COMPONENTS IN THE 2013 TO 2015 PERFORMANCE PERIOD, AS DESCRIBED IN THE 2014 PROXY STATEMENT?

A. The first component is shareholder return in which the total shareholder return is compared to the total shareholder returns of peer group companies. The description of this component, which accounts for 30% of the target award, is "Shareholder Return incentivizes executives to generate additional value for our stockholders."

The second component, which accounts for 35% of the target award, is growth in long-term earnings in which total capital expenditures as a percent of total capitalization is compared to peer group companies. The description of this component states: "In the long-term, the Company's growth is dependent upon continuous investment of capital at levels sufficient to drive growth."

The final component, accounting for 35% of the target award, is Earning Performance which is the average return on equity as compared to pre-determined targets. The description of the Earning Performance target states: "Return on equity measures the Company's ability to generate current income using equity investors' capital."

The 2014 Proxy Statement indicates that for Mr. Jeffrey M. Householder, the President of Florida Public Utilities, the Shareholder Return component is the same as the other named executive officers, but that the Growth in Long-Term Earnings and Earnings Performance components for him include the ". . . combined investment levels and financial results for several regulated and unregulated businesses in Florida."

Q. DO YOU RECOMMEND THAT THE STOCK-BASED COMPENSATION COSTS BE INCLUDED IN THE PROJECTED TEST YEAR EXPENSES?

A. No, I do not. The components in determining the stock-based compensation awards are clearly focused on CUC's shareholders and are based on regulated and unregulated businesses. Clearly, the goals are not focused on benefitting Florida Public Utility's electric ratepayers. As indicated at page 34 of the 2014 Proxy Statement: "The equity incentive awards are designed to reward executives for <u>improving stockholder value</u> by achieving growth in earnings while investing the future growth of both our regulated and unregulated businesses." (Emphasis added) Given that the determination of the awards is focused entirely on CUC's shareholders, I recommend that the cost be removed from the projected test year. As shown on Exhibit DMR-2, Schedule C-1, page 2 of 2, test year expenses should be reduced by $97,287 to remove stock-based compensation expense.

Corporate Bonuses Allocated to FPUC Electric Operations

Q. HOW MUCH IS INCLUDED IN THE TEST YEAR FOR CORPORATE BONUSES ALLOCATED TO THE FPUC ELECTRIC OPERATIONS?

A. According to the response to OPC Interrogatory No. 13, historic test year expenses include $195,887 and projected test year expenses include $173,491 for ". . . Corporate Bonus amounts allocated to the Electric Florida Business Unit . . ."

Q. HAS THE COMPANY PROVIDED ANY INFORMATION DEMONSTRATING THAT THE CORPORATE BONUS OR INCENTIVE PLAN FOR WHICH COSTS ARE ALLOCATED TO THE FLORIDA ELECTRIC OPERATIONS ARE FOCUSED ON GOALS THAT BENEFIT THE FLORIDA ELECTRIC RATEPAYERS?

A. No, the Company has provided no information demonstrating that the corporate bonus plans in which the costs are allocated to the Florida electric operations are focused on goals and targets that would benefit the Florida electric ratepayers. OPC Interrogatory No. 14 requested a copy of each of the Company's incentive compensation plans, bonus plans and stock option plans for 2012, 2013 and 2014. While the Company provided a copy of the 2013 Incentive Performance Plan specific to Florida Business Unit employees with the response, as well as information regarding the long-term equity based compensation plan previously addressed in this testimony, it did not include the incentive plan information for the Corporate employees of which part of the cost is allocated to the Florida electric operations.

Q. SHOULD THE ALLOCATED CORPORATE BONUS EXPENSE AMOUNTS INCLUDED IN THE PROJECTED TEST YEAR BE PASSED ON TO THE COMPANY'S ELECTRIC CUSTOMERS?

A. No, they should not. The Company has not justified the recovery of the allocated corporate bonus expenses from Florida electric ratepayers. There has been no information provided regarding the plan goals and targets and no information has been provided indicating that the costs are driven by factors that benefit FPUC's customers. As such, I recommend that the allocated corporate bonus expense be removed. Later in this testimony, I recommend that charges from CUC to the FPUC electric operations be limited to the historic test year expense amount plus escalation. Under this approach, projected test year expenses would include $209,031 for allocated corporate bonus expense, calculated as the historic test year expense of $195,887 times the payroll and customer growth factor of 1.0671. As shown on Exhibit DMR-2, Schedule C-1, page 2 of 2, test year expenses should be reduced by $209,031 to remove these unsupported CUC Corporate Bonuses. If the Commission does not adopt my recommended adjustment that limits the CUC corporate charges to FPUC electric operations to the historic test year level plus escalation, then projected test year expenses should be reduced by $173,491 to remove the corporate bonuses included by the Company in the projected test year.

<u>Incentive Performance Plan – FPUC</u>

Q. IN ADDITION TO THE CORPORATE BONUS EXPENSES ALLOCATED TO THE FLORIDA ELECTRIC OPERATIONS, ARE THERE COSTS INCLUDED IN THE TEST YEAR FOR INCENTIVE COMPENSATION SPECIFIC TO FPUC?

A. Yes. According to the response to OPC Interrogatory No. 13, test year expenses include $407,095 on an FPUC electric operations basis for the Incentive Performance Plan.

Q. HAVE THERE BEEN ANY RECENT CHANGES IN THE INCENTIVE PERFORMANCE PLAN ("IPP") THAT IMPACT THE AMOUNT OF EXPENSE INCURRED AT THE FLORIDA ELECTRIC OPERATIONS LEVEL?

A. Yes. According to the direct testimony of Mr. Householder, at pages 6 – 7, a Company-wide performance based pay system was recently introduced. The response to OPC Interrogatory No. 11 indicates that "The IPP Company wide performance based pay system was implemented in Florida for all employees in 2013." Thus, the IPP was expanded to include all Florida employees in 2013. The response to OPC Interrogatory No. 10 indicates that the IPP was offered to the unions beginning in 2013. The response also indicates that in 2012, 171 employees were eligible to receive incentive compensation with the number of eligible employees expanding to 305 in 2013.

Q. DID THE EXPANSION OF THE IPP TO ALL FLORIDA EMPLOYEES IN 2013 IMPACT THE OVERALL EXPENSE ASSOCIATED WITH THE PLAN?

A. Yes, the modifications had a significant impact on the overall costs to the electric operations. The response to OPC Interrogatory No. 13 shows that the actual expense to the Florida electric business unit associated with the IPP increased from $211,562 for the twelve months ended September 2012 to $382,590 in the historic test year ended September 2013, which is an increase of 81%. The response shows that the amount included in the projected test year is $407,095. The response also indicates that the expense to the electric operations was $157,423 for the twelve months ended September

2011, or less than half of the amount incurred in the historic test year. In other words, the cost more than doubled in a two-year period.

Q. DURING THE PERIOD THAT PARTICIPATION IN THE IPP WAS EXTENDED TO ALL OF THE FLORIDA EMPLOYEES, WERE BASE WAGES ALSO INCREASED FOR THE EMPLOYEES?

A. Yes. The response to OPC Interrogatory No. 9 shows that in the period the IPP was expanded to include the union employees during 2013, the union merit increase was 2.5% and the Target IPP % payout implemented was 4.0% in 2013. The response also shows that in 2013 non-union category merit increases were 3.0% and the Target IPP % payout was increased from 2.0% in 2012 to 4.0% in 2013. For Supervisor level employees, the 2013 merit increase was 3.0% while the Target IPP % payout was increased from 3.0% in 2012 to 5.0% in 2013. For Manager-First Line employees, the merit increase was 3.0% in 2013 and the Target IPP % payout was increased from 4.0% to 6.0%. For Managers-Direct employees, the merit increase was 3.0% in 2013 while the IPP Target % payout increased from 5.0% in 2012 to 8.0% in 2013. For directors, the merit increase was 3.0% in 2013 and the Target IPP % increased from 8.0% in 2012 to 15.0% in 2013. Thus, the IPP target payouts as a percentage of base pay increased significantly between 2012 and 2013 for all of the employee groups at the Director level or below.

Q. HAS THE COMPANY PROVIDED INFORMATION DESCRIBING THE IPP AND IDENTIFYING HOW THE AWARDS UNDER THE PLAN ARE DETERMINED?

A. Yes. In a confidential attachment to the response to OPC POD No. 14, the Company provided a copy of the 2013 IPP for FPUC employees. Additionally, as a confidential attachment to OPC Interrogatory No. 12, the Company provided details on the goals in place for the IPP, including the various goals and targets, for 2012 through 2014.

Q. WHAT ARE THE GOALS AND PERFORMANCE MEASURES IN THE IPP?

A. Based on the confidential attachments provided in response to OPC Interrogatory No. 12 and OPC POD No. 14, *****BEGIN CONFIDENTIAL***** [redacted]

[redacted]

[redacted]

Q. COULD YOU PLEASE DISCUSS SOME OF THE GOALS IDENTIFIED IN THE TABLE ABOVE?

A. [redacted]

[redacted]

[redacted]

[redacted]

[redacted] ***END CONFIDENTIAL***

Q. DO YOU HAVE A BREAKDOWN OF THE TOTAL PROJECTED TEST YEAR INCENTIVE PERFORMANCE PLAN COSTS BETWEEN EACH OF THE IPP GOALS?

A. No, I do not. While the Company provided total projected test year IPP expense of $407,095 in response to OPC Interrogatory No. 13, it did not provide the breakdown of that amount by goal category. Since the weighting of various goals varies by employee level, I am unable to provide a breakdown of the $407,095 by each of the IPP goals.

Q. ARE YOU RECOMMENDING AN ADJUSTMENT TO THE IPP EXPENSE INCLUDED IN THE TEST YEAR?

A. Yes. As shown on Exhibit DMR-3, Schedule C-5, I recommend that 45% of IPP expense be funded by shareholders instead of FPUC's electric ratepayers. This reduces test year expenses by $183,193. After the adjustment, rates would still include $223,902 for IPP costs to be funded by ratepayers, which exceeds the full expense level for the year ended September 30, 2012 of $211,562.

Q. HOW WAS YOUR RECOMMENDED SHAREHOLDER FUNDING LEVEL OF 45% DETERMINED?

A. Based on the table provided in the confidential section of this testimony, *****BEGIN CONFIDENTIAL***** [redacted]

[redacted]

[redacted] *****END CONFIDENTIAL***** Thus, I recommend that 45% of the costs be funded by shareholders.

<u>Update Pension Expense to Current Projections</u>

Q. HOW DID THE COMPANY ESTIMATE THE PROJECTED TEST YEAR PENSION EXPENSE INCORPORATED INTO THE FILING?

A. The direct testimony of Cheryl Martin, at page 40, indicates that the projected test year pension expense totals $280,218 and the amount was projected by the CUC corporate office. According to the direct Testimony of Matthew Kim, at pages 19 through 21, the Company decided to base the projected cost on an average of historic costs due to the volatility in the past discount rate assumptions and the difficulty in projecting future discount rate assumptions. Based on a review of the Company’s workpapers, the Company determined the average pension expense using the years 2010 through 2013. This resulted in a four-year average pension expense of $6,235 on an FPUC electric operations basis. This amount was increased by $273,983 associated with the electric operations portion of a pension regulatory asset that resulted from the 2009 merger with CUC.

Q. DO YOU AGREE THAT THE PROJECTED TEST YEAR PENSION EXPENSE SHOULD BE BASED ON THE HISTORIC FOUR-YEAR AVERAGE AMOUNT?

A. No, I do not. FPUC has provided no information demonstrating that the historic four-year average cost level is reflective of the expense it will incur in the projected test year. While pension expense is impacted by the discount rate selected, it is also impacted by other actuarial assumptions, such as the expected long-term rate of return, and by the funding status of the pension plan assets. Since the pension plan was frozen by the Company many years ago, the Company no longer incurs a service cost associated with the pension plan. Thus, the annual pension expense consists largely of the interest cost and the expected return on plan assets, as well as the amortization of the pension regulatory asset. In both 2013 and as projected for 2014, the expected return on plan assets exceeds the plan interest costs. Thus, absent the amortization of the pension regulatory asset, the Company is currently in a negative pension expense, or pension income, situation.

While the discount rate assumption used in the actuarial projection has fluctuated from year to year, the response to OPC POD No. 57 shows that the long-term rate of return assumption has remained at 7.0% since at least 2010. Additionally, the response shows that contributions have been made to the pension plan assets each year since at least 2010. The workpapers provided in response to OPC POD No. 1, at FPU RC-24, also show that a significant cash contribution is anticipated for 2014. These cash contributions put downward pressure on the actuarially determined pension expense. The response to OPC Interrogatory No. 23 also indicates that the discount rate for 2014 has been selected and is 4.75%, and the 7.0% long-term rate of return assumption remains in place for 2014.

Q. WHAT DO YOU RECOMMEND THE PROJECTED TEST YEAR PENSION EXPENSE BE BASED ON?

A. I recommend that projected test year pension expense be based on the most recent actuarial projections received by the Company. The Company was required to select the actuarial assumptions for use in the 2014 pension plan year at the end of 2013. The most recent estimates of the net periodic pension cost, or pension expense, were provided by the Company in response to OPC POD No. 15. These projections include the impact of the discount rate assumption and the long-term rate of return assumption selected by the Company for use in determining 2014 pension expense. They were prepared by an actuarial firm and are dated January 29, 2014. The projected 2014 amounts identified in the response are also consistent with the 2014 pension expense amounts identified in the workpapers provided by FPUC in response to OPC POD No. 1. They would also include the impact of pension plan funding that has been made in recent years, whereas the historic average would not fully factor in such impacts.

Q. WHAT ADJUSTMENT IS NEEDED TO BASE THE PROJECTED TEST YEAR PENSION EXPENSE ON THE MOST RECENT ACTUARIAL PROJECTIONS FOR THE COMPANY?

A. As shown on Exhibit DMR-2, Schedule C-6, the projected test year pension expense should be reduced by $151,914 to reflect the most recent projections provided by the Company's actuarial firm. This would include the impact of the actuarial assumptions selected by the Company for the 2014 pension plan year and would more fully reflect the plan funding status as compared to the historic average methodology proposed by the Company. It also includes the amortization of the pension regulatory asset. The most recent projections result in a projected test year pension expense, inclusive of the pension regulatory asset amortization, of $128,304.

<u>Paid Time Off Policy Change – Regulatory Liability</u>

Q. PLEASE DISCUSS THE PAID TIME OFF ("PTO") POLICY CHANGE THAT OCCURRED DURING THE HISTORIC TEST YEAR.

A. At page 33 of her direct testimony, Ms. Martin indicates that during 2013, CUC made a change to the PTO policy for FPUC employees to align them with the company-wide PTO policy. The prior policy was in place at the time of FPUC's last electric rate case proceeding and continued through the date during the historic test year in which the policy was changed to align the FPUC policy with the CUC policy. According to Ms. Martin's testimony, the change triggered a one-time reversal of the total accumulated PTO liability existing on the books during the historic test year, resulting in a $141,687 reduction to historic test year electric division expenses. In Ms. Martin's testimony, she indicates that the historic test year was adjusted in the Company's filing to remove the impact of the change, increasing test year expenses by $141,687. According to the Company's response to OPC interrogatory No. 65, the accrued vacation pay was built up over a long period under the old PTO policy.

Q. DO YOU AGREE THAT THE FULL AMOUNT OF THE ONE-TIME REVERSAL OF THE TOTAL ACCUMULATED PTO LIABILITY SHOULD BE REMOVED FROM THE HISTORIC TEST YEAR?

A. No. Rates set in the prior FPUC electric division rate case would have been based on the prior PTO policy for FPUC employees. As indicated in the response to OPC Interrogatory No. 65, the liability associated with the prior PTO policy was built-up over a long period of time. During the time the liability was built-up on the electric division's books, rates charged to customers were based on the prior PTO policy that resulted in the liability. As such, I recommend that the one-time reversal of the liability or gain resulting from the change in the PTO policy that was implemented in the historic test year be returned to ratepayers who paid for it. I further recommend that this amount be returned over a five-year period.

Q. WHAT ADJUSTMENTS ARE NEEDED TO REFLECT YOUR RECOMMENDATION THAT THE ONE-TIME REVERSAL OF THE LIABILITY BE RETURNED TO RATEPAYERS OVER A FIVE-YEAR PERIOD?

A. As shown on Exhibit DMR-2, Schedule C-1, page 2, projected test year expenses should be reduced by $28,337 in order to flow the one-time gain associated with the liability reversal back to ratepayers over a five-year period ($141,687 / 5 years = $28,337 per year). Additionally, the average unamortized balance for the projected test year needs to be reflected as a regulatory liability that offsets working capital. The reduction to working capital, totaling $127,518, is reflected on Schedule B-1, page 2 of 2. The amount is based on the full recommended regulatory liability to be returned to ratepayers of $141,687 less $14,169 in average test year accumulated amortization (or half a year of amortization).

General Liability Insurance and Reserve

Q. COULD YOU PLEASE DESCRIBE THE COMPANY'S REQUEST WITH REGARDS TO GENERAL LIABILITY COSTS AND CLAIMS?

A. Yes. In addition to the projected cost of liability insurance, the Company is proposing to increase historic test year expenses by $120,000 to cover three separate general liability-related requests. The $120,000 increase consists of: 1) $50,000 to amortize a requested regulatory asset associated with a large claim against FPUC over a five-year period; 2) $50,000 for annual contributions to a proposed new self-insurance reserve to cover potential future large claims against FPUC; and 3) $20,000 for annual contributions to the proposed new self-insurance reserve to cover potential small claims against FPUC. Thus, under the Company's proposal, $50,000 per year would be collected from ratepayers to recover a claim already paid by FPUC and $70,000 would be collected each year to establish a self-insurance reserve for claims that fall within the deductible limits.

Q. COULD YOU PLEASE ELABORATE ON THE LARGE CLAIM AGAINST FPUC THAT IT IS REQUESTING TO RECOVER FROM RATEPAYERS IN THIS CASE?

A. The direct testimony of Mr. Kim, at page 12, indicates that over the last five years ". . . FPU's electric operations had one large insurance claim, which was settled for $2.75 million." The general liability insurance policy covered the claim; however, there is a maximum deductible on the policy of $250,000 per claim. Thus, FPUC is seeking to recover the $250,000 it paid to satisfy the deductible over a five-year period. The response to OPC Interrogatory No. 53 indicates that the incident that gave rise to the claim occurred in July 2012, which predates the historic test year in this case. The final payment related to the matter was made in February 2014.

Q. DID THE COMPANY PROVIDE A COPY OF THE SETTLEMENT AGREEMENT IN THE MATTER OR OTHER INFORMATION JUSTIFYING THE RECOVERY OF THE DEDUCTIBLE FROM FPUC'S ELECTRIC RATEPAYERS?

A. No, it did not. OPC POD No. 55 requested a copy of the Settlement Agreement referenced in Mr. Kim's testimony. In response, FPUC objected to this request and indicated that the Settlement Agreement included terms that require the Parties to treat the agreement as confidential. While additional information was provided by FPUC to OPC counsel, that information is considered confidential. I was able to discover additional information regarding the matter and the claim that was filed through further research, which caused concern regarding the appropriateness and reasonableness of passing the costs on to FPUC's electric ratepayers; however, I am not disclosing the information in this testimony in the interest of the parties involved as the Company has indicated that the terms of the Settlement Agreement are confidential.

The Company has provided no information in the record in this case to date to demonstrate that the deductible paid by FPUC in the matter is a cost that should be recovered from FPUC's electric ratepayers. FPUC has the burden of proof in seeking special regulatory asset treatment to demonstrate that its actions were reasonable and prudent, that it was not negligent, and that the costs are costs that ratepayers should be required to fund. FPUC has not met this burden. Given FPUC's failure to support the recovery of this historic cost from customers, I recommend that the requested regulatory asset and the amortization thereof be disallowed.

Q. WHAT INFORMATION HAS FPUC PROVIDED IN SUPPORT OF ITS REQUEST TO COLLECT $70,000 PER YEAR TO ESTABLISH A SELF-INSURANCE RESERVE?

A. At pages 12 and 13 of the direct testimony of Mr. Kim, he states: ". . . FPU is requesting an additional $250,000 to be included in the next five-year period to establish a general liability reserve sufficient to cover another potential claim with similar financial exposure that may arise during that period, as well as $20,000 per year to cover any other smaller general liability claims." Similarly, at pages 44 and 45 of her direct testimony, Ms. Martin indicates that the Company is seeking to establish a self-insurance reserve to cover future general liability claims and ". . . is proposing to accrue $50,000 per year to cover large claims, and $20,000 of smaller claims on an annual basis for the basis of the self-insurance reserve."

Q. HAS THE COMPANY SUPPORTED THE NEED TO ESTABLISH A SELF-INSURANCE RESERVE WITH $70,000 OF ANNUAL FUNDING TO THE RESERVE?

A. No, it has not. In response to OPC Interrogatory No. 77, the Company provided the total amount of claims incurred for each year, 2009 through 2014 year to date, separated between large and small claims. As previously indicated, FPUC is requesting $20,000 per year associated with small claims. The response identifies the following amounts incurred by the Company associated with small claims during the last 5 ½ years: $12,694 in 2009, $3,847 in 2010, $20,541 in 2012, $5,020 in 2013 and $9,239 for 2014 year to date. This results in an average cost associated with small claims over the past 5 ½ years of $9,335 per year, which is well below the $20,000 per year requested by the Company in this case. Similarly, the Company is requesting to collect $50,000 per year from customers to go towards potential large claims. However, based on the amounts provided in response to OPC Interrogatory No. 77 and OPC POD No. 55, the only amount paid in the last five years associated with large claims is for the amount the Company is requesting to recover in the regulatory asset in this case, which is based on a single claim. Thus, the Company has only experienced one large claim over the last 5 ½ years.

Q. ARE THERE ANY ADDITIONAL REASONS FOR NOT ESTABLISHING A SELF-INSURANCE RESERVE FOR FPUC ELECTRIC OPERATIONS?

A. Yes. If a self-insurance reserve is established to cover the liability claims incurred by FPUC that fall within the insurance deductible of $250,000, there is a concern that potential future liabilities that may not be appropriate to charge to ratepayers would be recorded in the liability reserve account. By recording claims expenses in the reserve account between rate cases, there may be less future regulatory scrutiny in evaluating whether or not the costs charged to the account are appropriate for recovery from customers. As indicated previously in this testimony, there are concerns regarding whether or not the costs associated with the one large claim paid by the Company are appropriate costs that should be the responsibility of ratepayers. If a reserve had been in place, such claim costs would presumably be booked by FPUC to the reserve between rate case proceedings. Given the potential reduction in regulatory scrutiny with charges to a self-insurance reserve, coupled with the Company’s failure to establish that such a reserve approach is necessary, I recommend that the Commission reject FPUC’s self-insurance reserve request.

Q. DO YOU RECOMMEND THAT ANY COSTS BE INCLUDED IN RATES ASSOCIATED WITH LIABILITY COSTS THAT FALL UNDER THE GENERAL LIABILITY DEDUCTIBLE?

A. Yes. I recommend that base rates include liability expense for amounts that would fall within the $250,000 deductible for the general liability coverage based on the most recent 5 ½ year average of actual claims paid by the Company. As shown on Exhibit DMR-2, Schedule C-7, this would allow for expense in rates of $54,289. The $54,289 is based on the most recent 5 ½ years of actual claims experience for the Company, which includes several small claims discussed previously and the one large claim paid over that period. While I do not agree that the Company should be permitted to establish a regulatory asset for the large deductible it paid on the single claim, it is not unreasonable to include the cost associated with a single large claim in determining an average expense level to include in rates. However, since only one large claim has been paid by the Company over the past 5 ½ years, and there are questions regarding the appropriateness of the associated costs to the Company, I recommend that this issue be revisited in FPUC's next rate case and a longer period (i.e., longer than 5 ½ years) be reviewed and considered in establishing a normalized expense level to include in rates.

Q. WHAT IS THE OVERALL ADJUSTMENT THAT NEEDS TO BE MADE TO GENERAL LIABILITY COSTS IN THIS CASE?

A. As shown on Exhibit DMR-2, Schedule C-7, test year expenses should be reduced by $65,711. This adjustment results in the following: 1) removes the proposed regulatory asset for the large claim and the $50,000 amortization thereof; 2) removes the Company's requested $70,000 for funding of a self-insurance reserve; and 3) allows for a normalized claims expense to be included in rates of $54,289.

Tree Trimming Expense

Q. WHAT AMOUNT WAS RECORDED DURING THE HISTORIC TEST YEAR ENDED SEPTEMBER 30, 2013 FOR TREE TRIMMING EXPENSE AND HOW DOES IT COMPARE TO THE AMOUNT INCLUDED IN THE PROJECTED TEST YEAR?

A. According to the response to OPC Interrogatory No. 79, historic test year expenses include $828,915 for tree trimming expense. The response shows that the Company escalated the $828,915, using a combined inflation and customer growth trend factor of 1.0516, to $871,687 in the projected test year. For both the historic test year and the projected test year, the Company increased the costs by $50,500 to “normalize” the historic test year amount. As a result of the trending and “normalization” adjustment, the projected test year includes $922,187 for tree trimming expense, which is $93,272 higher than the recorded historic test year amount of $828,915.

Q. WHAT IS THE BASIS OF THE COMPANY’S $50,500 NORMALIZATION ADJUSTMENT?

A. The response to OPC Interrogatory No. 79 indicates that the “. . . normalization of the historic 12 months ending September 2013 . . .” was based on the annualization of the tree trimming expense recorded in April 2013 and May 2013. The resulting annualized amount based on two months of data was then compared to the amount recorded during the historic test year to determine the $50,500 “normalization” adjustment. The response indicates that since the monthly amount varies, the “. . . electric operations managers identified April 2013 and May 2013 as typical months.” No further information was provided to explain why the full amount recorded during the test year ended September

30, 2013 would be considered abnormal or not reflective of normal tree trimming operations. There was also no indication that the Company cut back during the test year on the needed level of tree trimming. Additionally, there was no explanation regarding why the amounts recorded in April and May were expected to be reflective of the "typical" level of costs or reflective of a normal annual level when annualized.

Q. DOES THE HISTORIC TEST YEAR TREE TRIMMING EXPENSE APPEAR TO BE ABNORMAL WHEN COMPARED TO PRIOR YEAR EXPENSE AMOUNTS?

A. No, it does not. In fact, the amount actually recorded during the historic test year, while slightly lower than the amount recorded for the year ended December 31, 2013, is higher than the average cost for the past three calendar years. According to the response to OPC Interrogatory No. 79, in which the Company provided the historic cost levels, tree trimming is done on a three-year tree trimming cycle. Based on the response, the table below presents the amount of tree trimming expense recorded each year, 2011 through 2013. The table also presents the most recent three-year average cost level as compared to the amount recorded by the Company during the historic test year.

	Amount
2011	$ 753,971
2012	$ 691,885
2013	$ 843,000
3 Year Average	$ 762,952
Historic TYE 9/30/13	$ 828,915
Amount Above 3 Yr Avg.	$ 65,963

As shown in the table, the amount recorded in the historic test year is higher than the most recent three-year average. While the historic test year amount is slightly lower than the expense recorded in the calendar year ended December 31, 2013, the Company has escalated the historic test year expense based on both CPI and customer growth factors in determining the projected test year balance.

Q. DO YOU RECOMMEND THAT THE AMOUNT INCLUDED IN THE PROJECTED TEST YEAR FOR TREE TRIMMING EXPENSE BE ADJUSTED?

A. Yes. I recommend that FPUC's proposed "normalization" adjustment of $50,500 be removed from the projected test year. This is shown on Exhibit DMR-2, Schedule C-1, page 2 of 2. FPUC has not demonstrated that the amount recorded during the historic test year was abnormal and not reflective of normal tree trimming cost levels, nor has it demonstrated that its methodology of normalizing the costs based on only two months of expenditures is reasonable or reflective of a typical annual cost level. As indicated above, tree trimming is based on a three-year cycle for FPUC, and the amount recorded in the historic test year is higher than the historic three-year average. After removal of the $50,500 "normalization" adjustment proposed by FPUC, the adjusted test year tree trimming expense is $871,687, which is higher than the actual costs incurred in each of the last three calendar years and the historic test year. Because the amount that I am recommending exceeds the historic three-year average cost level, it also allows for the impact of potential increases in rates and labor costs charged by contractors that perform the tree trimming service on behalf of FPUC.

<u>Pole Attachments – Joint Use Audit Costs</u>

Q. COULD YOU PLEASE DISCUSS THE ADJUSTMENT MADE BY FPUC FOR THE POLE ATTACHMENT AND JOINT USE INVENTORY AUDIT?

A. Yes. On MFR Schedule C-7 (2015), at page 9 of 9, FPUC increased test year expenses by $10,756 to reflect one-fifth of the costs of an audit on pole attachments and joint use inventory. The workpapers for the adjustment provided in response to OPC POD No. 21 indicate the following:

- The pole attachment and joint use inventory audit is anticipated to be performed in 2014.
- The joint use audit is to be performed on all poles every 5 years.
- The total projected cost is based on 15,366 poles at an estimated cost per pole of $3.50, resulting in total projected costs of $53,781. The annual amortization of the total projected cost of $53,781 over five years results in the annual cost of $10,756 added by FPUC to test year expenses ($53,781 / 5 years = $10,756 per year).

Q. BASED ON THE WORKPAPERS PROVIDED BY THE COMPANY IN SUPPORT OF THE ADJUSTMENT, DO YOU AGREE THAT THE FULL $10,756, WHICH IS REPRESENTATIVE OF 1/5 OF THE TOTAL PROJECTED COSTS, SHOULD BE INCLUDED IN THE PROJECTED TEST YEAR?

A. No, I do not. The workpapers provided in response to OPC POD No. 21 state: "Could cost FPU up to $3.50 but FPU hopes to share cost with joint attachers." The workpapers also included a proposal to conduct the joint use audit submitted to FPUC by the vendor TRC dated January 17, 2014. The proposal identifies the proposed cost of $3.50 per location, but also states under the Fee Proposal section: "Based upon TRC's review of FPUC's attachment billing it is anticipated that these costs will be divided equally between the cable companies, telephone companies, and FPUC." Based on both FPUC's "hopes" to share the costs with the joint users of the poles and the statement that the vendor anticipates the costs will be divided equally between the cable companies, telephone companies, and FPUC, the full cost of the audit should not be passed on to FPUC's ratepayers.

Q. WHAT ADJUSTMENT DO YOU RECOMMEND?

A. I recommend that two-thirds of the annual amortization be removed from the projected test year expenses in order to reflect equal sharing of the costs between: 1) FPUC; 2) the telephone companies; and, 3) the cable companies. Under this sharing, presumably FPUC will be responsible for 1/3 of the cost, which is $17,927 ($53,781 total cost divided by 3 parties), or $3,585 per year over the 5-year amortization period ($17,927 / 5 years). Thus, projected test year expenses should be reduced by $7,171 to reflect only FPUC's projected cost share in rates. This is calculated as the recommended annual allowance based on the cost sharing of $3,585 less the amount included in the filing by FPUC of $10,756. The $7,171 reduction to projected test year expenses to reflect the cost sharing is shown on Exhibit DMR-2, Schedule C-1, page 2 of 2.

<u>Advertising Expense</u>

Q. WHAT AMOUNT IS INCLUDED IN THE PROJECTED TEST YEAR IN ACCOUNT 913 – ADVERTISING EXPENSE, AND HOW WAS THAT AMOUNT DETERMINED?

A. Projected test year expenses in Account 913 – Advertising Expense includes $207,648. During the historic test year, the Company recorded $226,202 in the account. In the filing, the Company moved $28,750 from Account 913 to Account 930.2 associated with Economic Development costs, resulting in $197,452 in the adjusted historic test year for advertising expense. The Company then applied a 1.0516 escalation factor to the remaining historic test year balance, resulting in the projected test year advertising expense of $207,648. Thus, the projected test year cost is based on the historic test year level, less the portion applicable to economic development, with escalation applied.

Q. ARE YOU RECOMMENDING ANY ADJUSTMENTS TO ADVERTISING EXPENSE?

A. Yes. I am recommending three separate adjustments to advertising expense. In the first adjustment, presented on Exhibit DMR-2, Schedule C-8, I recommend that the test year advertising expense be reduced by $57,561 to remove the costs associated with sponsorships, donations, golf tournaments and golf-related costs. In the second adjustment, shown on Exhibit DMR-2, Schedule C-9, I recommend that test year advertising expense be reduced by an additional $67,134 to remove public relations campaign costs and image building advertising costs that should not be passed on to FPUC's customers. Finally, on Exhibit DMR-2, Schedule C-1, page 2 of 2, I recommend test year advertising expense be reduced an additional $23,465 to remove Shrimp Festival costs that should not be passed on to the ratepayers. These three adjustments result in a total reduction to Account 913 – Advertising expense of $148,160. After the $148,160 is removed from the projected test year, the remaining advertising expense in Account 913 is $59,488 ($207,648 - $148,160).

Q. PLEASE DISCUSS YOUR FIRST RECOMMENDED ADVERTISING EXPENSE ADJUSTMENT.

A. In response to OPC POD 49, the Company provided numerous invoices for the various costs it recorded in Account 913 – Advertising expense during the historic test year. A review of those invoices made it clear that the Company included numerous charges in the account for corporate donations, sponsorships, charity golf tournament sponsorships and participation, golf balls with the Company logo, and golf towels with the Company logo. While it is commendable that the Company is making numerous donations and sponsorships to various organizations within the communities in which it operates, it is not appropriate to pass the costs associated with the donations and sponsorships to the Company's captive ratepayers. If the ratepayers chose to fund and sponsor such causes and organizations, they may do so of their own volition. They should not be forced to provide sponsorships and donations to various charity groups and organizations as part of the electric rates paid to FPUC. The donations, sponsorships and golf outings are not costs that are necessary for the provision of electric service to customers. If FPUC chooses to donate to and sponsor events for the various organizations and charities, it should do so with shareholder funds, not with ratepayer funds.

Q. IS IT COMMON FOR PUBLIC UTILITIES TO MAKE DONATIONS AND SPONSORSHIPS FOR CHARTITY AND COMMUNITY ORGANIZATIONS?

A. Yes. Based on my 20 plus years of experience in evaluating and addressing revenue requirements in regulatory proceedings, it is very common for public utilities to make donations to charity and community organizations and pay sponsorships for charity events. However, my experience has been that such costs are typically recorded in Account 426.1 – Donations, which is a below-the-line account that is excluded from the revenue requirements of utilities. In other words, utilities do not typically seek to recover such costs from ratepayers. In fact, the Federal Energy Regulatory Commission ("FERC") Uniform System of Accounts defines Account 426.1 – Donations, which is a below-the-line account, as follows: "This account shall include all payments or donations for charitable, social or community welfare purposes." Instead of recording the donations and payments to charitable, social and community welfare associations in Account 426.1, FPUC is recording such costs in Account 913 – Advertising Expense.

Q. HAVE YOU ITEMIZED THE VARIOUS SPONSORSHIPS, DONATIONS, AND GOLF-RELATED COSTS THAT YOU RECOMMEND BE REMOVED FROM THE TEST YEAR?

A. Yes. On Exhibit DMR-2, Schedule C-8, pages 1 and 2 of 2, I provide a list of all such costs that I recommend be removed from test year costs to be charged to customers. The list identifies 73 separate payments made by FPUC that were included in Account 913 – Advertising expense for the electric operations, totaling $54,737 in the historic test year. After escalation to the projected test year, I recommend that advertising expense be reduced by $57,561.

While some of the sponsorships listed on the schedule may have included a provision that FPUC can have a banner at an event or include small advertisements in pamphlets or brochures associated with the charity event, such costs should not qualify as advertising costs to be passed on to ratepayers. Additionally, FPUC's name association with various charity events may serve to enhance or promote FPUC's image and name recognition in the community, and such image-enhancing costs should not be passed on to ratepayers.

Q. PLEASE DISCUSS YOUR SECOND RECOMMENDED ADJUSTMENT TO ADVERTISING EXPENSE?

A. Exhibit DMR-2, Schedule C-9, lists eight separate charges to advertising expense during the test year associated with public relations and image-building efforts totaling $63,840 in the historic test year and $67,134 in the projected test year after escalation.

As shown on lines 1 and 2 of the schedule, the charges include $35,000 paid to Ron Sachs Communications/Sachs Media Group, Inc. for public relations consulting

(Documents FPU RC-004965 - 004967 and FPU RC-005120 – 005121). The entry made by the Company in recording the charges describes the costs as "Initial PR Campaign Preparation for Marianna" and "2 of 2 Installments, PR Firm, Marianna Lawsuit." The first invoice from the vendor describe the charges as:

> Initial campaign plan to be launched March 7, pending the Board's vote of the sale of the system. Creation of campaign name, theme, key messages and preparation of material and campaign collateral including but not limited to news releases, ads, open letter to the community.

The second invoice from the vendor describes the charges as "Public relations consulting and media services – Installment 2 of 2 per proposal/agreement."

Clearly these costs are associated with public relations and promoting FPUC's images during the City of Marianna's referendum to acquire FPUC electric assets. Such costs should not be passed on to customers. Additionally, because the referendum resulted in voters rejecting the purchase of FPUC's facilities by the City of Marianna, the costs are non-recurring.

The remaining charges identified on Schedule C-9 are for payments to MTN Advertising. They include advertising costs associated with the "Vote NO Campaign", "Vote NO Thank You Ads", news updates described as "Thank You Marianna" and other community campaign and public relations-related costs. These costs related to the City of Marianna referendum and image building should not be passed onto FPUC's ratepayers.

As shown on Exhibit DMR-2, Schedule C-9, test year expenses should be reduced by $67,134 to remove these charges from Ron Sachs Communications/Sachs Media Group, Inc. and MTN Advertising.

Q. PLEASE DISCUSS YOUR THIRD ADVERTISING EXPENSE ADJUSTMENT, WHICH REMOVES SHRIMP FESTIVAL COSTS FROM THE TEST YEAR.

A. The response to OPC Interrogatory No. 150 identifies $22,314 incurred during the historic test year and $23,465 included in the projected test year expenses in Account 913 – Advertising expense associated with the annual Shrimp Festival. The response indicates that the annual Shrimp Festival is included in FPUC's ". . . overall community development and outreach effort." I recommend that the costs spent by FPUC associated with the annual Shrimp Festival not be included in rates charged to FPUC's electric ratepayers. While FPUC's expenditures for the Shrimp Festival may enhance the Company's image in the community, the costs are not necessary for providing electric service to the Company's customers. As shown on Exhibit DMR-2, Schedule C-1, page 2 of 2, I recommend that test year expenses be reduced by $23,465 to remove these costs.

Q. ON WHAT BASIS IS THE COMPANY INCLUDING THE COSTS IN EXPENSES TO BE FACTORED INTO RATES CHARGED TO THE ELECTRIC CUSTOMERS?

A. In response to OPC Interrogatory No. 150, the Company states the following with regards to the Shrimp Festival costs:

> In addition to supporting general community outreach efforts, at this event, the Company has a booth manned by Company personnel, who provide information to festival participations [sic] regarding the Company's conservation programs. Our support of this festival is consistent with our economic development objectives, because this is a significant event in the community, which attracts numerous visitors to the area, as well as revenue, and provides an additional avenue to the City to showcase all it has to offer to new residents and potential new businesses.

Q. DOES THIS EXPLANATION PURSUADE YOU THAT THE COSTS SHOULD BE INCLUDED IN RATES CHARGED TO FPUC'S ELECTRIC CUSTOMERS?

A. No, it does not. While the Company attempts to tie the Shrimp Festival expenditures with conservation programs and economic development objectives, economic development expenditures should be focused on more targeted programs to promote economic development in the community than on an annual festival. While the festival may be an enjoyable annual event for the attendees and participants, ratepayers should not be required to fund costs associated with the festival and FPUC's corporate sponsorship of the festival in their electric rates. If FPUC chooses to sponsor the festival, the sponsorship costs should be recorded below-the-line to be excluded from costs charged to ratepayers.

Q. IS THE COMPANY INCLUDING THE SHRIMP FESTIVAL COSTS IN THE ECONOMIC DEVELOPMENT COSTS IT IS SEEKING TO INCLUDE IN RATES?

A. As will be discussed further in the next section of this testimony, the Company has historically considered the festival costs as Economic Development costs. However, in projecting the test year Economic Development cost, the Company did not include the festival costs. Rather, the Company classified the festival costs as advertising expense in the projected test year and not as part of the Economic Development request.

<u>Economic Development Expense</u>

Q. HOW MUCH IS THE COMPANY REQUESTING FOR INCLUSION IN THE PROJECTED TEST YEAR FOR ECONOMIC DEVELOPMENT EXPENDITURES?

A. In the Commission's Order in FPUC's last electric rate case, Order No. 08-0327-FOF-EI, the Commission allowed recovery of $15,701 annually for economic development expense. The Order also indicated, at page 56, that any unused economic development funds should be transferred to the storm reserve. In this case, FPUC is requesting to increase the annual economic development expense to be included in rates to $50,000, which is substantially higher than the amount requested in the prior rate case.

Q. HOW DOES THE REQUESTED ANNUAL EXPENSE OF $50,000 COMPARE TO THE ANNUAL EXPENDITURES INCURRED BY FPUC SINCE THE LAST RATE CASE?

A. The requested $50,000 is substantially higher than what FPUC has expended, on average, since the last rate case. In response to OPC Interrogatory No. 36, FPUC provided the historic economic development expenditures for the electric operations for each year, 2009 through 2013. Additionally, in response to OPC POD No. 42 the Company provided a breakdown of the costs it classified as economic development, by year, since the last rate case. The amounts presented by the Company, by year, are presented on Exhibit DMR-2, Schedule C-10, and total $195,051 over the five-year period from 2009 to 2013. However, included in the five-year total cost of $195,051 is $60,096 associated with Shrimp Festival expenditures. The breakdown of items associated with the Shrimp Festival that FPUC classified as "economic development" are provided on Schedule C-10, lines 7 through 13. While a detail of the festival charges was not provided for 2012 and 2013 (only dollar amounts provided and not an itemization of the costs), the 2011 charges included $426 for helium rental, $14,254 on an electric operations basis for pencils and balloons acquired for the festival and costs associated with festival T-shirts.

Once the festival costs are removed, the five-year total amount spent on Economic Development was $134,955, which averages to $26,991 per year.

Q. WHAT AMOUNT DO YOU RECOMMEND FOR INCLUSION IN BASE RATES FOR ECONOMIC DEVELOPMENT EXPENSE?

A. I recommend that the amount to be included in rates for economic development on a FPUC electric operations basis be limited to $27,000 per year. I also recommend the continuation of the current Commission requirement that economic development costs included in FPUC's electric rates that are not expended on qualifying activities in a given year be applied to the storm reserve. Specifically, I recommend that Shrimp Festival sponsorship and expenditures not qualify as "Economic Development" costs. My recommended annual allowance of $27,000 is 72% higher than the $15,701 factored into current rates and is consistent with the average amount of expenditures (excluding festival costs) incurred over the last five years of $26,991. As shown on Exhibit DMR-2, Schedule C-10, projected test year expenses should be reduced by $23,000 to limit the allowance to $27,000 annually.

Chesapeake Utilities Corporation Cost Allocations

Q. DID YOU REVIEW AND ANALYZE THE AMOUNT INCLUDED IN PROJECTED TEST YEAR EXPENSES FOR COSTS CHARGED FROM THE CUC CORPORATE OPERATIONS TO THE FPUC ELECTRIC OPERATIONS?

A. Yes, I did. As part of my review and analysis, I compared the amounts included in the historic base year to the projected test year levels, reviewed CUC Corporate Department budget variance reports for 2012 through April 2014, and reviewed the Company's benchmark analysis comparing the O&M expenses from the last 2008 test year to the projected test year ending September 30, 2015 requested levels. My analysis reflects that the Company's requested corporate allocations included in the projected test year expenses are excessive. I discuss each of these areas below.

Q. WHAT AMOUNT IS INCLUDED IN THE PROJECTED TEST YEAR EXPENSES FOR CHARGES FROM CUC, AND HOW DOES THAT AMOUNT COMPARE TO THE AMOUNT RECORDED IN THE HISTORIC TEST YEAR?

A. In the filing, the Company has projected a significant increase in the costs charged from CUC to the FPUC electric operations. The table below provides a breakdown of the payroll and non-payroll charges from CUC to FPUC electric operations in the adjusted historic test year as compared to the amounts included in the projected test year. For purposes of this comparison, I have excluded the $120,000 increase to the projected test year for the general liability reserve for past and future claims addressed previously in this testimony. FPUC included the $120,000 adjustment as part of the CUC expense category in its filing.

	Payroll Expense	Non-Payroll Expense	Total Expense
Projected Test Year	$ 968,454	$ 1,974,242	$ 2,942,696
Historic Test Year Adjusted	$ 779,551	$ 1,641,846	$ 2,421,397
Increase Above Historic	$ 188,903	$ 332,396	$ 521,299
Percentage Increase	24.2%	20.2%	21.5%

As shown above, the filing includes an $188,903 or 24.2% increase in CUC payroll costs charged to FPUC, a $332,396 or 20.2% increase in non-payroll costs charged to FPUC, and an overall increase in expenses charged from CUC of $521,299 or 21.5%.[1] This projected $521,299 increase is over a short two-year period.

[1] As discussed later in this testimony, FPUC shifted costs allocated from the CUC Strategic Development Department from the Corporate O&M expenses category to the Non-Corporate O&M Expense category. If the

Q. ARE THE PROJECTED TEST YEAR EXPENSES FROM CUC TO THE FPUC ELECTRIC OPERATIONS BASED ON THE HISTORIC TEST YEAR ACTUAL BALANCES WITH SPECIFIC ADJUSTMENTS FOR KNOWN AND MEASURABLE CHANGES AND ESCALATION APPLIED?

A. No. The projected test year charges to FPUC electric operations from CUC are based on CUC's budgets. Thus, the CUC expenses incorporated in the filing are not based on the actual historic test year expense with known and measurable adjustments and escalation applied. Rather, the expenses are based on CUC's internal budgets and the amount CUC projects it will charge to the FPUC electric operations in the projected test year, which greatly exceeds the costs charged to FPUC electric operations in the historic test year. Conversely, the specific FPUC operation-level allocations to FPUC's electric division are based predominately on historic test year expenses escalated to the projected test year with specific normalization adjustments and adjustments for known and measurable changes.

Q. CAN YOU GIVE EXAMPLES OF CUC DEPARTMENTS FOR WHICH THE CHARGES TO FPUC ELECTRIC OPERATIONS ARE PROJECTED TO INCREASE?

A. Yes. As part of its response to OPC POD No. 1, at FPU RC-1155 and FPU RC-1199, breakdowns of the historic test year and the projected test year charges to FPUC electric operations from CUC were provided by department. For example, the response shows that the charges for Information Technology ("IT") General Staff are projected to increase from $222,224 in the historic test year to $318,071 in the projected test year.

---

expenses from the CUC Strategic Development Department were included in the table, the increase would be even greater at $598,244 or 24.4%.

Charges from the Human Resources ("HR") Department, which includes "HR staff and related consulting fees," are projected to increase from $188,868 in the historic test year to $231,974 in the projected test year. Charges from the Communications Department, described as "Corporate communications (branding, communications, annual report, etc.)," are projected to increase from $103,197 to $145,756.

Q. WERE THERE ADDITIONAL CUC CORPORATE DEPARTMENTS FOR WHICH THE CHARGES TO THE FPUC ELECTRIC OPERATIONS WERE PROJECTED TO INCREASE SIGNIFICANTLY FROM THE HISTORIC TEST YEAR TO THE PROJECTED TEST YEAR?

A. Yes, there were four additional CUC corporate departments for which the costs were projected to increase significantly. The departments are Senior Vice President ("SVP") of Strategic Development, New Energy Development, Strategic Development and Other Overhead Costs.

Q. PLEASE EXPLAIN THE INCREASES FOR EACH OF THESE DEPARTMENTS.

A. The charges from the SVP of Strategic Development are projected to increase from $113,140 to $157,272. Charges from the New Energy Development Department, described as "Development of new energy-related business opportunities" increase from $83,912 in the historic test year to $183,796 in the projected test year. Additionally, charges from the Strategic Development Department, which is described as "Strategic corporate planning, assessment of business opportunities" increase from $35,510 in the historic test year to $115,848 in the projected test year. The charges from "Other Overhead Costs" increase from $87,699 in the historic test year to $186,747 in the projected test year. A further breakdown of these charges shows that the cost of "Outside services for general corporate matters" is projected to increase from $46,465 in the historic test year to $157,263 in the projected test year (which is related to strategic development costs as detailed later in my testimony).

Q. PLEASE EXPLAIN YOUR REVIEW OF THE CUC BUDGET VARIANCE REPORTS FOR THE CORPORATE DEPARTMENTS FOR 2012 THROUGH APRIL 2014.

A. In response to OPC POD No. 52, at FPU RC-5428, the Company provided a copy of the CUC operating expense variance reports for the Corporate Departments for 2012, 2013, and thru April 2014. I reviewed these variance reports to evaluate the accuracy of CUC's past budgets. The CUC Corporate Departments are the departments for which a portion of the expenses are charged or allocated to the FPUC electric operations. The 2012 variance report shows that on a total CUC Corporate Department basis, actual expenses were $1,006,816 or 4.1% below budget and expenses charged to FPUC electric were $207,247 or 8.5% below budget. The 2013 variance report shows that on a total CUC Corporate Department basis, actual expenses were $1,763,260 or 6.1% below budget and expenses charged to FPUC electric were $164,762 or 5.6% below budget. For the four-month period January 2014 to April 2014, total actual CUC expenses were $860,506 or 8% below budget, and charges to the electric operations were $38,672 or 4% below budget. Thus, for the last two calendar years and for 2014 through April, the total CUC expenses for the Corporate Departments and the expenses charged to FPUC Electric operations from CUC were consistently below the budgeted amounts.

Q. SINCE THE ACQUISITION OF FPUC BY CUC, HOW MUCH HAVE FPUC'S O&M EXPENSES INCREASED?

A. MFR Schedule C-37 shows, that after the purchased power and conservation costs are removed, O&M expenses increased from $9,309,831 (the adjusted 2008 base year amount in FPUC's last rate case prior to the acquisition) to $12,160,672 in the projected test year ended September 30, 2015. This is an increase of $2,850,841 or 31%. The same exhibit shows that the test year benchmark amount, based on the adjusted O&M expenses for 2008 as escalated, is $10,568,520. The benchmark variance, or comparison of the escalated 2008 costs to the projected test year costs in the current case, is $1,592,152. In other words, the projected test year O&M expenses (excluding purchase power and conservation) in the filing are $1,592,152 or 15% higher than the benchmark. The largest portion of the benchmark variance is in the Administrative and General Expense category, which exceeds the benchmark by $1,340,151. The majority of the projected test year expenses charged from CUC to FPUC electric operations is included in the Administrative and General Expense category. While the benchmark variance is impacted by the $120,000 projected adjustment associated with the general liability reserve, the benchmark variance is still significant at $1,472,152 or 14% with the $120,000 adjustment removed.

Q. HAS THE COMPANY DEMONSTRATED THAT A 21.5% INCREASE IN CHARGES FROM CUC TO THE FPUC ELECTRIC OPERATIONS FROM THE HISTORIC TEST YEAR TO THE PROJECTED TEST YEAR IS REASONABLE?

A. No, it has not. The Company has not presented evidence demonstrating that a 21.5% increase over a two-year period in CUC corporate costs being allocated to FPUC electric operations is reasonable or necessary. It also has not established that substantial customer benefits will result from a 21.5% increase in corporate cost allocations. Additionally, as previously shown, the total CUC Corporate Department expenses that are being incurred and the amount of CUC Corporate Department expenses charged to the FPUC electric operations have consistently been below the budgeted amounts.

Q. ARE YOU RECOMMENDING ANY ADJUSTMENTS TO THE CHARGES FROM CUC TO FPUC'S ELECTRIC OPERATIONS AS A RESULT OF YOUR ANALYSIS?

A. Yes, I am recommending several adjustments. The Company has not demonstrated that a 21.5% increase in corporate costs charged from CUC is either supported or needed to effectively serve FPUC's customers. The Company also has not demonstrated that the CUC budgeted amounts are accurate projections. I first recommend that the projected test year charges to FPUC electric operations from CUC's corporate operations be limited to the historic test year amount with escalation applied. I also recommend that the escalation factors to be applied be based on those used by the Company in escalating FPUC's expenses from the historic test year to the projected test year. This would result in an escalation factor of 1.0671 for payroll costs based on the combined payroll and customer growth factor, and an escalation rate of 1.0516 for the non-payroll costs based on the inflation and customer growth factor. As shown on Exhibit DMR-2, Schedule C-11, limiting the charges from CUC to the FPUC electric operations to the historic test year level, escalated to the projected test year level, results in a $384,272 reduction to the projected test year expenses charged from CUC to the FPUC electric operations[2].

[2] As addressed previously in this testimony, my adjustment regarding the corporate bonus amounts allocated to the FPUC electric operations is not included in the above CUC corporation allocation adjustment and is reflected on Exhibit DMR-2, Schedule C-1, page 2 of 2.

Q. ARE THERE ANY EXPENSES THAT WERE INCURRED BY CUC IN THE HISTORIC TEST YEAR THAT WERE ALLOCATED TO FPUC THAT WILL NOT RECUR IN THE PROJECTED TEST YEAR?

A. Yes. During the historic test year, payments were made to two former executives of FPU, Charles Stein and George Bachman. According to the response to OPC Interrogatory No. 120, each of these executives' employment was terminated in 2011. At that time, the Company entered into consulting service agreements with the two executives for a three-year period. The consulting agreements expired in early 2014. The responses to OPC POD No. 1, at FPU RC-1139, and OPC Interrogatory No. 120 indicate that the total payments to Charles Stein during the historic test year were $180,000, with $14,930 allocated to FPUC electric operations. The same responses identify that the total amount paid to George Bachman during the historic test year was $162,000, with $13,373 allocated to the FPUC electric operations. Thus, the historic test year includes $28,303 in non-recurring consulting payments to the two terminated executives on an FPUC electric operations basis.

Q. DO YOU RECOMMEND THESE NON-RECURRING COSTS BE REMOVED FROM THE PROJECTED TEST YEAR?

A. Yes. If the Commission adopts my recommendation that projected test year charges from CUC to the FPUC electric operations be limited to the actual historic test year amount plus escalation, then an additional adjustment should be made to remove these non-recurring charges. The amount of these non-recurring charges included in the projected test year under my recommended approach would be $29,763 ($28,303 x 1.0516 escalation factor). I have reduced the projected test year expenses by $29,763 on Exhibit DMR-2, Schedule C-1, page 2 of 2, to remove these non-recurring consulting charges.

Q. IF THE COMMISSION DOES NOT ACCEPT YOUR ADJUSTMENT TO LIMIT THE CUC CHARGES TO THE HISTORIC TEST YEAR LEVEL PLUS ESCALATION, ARE ANY ADDITIONAL ADJUSTMENTS NEEDED?

A. Yes. In response to OPC Interrogatory No. 138(d), the Company indicated that the allocation of charges from CUC Department IT 802 – Utilicis Natural Gas Billing System to FPU electric operations in the projected test year was done in error as the FPUC electric operations do not utilize the Utilicis billing system. There were no charges to FPUC electric operations during this historic test year from this department; thus, if my adjustment is accepted, then the amount for this department remains at $0 in the projected test year. Based on the response to OPC POD No. 1, at FPU RC-1198, the projected test year expenses in the filing include $8,020 for charges from this department. If the Commission does not accept my recommendation that charges to FPUC electric operations be limited to the historic test year amount plus escalation, then the Company's projected test year expenses need to be reduced by $8,020 to remove the costs associated with the CUC Utilicis Natural Gas Billing System department.

<u>Non-utility Related Activities</u>

Q. IN YOUR OPINION HAS THE COMPANY INCLUDED ANY NON-UTILITY CUC COST ALLOCATIONS IN THE HISTORICAL AND PROJECTED FPUC EXPENSES?

A. Yes. In OPC's review of FPUC's responses to discovery, there are charges from several departments whose activities do not appear to be related to the function of the FPUC electric operations. For both the historic test year and the projected test year, the departments that appear to be non-utility are the New Energy Department, the SVP of

Strategic Development, and the Strategic Development Department. For the projected test year, an additional portion of the Other Overhead Costs Department for the increase in outside service for general corporate matters is also related to strategic development costs. I will address each of these separately below.

Q. DOES THE COMPANY'S RESPONSE TO OPC'S DISCOVERY PROVIDE SUPPORT FOR WHY THE ELECTRIC CUSTOMERS SHOULD BE ALLOCATED CHARGES FROM CUC'S NEW ENERGY DEPARTMENT?

A. No. The charges from the New Energy Development Department to the FPUC Electric operations are $83,912 in the historic test year and have been increased to $183,796 for the projected test year. In response to OPC Interrogatory No. 137, the Company indicated that the New Energy Development Department was formed during the historic test year so a full year of expense for the department was not included in the historic period. In response to OPC Interrogatory No. 141, the Company indicated that the New Energy Development Department ". . . supports various corporate and business unit efforts to identify, evaluate, and assess new business initiatives in the energy industry that can complement our existing business strategies." The response also indicated that the department ". . . also provides various skill-sets, such as market trends/intelligence, financial modeling, energy supply analysis, and other business development, which Chesapeake's business units, including FPU electric division, utilize." The response does not explain why the $83,912 historical costs or $183,796 in projected test year charges to FPUC's electric operations for new energy development are necessary for providing service to FPUC's customers, why CUC's development of new energy-related business opportunities benefit FPUC's existing customers, or why the services of this department are needed beyond the functions already done by FPUC staff. No information has been provided demonstrating that the New Energy Development Department is focused in any way on the existing regulated electric operations. Thus, I recommend that the charges from CUC associated with the New Energy Development Department not be passed on to FPUC's electric ratepayers as the Company has not demonstrated a clear benefit to the FPUC electric operations from this department.

Q. ARE THE COMPANY'S RESPONSES TO OPC'S DISCOVERY SUFFICIENT TO EXPLAIN WHY THE CHARGES FROM CUC'S SVP OF STRATEGIC DEVELOPMENT DEPARTMENT SHOULD BE ALLOCATED TO FPUC ELECTRIC DIVISION CUSTOMERS?

A. No. The historical charges allocated from the SVP of Strategic Development Department are $113,140 and have been increased to $157,272 in the projected test year. In response to OPC Interrogatory No. 138(i), the Company described the significant increase in charges from CUC corporate operations to FPUC electric operations for the SVP of Strategic Development Department. It indicated that the increased costs are due to the hiring of a Vice President of HR to ". . . coordinate the overall compensation, benefit, staffing, recruiting and other HR-related matters" and that ". . . efforts are under-way to recruit a director of government relations to coordinate various governmental policy and relationship matters." The HR costs in the SVP Strategic Development Department would be incremental to the HR costs already charged to FPUC electric operations from a separate CUC HR Department, which totaled $188,868 in the historic test year. The Company has not demonstrated that the existing FPUC electric ratepayers benefit from this department, or that the department is focused on the existing regulated electric operations. I recommend that the historical charges from CUC for the SVP of Strategic Development Department not be passed on to FPUC's electric ratepayers.

Q. WHAT ADJUSTMENT IS NEEDED TO REMOVE THE COSTS ASSOCIATED WITH CUC'S NEW ENERGY DEVELOPMENT DEPARTMENT AND SVP OF STRATEGIC DEVELOPMENT DEPARTMENT?

A. If the Commission accepts my adjustment to limit the charges to FPUC electric operations from CUC to the historic test year amount plus escalation, then the adjusted test year expenses should be reduced by an additional $205,043 to remove the charges from these two CUC departments. The calculation of this adjustment is presented on Exhibit DMR-2, Schedule C-12. If the Commission does not accept my recommendation to limit the charges to the historic test year amount plus escalation, then the full amount included by FPUC in its projected test year for charges from these two departments should be removed. As shown on Line A.3 of Exhibit DMR-2, Schedule C-12, FPUC's projected test year expenses included $332,862 for charges from these two CUC departments.

Q. YOU PREVIOUSLY TESTIFIED THAT THE STRATEGIC DEVELOPMENT DEPARTMENT COSTS APPEAR TO BE NON-UTILITY AS WELL. PLEASE DISCUSS YOUR CONCERNS.

A. OPC Interrogatory No. 138(g) (which refers to OPC POD No. 1 at FPU RC1199, specifically the tab titled "Summary of Corporate Costs"), asked the Company to explain, in detail, why the Strategic Development Department costs charged to FPUC electric operations were projected to increase from $35,510 in the historic test year to $115,848 in the projected test year, and to provide the rationale for the large increase. In response, the Company indicated that the Strategic Development Department is a new department that was formed during the historic test year so a full year of expenses for the department was not included in the historic period. The response indicates that the department ". . . assists in various strategic development areas of different businesses of Chesapeake." The response also indicates that for FPU electric, the department ". . . assists in system planning activities." The response does not explain why the charges in the historic test year or the projected test year to FPUC's electric operations are necessary for providing service to FPUC's customers or why the additional system planning activities beyond those already done by FPUC staff are needed. Further, the Company has not documented any direct benefit to FPUC electric ratepayers from the activities of the CUC Strategic Development Department.

Q. DID THE COMPANY ACCOUNT FOR THE CUC STRATEGIC DEVELOPMENT DEPARTMENT COSTS CHARGED TO THE FPUC ELECTRIC OPERATIONS IN THE SAME MANNER AS THE MAJORITY OF THE OTHER CUC CORPORATE DEPARTMENTS?

A. No, it did not. For this department, the Company shifted costs charged from the corporate O&M expenses to the FPUC electric operations non-corporate O&M expenses in its filing. As part of its normalization adjustments to the historic test year on MFR Schedule C-7 (2013), pages 2 and 6[3], the Company moved or "reclassified" the historic test year charges from the CUC Strategic Development Department from the Corporate O&M Expense category to the Non-Corporate Distribution O&M Expenses in FERC Account 580 – Operation, Supervision and Engineering. The amount moved to FERC account 580 for charges from the Strategic Development Department in the historic test year was $34,351. As part of its "Over and Under Adjustments" presented on MFR Schedule C-7 (2015), page 9 of 9, the Company increased the amount charged to FPUC

[3] These adjustments are reflected on Schedule C-7 on pages 19 and 23 of Section C in the MFRs.

electric operations from the CUC Strategic Development Department by $76,945 in the projected test year, resulting in total projected test year charges to FPUC electric operations from this CUC department of $111,296. On MFR Schedule C-7 (2015), page 9 of 9, the Company included the adjustment in the "Expenses for Electric Operations" instead of the "Expenses for Corporate Services and Overheads" even though the costs are allocated to FPUC electric operations from CUC. The MFR schedule identifies the adjustment as "System Planning" and the reason for the adjustment as "Full staff and related new Dept expense." The MFR Schedule does not indicate that the adjustment is for charges from the CUC Strategic Planning Department. However, the Company's response to OPC POD No. 21 at FPU RC-003059 makes it clear that the adjustment is for Department SP 900 – which is the CUC Strategic Development Department. Additionally, the resulting projected test year amount of $111,296, after the Over and Under Adjustment was made, can be tied to various CUC corporate and FPUC electric operations workpapers which were provided.

Q. WHAT ADJUSTMENT IS NEEDED TO REMOVE THE CUC STRATEGIC DEVELOPMENT DEPARTMENT EXPENSES FROM THE PROJECTED TEST YEAR?

A. Because these costs were moved by the Company out of the Corporate O&M cost category to the non-corporate distribution expense category in the MFRs, my previously recommended adjustment to CUC corporate costs allocated to the FPUC electric operations would not include an adjustment to the CUC Strategic Development Department expenses contained in the filing. As such, projected test year expenses need to be reduced by $111,296 to remove the Strategic Development Department costs. This $111,296 reduction is shown on Exhibit DMR-2, Schedule C-1, page 2 of 2.

Q. IS AN ADJUSTMENT NEEDED TO REMOVE THE CUC OTHER OVERHEAD COSTS DEPARTMENT EXPENSES RELATED TO OUTSIDE SERVICES FOR GENERAL CORPORATE MATTERS FROM THE PROJECTED TEST YEAR?

A**.** No, if the Commission accepts my recommended adjustment to limit the CUC charges to the historic test year level plus escalation, no further adjustment is necessary. However, if the Commission disagrees with my limiting adjustment, an additional adjustment will be necessary based on the Company's response to discovery. In describing the cause of the large increase in the charges from the CUC Other Overhead Costs charged to FPUC electric operations in the projected test year, the response to OPC Interrogatory 137(c) states: "The amount in the projected test year includes approximately $100,000 in additional costs associated with increased resources to help senior management identify, develop and execute various business and improvement initiatives to further the Company's growth and provide adequate support the current and future growth." Thus, these costs are related to strategic development and the growth of CUC and should not be charged to the FPUC electric operations. Therefore, an adjustment will be necessary to remove the $100,000 of additional strategic development and CUC growth related costs.

<u>Remove Winter Event Costs</u>

Q. WHAT IS THE WINTER EVENT AND HOW MUCH IS INCLUDED IN THE TEST YEAR FOR THE EVENT?

A. The response to OPC Interrogatory No. 164 indicates that there is a winter event for employees in each FPUC district with a portion of the costs allocated from FPUC corporate to the electric operations. During the historic test year in February 2013, the Marianna winter event was held at Sandestin Golf and Beach Resort, the Fernandina Beach winter event was held at Disney World, and the West Palm Beach winter event was held on Windridge Yacht Charters. The Company described the purpose of the winter events as follows:

> The events include presentations by the officers and senior managers of the Company and are used to show appreciation to the employees, inform them of the status of the Company as a whole, and acknowledge them for their achievements and impacts to the Company. In addition, motivational presentations are made to encourage employees to continue to provide great customer service both at an internal and external level and to identify and implement further customer experience enhancements. Employees are recognized for meeting these goals at the events. In addition, these meetings give the employees an opportunity to network with their peers and strengthen relationships, which improve teamwork and customer service.

The response also indicates that the costs allocated to the electric operations for the winter events during the historic test year were $16,838, which was escalated to $17,968 in the projected test year.

Q. DO YOU RECOMMEND THAT THESE COSTS BE INCLUDED IN RATES TO BE CHARGED TO THE ELECTRIC CUSTOMERS?

A. No, I do not. Having employee appreciation and informative events at such costly venues such as yachts, amusement parks, and golf/beach resorts is not a necessary cost in providing service to the Company's customers. There are more economic ways and locations in which employee appreciation and informative events can be held. I recommend that the costs for the winter events be removed from the projected test year. The removal, which reduces test year expenses by $17,968, is shown on Exhibit DMR-2, Schedule C-1, page 2 of 2.

<u>Tax Step-Up Regulatory Asset and Amortization</u>

Q. PLEASE EXPLAIN WHAT THE COMPANY IS REQUESTING IN THIS CASE WITH REGARDS TO THE PROPOSED TAX STEP-UP REGULATORY ASSET?

A. As a result of the acquisition of Florida Public Utilities by CUC, the federal income tax rate for FPUC increased from 34% to 35%. The increase is the effect of FPUC being part of the larger corporate group for federal income tax purposes. As a result of changing to the higher federal income tax rate, the Company was required at the time of the acquisition to adjust its accumulated deferred income tax liability in Account 282 to reflect the impact of the higher federal income tax rate that would be realized as a result of the acquisition. Based on the journal entry provided in response to OPC Interrogatory No. 27, the Company increased the accumulated deferred income tax ("ADIT") liability recorded in Account 282.2 by $256,777 for the electric operations with an application date of October 31, 2009. Since the time of the acquisition, increases in the ADIT liability balances on FPUC's books would have been calculated based on the effective federal income tax rate, which is 35% or the higher post-acquisition rate.

According to the testimony of Mr. Kim, at pages 18-19, the amount by which the Company was required to increase the ADIT liability was reflective of a deficiency in the deferred tax reserve and represents the amount of taxes associated with timing differences that FPUC had previously been allowed to recover under the prior, lower effective income tax rate that will be paid in the future by FPUC at the current higher applicable income tax rate.

The calculation of the amount requested for recovery by the Company as a regulatory asset was provided in response to OPC Interrogatory No. 27. In determining the amount requested for recovery, the Company included $256,777 that it booked at the time of the acquisition for the increase in the ADIT liability. The Company then calculated the change in the ADIT liability that would occur for the period November 1, 2009 through

September 30, 2015 based on both the prospective applicable rate and a lower pre-acquisition rate, resulting in a difference of $59,293, which it grossed up for taxes to $96,530. While the Company would have recorded the ADIT subsequent to the acquisition at the higher tax rate, the calculation of the requested regulatory asset assumes that it was recovered at the lower pre-acquisition tax rate. The Company then combined the actual booked increase in the ADIT liability of $256,777 with the $59,293 amount it calculated for the period November 2009 through September 2015 to derive its requested Tax Step-up Regulatory Asset of $353,307. The Company is requesting to recover the proposed regulatory asset over a period of 26 years, which is the average remaining life of the electric operation plant assets.

Q. WHAT AMOUNTS ARE INCLUDED IN THE FILING FOR THE PROPOSED REGULATORY ASSET AND THE AMORTIZATION THEREOF?

A. Exhibit No. CMM-4 attached to Ms. Martin's testimony shows that the average test year working capital includes $346,515 for the proposed regulatory asset. Additionally, page 42 of Ms. Martin's testimony and MFR Schedule C-19 show that $13,584 is included in test year amortization expense associated with the proposed regulatory asset.

Q. DID THE COMPANY ACTUALLY RECORD A REGULATORY ASSET ON ITS BOOKS ASSOCIATED WITH ITS TAX STEP-UP ADJUSTMENT FOR THE ELECTRIC OPERATIONS AT THE TIME OF THE ACQUISITION?

A. No, it does not appear so. As part of its response to OPC Interrogatory No. 27, FPUC provided one side of the journal entry posted on May 13, 2010 with an application date of October 31, 2009 for the increase in the ADIT liability balance in Account 282. The journal entry that was provided only included the increase in the ADIT balance of

$256,777, with the description of "Acquis adj-Fed Rate to 35%". The information excluded the other side of the entry showing the account to which the corresponding debits were booked. As a result of the incomplete entry being provided, OPC Interrogatory No. 102 referenced the partial entry and asked for the complete journal entry that recorded the tax step-up deferred income tax adjustment recorded in 2010, reflecting all of the debits and credits made to each account related to the tax step-up deferred tax adjustment. Unfortunately, the journal entry provided in response to OPC Interrogatory No. 102 consisted of a reclassification entry in which the Company transferred the $256,777 originally booked to Account 282.2 to different subaccounts, or segment codes, within Account 282.2 for tracking purposes. However, the revised response still did not disclose what accounts the original debits were booked to when the $256,777 was credited to the ADIT liability. The description in the journal entry that was provided in response to OPC Interrogatory No. 102 remains "Acquis adj – Fed Rate to 35%". Thus, it appears from the description that the increase in the ADIT liability was booked as part of the acquisition adjustment resulting from CUC's acquisition of FPUC. The Company has not requested recovery of an acquisition adjustment for the electric operations. In fact, in response to OPC Interrogatory No. 27(c), the Company indicated that there was no positive acquisition adjustment for the electric operation of FPUC. Thus, if the other side of the journal entry was to an acquisition adjustment, it did not result in a positive acquisition adjustment for the electric operations.

Q. DOES THE COMMISSION REQUIRE THAT REGULATORY ASSETS OR LIABILITIES BE ESTABLISHED DUE TO CHANGES IN THE ADIT BALANCES RESULTING FROM CHANGES IN FEDERAL INCOME TAX RATES?

A. Florida PSC Rule 25-14.013 – Accounting for Deferred Income Taxes Under SFAS 109 at paragraph 10 states that:

> When the statutory income tax rate is changed as a result of legislative action after the implementation of SFAS 109, each utility shall adjust its deferred income tax balances to reflect the new statutory income tax rate. The recording of regulatory assets and liabilities for the excess or deficient deferred income taxes, accounting detail and reversal of the excess and deficient deferred income taxes shall comply with subsections (4) through (9) of this rule.

While the establishment of regulatory assets or liabilities associated with changes in tax rates are addressed in the rule as it pertains to changes in income tax rates as a result of legislative action, the rule is silent on changes in effective income tax rates resulting from acquisitions or mergers.

Q. DO YOU RECOMMEND THAT THE COMPANY BE PERMITTED TO ESTABLISH AND RECOVER THE TAX STEP-UP REGULATORY ASSET IT IS REQUESTING IN THIS CASE?

A. No, I do not. At the time of the acquisition, it appears that the Company appropriately increased the ADIT liability in Account 282.2 for the impact of the increase in the effective federal income tax rate. However, the other side of the journal entry recording the increase, which FPUC has not provided, would have been recognized on FPUC's books at the time the step-up adjustment was recorded to the ADIT balance. There is no basis for FPUC to now request a regulatory asset associated with the initial step-up for the ADIT balance from ratepayers more than four years after the acquisition by CUC took place. If the increased federal income tax to be paid by FPUC as a result of the acquisition caused FPUC to under-earn, it had the ability to come in and request a rate increase from the Commission. The Company also had the ability to request at the time that a regulatory asset be established for the required increase in its ADIT liability balance that it booked as a result of the acquisition, which it did not. It is not appropriate to now request a regulatory asset many years after the adjustment was made on the Company's books and many years after the acquisition occurred. Thus, I recommend that the Company's proposed tax step-up regulatory asset and the amortization thereof be rejected.

Q. WHAT ADJUSTMENTS NEED TO BE MADE TO REMOVE THE REGULATORY ASSET AND THE AMORTIZATION?

A. As shown on Exhibit DMR-2, Schedule B-1, page 2, working capital should be reduced by $346,515 to remove the regulatory asset from rate base. Additionally, as shown on Exhibit DMR-2, Schedule C-1, page 2, amortization expense should be reduced by $13,584.

<u>Payroll Tax Expense</u>

Q. DO ANY OF YOUR RECOMMENDED ADJUSTMENTS IMPACT PAYROLL TAX EXPENSE?

A. Yes. In this testimony, I recommend several adjustments to the projected test year employee costs. This includes adjustments to severance expense, special bonuses, CUC corporate bonuses, and incentive performance plan costs. Each of these adjustments also impact payroll tax expense. On Exhibit DMR-2, Schedule C-13, I calculate the impact of the various labor adjustments on the projected test year payroll tax expense. As shown on this schedule, payroll tax expense should be reduced by $41,716 to reflect the impact of the various labor cost adjustments. The amount was determined by applying the FICA rate of 7.65% to the various labor adjustments presented in this testimony.

<u>Property Tax Expense</u>

Q. WHAT AMOUNT HAS THE COMPANY INCLUDED IN THE PROJECTED TEST YEAR FOR PROPERTY TAX EXPENSE, AND HOW DOES THE PROJECTED AMOUNT COMPARE TO HISTORIC COST LEVELS?

A. In the filing, the Company projects that property taxes will increase from the historic test year amount of $601,193 to $690,483 in the projected test year, which is an increase of $89,290 or 14.85% in a two-year period. In response to OPC Interrogatory No. 45, the Company provided the tax basis and the property tax expense for each year, 2010 through 2013. The table below presents the historic amounts provided by the Company as well as the projected amounts included in the Company's filing.

Period	Tax Basis	Property Tax
2010	$ 37,330,579	$ 575,126
2011	$ 37,956,260	$ 586,923
2012	$ 37,814,122	$ 582,345
2013	$ 39,973,520	$ 620,516
TY Ended 9/30/15	$ 49,243,103	$ 690,483

Based on the information shown in the table above, for the period from 2010 to 2013, the property tax basis only increased by $2.64 million or 7.1% while the property tax expense increased by only $45,390 or 7.9% over that same four-year period. This is during the timeframe following the merger with CUC in which the Company contends that it has invested more in improving its system. While the historic increase from 2010 through 2013 was only 7.1% for the tax basis and 7.9% for the overall property tax expense, the Company projected a significant increase in both the tax basis and the tax expense from the historic test year to the projected test year. Based on the above amounts, the Company's filing projected the tax basis to increase by $9,269,583 or 23.2% between the calendar year ended December 31, 2013 and the projected test year ended September 30, 2015. During that same period of less than two years, the Company is projecting a

$69,967 or 11.3% increase in property tax expense. In response to OPC Interrogatory No. 130 the Company indicated that the increase in the tax basis it incorporated in the projected test year was incorrect, and the projected test year tax basis should have been $43,912,268 instead of the $49,243,102 presented in MFR Schedule C-20. However, in the same response, the Company contends that its projected property tax expense was calculated correctly based on the historic test year amount escalated for both an inflation factor and a net plant increase factor.

Q. HAS THE COMPANY SUPPORTED THE SIGNIFICANT PROJECTED INCREASE IN PROPERTY TAX EXPENSE CONTAINED IN ITS FILING?

A. No, it has not. While the Company is projecting some large increases in plant in service between the historic test year and the projected test year, it has also indicated that the Company has invested in the system since the merger with CUC. Although the Company did recently add a new building that could put upward pressure on property tax expense and the property tax basis, it also recently sold a building that should offset the impact of the new building on property tax expense. Thus, there is no reasonable explanation for why such a large increase in both the tax basis and the property tax expense is anticipated, particularly given the much lower increases that have occurred in the period subsequent to the merger. The direct testimony of Ms. Martin, at page 47, indicates that property taxes were increased by inflation and plant growth. However, it does not appear that over the past four years the property tax expense has increased by a similar rate.

Q. WHAT ADJUSTMENT DO YOU RECOMMEND?

A. I recommend that the projected property tax expense be determined by applying the average property tax expense increase factor based on the post-merger period, 2010 through 2013, to the historic test year expense, escalated for the two-year period to the test year ended September 30, 2015. As shown on Exhibit DMR-2, Schedule C-14, property tax expense has increased by an average of 2.61% between 2010 and 2013. Escalating the historic test year cost of $601,193 by the average annual increase factor for a two-year period to the projected test year results in projected property tax expense of $632,968, which is $57,515 lower than the amount proposed by FPUC. As shown on Schedule C-14, test year property tax expense should be reduced by $57,515.

Income Tax Expense

Q. HAVE YOU ADJUSTED INCOME TAX EXPENSE TO REFLECT THE IMPACT OF YOUR RECOMMENDED ADJUSTMENTS TO NET OPERATING INCOME?

A. Yes. On Exhibit DMR-2, Schedule C-15, I calculate the impact of federal and state income tax expenses resulting from the recommended adjustments to operating expenses. The result is carried forward to the Net Operating Income Summary on Exhibit DMR-2, Schedule C-1.

Interest Synchronization

Q. WHAT IS THE PURPOSE OF YOUR INTEREST SYNCHRONIZATION ADJUSTMENT ON EXHIBIT DMR-2, SCHEDULE C-16?

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

OVERALL FINANCIAL SUMMARY – ALTERNATIVE RECOMMENDATION

Q. HAVE YOU CALCULATED THE REVENUE REQUIREMENT BASED ON THE ALTERNATIVE CAPITAL STRUCTURE AND COST RATES PRESENTED BY DR. WOOLRIDGE?

A. Yes. Exhibit DMR-3, totaling 4 pages, shows the revisions that need to be made to OPC's primary recommendation presented in Exhibit DMR-2 if the Commission adopts Dr. Woolridge's alternative capital structure recommendation instead of his primary recommendation. As shown on page 1 of Exhibit DMR-3, if the Commission adopts Dr. Woolridge's alternative recommendation, the revenue requirements would result in an increase of $2,314,651 to FPUC's current rates.

Q. WHAT IS THE REVISED OVERALL RATE OF RETURN UNDER THIS ALTERNATIVE SCENARIO?

A. The overall rate of return would increase from OPC's primary recommendation in this case from 5.56% to 5.74%. Under the alternative scenario, the calculation of OPC's recommended rate of return, as well as the resulting reconciliation of OPC's recommended rate base to the capital structure, is presented on Exhibit DMR-3, page 2 of 4.

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

A. The weighted cost of debt changes as the debt-to-equity ratio differs between the primary recommendation and the alternative recommendation. This impacts the calculation of the interest synchronization adjustment. Exhibit No. DMR-3, page 4, presents the interest synchronization calculation based on OPC's recommended rate base and the weighted cost of debt under the alternative scenario. The result of this calculation is carried forward to page 3 of Exhibit DMR-3 to determine the impact on OPC's recommended net operating income resulting from the modification to the interest synchronization calculation.

Q. DOES THIS COMPLETE YOUR PREFILED TESTIMONY?

A. Yes, it does.

DIRECT TESTIMONY

OF

J. RANDALL WOOLRIDGE

On Behalf of the Office of Public Counsel

Before the

Florida Public Service Commission

Docket No. 140025-EI

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 Exhibit JRW-16, Appendix A.

I. <u>SUBJECT OF TESTIMONY AND SUMMARY OF RECOMMENDATIONS</u>

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 overall fair rate of return or cost of capital for the Florida Public Utilities Company ("FPUC" or "Utility") and to evaluate FPUC's rate of return testimony in this proceeding.

Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. First, I will review my cost of capital recommendation for FPUC, and review the primary areas of contention between FPUC's rate of return position and OPC's. Second, I provide an assessment of capital costs in today's capital markets. Third, I discuss my proxy group of electric utility companies for estimating the cost of capital for FPUC. Fourth, I present my recommendations for the Utility's capital structure and debt cost rate. Fifth, I discuss the concept of the cost of equity capital, and then estimate the equity cost rate for FPUC. Finally, I critique the Utility's rate of return analysis and testimony. I have a table of contents just after the title page for a more detailed outline.

Q. PLEASE REVIEW YOUR RECOMMENDATIONS REGARDING THE APPROPRIATE RATE OF RETURN FOR FPUC.

A. I have reviewed the Utility's proposed senior capital cost rates, capital structure and common equity cost rate. I conclude that the recommended short-term debt cost rate is well in excess of current market rates and the recommended capital structure includes a common equity ratio that is much higher than the average common equity ratios of electric utility companies. Therefore, I have made adjustments to these two elements of the Utility's recommendation.

I have applied the Discounted Cash Flow Model ("DCF") and the Capital Asset Pricing Model ("CAPM") to a proxy group of publicly-held electric utility companies ("Electric Proxy Group"). I have also employed the group developed by the Utility's rate of return witness, Mr. Paul R. Moul ("Moul Proxy Group"). My analysis indicates that an equity cost rate in the range of 8.75% to 9.00% is appropriate for the Utility. My recommended return on equity ("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, I recommend an equity cost rate of 9.0% for FPUC. If the Commission adopts the Company's recommended capital structure with a 58.20% common equity ratio, I recommend an equity cost rate of 8.75%. My cost of capital recommendations are summarized in Exhibit JRW-1.

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

A. As noted above, I have made adjustments to Mr. Moul's recommended short-term debt cost rate and capital structure. FPUC employs the capital structure of its parent company, Chesapeake Utilities (CUC or Chesapeake), which is made of regulated (several natural gas companies and one electric company) and non-regulated businesses. This capital structure has a common equity ratio that is much higher and is out of line with other electric utilities. I note that an equity-heavy capital structure may be required to support Chesapeake's high level of unregulated businesses. My proposed capital structure, with a common equity ratio of 50%, is similar to the capital structure used by the Commission in the Utility's last rate case prior to FPUC's acquisition by Chesapeake.

FPUC has proposed an equity cost rate of 11.25%. My analysis indicates an equity cost rate in the range of 8.75% to 9.00% is appropriate for FPUC. Both Mr. Moul and I have applied the DCF and the CAPM approaches to groups of publicly-held electric utility companies. Mr. Moul has also used Risk Premium ("RP") and Comparable Earnings ("CE") approaches to estimate an equity cost rate for FPUC. In addition, Mr. Moul has included a flotation cost adjustment in his rate of return recommendation.

As I discuss in my testimony, my equity cost rate recommendation is consistent with the current economic environment. Despite the increase in interest rates over the past two years, long-term interest rates are still at low levels not seen since the 1950s. There are two primary errors in Mr. Moul's DCF analysis. First, his DCF dividend yield adjustment is excessive. Second, Mr. Moul's recommended DCF growth rate of 5.25% is higher than the growth rate indicated by his growth rate measures. In developing my DCF growth rate, I have used 13 growth rate measures, including historic and projected growth rate measures, and have evaluated growth in dividends, book value, and earnings per share. In developing my DCF growth rate, I have recognized that the long-term earnings growth rates of Wall Street analysts are overly optimistic and upwardly-biased.

The CAPM approach requires an estimate of the risk-free interest rate, beta, and the equity risk premium. Mr. Moul uses a risk-free interest rate that is more than 100 basis points above current market rates. However, the major area of disagreement involves the measurement and magnitude of the market or equity risk premium. In short, Mr. Moul'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. Moul uses a market risk premium of 6.86% in his CAPM. In developing his market risk premium, Mr. Moul has used an inflated measure of the historical risk premium and a projected market risk premium that include unrealistic assumptions regarding future economic and earnings growth and stock returns. I have used a market 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; (2) employed by leading investment banks and management consulting firms; and (3) that result from surveys of companies, financial forecasters, financial analysts, and corporate CFOs.

The size premium is based on historical stock returns and, as discussed in my testimony, there are a number of errors in using historical market returns to compute risk premiums. In addition, any equity cost rate adjustment based on the relative size of a public utility is inappropriate. One study noted in my testimony tested for a size premium in utilities and concluded that, unlike industrial stocks, utility stocks do not exhibit a significant size premium. The primary reason that a size premium is not required for utilities is that utilities are regulated closely by state and federal agencies and commissions, and hence their financial performance is monitored on an on-going basis by both the state and federal governments.

Mr. Moul also estimates an equity cost rate using his RP model. There are two errors in his approach. First, Mr. Moul uses a projected long-term A-rated utility bond yield of 5.50% which is about 100 basis points above current market rates. Second, Mr. Moul's risk premium is based on the historical relationship between common stocks and the yields on long-term Treasury and corporate bonds. Mr. Moul's historical market risk premium of 6.50% is overstated. I demonstrate that there are a number of empirical issues in using historical risk premiums as measures of expected market risk premiums.

Mr. Moul includes a flotation cost adjustment to his equity cost rate estimates. Such an adjustment is not needed because Mr. Moul has not identified any flotation costs for the Utility. In addition, I demonstrate that there is no dilution of shareholders' equity associated with any equity issuances.

There is another issue that I believe significant in this proceeding. This is the presumed risk profile of FPUC and the appropriate return for the Company. With respect to risk, FPUC is not directly comparable to other Florida electric utilities. Unlike Florida Power & Light, Duke Energy Florida, Tampa Electric Company, and Gulf Power Company, FPUC is a transmission/distribution-only electric utility. Hence, FPUC does not generate the power that it sells and, therefore, does not have the risk associated with generation. The lower risk is reflected in low authorized ROEs for distribution-only electric utilities. In addition, the riskiness of FPUC is directly tied to its parent company, Chesapeake. CUC operates in three segments: Regulated Energy, Unregulated Energy, and Other. The Regulated Energy segment, which distributes natural gas in Delaware, Maryland and Florida, and electricity in

Florida, accounts for only 60% of revenues. The Unregulated Energy segment wholesales and distributes propane, markets natural gas, and provides other merchandise sales for heating, ventilation, air conditioning, plumbing, and electrical services. And the Other segment provides information technology services and solutions for enterprise and e-business applications. Hence, the other unregulated business activities of CUC add risk to the overall business profile of the parent company.

In summary, the primary areas of disagreement in measuring FPUC's cost of capital are: (1) FPUC's proposed capital structure, short-term and legacy long-term debt cost rates; (2) the DCF equity cost rate estimates, and in particular, Mr. Moul's DCF growth rate which is greater than his DCF growth rate indicators; (3) the base interest rate and market or equity risk premium in the RP and CAPM approaches; (4) the use of the CE approach which is outdated and not market-oriented; and (5) whether or not equity cost rate adjustments are needed to account for size and flotation costs.

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 bonds. The yields on 10-year U.S. Treasury bonds from 1953 to 2011 the present are provided on Panel A 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, U.S, 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 10-year U.S. Treasuries declined from 2.5% to 1.5% as the Federal Reserve continued to support a low interest rate environment and economic uncertainties persisted. These yields increased from mid-2012 to about 3.0% as of December 2013 on speculation of a tapering of the Federal Reserve's aggressive monetary policy. After the Federal Reserve's December 18, 2013 announcement that it was indeed tapering its bond buying program, these yields began to decline and were approximately 2.5% as of July 2014.

Panel B on Exhibit JRW-2 shows the differences in yields between 10-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 U.S. Treasury yields. The differential subsequently declined, and has been in the 2.5% to 3.5% range over the past four 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 that the forward-looking equity risk premium is actually in the 4.0% to 6.0% 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 ON LONG-TERM UTILITY BONDS.

A. Panel A of Exhibit JRW-3 provides the yields on A-rated public utility bonds. These yields peaked in November 2008 at 7.75% and henceforth declined significantly. These yields declined to below 4.0% in mid-2013, and then increased with interest rates in general to the 4.75% range as of late 2013. They have since declined to about

4.50%. Panel B of Exhibit JRW-3 provides the yield spreads between long-term A-rated public utility bonds relative to the yields on 20-year U.S. 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 3.4% in November 2008, declined to about 1.5% in the summer of 2012, and have since remained in the 1.5% range.

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

A. On September 13, 2012, the Federal Reserve (the "Fed") released its policy statement relating to Quantitative Easing III ("QEIII"). In the statement, the Federal Reserve announced that it intended to expand and extend its purchasing of long-term securities to about $85 billion 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 1/4 percent through at least mid-2015. In subsequent meetings over the next year, the Federal 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 FOMC kept the target range for the federal funds rate at 0 to 1/4 percent and reiterated its opinion that this exceptionally low range for the federal funds rate will be appropriate at least as long as the unemployment rate remains

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

above 6.5%.[2] Beginning in May 2013, the speculation in the markets was that the Federal Reserve's bond buying program would be tapered or scaled back. This speculation was fueled by more positive economic data on jobs and the economy, as well as by statements from FOMC members indicating that QEIII could be reduced later this calendar year. The speculation led to an increase in interest rates, with the 10-year U.S. Treasury yield increasing to about 3.0% as of December 2013.

In response to continuing positive economic data, the Fed did decide to taper QEIII at its December 18, 2013 meeting. The Fed voted to reduce its purchases of mortgage-backed securities and Treasuries by $5 billion per month beginning in January 2014. However, this tapering did not involve monetary tightening by the Fed. Indeed, the Fed extended its commitment to keep short-term interest rates "exceptionally low" until either the unemployment rate falls to around 6.5% or the inflation rate exceeds 2.5% a year.[3] Despite the announcement of the QEIII tapering, the markets reacted positively to the news due to the clarity provided by the FOMC on the future of the monetary stimulus, interest rates, and economic activity. At the time of the December 18, 2013 FOMC announcement, the yield on the 10-year U.S. Treasury yield was 2.9%.

Q. PLEASE DISCUSS THE FEDERAL RESERVE'S ACTIONS IN 2014 AND INTEREST RATES.

A. The January 29, 2014 FOMC meeting was historic as Janet Yellen took over for Ben Bernanke as the Fed Chairman. The FOMC also tapered its bond buying program by

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

[3] Board of Governors of the Federal Reserve System, FOMC Press Release, December 18, 2013.

another $5 billion per month beginning in February.[4] The FOMC also reiterated the importance of its bond buying program and continued "highly accommodative" monetary policy and has indicated that the monetary stimulus program will continue into the foreseeable future.[5]

Q. HOW HAVE THE MARKETS REACTED TO THE FEDERAL RESERVE'S SCALE BACK OF QEIII AND UPDATED CLARITY ON MONETARY POLICY?

A. The yield on the 10-year U.S. Treasury yield was 3.0% as of January 2, 2014. This yield trended down in January and was at 2.72% after the January FOMC meeting. Since that time, the 10-year U.S. Treasury yield has traded in the 2.5% to 2.8% range, and is currently 2.5%. To provide some perspective on the level of interest rates, the last time that the 10-year Treasury yield traded as low as 2.5%, prior to the onset of the financial crises in 2008, was in 1954!

Q. BASED ON THIS DISCUSSION, WHAT IS YOUR CONCLUSION CONCERNING CAPITAL COSTS IN TODAY'S MARKETS?

A. Capital costs remain at historically low levels. The increase in interest rates which were anticipated to occur when the Fed began tapering its bond buying program have not occurred. In fact, interest rates have declined since the beginning of the tapering program in January of 2014.

[4] Board of Governors of the Federal Reserve System, FOMC Press Release, January 29, 2014.
[5] Board of Governors of the Federal Reserve System, FOMC Press Release, June 18, 2014.

III. PROXY GROUP SELECTION

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

A. To develop a fair rate of return recommendation for FPUC, I have evaluated the return requirements of investors on the common stock of a proxy group of publicly-held electric utility companies.

Q. PLEASE DESCRIBE YOUR PROXY GROUP OF COMPANIES.

A. The selection criteria for my proxy group include the following:

1. At least 50% of revenues are from regulated electric operations as reported by *AUS Utilities Report*;
2. Listed as Electric Utility by *Value Line Investment Survey* and listed as an Electric Utility or Combination Electric & Gas Utility in *AUS Utilities Report*;
3. An investment grade corporate credit and bond rating;
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 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 32 companies. Summary financial statistics for the proxy group are listed in Exhibit JRW-4.[6] The median operating revenues and net

[6] 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.

plant among members of the Electric Proxy Group are $3,412.1 million and $9,618.4 million, respectively. The group's median receives 85% of revenues from regulated electric operations, has a BBB+ bond rating from Standard & Poor's, has a current common equity ratio of 47.4%, and has an earned return on common equity of 9.8%.

Q. PLEASE DESCRIBE THE MOUL PROXY GROUP.

A. Mr. Moul has selected a proxy group of eleven electric utilities. Mr. Moul's group is different in that he requires that the electric utilities be located in the southeastern U.S. Whereas I believe that my group provides a more comprehensive sample to estimate an equity cost rate for the Company, I will also include the Moul Proxy Group in my analysis.

Summary financial statistics for Mr. Moul's proxy group is provided in Panel B of page 1 of Exhibit JRW-4. The median operating revenues and net plant for the Moul Proxy Group are $11,990.9 million and $28,008.7 million, respectively. The group receives 77% of its revenues from regulated electric operations, has a BBB+ bond rating from S&P, a current common equity ratio of 44.5%, and a current earned return on common equity of 10.3%.

Q. HOW DOES THE INVESTMENT RISK OF FPUC COMPARE TO THAT OF YOUR ELECTRIC PROXY GROUP AND THE MOUL PROXY GROUP?

A. I believe that bond ratings provide a good assessment of the investment risk of a company. FPUC's bonds are not rated by S&P and Moody's. However, as highlighted by Mr. Moul, FPUC's bonds are rated by the National Association of

Insurance Commissioners ("NAIC"). FPUC has a NAIC designation of 1, which presumes an S&P equivalent rating ranging from A- to AAA. Conservatively, I will associate an S&P bond rating of A from the NAIC designation of 1. As shown in Exhibit JRW-4, page 1, the average S&P's and Moody's bond ratings for the Electric and Moul Proxy Groups are both BBB+. Therefore, based on bond ratings, FPUC's risk is lower than that of the two proxy groups.

In addition, on page 2 of Exhibit JRW-4, I have assessed the riskiness of FPUC's parent, CUC, relative to the Electric and Moul Proxy Groups using five different risk measures published by *Value Line*. These measures include Beta, Financial Strength, Safety, Earnings Predictability, and Stock Price Stability. CUC has a Safety measure of '3' versus an average of '2' for the two groups and a Financial Strength measure of 'B+" versus 'B++' for the two groups. While these two measures suggest CUC is slightly riskier than the two groups, the other risk measures indicate that CUC's risk is about the same as that of the two groups. Given these results, and relying primarily on the relative bond ratings, it is my position that the two proxy groups represent a risk-comparable group for FPUC.

IV. CAPITAL STRUCTURE RATIOS AND DEBT COST RATES

Q. WHAT IS FPUC'S CURRENT CAPITAL STRUCTURE FOR RATEMAKING PURPOSES?

A. FPUC's recommended capital structure from investor capital sources for ratemaking purposes includes 6.50% short-term debt, 35.30% long-term debt, and 58.21%

common equity. This is provided in Panel A of Exhibit JRW-5. Since FPUC does not have its own capital structure, this capital structure represents that of its parent.

Q. PLEASE DISCUSS THE CAPITAL STRUCTURES OF THE COMPANIES IN THE MOUL PROXY GROUP.

A. Panel B of Exhibit JRW-5 provides the average quarterly capitalization ratios for the companies in the Electric Proxy Group. Page 2 of Exhibit JRW-5 provides the supporting company data. The average of the quarterly capitalization data for the proxy group is 6.44% short-term debt, 50.18% long-term debt, 0.20% preferred stock, and 43.19% common equity. These are the capital structure ratios for the holding companies that trade in the markets and that are used to estimate an equity cost rate for FPUC. These ratios indicate that the Moul Proxy Group has, on average, a much lower common equity ratio and higher financial risk than FPUC. In fact, there is not one company in the proxy group that has a common equity ratio as high as 58.21%.

Q. WHY DOES FPUC HAVE A CAPITAL STRUCTURE WITH SUCH A HIGH COMMON EQUITY RATIO?

A. I do not know; however, I presume that it may be associated with the relatively high level of unregulated businesses. Prior to its acquisition by CUC, FPUC had a capital structure that included a common equity ratio of about 50%.

Q. GIVEN THE EXTREMELY HIGH COMMON EQUITY RATIO OF FPUC RELATIVE TO THE PROXY GROUP, HOW DOES MR. MOUL CONCLUDE THAT IT IS REASONABLE FOR THE COMPANY?

A. On page 20 of his testimony, Mr. Moul justifies his recommended capital structure for FPUC by referencing the market value capital structures of the companies in his proxy group. Pure and simple – this is an 'apples-to-oranges' comparison. Regulatory ratemaking uses book value rate bases and capitalizations and not market values. As such, Mr. Moul's justification is without merit.

Q. PLEASE DISCUSS 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 into 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 the 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 the Moul Proxy Group is 43%. In my experience, this value is typical for large electric utilities.

Q. GIVEN YOUR VIEW THAT FPUC'S EQUITY RATIO IS MUCH 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 to reflect the imputed capital structure in revenue requirements; or (2) to recognize the downward impact that an unusually high equity ratio will have on the 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. PLEASE DESCRIBE YOUR RECOMMENDED CAPITAL STRUCTURE FOR FPUC.

A. The capital structure data for FPUC has a much higher common equity ratio than the Moul Proxy Group. To balance these capital structures, and to provide for a more reasonable capitalization, I use a capital structure with a common equity ratio of 50.0%. A capital structure with a 50% common equity ratio is very close to the average of the common equity ratio proposed by Mr. Moul (58.21%) and the average common equity ratio of his proxy group (43.19%).

In Panel C of Exhibit JRW-5 (page 1 of 3), I have used a common equity ratio of 50.0% and I have adjusted FPUC's short-term and long-term debt upwards on a pro rata basis such that they account, collectively, for 50.0% of total capital. The resulting capital structure includes 7.78% short-term debt, 42.22% total long-term debt, and 50.0% common equity.

Q. ARE THERE ANY OTHER REASONS WHY A CAPITAL STRUCTURE WITH A COMMON EQUITY RATIO OF 50.0% IS APPROPRIATE FOR FPUC?

A. Yes. In FPUC's last rate case, Docket No. 070304-EI, the Commission approved a capital structure which included a common equity ratio of 50.41%. FPUC was acquired by CUC in 2009. There is no justifiable basis why customers should pay higher utility bills associated with a higher return on rate base just because one utility has purchased another utility and uses the parent company's equity-heavy capital structure in setting rates.

Q. WHAT ARE FPUC'S RECOMMENDED SENIOR CAPITAL COST RATES?

A. Mr. Moul has recommended cost rates of 3.70% for short-term debt, 12.74% for the legacy long-term debt, and 4.90% for the parent company long-term debt.

Q. WHAT SENIOR CAPITAL COST RATES ARE YOU RECOMMENDING FOR FPUC?

A. I will use Mr. Moul's recommended cost rates for the parent company long-term debt. However, the recommended short-term debt cost rate of 3.70% is excessive. Mr. Moul's recommended short-term debt cost rate is the sum of a projected London Interbank Offer Rate (LIBOR) rate of 2.60% and a 1.10% margin required on the Company's short-term credit facility. The LIBOR forecasts range from 0.90% for 2015 to 4.00% for 2018. Such long-term forecasts for LIBOR rates are simply not credible. As shown in Panel A of page 3 of Exhibit JRW-5, the current 1-month and 3-month LIBOR rates are 0.15% and 0.23%, respectively. Given the possibility that LIBOR rates will increase, I use the average of the current 1-month and 3-month LIBOR rates and the projected 2015 LIBOR rate. As shown in Panel B of page 3 of Exhibit JRW-5, in conjunction with the 1.10% margin required on the Company's short-term credit facility, this produces a short-term debt cost rate of 1.65%.

Q. WHAT ARE YOUR RECOMMENDATIONS WITH RESPECT TO THE COMPANY'S FPUC LEGACY DEBT?

A. Mr. Moul's conventional capital structure includes FPUC legacy debt of 1.09% with a 12.74% cost rate. However, in developing its regulatory capital structure for the year 2015, the Company increased the legacy debt portion of the capital structure in its pro-rata allocation of capital. The Company argues that this is done so that non-FPUC customers of CUC are not burdened with the legacy debt cost of FPUC. I do not accept this adjustment. FPUC does not have its own capital structure. The proposed capital structure is that of CUC. This capital structure finances CUC's regulated and unregulated businesses and not any of the specific businesses of CUC. Hence, this reallocation of more legacy debt to FPUC is not appropriate.

V. <u>THE COST OF COMMON EQUITY CAPITAL</u>

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. Because of the lack of competition and the essential nature of their services, it is not appropriate to permit monopoly utilities to set their own prices. Thus, regulation seeks to establish prices that are fair to consumers and, at the same time, 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 a company or 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:[7]

> 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.

[7] James M. McTaggart, "The Ultimate Poison Pill: Closing the Value Gap," *Commentary* (Spring 1986), p.3.

> 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.

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

A. This relationship is discussed in a classic Harvard Business School case study entitled "Note on Value Drivers." On page 2 of that case study, the author describes the relationship very succinctly:[8]

> For a given industry, more profitable firms – those able to generate higher returns per dollar of equity– should have higher market-to-book ratios. Conversely, firms which are unable to generate returns in excess of their cost of equity 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 ROE and market-to-book ratios using natural gas

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

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.[9] This demonstrates the strong positive relationship between ROEs and market-to-book ratios for public utilities.

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. Then, they declined to the 4.0% range in 2012, and have since increased to the 4.85% range over the past 18 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 four years and now are about 4.2%.

---

[9] 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.

Average earned returns on common equity and market-to-book ratios for the Electric Proxy 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 four years. The average market-to-book ratio for the group was in the 1.10X to 1.80X during the past decade. The average declined to about 1.10X in 2009, but has since increased to 1.40X as of 2013.

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 97 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.* The study shows that the investment risk of utilities is very low. The average betas for electric, water, and gas utility companies are 0.72, 0.71, and 0.73, respectively. 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 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 model. I have also performed a capital asset pricing model

("CAPM") study; however, 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. PLEASE 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, Page 1 of 2. 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 maturity (or 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 an 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 the expected growth rate). The dividend yield can be measured precisely at any point in time; however, it 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 HAVE YOU REVIEWED?

A. I have calculated the dividend yields for the companies in the two proxy groups using the current annual dividend and the 30-day, 90-day, and 180-day average stock prices. These dividend yields are provided on page 2 of Exhibit JRW-10 for the Electric and Moul Proxy Groups, respectively. For the Electric Proxy Group, the mean and median dividend yields using the 30-day, 90-day, and 180-day average stock prices range from 3. 6% to 3.9%. Given this range, I use 3.8% as the dividend yield for the Electric Proxy Group. For the Moul Proxy Group, provided in Panel B of page 2 of Exhibit JRW-10, the mean and median dividend yields range from 3. 8% to 4.1% using the 30-day, 90-day, and 180-day average stock prices. Given this range, I use a dividend yield of 4.1% for the Moul Proxy Group.

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.[10]

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.

[10] *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).

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 DO YOU USE FOR YOUR DIVIDEND YIELD?

A. I adjust the dividend yield by one-half (1/2) of the expected growth so as to reflect growth over the coming year. This is the approach employed by the Federal Energy Regulatory Commission ("FERC").[11] 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, the 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?

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

A. I have analyzed a number of measures of growth for companies in the proxy groups. 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 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 PROVIDE 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 four analysts have provided EPS estimates for the quarter ending September 30, 2014. The mean, high, and low estimates are \$1.56, \$1.75, and \$1.46, respectively. The second line shows the quarterly EPS estimates for the quarter ending December 31, 2014 of \$0.42 (mean), \$0.53 (high), and \$0.18 (low). Lines three and four show the annual EPS estimates for the fiscal years ending December 2014 (\$3.51 (mean), \$3.55 (high), and \$3.47 (low)) and December 2015 ((\$3.66 (mean), \$3.94 (high), and \$3.57 (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, three analysts have provided long-term EPS growth rate forecasts, with mean, high, and low growth rates of 5.27%, 6.00%, and 4.80%, 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 DO YOU NOT RELY EXCLUSIVELY ON THE EPS FORECASTS OF WALL STREET ANALYSTS IN ARRIVING AT A DCF GROWTH RATE FOR THE PROXY GROUP?

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.[12] 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

[12] M. Lacina, B. Lee & Z. Xu, "An Evaluation of Financial Analysts and Naïve Methods in Forecasting Long-term Earnings', Kenneth D. Lawrence, Ronald K. Klimberg (ed.), Emerald Group Publishing Limited, *Advances in Business and Management Forecasting (Vol. 8),* pp. 77-101.

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 Exhibit JRW-16, Appendix B 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.[13]

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

A. Yes, I 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.

[13] 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 (August 2006).

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 EPS, DPS, and BVPS for the companies in the two proxy groups, as published in the *Value Line Investment Survey.* The median historical growth measures for EPS, DPS, and BVPS for the Electric Proxy Group, as provided in Panel A, range from 2.0% to 4.3%, with an average of 3.6%. For the Moul Proxy Group, as shown in Panel B of page 3 of Exhibit JRW-10, the historical growth measures in EPS, DPS, and BVPS, as measured by the medians, range from 3.0% to 5.0%, with an average of 4.0%.

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 stated above, due to the presence of outliers, the medians are used in the analysis. For the Electric Proxy Group, as shown in Panel A of page 4 of Exhibit JRW-10, the medians range from 4.0% to 5.0%, with an average of 4.5%. For the Moul Proxy Group, as shown in Panel B of page 4 of Exhibit JRW-10, the medians range from 4.0% to 5.0%, with an average of 4.5%.

Also provided on page 4 of Exhibit JRW-10 are the prospective sustainable growth rates for the companies in the two 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 a primary driver of long-run earnings growth. For the Electric Proxy Group and the Moul Proxy Group, the median prospective sustainable growth rates are 4.0% and 4.2%, 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. I have reported both the mean and median growth rates for the two groups. The mean/median of analysts' projected EPS growth rates for the Electric and Moul Proxy Groups are 5.0%/4.9 and 4.7%/4.8%, respectively.[14] 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 groups.

[14] Given the higher mean of analysts' projected EPS growth rates for the Moul Proxy Group, I have also considered the mean figures in the growth rate analysis.

The historical growth rate indicators for my Electric Proxy Group imply a baseline growth rate of 3.6%. The average of the projected EPS, DPS, and BVPS growth rates from *Value Line* is 4.5%, and *Value Line*'s projected sustainable growth rate is 4.0%. The high end of the range for the Electric Proxy Group are the projected EPS growth rate of Wall Street analysts, which are 5.0% and 4.9% as measured by the mean and median growth rates. The overall range for the projected growth rate indicators is 3.6% to 5.0%. Giving more weight to the projected EPS growth rate of Wall Street analysts, I believe that a growth rate in the range of 4.75% to 5.0% is appropriate. I will use the midpoint of this range, 4.875%, as the DCF growth rate for the Electric Proxy Group. This growth rate figure is clearly in the upper end of the range of historic and projected growth rates for the Electric Proxy Group.

The historical growth rate indicators for the Moul Proxy Group indicate a growth rate of 4.0%. *Value Line*'s average projected EPS, DPS, and BVPS growth rate for the group is 4.5%, and *Value Line*'s projected sustainable growth rate is 4.2%. The mean/median projected EPS growth rates of Wall Street analysts for the group are 4.7.0% and 4.8%, respectively. The range for the projected growth rate indicators is 4.0% to 4.8%. Giving more weight to the projected EPS growth rate of Wall Street analysts, I use 4.75% as the DCF growth rate for the Moul Proxy Group. As with the Electric Proxy Group, this growth rate figure is in the upper end of the range of historic and projected growth rates.

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 and in the table below.

	Dividend Yield	1 + ½ Growth Adjustment	DCF Growth Rate	Equity Cost Rate
Electric Proxy Group	**3.80%**	**1.02438**	**4.88%**	**8.75%**
Moul Proxy Group	**4.10%**	**1.02375**	**4.75%**	**9.00%**

The DCF calculation for my Electric Proxy Group is the 3.80% dividend yield, times the 1 and ½ growth adjustment factor of 1.02438, plus the DCF growth rate of 4.875%, which results in an equity cost rate of 8.75%. The DCF calculation for the Moul Proxy Group include a dividend yield of 4.1%, times the 1 and ½ growth adjustment factor of 1.02375, plus the DCF growth rate of 4.75%, which results in an equity cost rate of 9.0%.

C. CAPITAL ASSET PRICING MODEL

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 U.S. 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 U.S. 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 U.S. Treasury bonds has been in the 3.0% to 4.0% range over the 2013–2014 time period. These rates are currently in the 3.35% range. Given the recent range of yields and the higher recent interest rates, I 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 that 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 betas for the companies in the Electric and Moul Proxy Groups are 0.73 and 0.70, 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 range of 5% to 7% 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.[15]

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 (Chief Financial Officers), which includes questions regarding their views on the current expected returns on stocks and bonds. Typically, over 350 CFOs normally participate in the survey.[16] 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*.[17] 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.[18]

---

[15] Rajnish Mehra & Edward C. Prescott, *The Equity Premium: A Puzzle*, J. MONETARY ECON. 15 (1985).

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

[17] Federal Reserve Bank of Philadelphia, *Survey of Professional Forecasters,* (February 14, 2014). 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.

[18] Pablo Fernandez, Pablo Linares and Isabel Fernandez Acín, "Market Risk Premium used for 88 countries in 2014: a survey with 8,228 answers," June 20, 2014.

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

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.[19] 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. 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. I have also included the results of the "Building Blocks" approach to estimating the equity risk premium, including a study

[19] *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).

I performed, which is presented in Exhibit JRW-16, Appendix C1 of this testimony. The Building Blocks approach is a hybrid approach employing elements of both historical and *ex ante* models. There are results reported for over 30 studies and the median equity risk premium is 4.28%.

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 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, I have reconstructed page 5 of Exhibit JRW-11 on page 6 of Exhibit JRW-11; however, I have eliminated all studies dated before January 2, 2010. The median for this subset of studies is 4.90%.

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 4.0% to 6.0% 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, 2014 CFO survey conducted by *CFO Magazine* and Duke University, the expected 10-year equity risk premium was 3.9%.

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 2014 survey, the median long-term expected stock and bond returns were 6.43% and 4.25%, respectively. This provides an *ex ante* equity risk premium of 2.18% (6.43%-4.25%).

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 2014 survey of academics, financial analysts and companies.[20] This survey included over 8,000 responses. The median equity risk premium employed by U.S. analysts and companies was 5.0%.

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

[20] Pablo Fernandez, Javier Auirreamalloa, and Javier Corres, "Market Risk Premium Used in 51 Countries in 2013: A survey with 6,237 Answers," June 26, 2013.

A. The results of my CAPM study for the proxy groups are summarized on page 1 of Exhibit JRW-11 and in the table below.

$$K = (R_f) + ß * [E(R_m) - (R_f)]$$

	Risk-Free Rate	Beta	Equity Risk Premium	Equity Cost Rate
Electric Proxy Group	**4.0%**	**0.73**	**5.0%**	**7.6%**
Moul Proxy Group	**4.0%**	**0.70**	**5.0%**	**7.5%**

For the Electric Proxy Group, the risk-free rate of 4.0% plus the product of the beta of 0.73 times the equity risk premium of 5.0% results in a 7.6% equity cost rate. For the Moul Proxy Group, the risk-free rate of 4.0% plus the product of the beta of 0.70 times the equity risk premium of 5.0% results in a 7.5% equity cost rate.

D. EQUITY COST RATE SUMMARY

Q. PLEASE SUMMARIZE YOUR EQUITY COST RATE STUDY.

A. My DCF analyses for the Electric and Moul Proxy Groups indicate equity cost rates of 8.75% and 9.0%, respectively. My CAPM analyses for the Electric and Moul Proxy Groups indicate equity cost rates of 7.6% and 7.5%.

	DCF	CAPM
Electric Proxy Group	**8.75%**	**7.6%**
Moul Proxy Group	**9.00%**	**7.5%**

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

A. Given these results, I conclude that the appropriate equity cost rate for companies in my Electric Group and the Moul Proxy Group is in the 7.5% to 9.0% range.

However, since I rely primarily on the DCF model, I am using the upper end of the range as the equity cost rate. Therefore, I conclude that the appropriate equity cost rate for FPUC is in the range of 8.75% and 9.0%.

Q. HOW DOES YOUR PREVIOUS DISCUSSION ON CAPITAL STRUCTURE AFFECT YOUR COST OF EQUITY RECOMMENDATION FOR FPUC?

A. I have estimated an equity cost rate in the range of 8.75% to 9.0% based on my evaluation of the Electric and Moul Proxy Groups. As previously discussed, the riskiness of FPUC as indicated by their NAIC bond rating is slightly below the riskiness of the two groups. Said differently, FPUC has less risk than the two proxy groups. Moreover, as shown on page 1 of Exhibit JRW-4, these two proxy groups have capital structures with median common equity ratios of 47.4% and 44.5%, respectively. As such, the equity cost rates computed using these groups are associated with much higher levels of financial risk than FPUC with a capital structure using a common equity ratio of 58.21%. To achieve a middle ground, and to be consistent with the Commission's order prior to FPUC's acquisition by CUC, I have recommended a capital structure for FPUC 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 FPUC's 58.21% equity capital structure. If the Commission adopts OPC's recommended capital structure with a common equity ratio of 50.0%, I recommend an equity cost rate of 9.0% for FPUC.

Q. PLEASE DISCUSS THE INCREASE IN INTEREST RATES OVER THE PAST TWO YEARS AND YOUR RECOMMENDATION.

A. As previously noted, interest rates have increased over the past two years as the economy has improved and the Federal Reserve has scaled back its bond buying program. The yield on 10-year U.S. Treasury bonds increased from 1.50% in July 2012 to about 3.0% in late 2013. These yields have since declined to about 2.55%. The extremely low rates in 2012 were largely attributable to slow economic growth and the Federal Reserve's QEIII program.

Q. PLEASE INDICATE WHY AN 8.75%-9.00% RETURN IS APPROPRIATE FOR FPUC AT THIS TIME.

A. There are a number of reasons why an 8.75% to 9.00% return on equity is appropriate and fair for FPUC in this case. First, as shown in Exhibit JRW-8, the electric utility industry is 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 Exhibits JRW-2 and 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 years. Furthermore, as previously discussed, interest rates and utility bond yields have decreased since the Federal Reserve announced the tapering of its QEIII program in December 2013.

Third, while the markets have recovered significantly over the past five years, the growth in the economy is tepid and unemployment is still at 6.3%. The continuation of the Fed's "highly accommodative" monetary and scaled back QEIII illustrates the Federal Reserve's concern over the economy. The relatively slow economic growth is a major reason that interest rates and inflation are still at historically low levels, and hence the expected returns on financial assets remain low. Fourth, utility stocks have produced very good returns this year. The overall market, as measured by the S&P 500, began the year by dropping about 10% in January. However, by the end of the second quarter, the market had recovered and was up about 7% for the year. Meanwhile, utilities have been the best performing sector of the market. A comparsion of the performance of the Dow Jones Utilities (DJU) Index (blue shaded area) relative to the S&P 500 (red line) is provided on page 1 of Exhibit JRW-12. For the year, the DJU is up 13% while the S&P 500 is at 7%.

Finally, FPUC is a distribution-only electric utility that does not have the risks associated with the generation component of integrated utilities. The authorized ROEs for transmission/distribution utilities have been below those for integrated electric utilities in recent years. Page 2 of Exhibit JRW-12 provides the authorized ROEs in nineteen rate cases in 2013 and 2014 involving distribution-only electric utilities. There are no authorized ROEs of 10% or higher, and the average for the distribution-only electric is 9.48%.

VI. CRITIQUE OF FPUC'S RATE OF RETURN TESTIMONY

Q. PLEASE SUMMARIZE MR. MOUL'S RATE OF RETURN RECOMMENDATION FOR FPUC.

A. The Company's rate of return recommendation is summarized on page 1 of Exhibit JRW-13. FPUC's recommended capital structure from investor sources for ratemaking purposes includes 6.50% short-term debt, 35.30% long-term debt, and 58.21% common equity. FPUC uses a short-term debt cost rate of 3.70%, a legacy long-term cost rate of 12.74%, a parent company debt cost rate of 4.90% and an equity cost rate of 11.25%.

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

A. The primary areas of disagreement in measuring FPUC's cost of capital are: (1) FPUC's proposed capital structure, short-term debt cost rate, and possibly the legacy long-term debt cost rate; (2) the DCF equity cost rate estimates, and in particular, Mr. Moul's DCF growth rate which is greater than his DCF growth rate indicators; (3) the base interest rate and market or equity risk premium in the RP and CAPM approaches; (4) the use of the CE approach which is outdated and not market-oriented; and (5) whether or not equity cost rate adjustments are needed to account for size and flotation costs. The proposed capital structure and short-term debt cost rate issues were previously addressed. The other issues are discussed below.

A. DCF APPROACH

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

A. On pages 23-31 of his testimony and Schedules 5-7 of Exhibit PRM-1, Mr. Moul develops an equity cost rate by applying a DCF model to his group of electric companies. In the traditional DCF approach, the equity cost rate is the sum of the dividend yield and expected growth. Mr. Moul adjusts the dividend yield to reflect the quarterly payment of dividends and an ex-dividend adjustment to the stock price. Mr. Moul reviews a number of historical and projected measures of expected growth for his DCF model. He uses the projected EPS growth rate forecasts from Zack's, Morningstar, SNL, IBES-First Call and *Value Line*. Mr. Moul's DCF results are provided in Panel B of page 2 of Exhibit JRW-13. Based on these figures, Mr. Moul claims that the DCF equity cost rate for his group is 9.40%. Mr. Moul then makes a flotation cost adjustment to this figure to arrive at a DCF equity cost rate of 9.59% for FPUC.

Q. PLEASE EXPRESS YOUR CONCERNS WITH MR. MOUL'S DCF STUDY.

A. I have two issues with Mr. Moul's DCF equity cost rate: (1) the DCF growth rate; and (2) the flotation cost adjustment.

1. DCF Growth Rate

Q. PLEASE CRITIQUE MR. MOUL'S DCF GROWTH RATE OF 5.25%.

A. In Schedules 6 and 7 of Exhibit PRM-1, Mr. Moul provides 17 alternative measures of growth he claims to have reviewed in arriving at his 5.25% growth rate. The average of these growth rates is only 4.62%. In addition, only four of the 17 growth rates are as large as 5.25%. The data reviewed by Mr. Moul support a DCF growth rate at least 50 basis points below Mr. Moul's 5.25%. Using such a growth rate would produce a DCF equity cost rate of 9.0%.

2. Flotation Costs

Q. PLEASE DISCUSS MR. MOUL'S ADJUSTMENT FOR FLOTATION COSTS.

A. Mr. Moul claims that an upward adjustment to his DCF, RP, and CAPM equity cost rates are necessary to account for flotation costs. This adjustment factor is erroneous for several reasons.

First, he has not identified any flotation costs for FPUC. Therefore, FPUC is requesting annual revenues in the form of a higher return on equity for flotation costs that have not been identified.

Second, it is commonly argued that a flotation cost adjustment (such as that used by the Company) is necessary to prevent the dilution of the existing shareholders. In this case, Mr. Moul justifies a flotation cost adjustment by referring to bonds and the manner in which issuance costs are recovered by including the amortization of bond flotation costs in annual financing costs. However, this is incorrect for several reasons:

(1) If an equity flotation cost adjustment is similar to a debt flotation cost adjustment, the fact that the market-to-book ratios for electric utility companies are over 1.5X actually suggests that there should be a flotation cost reduction (and not an increase) to the equity cost rate. This is because when (a) a bond is issued at a price in excess of face or book value, and (b) the difference between market price and the book value is greater than the flotation or issuance costs, the cost of that debt is lower than the coupon rate of the debt. The amount by which market values of electric utility companies are in excess of book values is much greater than flotation costs. Hence, if common stock flotation costs were exactly like bond flotation costs, and one was making an explicit flotation cost adjustment to the cost of common equity, the adjustment would be downward;

(2) If a flotation cost adjustment is needed to prevent dilution of existing stockholders' investment, then the reduction of the book value of stockholder investment associated with flotation costs can occur only when a company's stock is selling at a market price at/or below its book value. As noted above, electric utility companies are selling at market prices well in excess of book value. Hence, when new shares are sold, existing shareholders realize an increase in the book value per share of their investment, not a decrease;

(3) Flotation costs consist primarily of the underwriting spread or fee and not out-of-pocket expenses. On a per-share basis, the underwriting spread is the difference between the price the investment banker receives from investors and the price the investment banker pays to the company. Therefore, these are not expenses that must be recovered through the regulatory process. Furthermore, the underwriting

spread is known to the investors who are buying the new issue of stock, and who are well aware of the difference between the price they are paying to buy the stock and the price that the Company is receiving. The offering price which they pay is what matters when investors decide to buy a stock based on its expected return and risk prospects. Therefore, the company is not entitled to an adjustment to the allowed return to account for those costs; and

(4) Flotation costs, in the form of the underwriting spread, are a form of a transaction cost in the market. They represent the difference between the price paid by investors and the amount received by the issuing company. Whereas the Company believes that it should be compensated for these transaction costs, it has not accounted for other market transaction costs in determining its cost of equity. Most notably, brokerage fees that investors pay when they buy shares in the open market are another market transaction cost. Brokerage fees increase the effective stock price paid by investors to buy shares. If the Company had included these brokerage fees or transaction costs in its DCF analysis, the higher effective stock prices paid for stocks would lead to lower dividend yields and equity cost rates. This would result in a downward adjustment to their DCF equity cost rate.

Q. IF THE COMPANY DOES HAVE EQUITY ISSUANCE COSTS, HOW WOULD YOU RECOMMEND THEY BE TREATED FOR REGULATORY PURPOSES?

A. I would recommend that the Company's out-of-pocket expenses be treated as a cost of service. I do not recommend an adjustment to the equity cost rate.

B. RISK PREMIUM ("RP") APPROACH

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

A. On pages 31-35 of his testimony and Schedules 10 and 11 of Exhibit PRM-1, Mr. Moul develops an equity cost rate using the RP model. Mr. Moul's RP results are provided in Panel C Exhibit JRW-13. Mr. Moul's RP equity cost rate for his group is 12.00%. Mr. Moul then makes a flotation cost adjustment to this figure to arrive at a RP equity cost rate of 12.19% for FPUC.

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

A. The errors in Mr. Moul's RP equity cost rate approach include: (1) an inflated base interest rate; (2) an excessive risk premium, which is based on the historical relationship between stock and bond returns; and (3) the flotation cost adjustment. The flotation cost issue was previously addressed.

1. Base Interest Rate

Q. PLEASE DISCUSS THE BASE YIELD OF MR. MOUL'S RP ANALYSIS.

A. The base yield in Mr. Moul's RP analysis is the prospective yield on long-term, 'A' rated public utility bonds. This is erroneous for two reasons. First, the 5.50% projected yield is more than 100 basis points above current long-term utility bond yields. Second, using the yield on these securities inflates the required return on equity for the Company in two ways: (1) long-term bonds are subject to interest rate risk, a risk which does not affect common stockholders since dividend payments (unlike bond interest payments) are not fixed but tend to increase over time; and (2) the base yield in Mr. Moul's risk premium study is subject to credit risk since it is not default risk-free like an obligation of the U.S. Treasury. As a result, its yield-to-maturity includes a premium for default risk and, therefore, is above its expected return. Hence, using a bond's yield-to-maturity as a base yield, results in an overstatement of investors' return expectations.

Q. PLEASE REVIEW MR. MOUL'S RP STUDY.

A. Mr. Moul performs a historical RP study that appears in Schedules 10 and 11 of Exhibit PRM-1. This study involves an assessment of the historical differences between the arithmetic mean returns on large company common stocks and long-term corporate and U.S. Treasury bonds over various time periods between the years 1926-2013. Based on his review of the differences in the arithmetic mean returns between stock and bonds, and in particular he cites arithmetic mean equity risk premiums of 7.60% during low interest rate environments and 5.79% during all interest rate environments. Based on these figures, Mr. Moul selects a risk premium of 6.50%.

Q. WHAT ARE THE ERRORS IN MR. MOUL'S RISK PREMIUM OF 6.50%?

A. The risk premium of 6.50% is erroneous and should be ignored for three reasons. First, it is well known that electric utility stocks are less risky than stocks in general. However, Mr. Moul does not account for the lower risk of electric utility stock. Second, Mr. Moul has computed historical risk premiums during high, low, and all interest rate environments. His definition of these alternative environments, and the time period over which he computes the equity risk premium, are arbitrary and not specified or analyzed by Mr. Moul. As such, the historical risk premium of 7.60% during low interest rate environments is an arbitrary figure created by Mr. Moul. Finally, it is well known that using the historical relationship between stock and bond returns to measure an *ex ante* equity risk premium is erroneous and overstates the true market equity risk premium.

Q. PLEASE ADDRESS THE ISSUES INVOLVED IN USING HISTORICAL STOCK AND BOND RETURNS TO COMPUTE A FORWARD-LOOKING OR *EX ANTE* RISK PREMIUM.

A. As previously discussed, it is common to compute a market risk premium as the difference between historic stock and bond returns. However, this approach can produce differing results depending on several factors, including the measure of central tendency used, the time period evaluated, and the stock and bond market index employed. In addition, there are a myriad of empirical problems in the approach, which result in historical market returns producing inflated estimates of expected risk premiums. Among the errors are the U.S. stock market survivorship bias (the "Peso Problem"), the company survivorship bias (only successful companies survive – poor companies do not survive), and unattainable return bias (the Ibbotson procedure presumes monthly portfolio rebalancing). These issues are discussed in Exhibit JRW-16, Appendix D of this testimony.

C. CAPM APPROACH

Q. PLEASE DISCUSS MR. MOUL'S CAPM.

A. On pages 35-39 of his testimony and Schedule 12 of Exhibit PRM-1, Mr. Moul develops an equity cost rate by applying a CAPM model to his group of electric utility companies. Mr. Moul's CAPM results are provided in Panel D of page 2 of Exhibit JRW-13. Mr. Moul uses a long-term risk-free rate of 4.50%, a beta of 0.73, and a market risk premium of 6.86%. Based on these figures, Mr. Moul estimates an equity cost rate using the CAPM of 9.51%. He then adds a size premium of 1.14% and a flotation cost adjustment of 0.19% to this figure to get a CAPM equity cost rate of 10.84% for FPUC.

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

A. There are four flaws with Mr. Moul's CAPM analysis: (1) the risk-free interest rate; (2) the equity risk premium of 6.86%; (3) the size adjustment of 1.14%; and (4) the flotation cost adjustment. The flotation cost issue was previously addressed.

1. Risk-Free Interest Rate

Q. PLEASE DISCUSS THE BASE YIELD OF MR. MOUL'S RP ANALYSIS.

A. Mr. Moul uses a risk-free interest rate of 4.50% in his CAPM. This figure is highly inflated as the current yield on long-term Treasury bonds is only 3.37%.

2. Market Risk Premium

Q. PLEASE REVIEW THE ERRORS IN MR. MOUL'S EQUITY OR MARKET RISK PREMIUM USED IN HIS CAPM APPROACH.

A. The primary problem with Mr. Moul's CAPM analysis is the size of the market or equity risk premium. Mr. Moul develops a market risk premium of 6.86% which is the average of: (1) the 1926-2013 historic risk premium results from the lbbotson study of 8.03%; and (2) a projected market risk premium of 5.69% which uses an expected market return that is the average of: (a) *Value Line's* 3-5 year annual return projection of 8.68% and (b) a DCF expected market return using the S&P 500 of 11.69%, minus the risk-free rate of 4.50%. The primary error with Mr. Moul's equity risk premium is that both the lbbotson historic returns and Mr. Moul's projected market returns are poor measures of expected market risk premiums.

Q. PLEASE ADDRESS THE PROBLEMS WITH MR. MOUL'S HISTORIC RISK PREMIUM.

A. Mr. Moul computes a historic risk premium of 8.03% based on the difference between the arithmetic mean stock and bond income returns over the 1926-2013 period. There are two flaws to this approach. First, he uses total stock returns but not total bond returns. Using only the bond income returns decreases the return on bonds and hence inflates the indicated market risk premium. Second, as previously discussed, there are issues with computing an expected equity risk premium using historical stock and bond returns. In short, there are a myriad of empirical problems, which result in historical market returns producing inflated estimates of expected risk premiums. Among the errors are the U.S. stock market survivorship bias (the "Peso Problem"), the company survivorship bias (only successful companies survive – poor companies do not survive), and unattainable return bias (the Ibbotson procedure presumes monthly portfolio rebalancing). These issues are addressed in Exhibit JRW-16, Appendix D of this testimony.

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

A. Mr. Moul also estimated an expected market return of 11.69% by applying the DCF model to the S&P 500. This approach uses a dividend yield of 2.02% and an expected DCF growth rate of 9.67%. The primary error is that the expected DCF growth rate is the projected 5-year EPS growth rate for the companies in the S&P 500 as reported by First Call. As explained below, this produces an overstated expected market return and equity risk premium.

Q. WHAT EVIDENCE CAN YOU PROVIDE THAT MR. MOUL'S S&P 500 GROWTH RATE IS ERRONEOUS?

A. Mr. Moul's expected S&P 500 growth rate of 9.67% represents 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 previously in my testimony. Further, a long-term growth rate of 9.67% is inconsistent with economic and earnings growth in the U.S. The long-term economic and earnings growth rate in the U.S. has only been in the 6% to 7% range. I have 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 given in the table below.

GDP, S&P 500 Stock Price, EPS, and DPS Growth
1960-Present

Nominal GDP	6.69%
S&P 500 Stock Price	6.75%
S&P 500 EPS	6.92%
S&P 500 DPS	5.64%
Average	6.50%

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. Moul's long-run growth rate projection of 9.67% is vastly overstated. These estimates suggest that companies in the U.S. would be expected to: (1) increase their growth rate 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, are presented in Panel A of page 3 of Exhibit JRW-14 and in the table below.

Historic GDP Growth Rates

10-Year Average	3.9%
20-Year Average	4.6%
30-Year Average	5.2%

40-Year Average	**6.4%**
50-Year Average	**6.8%**

These data 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 VARIOUS GOVERNMENT AGENCIES?

A. There are several forecasts of annual GDP growth that are available from economists and government agencies. These are listed in Panel B of page 3 of Exhibit JRW-14. The mean 10-year nominal GDP growth forecast (as of February 2014) by economists in the recent *Survey of Professional Forecasters* is 4.9%. The Energy Information Administration (EIA), in its projections used in preparing *Annual Energy Outlook,* forecasts long-term nominal GDP growth of 4.5% for the period 2011-2040. The Congressional Budget Office, in its forecasts for the period 2014 to 2024, projects a nominal GDP growth rate of 4.8%.

Q. WHY IS GDP GROWTH RELEVANT IN YOUR DISCUSSION OF MR. MOUL'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 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 to 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. Moul'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. MOUL'S PROJECTED EQUITY RISK PREMIUM DERIVED FROM EXPECTED MARKET RETURNS.

A. Mr. Moul's market risk premium derived from his DCF application to the S&P 500 is

---

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

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, 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 2014 *CFO Magazine* – Duke University Survey of over 350 CFOs forecast an expected return on the S&P 500 of 6.6% over the next ten years. In addition, the financial forecasters in the February 2014 Federal Reserve Bank of Philadelphia survey expect an annual market return of 6.43% 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.

3. Size Adjustment

Q. PLEASE DISCUSS MR. MOUL'S SIZE ADJUSTMENT.

A. Mr. Moul includes a size adjustment of 1.14% in his CAPM approach for the size of the companies in his proxy group. There are three reasons that there is no need for a size premium: (1) FPUC's credit rating includes the size of the company: (2) the size premium is based on historical returns which are upwardly biased measures of expected risk premiums; and (3) empirical studies show that size premiums are not required for utilities.

First, FPUC's credit rating, as provided by NAIC, incorporates many different risk factors, including the size of the company. FPUC's NAIC designation of 1 relates to an A bond rating which is better than the average of the Electric and Moul Proxy Groups. Therefore, there is no valid reason to include a size premium in the equity cost rate.

Second, this size adjustment is based on the historical stock market returns studies as performed by Morningstar (formerly Ibbotson Associates). As discussed in Exhibit JRW-16, Appendix D of this testimony, there are numerous errors in using historical market returns to compute risk premiums. These errors provide inflated estimates of expected risk premiums. Among the errors are survivorship bias (only successful companies survive – poor companies do not survive) and unattainable return bias (the Ibbotson procedure presumes monthly portfolio rebalancing). The net result is that Ibbotson's size premiums are poor measures for risk adjustment to account for the size of the utility.

Third, Professor Annie Wong has tested for a size premium in utilities and concluded that, unlike industrial stocks, utility stocks do not exhibit a significant size premium.[22] As explained by Professor Wong, there are several reasons why such a size premium would not be attributable to utilities. Utilities are regulated closely by state and federal agencies and commissions, and hence, their financial performance is monitored on an ongoing basis by both the state and federal governments. In addition, public utilities must gain approval from government entities for common financial transactions such as the sale of securities. Furthermore, unlike their industrial

[22] Annie Wong, "Utility Stocks and the Size Effect: An Empirical Analysis," *Journal of the Midwest Finance Association*, pp. 95-101, (1993).

counterparts, accounting standards and reporting are fairly standardized for public utilities. Finally, a utility's earnings are predetermined to a certain degree through the ratemaking process in which performance is reviewed by state commissions and other interested parties. Overall, in terms of regulation, government oversight, performance review, accounting standards, and information disclosure, utilities are much different than industrials, which could account for the lack of a size premium.

Q. PLEASE DISCUSS OTHER RESEARCH ON THE SIZE PREMIUM IN ESTIMATING THE EQUITY COST RATE.

A. As noted, there are errors in using historical market returns to compute risk premiums. With respect to the small firm premium, Richard Roll (1983) found that one-half of the historic return premiums for small companies disappears once biases are eliminated and historic returns are properly computed. The error arises from the assumption of monthly portfolio rebalancing and the serial correlation in historic small firm returns.[23]

In another paper, Ching-Chih Lu (2009) estimated the size premium over the long-run. Mr. Lu acknowledges that many studies have demonstrated that smaller companies have historically earned higher stock market returns. However, Mr. Lu highlights that these studies rebalance the size portfolios on an annual basis. This means that at the end of each year the stocks are sorted based on size, split into decile, and the returns are computed over the next year for each stock decile.[24] This annual

[23] *See* Richard Roll, "On Computing Mean Returns and the Small Firm Premium," *Journal of Financial Economics*, pp. 371-386, (1983).

[24] By sorting data into deciles means that observations are ranked largest to smallest, and then placed into ten

rebalancing creates the problem. Using a size premium in estimating a CAPM equity cost rate requires that a firm carry the extra size premium in its discount factor for an extended period of time, not just for one year, which is the presumption with annual rebalancing. Through an analysis of small firm stock returns for longer time periods (and without annual rebalancing), Lu finds that the size premium disappears within two years. Lu's conclusion with respect to the size premium is:[25]

> However, an analysis of the evolution of the size premium will show that it is inappropriate to attach a fixed amount of premium to the cost of equity of a firm simply because of its current market capitalization. For a small stock portfolio which does not rebalance since the day it was constructed, its annual return and the size premium are all declining over years instead of staying at a relatively stable level. This confirms that a small firm should not be expected to have a higher size premium going forward sheerly because it is small now.

D. Comparable Earnings ("CE") Approach

Q. PLEASE DISCUSS MR. MOUL'S CE ANALYSIS.

A. On pages 39-42 of his testimony and Schedule 13 of Exhibit PRM-1, Mr. Moul develops an equity cost rate for the Company employing the CE approach. His methodology involves averaging historic and prospective returns on common equity for a proxy group of non-utility companies which are "comparable" in risk to his proxy group as determined from screening *Value Line's* Value Screen database. Mr. Moul screens the database on six risk measures and arrives at a group of eleven unregulated comparable companies. As shown in Panel E of page 2 of Exhibit JRW-

---

different groups, with 1/10 of the observations in each group or decile.

[25] Ching-Chih Lu, "The Size Premium in the Long Run," 2009 Working Paper, SSRN abstract no. 1368705, at p. 5.

13, the average of the historic and projected median returns on common equity for the group is 13.3%.

This approach is fundamentally flawed for several reasons. Mr. Moul has not performed any analysis to examine whether his return on equity figures are likely measures of long-term earnings expectations. Second, the financial statistics for the companies suggest that these companies are not comparable to his utility proxy companies. Financial statistics for the group and Mr. Moul's proxy group are provided in Exhibit JRW-15. The data indicate that the "comparable group" is much less capital intensive (fixed asset turnover of 1.14 vs. 0.28), has a higher valuation level (median P/E of 18 vs. 15), has a higher projected ROE than the electric group (estimated ROE of 19.88% vs. 11.05%), has a market-to-book ratio more than twice the group (Price-to-Book Value of 5.84 vs. 2.08), and its projected long-term EPS growth rate is double that of the proxy group (projected EPS Growth Rate of 9.47% vs. 4.32%). In summary, the financial data indicates that Mr. Moul's "comparable group" is not very comparable to the group of proxy companies.

Finally, and more importantly, since Mr. Moul has not evaluated the market-to-book ratios for these companies, he cannot indicate whether the past and projected returns on common equity are above or below the investors' requirements. These returns on common equity are excessive if the market-to-book ratios for these companies are above 1.0. For example, Campbell Soup is one of the companies listed as being 'comparable' to FPUC. The average return on equity of Campbell Soup is 84.5%. However, I doubt if any financial analyst, including Mr. Moul, would suggest that Campbell Soup has an equity cost rate of 84.5%. Indeed, the market-to-book ratio for the company is in excess of 10.0. This indicates that its return on equity is well above its cost of equity capital.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

(Transcript continues in sequence with Volume 3.)

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 16th day of September, 2014.

Linda Boles

LINDA BOLES, CRR, RPR
FPSC Official Hearings Reporter
(850) 413-6734