BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

In the Matter of

PETITION FOR RATE INCREASE BY FLORIDA POWER & LIGHT COMPANY.	DOCKET NO. 050045-EI
2005 COMPREHENSIVE DEPRECIATION STUDY BY FLORIDA POWER & LIGHT COMPANY.	DOCKET NO. 050188-EI

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PROCEEDINGS:	HEARING
BEFORE:	CHAIRMAN BRAULIO L. BAEZ COMMISSIONER J. TERRY DEASON COMMISSION RUDOLPH "RUDY" BRADLEY COMMISSIONER LISA POLAK EDGAR
DATE:	Monday, August 22, 2005
TIME:	Commenced at 9:55 a.m.
PLACE:	Betty Easley Conference Center Room 148 4075 Esplanade Way Tallahassee, Florida
REPORTED BY:	LINDA BOLES, RPR, CRR Official FPSC Hearings Reporter (850) 413-6734
APPEARANCES:	(As heretofore noted.)

I N D E X

WITNESSES

STATE OF FLORIDA

BEFORE THE

PUBLIC SERVICE COMMISSION

IN RE: PETITION FOR RATE INCREASE)
BY FLORIDA POWER & LIGHT COMPANY) Docket No. 050045-EI

I. QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Matthew I. Kahal. I am employed as an independent consultant, retained by the consulting firm Exeter Associates, Inc. My business address is 5565 Sterrett Place, Suite 310, Columbia, Maryland 21044.

Q. PLEASE STATE YOUR EDUCATIONAL BACKGROUND.

A. I hold B.A. and M.A. degrees in economics from the University of Maryland and have completed all course work and examination requirements for the Ph.D. degree in economics. My areas of academic concentration include industrial organization, economic development and econometrics.

Q. WHAT IS YOUR PROFESSIONAL BACKGROUND?

A. I have been employed in the area of energy, utility and telecommunications consulting for the past 25 years working on a wide range of subjects. Most of my work over the years has focused on utility integrated planning, power plant licensing, environmental compliance, purchase power contracts and a variety of utility ratemaking issues. This has included extensive work on cost of capital and utility financial studies. Much of my professional work in recent years has shifted to electric utility restructuring, mergers and competition.

Prior to entering consulting, I served on the faculties of the University of Maryland (College Park) and Montgomery College, teaching a range of undergraduate courses in economics and business.

Appendix A, which is attached to my testimony, provides a statement of my qualifications.

Q. HAVE YOU PREVIOUSLY TESTIFIED AS AN EXPERT WITNESS?

A. Yes. I have testified before approximately two dozen state and federal utility regulatory commissions in more than 250 separate regulatory cases. My testimony has addressed a wide range of topics including rate of return, need for power, rate design, integrated resource planning, purchase power contracts, stranded costs, utility mergers, and other policy and ratemaking issues. These cases have encompassed electric, gas, telephone and water utilities. I also have testified before the U.S. Congress, Committee on Ways and Means, on proposed tax legislation affecting utilities. These cases are listed in Appendix A.

II. OVERVIEW

A. Recommendation Summary

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

A. I have been retained by the Federal Executive Agencies ("FEA") to evaluate the rate of return request in this case for Florida Power & Light ("FPL" or the "Company"). As part of that assignment, I have prepared an independent study of the cost of common equity relating to the Company's jurisdictional electric service rate base.

Q. WHAT ARE YOU RECOMMENDING AT THIS TIME?

A. I am recommending that this Commission set the authorized rate of return on common equity (ROE) at a figure in the range of 9.0 to 10.0 percent, with a midpoint value of 9.5 percent being a reasonable point value to determine FPL's revenue deficiency in this case. If the projected 2006 test-year capital structure proposed in this case by FPL is employed, this would result in an overall rate of return applicable to an original cost rate base of 6.74 percent. This employs the Company's projected average capital structure and debt cost rates for 2006, my 9.5 percent ROE and a small downward adjustment to FPL's projected cost of debt. My testimony briefly discusses the Company's capital structure and debt cost proposal and my adjustment. My recommendation on the overall rate of return is summarized on Schedule MIK-1, page 1 of 1.

Q. HOW DOES YOUR RECOMMENDATION IN THIS CASE COMPARE WITH THE COMPANY'S PROPOSAL?

A. The Company in this case is requesting 8.22 percent, including a common equity return of 12.3 percent, which incorporates a 50 basis point (0.5 percent) performance bonus. The requested rate of return is sponsored by Company witness Dewhurst, but the Company's cost of equity witness is Dr. William Avera. Dr. Avera concludes that the cost of equity applicable to FPL at this time is 11.8 percent, which is inclusive of 0.3 percent for flotation expense. After including the 50 basis points for performance (sponsored by Mr. Dewhurst), he obtains his final ROE recommendation of 12.3 percent.

Q. HOW DID DR. AVERA CONDUCT HIS COST OF EQUITY STUDY?

A. Dr. Avera applied the DCF model to a proxy group of single A-rated electric utilities, obtaining a return estimate (as of March 2005) of 9.4 percent. He then performed a series of three risk premium studies, obtaining estimates ranging from 9.7 to 11.8 percent, based on his "current estimate" of market interest rates. However, his "test year" risk premium results, based on assumed <u>increases</u> in market interest rates from current levels, range from 10.9 to 12.0 percent. Combining the DCF and risk premium evidence, he concludes that the cost of equity for FPL is 10.0 to 12.0 percent, or 10.3 to 12.3 percent with his 30 basis point flotation expense adder.

Q. GIVEN THESE DCF AND RISK PREMIUM RETURN CALCULATIONS, HOW DID HE DEVELOP HIS FPL ROE RECOMMENDATION OF 12.3 PERCENT?

A. Dr. Avera next increases his lower end 10.3 percent result to 11.3 percent in order to address "the need for FPL to attract capital under adverse circumstances" (page 4), thereby obtaining an ROE range of 11.3 to 12.3 percent. To the midpoint of this range of 11.8 percent, he adds the 50 basis point performance bonus, producing a final recommended ROE award of 12.3 percent.

Q. HOW DID YOU OBTAIN YOUR RECOMMENDED 9.5 PERCENT RETURN ON EQUITY RECOMMENDATION?

A. I conducted a standard DCF study applied to a proxy group of electric utility companies comparable in risk to FPL. This produces an estimate in the range of about 8.9 to 9.4 percent inclusive of a small adjustment (0.1 percent) for flotation expense. As a check, I also conducted a capital asset pricing model (CAPM) study, and using conservative assumptions, I obtained a cost of equity range of 8.63 to 10.25 percent, with a 9.4 percent midpoint. Given this range of study results, I conclude that the cost of equity for FPL at this time is about 9.0 to 9.5 percent, with the preponderance of evidence supporting the lower end of this range.

I do not specifically support (or oppose) the 50 basis point adjustment to ROE proposed in this case to reward the Company for its asserted superior performance since I have not conducted an analysis to determine whether the Company's analysis supporting the superior performance claim is valid. However, as the Company itself acknowledges, this bonus will increase customer rates by about $50 million per year, and this will occur at a time when FPL's retail rates already are quite high relative to those of the benchmark electric utilities employed in this case by the Company (including other major utilities in the Southeast). Consequently, even if the Commission determines that a performance bonus of some amount is warranted, the requested $50 million per year seems extremely large and burdensome to customers.

Rather than recommending (or opposing) a specific performance bonus, I am recommending that the Commission consider a range for the fair ROE to be 9 to 10 percent. The midpoint value of 9.5 percent is the upper end of my DCF cost of equity evidence and is consistent with my CAPM results. As I shall demonstrate, Dr. Avera's analysis -- when corrected -- also falls into or close to this range.

Q. WHY IS YOUR RECOMMENDATION ON RETURN ON EQUITY SO MUCH LOWER THAN DR. AVERA'S COST OF EQUITY ESTIMATES?

A. Dr. Avera and I obtain substantially similar DCF results, with my results being only slightly lower. However, his risk premium/CAPM estimates overstate FPL's cost of equity, most notably because he assumes that investors expect overall, long-term stock market returns in the 12 to 14 percent per year range, returns that are simply are not credible. A further problem is his willingness to use speculative interest rate projections in place of actual market data to develop his risk premium estimates. I also find that his 30 basis points flotation expense adder is excessive.

Q. ARE YOU PROPOSING ANY MODIFICATIONS TO THE PROPOSED FUTURE TEST YEAR CAPITAL STRUCTURE AND COST OF DEBT?

A. I am not proposing a capital structure modification at this time although I am concerned that the proposed 62 percent equity ratio (based on investor-supplier capital) is very expensive and far in excess of what management judges is necessary for the consolidated corporation. I have adjusted FPL's proposed embedded cost of debt downward from 5.89 percent to 5.65 percent to reflect more reasonable assumptions concerning the cost rates for future 2005 and 2006 debt issues. Specifically, FPL has assumed that over the next year it will issue new debt at cost rates of 6.8 to 7.2 percent which is well above current market rates and the Company's recent experience. I have instead assumed a cost rate of 6.0 percent, which is much more realistic although still above current and recent cost rates for FPL.

B. <u>Capital Cost Trends</u>

Q. HAVE YOU REVIEWED THE TRENDS IN MARKET CAPITAL COSTS OVER THE PAST DECADE?

A. Yes. Schedule MIK-2 shows capital cost indicators on an annual basis since 1992 and on a monthly basis from January 2002 to May 2005. This includes inflation (as measured by the annual CPI change), short-term Treasury yields, ten-year Treasury yields and published yields on single A Moody's public utility bonds.

This schedule shows that despite year-to-year fluctuations there is a clear downward trend in capital costs over this time period, particularly for long-term securities. For example, during the early part of this time period utility bonds were yielding around 8 percent, but during the first half of this year utility bond yields were in the 5.6 to 5.8 percent range. There has been a similar decline in yields on the ten-year Treasury notes, from 6 to 7 percent in past years to close to 4 percent in recent months. This declining trend is unmistakable and dramatic, and clearly is a benefit for consumers and businesses (including FPL) making use of credit markets. Long-term interest rates are at historic lows or close to the lowest they have been in several decades.

These very favorable capital cost trends are driven by a number of underlying economic forces. In particular, the recent experience and outlook for inflation has been quite favorable. The rate of inflation over the past year has been 2.8 percent, and absent the volatile food and fuel sectors inflation is a mere 2.2 percent (referred to as "core inflation"). The favorable inflation outlook reflects strong productivity growth and the expansion of global competition (and production capacity) which holds down increases in U.S. product prices.

Q. YOU HAVE DISCUSSED INTEREST RATES ON LONG-TERM SECURITIES. IS THE TREND SIMILAR FOR SHORT-TERM INTEREST RATES?

A. Not entirely. While there is a downward trend over time in short-term interest rates, those rates have begun to move back up in the last two years. This reflects the gradual strengthening of the U.S. economy, and the decision by the Federal Reserve (Fed) to increase short-term interest rates. It is notable that despite the Fed's efforts to increase short-term rates, long-term rates have remained quite low and have not increased.

Q. YOUR SCHEDULE SHOWS THAT LONG-TERM INTEREST RATES ARE QUITE LOW COMPARED TO PAST YEARS. DOES THIS ALSO APPLY TO THE COST OF EQUITY?

A. Yes, I believe so. The underlying factors that have led over time to the very low observed long-term interest rates also favorably affect the cost of equity, and there is no reason to believe this would not apply to FPL as well. There is another force at work that favorably affects the utility cost of equity but does not have a similar beneficial effect on the cost of debt -- federal tax policy. In 2003, Congress enacted tax legislation reducing income tax rates on both capital gains and on common stock dividends. Lower taxes on returns to equity investments mean that investors are willing (or should be willing) to accept lower market returns for holding common stocks, particularly as compared with bonds. I believe that my DCF analysis captures these costs of equity-reducing effects since my analysis incorporates relatively recent stock market data from the time period subsequent to the enactment of that legislation. Certain risk premium methods, particularly those based on historical measures, might not capture that effect.

Q. WHAT IS THE CURRENT TREND AND NEAR-TERM OUTLOOK FOR CAPITAL COSTS?

A. During the past year and a half, capital costs (and inflation) have been very low and declining. Long-term interest rates in 2004 reached a low point in early Spring but then trended up somewhat during the Summer 2004. This upward movement proved to be brief and temporary, and there has been a gradual declining trend since then. For example, the published yield on single A utility bonds (Moody's) has fallen from

6.6 percent in June 2004 to 5.5 percent in May 2005. This downward trend in long-term rates occurred at during the same time period that the Fed was increasing short-term rates.

A discordant note during recent months is that economic forecasters are expecting some degree of reversal of this favorable interest rate trend. According to the Blue Chip Economic Indicators "Consensus" forecast (July 10, 2005), yields on ten-year Treasury notes are projected to increase from current levels of about 4.1 percent to 4.4 percent for calendar 2005 and 4.9 percent for calendar 2006. Inflation, however, is expected to remain under control at 2.5 percent for 2006. This is the average outlook for the approximately 40 forecasting organizations contributing to the Blue Chip survey.

Q. DOES YOUR RECOMMENDATION IN THIS CASE REFLECT THOSE CAPITAL MARKET CONDITIONS?

A. Yes, I believe so. My DCF analysis attempts to use recent stock market data and published investors analyst earnings forecast. Moreover, my ROE recommendation in this case is a range of 9.0 to 10.0 percent, even though current market evidence would support a result closer to the 9.0 percent lower end. Thus, while I employ reasonably current market data, the 9.0 to 10.0 percent range would be valid even if market cost rates move upward, as some analysts predict, as I discuss in the next section of my testimony.

Q. YOUR SCHEDULE MIK-2 INCLUDES YIELDS ON SINGLE A UTILITY BONDS. IS FPL RATED SINGLE A?

A. Yes. FPL is rated strong single A by the major rating agencies, with FPL's first mortgage bonds rated a low double A by Moody's. During the past two years, FPL has been able to issue long-term debt at coupon rates below 6 percent, as I discuss in the next section of my testimony.

C. Testimony Organization

Q. HOW IS THE REMAINDER OF YOUR TESTIMONY ORGANIZED?

A. Section III is a brief discussion of the capital structure and debt cost rate proposed by the Company in this case. I also describe my adjustment to the debt cost rate.

Section IV presents my DCF study, which provides the basis of my recommended ROE in this case. This section also presents my CAPM study which I employ as a check on my DCF results. This helps respond to Dr. Avera's concerns that risk premium-type evidence should be considered along with the DCF analysis.

I present my critique of Dr. Avera's cost of capital studies and his accompanying recommendation in Section V of my testimony. One of my main objections is Dr. Avera's improper use of projected capital costs in place of actual capital costs, which is incorrect and contrary to accepted practice. Also, I explain that his ROE recommendation is not consistent with his own evidence.

The final section of my testimony summarizes my recommended ROE and overall rate of return. In doing so, I discuss the need for an appropriate flotation adjustment and FPL's proposal for an ROE bonus.

III. CAPITAL STRUCTURE/DEBT COST

A. Capital Structure

Q. WHAT CAPITAL STRUCTURE IS FPL PROPOSING IN THIS CASE?

A. The proposed capital structure is a 13-month average for the future test year, 2006. The common equity component is 49.96 percent of total capital, but that is based on including accumulated deferred income taxes, customer deposits and unamortized investment tax credits in capitalization. On the basis of investor-supplied capital, the common equity ratio is approximately 62 percent, which is far above the industry average which approximates 45 percent. (Please note that the average for the electric companies comprising my proxy group is 48 percent, excluding consideration of short-term debt.) The use of a capital structure with an excessive amount of equity can result in customers paying excessive rates since equity carries a higher cost rate than utility debt and its returns are not tax deductible.

I show this capital structure on Schedule MIK-1, page 1 of 1. Please note that the accumulated balance of deferred taxes is included as zero cost capital.

Q. HAS THE COMPANY SOUGHT TO JUSTIFY THE USE OF THIS VERY HIGH EQUITY RATIO?

A. Yes. Dr. Avera states that the very high equity ratio is needed so that FPL can maintain a strong credit rating. This is because at least one of the credit rating agencies (S&P) imputes the long-term purchase power capacity payments to which FPL is contractually obligated as "debt equivalent." He estimates the imputation to be $1.1 billion for the future test year, and recognizing that amount means that FPL has an "equivalent" common equity ratio of 56 percent, which the Company believes to be reasonable for ratemaking. Dr. Avera seems to recognize that the adjusted 56 percent ratio exceeds both the equity ratio of proxy electrics and S&P's capital structure benchmark to retain the single A rating. However, he indicates that there is an industry trend toward maintaining higher equity ratios.

Q. DO YOU AGREE WITH DR. AVERA THAT THE ELECTRIC INDUSTRY IS MOVING TOWARD HIGHER EQUITY RATIOS?

A. Yes. There is at least a mild trend, although it does not support either the 56 percent or 62 percent ratios defended by Dr. Avera. The June 3, 2005 edition of the Value Line Investment Survey (page 156) estimates the industry-wide common equity ratio for 2005 to be 45.0 percent. It also projects that the equity ratio will rise over time to 48.5 percent by 2008-2010. (It is my understanding that these ratios are based on excluding short-term debt from capital structure.) Hence, the FPL 56 or 62 percent figures substantially exceed the industry's capitalization outlook, even accounting for debt imputation.

Q. DO YOU HAVE ANY OTHER CONCERNS REGARDING FPL'S CAPITAL STRUCTURE?

A. Yes. There is a substantial difference between the capital structures of FPL utility and FPL Group on a corporate consolidated basis, with FPL having the equity richer capital structure. I show a comparison of the two capital structures (using only investor-supplied capital) on Table 1 below at March 31, 2005 from the recently filed SEC Form 10Q report.

The comparison shows that FPL utility accounts for \$10.3 billion of total capital compared to \$17.9 billion for FPL Group (about 57 percent). However, the utility accounts for 77 percent of the expensive common equity. In other words, management has allocated a disproportionate amount of the expensive capital to the monopoly utility segment, while the consolidated corporation is capitalized with 45 percent common equity -- typical for the industry. Dr. Avera totally ignores this issue, and it cannot be explained away by "debt imputation" of purchased capacity since that affects both the utility and the consolidated corporation.

TABLE 1

Capital Structure Comparison at March 31, 2005 (millions $)

	FPL Utility		FPL Group	
	balance	**%**	**balance**	**%**
Long-term Debt	$ 2,813	27.4%	$ 8,501	47.4%
Commercial Paper	691	6.7	691	3.9
Current Maturities	496	4.8	636	3.6
Common Equity	6,262	61.0	8,090	45.2
Total	$10,262	100%	$17,918	100%

Source: FPL Group SEC Form 10Q for the quarter ending March 31, 2005.

Q. IN LIGHT OF THIS ISSUE, ARE YOU RECOMMENDING A MODIFICATION TO FPL'S CAPITAL STRUCTURE?

A. No, not at this time. While I am mindful of the need to recognize the net imputation problem, the discrepancy between the FPL and FPL Group capitalization practices cannot be explained by this issue. I believe that FPL should seek to moderate its expensive capital structure over time, and in this case the Commission should take into account the Company's very heavy equity ratio in setting the Company's authorized ROE.

B. FPL's Cost of Debt

Q. WHY HAVE YOU MODIFIED FPL'S DEBT COST RATE?

A. FPL is proposing the use of a 5.89 percent debt cost rate for the future test year. This compares with a debt cost rate of 5.24 percent for the historical 2004 test year. This substantial increase in the cost of debt is proposed because FPL estimates that it will issue over $1 billion of debt (on a 13-month average basis for 2006) at coupon cost rates in the range of 6.8 to 7.2 percent. FPL asserts that these relatively expensive debt issuances will drive up the cost of debt for 2006 as compared to its current cost of debt.

The problem is that the claimed costs of such issuances do not correspond to recent experience. In response to SFHHA Interrogatory 1-1, FPL identified the following recent issuances of 30-year First Mortgage Bonds.

Series	Issue Date	Principal Amount
5.625%	04/03	$500 Million
5.650	01/04	240
5.850	12/02	200
5.950	10/03	300

In addition, on June 2, 2005 the Company announced the sale of $300 million of First Mortgage Bonds at a coupon cost rate of 4.95 percent. In light of this current market data and recent cost of debt experience, it does not appear that FPL's proposal to increase its cost of debt is reasonable.

Q. HOW HAVE YOU MODIFIED FPL'S PROPOSAL?

A. I revised the cost of debt assuming new debt could be issued at an average cost rate of 6.0 percent during 2005 and 2006 rather than 6.8 to 7.2 percent. I regard that assumption as conservatively high compared to recent experience, and even the 6.0 percent would be a significant increase in market rates (an increase that may or may not actually occur). I show the debt cost recalculation on page 2 of Schedule MIK-1, which lowers the cost of debt from 5.89 to 5.65 percent.

Q. WOULD IT BE REASONABLE FOR THE COMMISSION TO CONSIDER AN EVEN LOWER COST OF NEW DEBT?

A. Yes. If the new debt is issued at an average cost rate of 5.6 percent (which is closer to recent experience), this would reduce interest expense by an additional $4 million per year. This would lower my 5.65 percent to 5.55 percent.

IV. THE DCF AND CAPM STUDIES

A. Using the DCF Model

Q. WHAT STANDARD ARE YOU USING TO DEVELOP YOUR RETURN ON EQUITY RECOMMENDATION?

A. As a general matter, the ratemaking process is designed to provide the utility an opportunity to recover its (prudently-incurred) costs of providing utility service to its customers, including the reasonable costs of financing its (used and useful) investment. Consistent with this "cost-based" approach, the fair and appropriate return on equity award for a utility is its cost of equity. The utility's cost of equity is the return required by investors (i.e., the "market return") to acquire or hold that company's common stock. A return award greater than the market return would be excessive and would overcharge consumers for utility service.

Although the concept of cost of equity may be precisely stated, its quantification poses difficulties. The market cost of equity cannot be directly observed (i.e., investors do not directly state their return requirements), and it therefore must be estimated using analytic techniques.

Q. IS THE COST OF EQUITY A FAIR RETURN AWARD?

A. Generally speaking, yes it is. A return award commensurate with the cost of equity provides fair and reasonable compensation to utility investors and normally should allow the utility to successfully finance its operations on reasonable terms.

In this case, FPL has proposed to augment its asserted estimate of its cost of common equity through the use of a 50 basis point performance adder, as discussed in the testimony of Mr. Dewhurst and Dr. Avera. This equates to a revenue burden for FPL customers of $50 million per year. While there may be conceptual merit in rewarding outstanding cost control or service quality performance, I must question the appropriateness of a bonus this large given FPL's relatively high retail rates.

Q. WHAT DETERMINES A COMPANY'S COST OF EQUITY?

A. It should be understood that the cost of equity is essentially a market price, and as such it is determined by the supply and demand forces operating in financial markets. In that regard, there are two key factors that determine this price. First, a company's cost of equity is determined by the fundamental conditions in capital markets (e.g., the outlook for inflation, tightness of monetary policy, investor behavior, etc.). The second factor (or set of factors) is the business and financial risk profile of the company in question. For example, the fact that a utility company operates as a regulated monopoly, dedicated to providing electric service (regarded as an "essential service") typically would imply low business risk and therefore a relatively low cost of equity. FPL's very strong balance sheet also contributes to its relatively low cost of equity.

Q. DOES DR. AVERA'S TESTIMONY REFLECT THESE PRINCIPLES?

A. Yes, he incorporates these principles in conducting his DCF analysis. However, his risk premium studies do not fully recognize FPL's low risk, nor does his decision to base his ROE recommendation on results exceeding much of his cost of equity evidence.

Q. WHAT METHODS ARE YOU USING IN THIS CASE?

A. I have employed the standard discounted cash flow (DCF) model, which I describe in this section, and the capital asset pricing model (CAPM), which I describe later in this section. I apply both models to a group of proxy electric utility companies comparable in risk to FPL.

The DCF model is one of the approaches employed by Dr. Avera, and based on my experience, is the cost of equity method most widely relied upon by state and federal regulatory commissions, including this Commission. Its widespread acceptance is due to the fact that the model is market-based and is derived from standard financial theory. The theory begins by recognizing that any publicly-traded common stock (utility or otherwise) will sell at a price reflecting the discounted stream of cash flows expected by investors. The objective is to estimate that discount rate.

Using certain simplifying assumptions, the DCF model for dividend paying stocks can be distilled to the following formula:

$K_e = D_o/P_o\ (1 + 0.5g) + g$, where:

K_e = cost of equity;

D_o = the current annualized dividend;

P_o = the stock price; and

g = the long-term dividend growth rate.

This is referred to as the constant growth model, because for mathematical simplicity, it is assumed that the growth rate is constant for an indefinitely long time period. While this assumption may be unrealistic in many cases, for traditional utilities (which typically are far more stable than unregulated companies) the assumption may be reasonable, particularly when applied to a group of companies.

Q. HOW HAVE YOU APPLIED THIS MODEL?

A. Strictly speaking, the model can be applied only to publicly-traded companies, i.e., companies whose market prices (and hence valuations) are transparently revealed.

Consequently, the model cannot be directly applied to FPL, and therefore a market "proxy" is needed. In theory, the model can be applied to FPL Group, FPL's corporate parent, and I have done so by including FPL Group in my group of proxy electric companies.

I believe that a (properly selected) proxy group study is likely to be more reliable than a single company study. This is because there is "noise" or fluctuations in stock price (or other) data that cannot always be readily accounted for in a simple DCF study. The use of an appropriate proxy group helps to allow such "data anomalies" cancel out in the averaging process. For the same reason, I prefer to use market data averaged over a period of several months (i.e., six months) rather than "spot" data.

B. DCF Study Using the Proxy Group of Electric Utility Companies

Q. PLEASE DESCRIBE YOUR ELECTRIC UTILITY PROXY GROUP.

A. For cost of equity purposes, I have selected eleven electric utility holding companies operating in the East and Central regions of the U.S. The eleven companies include:

$ Ameren Corp.
$ Entergy Corporation
$ FPL Group
$ Great Plains Energy
$ Progress Energy
$ SCANA Corp.
$ Southern Co.

! Vectren

$ WPS Resources Corp.

$ Westar Energy

$ Wisconsin Energy

I list these companies on Schedule MIK-3, along with certain risk or financial indicators.

Q. HOW DID YOU SELECT THIS PROXY GROUP?

A. This proxy group is derived from the Value Line data base for the Eastern and Central region electric utility companies. Starting with these two regional groups, I eliminated companies for the following reasons:

- Value Line Safety Rating higher than "2" (i.e., only "1" and "2" retained)

- Companies with substantial utility operations in retail access states were eliminated (i.e., virtually all Mid-Atlantic states, Northeast states, Ohio, Illinois, Texas, Michigan).

- Utility companies classified as "small cap" stocks.

- Companies not paying dividends.

In addition, I eliminated one other company that otherwise could qualify, Allete, Inc., due to that company's substantial non-regulated operations and recent corporate restructuring. I note that Dr. Avera similarly disqualified this company from his proxy group.

Q. IN TERMS OF INVESTMENT RISK, HOW DOES THIS GROUP COMPARE TO FPL?

A. Based on the information on Schedule MIK-3, it appears that FPL (or FPL Group) is similar to or less risky than the proxy group. The group average equity ratio is 48 percent compared with FPL's proposed 62 percent (or 56 percent adjusted for debt imputation). FPL Group's Safety Rating is "1" (the highest rating) compared to a group average 1.7, and FPL Group enjoys a Financial Strength rating of A+ (the proxy group's highest rating).

Dr. Avera discussed nuclear power generation in his testimony as an important risk factor, although recently, nuclear generation has become looked at by investors more favorably than in years past. However, ten of the eleven proxy companies in my group have nuclear generation in their supply mixes.

Q. HOW HAVE YOU APPLIED THE DCF MODEL TO THIS GROUP?

A. I have elected to use a six-month time period to measure the dividend yield component (Do/Po) of the equation. Using the Standard & Poors Stock Guide, I compiled month ending dividend yields for the six months ending May 2005, the most recent data available to me as of this writing. Hence, my market data cover essentially the first half of calendar 2005.

I show these dividend yield data on page 1 of Schedule MIK-4. Over the six month time period, the dividend yields for the eleven companies ranged from 4.25 in March to 4.05 percent in May, indicating a very slight downward trend over the recent six-month period, with a six-month average for the proxy group of 4.17 percent.

For DCF purposes, I am relying on the 4.17 percent proxy group six-month average.

Q. IS 4.17 PERCENT THE FINAL DIVIDEND YIELD?

A. Not quite. Strictly speaking, the dividend yield used in the model should be the value that the investor expects over the next 12 months. Using the standard "half-year" growth rate adjustment technique (which I assume to be 2.5 percent), the DCF adjusted yield is 4.3 percent (4.17 x 1.025).

Q. HOW HAVE YOU DEVELOPED YOUR GROWTH RATE COMPONENT?

A. Unlike the dividend yield, the investor-expected growth rate cannot be directly observed but instead must be inferred through a review of available evidence. The growth rate in question is the <u>long-term</u> dividend growth rate, but analysts frequently use earnings growth as a proxy for (long-term) dividend growth. This is because in the long run earnings are the ultimate source of dividend payments to shareholders, and dividend growth cannot exceed earnings growth over a long time period -- particularly for a group of companies.

One possible approach is to examine historical growth as a guide to investor expected growth, for example the recent five-year growth rates for earnings, dividends and book value. However, my experience with electric companies has been that these historic measures have become quite volatile in recent years and therefore provide little (or questionable) useful guidance concerning expected long-term growth trends. This is illustrated on Schedule MIK-5, page 4 of 4. The observed volatility in these financial measures is not surprising given the electric utility industry's extensive corporate and regulatory restructuring activities during the past five years. I note that Dr. Avera similarly considers but then rejects the use of the recent historical growth rates for DCF purposes.

Q. WHAT EVIDENCE, OTHER THAN HISTORICAL TRENDS, HAVE YOU REVIEWED?

A. The DCF growth rate should be prospective, and one particularly useful source of information on prospective growth is the projections of earnings per share (typically five years) prepared by securities analysts. In fact, Dr. Avera appears to give substantial weight to this information in conducting his DCF study. There are several publicly available sources of projected earnings prepared by securities analysts.

Schedule MIK-5, page 2 of 4, presents four well-known sources of projected earnings growth rates. Three of the four sources – First Call, Zacks and Standard & Poors (S&P) – provide averages from securities analyst surveys (typically the median value). The fourth, Value Line, is that organization's own estimates. Value Line publishes its estimate of five-year earnings growth using the average annual earnings during 2001 to 2003 to 2008-2010 for growth rate calculation purposes. As this schedule shows, the projected growth rates calculated in this manner tend to be very unstable. Consequently, I also calculate the five-year growth rate using Value Line's projection for 2009 versus a 2004 base year. These various sources appear to support an expected earnings growth range of about 4.5 to 5.0 percent. The three analyst surveys indicate five-year earnings growth rates for the group of 4.5, 4.6 and 4.9 percent -- supporting the 4.5 to 5.0 percent range.

Q. IS THERE OTHER GROWTH RATE EVIDENCE THAT SHOULD BE CONSIDERED IN ADDITION TO SECURITY ANALYST EARNINGS PROJECTIONS?

A. Yes. There are a number of reasons why investor expectations of <u>long run</u> growth could differ from the limited, five-year earnings projections from securities analysts. Consequently, while securities analyst estimates should be considered and given substantial weight, these growth rates should be subject to a reasonableness test and corroboration, to the extent feasible.

On Schedule MIK-5, page 3 of 4, I have compiled Value Line five-year growth rate projections of dividends, book value and retained earnings (the latter for the outyears 2008 to 2010) for each of the proxy companies. (Retained earnings growth measures the growth over time that one would expect from the reinvestment of earnings, i.e., earnings not paid as dividends.) As this schedule shows, Value Line figures tend to be somewhat less stable than the analyst surveys. However, these four measures support a range of 4.0 to 5.3 percent, which is at least roughly in line with my finding of 4.5 to 5.0 percent and even suggests that this range is conservatively high.

Q. WHAT IS YOUR DCF CONCLUSION?

A. I summarize my DCF analysis on page 1 of Schedule MIK-5. The adjusted dividend yield for the first half of 2005 for this proxy group is 4.3 percent. Available evidence would suggest a DCF growth range of about 4.5 to 5.0 percent (considering both Value Line projections and surveys of securities analyst earnings growth rates). This produces an investor total return of 8.8 to 9.3 percent, with a midpoint of 9.05 percent.

Q. DO YOU INCLUDE AN ADJUSTMENT FOR FLOTATION EXPENSE?

A. Yes. As discussed in the final section of my testimony, I include an adjustment for flotation expense of 0.1 percent. It is my understanding that this Commission permits such an adjustment, and in this case FPL Group undertook a public issuance of common stock issuance earlier this year of $575 million.

With an equity flotation expense adjustment the final DCF cost of equity becomes 8.9 to 9.4 percent, with a midpoint of 9.15 percent. As discussed in the final section of my testimony, I recommend that the Commission give consideration to an ROE range of 9.0 to 10.0 percent which is somewhat higher than my pure DCF results.

Q. DID YOU CONDUCT A DCF STUDY USING DR. AVERA'S PROXY COMPANIES?

A. No, I did not. Dr. Avera obtained a DCF result of 9.4 percent using data sources and methods generally similar to what I used. Since his 9.4 percent result falls within the range of my ROE recommendation, I see little reason to conduct a further DCF study using his proxy companies.

C. The CAPM Analysis

Q. PLEASE DESCRIBE THE CAPM MODEL.

A. The CAPM is a form of the "risk premium" approach and is based on modern portfolio theory. Based on my experience, the CAPM is the cost of equity method most often used in rate cases after the DCF method, and it is one of Dr. Avera's four methods.

According to this model, the cost of equity (Ke) is equal to the yield on a risk-free asset plus on equity risk premium multiplied by a firm's "beta" statistic. "Beta" is a firm-specific risk measure which is computed as the movements in a company's stock price (or market return) relative to contemporaneous movements in the broadly defined stock market. This measures the investment risk that cannot be reduced or eliminated through asset diversification (i.e., holding a broad portfolio of assets). The overall market, by definition, has a beta of 1.0, and a company with lower than average investment risk (e.g., a utility company) would have a beta below 1.0. The "risk premium" is defined as the expected return on the overall stock market minus the yield or return on a risk free asset.

The CAPM formula is:

$$K_e = R_f + \beta (R_m - R_f), \text{ where:}$$

K_e = the firm's cost of equity
R_m = the expected return on the overall market
R_f = the yield on the risk free asset
β = the firm (or group of firms) risk measure.

Two of the three principal variables in the model are directly observable -- the yield on a risk-free asset (e.g., a Treasury security yield) and the beta. For example, Value Line publishes betas for each of the companies that it covers. The difficulty, however, is in the measurement of the expected stock market return (and therefore the risk premium), since that variable cannot be directly observed.

Q. HOW HAVE YOU APPLIED THIS MODEL?

A. For purposes of my CAPM analysis, I have used a long-term (i.e., 20 year) Treasury yield as the risk free return and the average beta for the eleven proxy group companies. (See Schedule MIK-3 for the company-by-company betas.) In recent months, long-term Treasury yields have been approximately in the range of 4.5 to 5.0 percent, and the beta for the proxy group averages 0.75. Finally, and as explained below, I am using a stock market return estimate of 10 to 12 percent, although I see little support for the upper end of that range.

Using these data inputs, the CAPM results are shown on page 1 of Schedule MIK-6. My low-end estimate uses a risk-free rate of 4.5 percent and a stock market return of 10.0 percent:

$$K_e = 4.5\% + 0.75\ (10.0\% - 4.5\%) = 8.63\%$$

The upper end uses a risk-free rate of 5.0 percent and a stock market return of 12.0 percent.

$$Ke = 5.0 + 0.75\ (12\% - 5.0\%) = 10.25\%$$

Thus, with these inputs the CAPM provides a return range of 8.63 to 10.25 percent, with a midpoint of 9.44 percent. The CAPM analysis produces results slightly higher than the midpoint result than my DCF analysis, and I have factored this into the ROE range that I have identified for FPL. That is, the midpoint of 9.44 percent is well within my recommended 9.0 to 10.0 percent range.

Q. IT APPEARS THAT A KEY ELEMENT IN YOUR CAPM IS YOUR MARKET RETURN RANGE OF 10 TO 12 PERCENT. HOW DID YOU DERIVE THAT RANGE?

A. Various measures of market return (and therefore the equity risk premium) are shown on page 2 of Schedule MIK-6. These market returns average to about 11.0 percent, and therefore the various equity risk premium measures average about 6.2 percent, if one assumes a prospective risk-free return of 4.75 percent.

Q. PLEASE DESCRIBE THESE MEASURES.

A. In general, two approaches have been used to obtain either the risk premium or the market return required by the CAPM. The first is to perform a DCF calculation on the overall stock market, and the second approach makes use of historical expected returns data measured over a long time period. Dr. Avera adopts the first method in his CAPM analysis, which leads him to conclude (erroneously) that the equity risk premium (relative to a long-term Treasury bond yield) is approximately 9 percent.

Q. HAVE YOU PERFORMED A STOCK MARKET TOTAL RETURNS ANALYSIS?

A. Yes. Value Line publishes projections for its "Industrial Composite" twice each year, and that information can be used to perform a DCF total return calculation. As of April 2005, Value Line was projecting five-year earnings growth of 7.0 percent and long-term growth from retained earnings of 11.0 percent. Averaging the two measures provides a composite growth rate of 9.0 percent. When combined with Value Line's reported dividend yield of 1.9 percent for the Industrial Composite, the total return is 10.9 percent. The Industrial Composite is a broad measure of the overall stock market, excluding only utilities, financial services and non-North American companies.

Q. WHAT ARE THE HISTORICAL RISK PREMIUM VALUES?

A. Cost of equity analysts frequently cite to historic returns data compiled by Ibbotson Associates, and I have used that source as well. Based on historic (1926-2003) after-the-fact returns published by the Ibbotson in 2004, the stock market risk premium relative to long-term Treasury bonds averages 6.6 percent. Combining that value with recent long-term Treasury yields of about 4.75 percent provides a market return of 11.35 percent. Dr. Avera also employs the long-term historical risk premium from Ibbotson but cites a somewhat higher figure, 7.2 percent.

There are reasons, however, for believing that even the 6.6 percent historical premium is too high. A recent research study by Ibbotson and Chen, estimates a long-term (arithmetic) historic risk premium of 5.9 percent. The authors estimate this figure using a supply-side model removing the effects of a rising P/E ratio over the historical period. This analysis acknowledges that the historical trend of rising P/Es served to inflate the achieved historical returns and such an increase would not be expected to continue indefinitely into the future. Combining the Ibbotson/Chen 5.9 percent risk premium with a current long-term Treasury yield of 4.75 percent produces an overall stock market return of 10.65 percent.[1] I would note that Ibbotson/Chen also report a geometric average risk premium of about 4 percent.

Q. PLEASE SUMMARIZE THE MARKET RETURN EVIDENCE.

A. These four measures of overall stock market return range from 10.65 to 11.35 percent, validating the assumed range used in my CAPM study on page 1 of Schedule MIK-6 of 10 to 12 percent. These stock market return estimates imply a (midpoint) stock market risk premium (relative to long-term Treasury bonds) of about 6.2 percent.

It should be noted that my CAPM study results in certain respects are conservatively high, even though my cost of equity estimate is significantly lower than that of Dr. Avera (i.e., 11.8 percent). This is because I have employed the yield on long-term Treasury bonds as the "risk free return," when, in fact, Treasury bonds clearly are not risk free. Investors are well aware of the "interest rate risk" associated with Treasury bonds (i.e., bond prices will fall if interest rates rise). Moreover, I have made use of "arithmetic" historic average returns, even though investors are undoubtedly aware of both arithmetic and geometric averages. The geometric historic returns are somewhat lower than the arithmetic returns, as I show on page 2 of Schedule MIK-6. Providing some recognition of the geometric historic averages, along with the arithmetic historic average, would be reasonable and would lower the CAPM-derived cost of equity that I have presented.

Since my analysis incorporates both long-term Treasury yields and arithmetic historic returns, the CAPM results should be viewed as conservatively high estimates

[1] Roger G. Ibbotson and Peng Chen, "Stock Market Returns in the Long Run: Participating in the Real Economy," Financial Analyst Journal (forthcoming).

of the cost of equity. Hence, greater weight should be given to the lower end of my CAPM range, i.e., the 8.6 to 9.4 percent portion of my range.

IV. DR. AVERA'S ROE ANALYSIS

Q. HOW DID MR. AVERA OBTAIN HIS 12.3 PERCENT ROE RECOMMENDATION?

A. Dr. Avera performs a DCF analysis and three variants of the risk premium method (using both current debt cost rates and 2006 projected debt cost rates). One of the three risk premium variants is the CAPM, as discussed in the previous section, and to develop the stock market return component he uses both historical data and projections. The use of projected interest rates in his risk premium studies appears to add nearly a full percent point to his cost of equity study estimates. Notably, Dr. Avera does not factor in the assumption of increases in market capital costs in his DCF study. Dr. Avera characterizes these cost of equity results as falling in a range of 10.0 to 12.0 percent, which would seem to imply a midpoint of about 11.0 percent.

Dr. Avera then proceeds to raise these results by making the following three adjustments.

- He discards the lower half of his range and selects 11 to 12 percent instead of 10 to 12 percent due to FPL's "risk exposure" (a midpoint of 11.5 percent).
- He adds 0.3 percent for flotation expense, producing a midpoint cost of equity of 11.8 percent.
- He incorporates Mr. Dewhurst's performance bonus of 0.5 percent, to obtain a final 12.3 percent ROE award.

Q. DO YOU AGREE THAT HIS COST OF EQUITY STUDY ESTIMATES PRODUCE A RANGE OF 10 TO 12 PERCENT AND A MIDPOINT OF 11.0 PERCENT FOR FPL?

A. No. This range is obtained only by giving little weight to the DCF study (9.4 percent) and by the inclusion of projections of rising interest rates. The latter is highly improper and inconsistent with accepted cost of capital practice. For example, if one takes his cost of equity studies and (a) allocates a 50 percent weight to DCF and 50 percent weight to risk premium; and (b) includes risk premium studies that use only actual and not projected market interest rates, the following would result.

TABLE 2

Dr. Avera Cost of Equity Results

Risk Premium (using actual cost of debt)		
(1)	Authorized returns	10.6%
(2)	Realized Returns	9.7
(3)	CAPM Projected	11.8
(4)	CAPM Historical	10.1
	Average	10.55%
DCF Analysis		9.4%
Cost of Equity Average		**9.98%**

Source: Document WEA-11, page 1 of 1

Dr. Avera's results seem to support a cost of equity average of about 10.0 percent, although his projected return CAPM at 11.8 percent seems to be an outlier.

Q. IS DR. AVERA JUSTIFIED IN INCLUDING AN ADJUSTMENT FOR FLOTATION EXPENSE?

A. Yes, although I believe that 0.3 percent is too high. As I explain in the next section, I believe 0.1 percent would be reasonable compensation for FPL for flotation expense.

Q. WHY SHOULD THE COST OF CAPITAL STUDIES BASED ON PROJECTED RATHER THAN ACTUAL LONG-TERM INTEREST RATES BE REJECTED?

A. This is contrary to standard practice in performing cost of capital studies, and to his credit, Dr. Avera did not attempt to introduce assumptions about rising capital costs in his DCF study. The use of projected in place of actual long-term interest rates is a clear rejection of market price information and in doing so is contrary to accepted financial theory. Dr. Avera, in essence, is saying "markets are wrong," and they are pricing debt securities improperly.

Q. ARE YOU SAYING THAT FINANCIAL MARKETS ARE NOT ASSUMING THE LARGE INTEREST RATE INCREASES ON LONG-TERM BONDS IN 2006 THAT DR. AVERAGE HAS USED?

A. Yes. For example, Dr. Avera states that long-term Treasury bonds currently yield 4.6 percent, but he assumes a 2006 value of 5.8 percent, or 120 basis points higher. His current figure of 4.6 percent is within my range of 4.5 to 5.0 percent. An increase in Treasury bond yields to 5.8 percent would imply a huge drop in the prices of long-term Treasury bonds over the next year. While some investors may expect such a decline, it is obvious that preponderance of investors do not. No rational investor would hold a long-term Treasury bond if he expects (for example) a 20 percent price drop to occur over the next year. Rather, the investor's rational strategy would be to hold a short-term Treasury security, accept a slightly lower yield for one year, and wait for the price of Treasury bonds to fall. The rational investor would then purchase the bond at its much lower price. This behavior serves to arbitrage away the difference between current and expected prices (and interest rates) on long-term securities.

Dr. Avera's use of projected rather than actual long-term interest rates improperly assumes irrational behavior on the part of financial markets. This would be no different than if Dr. Avera had decided that the stock prices in his DCF study were too high and must be reduced by 20 percent.

Q. ARE YOU SAYING THAT FORECASTS MUST BE IGNORED?

A. No, I am not saying that. What I am saying is that cost of equity studies should be based on relatively current market price data, not hypothetical market prices that may or may not occur in the future. The forecasts that Dr. Avera relies upon are information readily available to investors and therefore priced in to securities already. However, the credible cost of equity evidence will provide the Commission with a range of results to consider. Within that range that Commission may wish to consider recent cost of capital trends, interest rate projections and other factors in selecting a final ROE award for FPL.

Q. WHAT IS YOUR DISAGREEMENT WITH DR. AVERA'S CAPM ANALYSIS?

A. Setting aside the interest rate projections issue, my only disagreement is with the risk premium/market return values used in his CAPM calculations. He utilizes an historical Ibbotson risk premium value of 7.2 percent and a projected stock market risk premium of 9.3 percent. The latter is based upon his estimates of a long-run annualized return on the stock market (i.e., the S&P 500) of about 14 percent. Both of these estimates are unreasonably high.

Dr. Avera apparently obtained the 7.2 percent figure from Ibbotson's 2004 Yearbook based on the difference between stock market and Treasury bonds returns over the historical period. However, as I show on my Schedule MIK-6, page 2, Ibbotson actually reports a risk premium of stocks over Treasury bonds of 6.6

percent, not 7.2 percent. This is based upon the difference between the historical average return on Large Company Stocks (12.4 percent) versus the historical average return on Long-term Government Bonds (5.8 percent) (Ibbotson, Stocks Bonds, Bills and Inflation, 2004, Table 4 "Summary Statistics of Annual Returns"). However, even the 6.6 percent is biased upwards by the increase over the historical period in price/earnings ratios, an increase that would not be expected to persist over time.

Ibbotson's recent study with Dr. Chen (cited in the last section of my testimony) develops a more realistic 5.9 percent (arithmetic) risk premium based upon their use of a supply side model. In explaining their derivation of the 5.9 percent equity risk premium, the authors make the following salient point:

> Supply side models can be used to forecast the long-run expected equity return. The supply of stock market returns is generated by the productivity of the corporations in the real economy. Over the long run, the equity return should be close to the long run supply estimate. In other words, investors should not expect a much higher or a much lower return than that produced by companies in the real economy. We believe the investors' expectations on the long-term equity performance should be based on the supply of equity returns produced by corporations. (Ibbotson and Chen, page 11)

Clearly, the Ibbotson/Chen 5.9 percent equity risk premium is linked -- properly

Q. SO -- TO THE PRODUCTIVITY OF THE U.S. ECONOMY. THIS IS SIGNIFICANTLY LOWER THAN BOTH THE REPORTED 6.6 PERCENT HISTORICAL VALUE AND DR. AVERA'S 7.2 PERCENT.

HOW DID DR. AVERA DERIVE HIS 9.3 PERCENT RISK PREMIUM ESTIMATE?

A. This is derived from his estimate of a 13.9 percent stock market long-run annualized return, which itself is based on earnings growth of 12.1 percent and a dividend yield of 1.8 percent.

Q. DO YOU BELIEVE INVESTORS EXPECT LONG-RUN EARNINGS GROWTH OF 12.1 PERCENT FOR THE S&P 500?

A. No, Dr. Avera's 12.1 percent earnings growth rate and 13.9 percent return on stocks are completely unrealistic, as demonstrated by the Ibbotson and Chen study. The historical and forecasted growth in nominal GDP (the overall U.S. economy) is about 6 percent (or slightly less), and hence the 12.1 percent earnings growth rate is more than double the growth rate of the U.S. economy. Growth of 12.1 percent per year on a long-run basis simply is not sustainable. Hence, even if investors were expecting 12 percent earnings growth for a period of several years, it is likely that they would anticipate some slow down thereafter.

I have also consulted other sources of projections for stock market earnings, and they are considerably less than Dr. Avera's very optimistic 12.1 percent. The Zacks survey projects five years earnings growth for the S&P 500 of 6.0 percent, while First Call projects five-year growth of 10.5 percent. Value Line projects five-year earnings growth for its broad industry growth (the "Industrial Composite") of 7 percent. Averaging these three sources produces a stock market earnings growth rate of about 8 percent (and therefore a stock market return of about 10 percent), which is far more realistic than Dr. Avera's 12.1 percent.

Q. WHAT DO YOU CONCLUDE REGARDING THE CAPM?

A. The majority of the evidence supports an equity risk premium for the overall market of about 6 percent, not the unrealistically high 7.2 or 9.3 percent used by Dr. Avera. Had Dr. Avera used that risk premium value, he would have obtained a CAPM result in the 9.0 to 9.5 percent range, consistent with my study.

Q. DR. AVERA PRESENTED AN AUTHORIZED RETURNS RISK PREMIUM ANALYSIS. PLEASE DESCRIBE THAT ANALYSIS.

A. This method observes authorized electric utility ROEs going back to the 1970s and calculates the implied risk premium (relative to utility bonds) each year. He then estimates a regression model that relates this risk premium to the contemporaneous level of interest rates, finding an inverse relationship. Dr. Avera uses the model to obtain a 10.6 percent cost of equity for 2005, assuming a current utility bond yield is 5.8 percent. However, since FPL's cost of debt at this time is probably somewhat lower than 5.8 percent, the 10.6 percent is somewhat overstated.

Q. IS THIS A REASONABLE WAY TO ESTIMATE THE COST OF EQUITY?

A. No, it is not. The first problem is that these historical ROEs are not the same thing as the cost of equity and therefore the model does not measure a risk premium -- at least not very well. The problem is that the authorized ROEs include a number of factors in addition to the regulators' cost of equity estimate -- flotation adders, performance bonuses, rate case settlement results (which typically are based on numerous factors), adjustments to address financial need, etc. For all of these reasons the authorized ROEs can differ significantly from the regulators' estimates of the utility cost of equity. It is likely that the authorized ROEs (and therefore risk premiums) reported by Dr. Avera may take into account some of the same adjustment factors embodied in developing his 12.3 percent recommendation in this case.

The regression model estimated by Dr. Avera finds an inverse relationship with interest rates, i.e., the equity risk premium rises as the interest rate falls. However, this result, if anything, is an observation on the behavior of the regulatory process rather than the requirements of financial markets. It merely indicates -- for better or for worse -- that there is a certain amount of inertia or regulatory lag in the rate setting and ROE award process. Specifically, over the time period of Dr. Avera's data base, the 1970s to 2004, there was a general declining trend in interest rates. Regulators lowered utility ROEs in response, but with a lag and not in lock step. Hence, the model illustrates and measures regulatory behavior, not the requirements of financial markets. While I find Dr. Avera's analysis provides insight into regulation, it cannot be considered to be a particularly useful cost of equity estimation method.

Q. DOES THIS MODEL OVERSTATE FPL'S COST OF EQUITY?

A. Yes, it does for several reasons. First, Dr. Avera used a "current" 5.8 percent debt cost rate, which probably overstates FPL's current cost of debt. Second, the risk premium values themselves likely embody a great many factors that influence ROE awards <u>in addition to</u> the pure cost of equity. Since Dr. Avera later proposes his own adders (i.e., flotation, "financial exposure," performance bonuses), he may have introduced a double counting problem with this analysis.

V. RECOMMENDATION ON ROE

Q. WHAT IS YOUR RECOMMENDATION ON THE AUTHORIZED ROE?

A. In this case, I have obtained a midpoint DCF of 9.15 percent and a midpoint CAPM of 9.4 percent. Hence, the bare bones cost of equity results support an award in the 9.0 to 9.5 percent range. However, there are a number of other factors raised in this case that the Commission may wish to consider that would somewhat expand the range. These have been discussed in my testimony and that of the Company witnesses.

- Inclusion of an allowance for flotation expense.
- FPL's unusually strong and expensive capital structure, as well as its very strong credit rating and favorable risk attributes.
- Projections of increases in capital costs.
- The request for a performance bonus.

Depending on the Commission's evaluation of these issues, any return in the range of 9.0 to 10.0 percent could be considered reasonable. For revenue deficiency purposes in this rate case, I have selected the midpoint of this range, i.e., 9.5 percent. However, I am not making a specific recommendation on the appropriate magnitude (if any) of a performance bonus.

Q. HOW HAVE YOU DEVELOPED YOUR FLOTATION ALLOWANCE OF 0.1 PERCENT?

A. Dr. Avera recommends an adjustment of 0.3 percent which appears to be based on the assumption that flotation expenses are 5 to 10 percent of stock issuance proceeds. This adjustment will cost ratepayers about $30 million per year, and I believe this to be excessive. A more realistic expense ratio (which mostly is to cover underwriter fees) would be 3 percent. It appears that a 3 percent value was accepted by this Commission in the recent Gulf Power Company case, Docket No. 010949-EI (June 10, 2002). Using my proxy group dividend yield of 4.17 percent, the 3 percent figure would add 13 basis points, i.e., an increase to the ROE of about 0.1 percent.

The flotation allowance is also reasonable since FPL Group conducted a $575 million stock issuance this year. If the cost incurred is 3 percent of the proceeds, this would imply a total cost of flotation of about $17 million. However, a major public issuance of common stock does not occur every year. Only two such issuances have occurred since January 2001 (response to Interrogatory 1-1 of SFHHA), and thus a two- or three-year amortization of that flotation cost would be appropriate for ratemaking purposes. Assuming a two-year amortization (i.e., roughly $8 million per year) and an FPL Group equity balance of about $8 billion, an equity return flotation adjustment of 0.1 percent (i.e., $8 million/$8 billion) would provide appropriate cost recovery.

Q. ARE THERE ANY REASONS WHY THE FLOTATION ADJUSTMENT SHOULD NOT EXCEED 0.1 PERCENT?

A. Yes. It appears that the need to issue new common stock is to a large degree driven by the unregulated side of FPL Group. Data supplied to Staff indicates that the utility segment pays out to its parent far more than what FPL Group actually pays to its common stock holders, as shown below:

TABLE 3

Dividend Payments, 1999-2004
(millions $)

	FPL to Group	Group to Investors
1999	$ 586	$335
2000	667	366
2001	667	377
2002	NA	400
2003	1,127	425
2004	603	467

Source: Response to Staff, Set 1, items 60 and 61.

Q. MR. DEWHURST PROPOSES A 50 BASIS POINT PERFORMANCE BONUS IN THIS CASE. WHAT IS THE BASIS FOR THIS REQUEST?

A. Mr. Dewhurst presents data indicating that FPL has incurred lower O&M and gross plant costs per kWh of sales than has a benchmark group of electric utilities selected by the Company for study purposes. (See Document No. MPD-1.)

Q. DO YOU AGREE WITH HIS ANALYSIS?

A. Mr. Dewhurst attempts to demonstrate that FPL's cost control efforts have provided customers with savings and the achievement of the savings warrants a $50 million per year profit bonus to be paid by retail customers. Given the schedule in this case, I have not had the opportunity to conduct an analysis of the Company's performance claims, and therefore I am not specifically supporting or opposing his analysis.

I do, however, believe there is merit in examining the proposed $50 million bonus in its proper context. In addition to the O&M/gross plant cost savings identified by Mr. Dewhurst, it is useful to compare FPL's retail rates (which comprehensively measure the total cost of service) to those of the Peer Group companies selected for the Company's benchmark study. Schedule MIK-7, page 1, shows this comparison for FPL and each of the peer electric utilities, and page 2 shows the comparison for other major electric utilities in the Southeast (SERC) region of the U.S. Both comparisons indicate that FPL's residential retail rates are well above average.

Q. WHAT IS THE SIGNIFICANCE OF THE RATES COMPARISON?

A. The retail rates comparison, which is adverse to FPL, indicates that it is difficult to reach firm overall conclusions over cost control/management efficiency performance. This comparison may indicate that O&M/gross plant is too narrow of a measure, or it also is possible that FPL may be subject to certain cost pressures that are not as prevalent for the other electric utilities.

It seems incongruous to award a large performance bonus -- which would further increases retail rates -- when customers are already burdened by rates that are well above average. In any event, I would urge the Commission to take into account these rates comparisons along with Mr. Dewhurst's analysis when determining whether a performance bonus in this case is warranted. When considering the request for a large performance bonus for shareholders, I believe it is important to consider the impact this award will have on retail customers and whether an award provides an appropriate balance of interests.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

FPSC DOCKET NO. 050045-EI

IN RE: FLORIDA POWER & LIGHT COMPANY'S PETITION FOR APPROVAL OF INCREASE IN BASE RATES

DIRECT TESTIMONY OF SHEREE L. BROWN

INTRODUCTION

Q: PLEASE STATE YOUR NAME AND OCCUPATION.

A: My name is Sheree L. Brown and I am the President and Managing Principal of Utility Advisors' Network, Inc., located at 530 Mandalay Rd., Orlando, Florida 32809.

Q: PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

A: I received a B. A. in Accounting from the University of West Florida and a Masters in Business Administration from the University of Central Florida. I am a Certified Public Accountant in the State of Florida.

I have been providing utility consulting services to municipal, cooperative, county, and institutional utilities and industrial and commercial consumers since 1981. My work has primarily focused in the areas of regulatory affairs, revenue requirement and costs of service, rates and rate design, deregulation and stranded costs, valuation and acquisition, feasibility studies, and contract negotiations.

Q: HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION ("FPSC" OR THE "COMMISSION') AND OTHER UTILITY REGULATORY AUTHORITIES?

A: Yes. I have participated in several proceedings before the FPSC, most recently including the Progress Energy Florida ("PEF") storm surcharge case, Docket No. 041272-EI; the last Florida Power & Light Company ("FPL") general rate proceeding, Docket No. 001148-EI; the last PEF general rate proceeding, Docket No. 000824-EI; and in the 2003 Fuel Cost Recovery Proceedings, Docket No. 030001-EI, on issues relating to Tampa Electric Company's fuel costs. I have also testified before the Federal Energy Regulatory Commission ("FERC"), and the following state and local regulatory authorities: the Arkansas Public Service Commission, Council of the City of New Orleans, Illinois Commerce Commission, Louisiana Public Service Commission, Massachusetts Department of Telecommunications & Energy, Minnesota Public Utilities Commission, New Hampshire Public Utilities Commission, North Carolina Utilities Commission, and the Texas Public Utilities Commission. I have also presented arbitration reports and live testimony in the Circuit Court of the Ninth Judicial Circuit in and for Orange County, Florida, and in the Circuit Court of the Eighteenth Judicial Circuit in and for Seminole County, Florida in recent arbitrations regarding acquisition of electric distribution facilities from Progress Energy Florida.

My testimony has addressed a wide range of regulatory and utility-related issues, including revenue requirement issues, cost of service, cost allocation, rate design, terms and conditions of service, merger impacts, utility valuations, stranded costs, and deregulation. My resume and a listing of my testimony experience is included as Appendix A to my testimony.

Q: ON WHOSE BEHALF ARE YOU TESTIFYING?

A: I am testifying on behalf of the Florida Retail Federation ("FRF"). Members of FRF are large and small commercial users of electricity whose costs of providing goods and services to their own customers are directly impacted by increases in the costs of electricity. FRF has more than 10,000 members in Florida, many of whom take electric service from FPL.

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

A: The purpose of my testimony is to address FPL's requested increase in base rates.

SUMMARY

Q: PLEASE PROVIDE A SUMMARY OF YOUR TESTIMONY.

A: My testimony addresses FPL's proposed 2006 Test Year revenue requirement. Based on my analyses, FPL's request for a $430 million increase in retail base rate revenues should be reduced by at least $417 million, even before consideration of an appropriate rate of return on equity. The following is a bullet-list summary of the issues I will address herein.

- The Company has understated its customers for the Test Year, resulting in an understatement of $33.972 million in Test Year revenues at present rates.
- FPL has overstated its employees for the Test Year, resulting in an overstatement of $16.2 million in the base rate revenue requirement.
- The Company has included approximately $29.9 million in expenses related to a Long-Term Incentive Plan. This plan includes stock-based compensation. The portion of FPL's stock-based compensation that does not require actual cash outlay should be removed from the Test Year

revenue requirement. Based on FPL's historical stock-based compensation as reported for 2004, the Test Year revenue requirement should be reduced by approximately $17 million.

- FPL has included $104 million for costs associated with the GridFlorida Regional Transmission Organization ("RTO") in the Test Year revenue requirement. These costs are uncertain and speculative and should be disallowed. FPL has further inflated its speculative 2006 costs by an additional $45 million by assuming a 5-year average of RTO projected costs. In addition, FPL has not created a regulatory liability in rate base for revenues it would recover during the Test Year for costs that would not be incurred until later years. The revenue impact of eliminating this expense is $102.6 million to the retail jurisdiction.
- FPL has proposed a 50 basis point adder to its proposed "fair" return on equity as an incentive or reward. Under the current regulatory structure, this adder will not provide an added incentive for performance. FPL has not demonstrated the need to earn in excess of a fair return on equity in order to attract investor capital. The 50 basis point adder should be denied, thereby reducing the Test Year revenue requirement by $49.2 million.
- The Company has overstated bad debt expense. Elimination of this overstatement reduces the Test Year revenue requirement by $3 million.

- FPL has overestimated costs associated with an increase in postage rates. Based on a recent filing by the United States Postal Service, FPL has overstated its postage expense by $1.32 million.
- The Company has requested deferral of rate case expenses incurred in 2004 and 2005, with amortization over a two-year period at $4.475 million a year and inclusion of the unamortized balance in rate base. The Commission should not allow FPL to defer these expenses based on the level of rate case expenses included in FPL's last filing and the level of earnings FPL is currently achieving. Elimination of the rate case expenses reduces the Test Year revenue requirement by $5.001 million.
- FPL has requested an increase in its annual storm damage accrual from $20 million to $120 million. When taking into consideration the Commission's past decisions allowing FPL to seek cost recovery for negative storm reserve balances, the past actual storm damage history, and the added burden on ratepayers associated with the 2004 hurricane damages, the storm damage accruals should be maintained at the $20 million level to cover smaller storms. This would decrease the jurisdictional Test Year revenue requirement by $99.5 million. With enactment of Senate Bill 1322, commonly called the "Securitization Bill", the Company has another added layer of protection, further preventing the need for increasing annual accruals to the storm damage reserve.
- In adjusting the capital structure to remove the accumulated deferred income taxes associated with the storm damage fund, the Company has

allocated the removal on a prorata basis across all capital components. Properly eliminating the accumulated deferred income taxes from the accumulated deferred income tax capital component reduces the Test Year revenue requirement by $4.071 million.

- The Company did not adjust its accruals to the Last Core Nuclear Fuel reserve or the End-of-Life Materials and Supplies Inventory to reflect the extension of the license lives of the nuclear units. The Commission should suspend accruals to these reserves until FPL justifies the appropriate level and timing of further accruals. Suspending accruals for the Test Year reduces the jurisdictional revenue requirement by $5.263 million and $2.334 million for Last Core Nuclear Fuel and End-of-Life Materials and Supplies, respectively.
- The Company's request to recover $1.538 million in charitable contributions should be denied.
- The Company has included $522.6 million in rate base for Construction Work in Progress ("CWIP"). Based on interest coverage ratios, CWIP should be removed from rate base in accordance with past Commission decisions. The revenue impact of this adjustment is $69.585 million.
- FPL has understated its regulatory liability for nuclear maintenance reserves by charging the reserve for outage costs at the beginning of the accrual period, rather than at the time actual costs are incurred. Correction of this error reduces the jurisdictional Test Year revenue requirement by $7.2 million.

FPL'S PROPOSED INCREASE

Q: PLEASE DESCRIBE FPL'S PROPOSED INCREASE IN BASE RATES.

A: FPL is requesting a $430.198 million increase in base rates, effective January 1, 2006. The Company is then proposing to transfer $58.551 million in gross receipts taxes from base rates to an adder on customer bills. The Company is also requesting another $122.757 million annual increase in base rates, effective July 1, 2007, which is 30 days after the Turkey Point No. 5 generating unit is projected to be placed in service. FPL's request includes revenues sufficient to produce a 12.3% after-tax return on equity, including a 50 basis point "adder" as an incentive or reward. Other major components of FPL's base rate increase request include $104 million in costs that FPL claims are related to the formation and operation of an RTO, a requested $100 million increase in accruals to the storm damage reserve, and a claimed increase of approximately $211 million in non-fuel operating and maintenance expenses over actual 2004 experience, exclusive of the RTO and storm damage expenses.

Q: IS FPL'S REQUESTED BASE RATE INCREASE OF $430.198 MILLION REASONABLE?

A: No. FPL's increase includes numerous cost projections that are, at best, aggressive and over-reaching, significantly overstating justifiable revenue requirements. These projections include, but are not limited to, an understatement of customers, resulting in an understatement of revenues; the inclusion of RTO costs in the Test Year; the increase of $100 million in storm damage accruals; an increase in bad debt expense; continued accruals for Last Core Nuclear Fuel and

End of Life Materials and Supplies Inventory; the overstatement of employee headcount, resulting in overstated labor and benefits expenses; an overestimated increase in postage rates; the inclusion of charitable contributions; the requested return on equity reward mechanism; the inclusion of CWIP in rate base; and an understatement of the nuclear maintenance reserve regulatory liability.

Q: ARE FPL'S PROPOSED RATES AND ITS PROPOSED REVENUE REQUIREMENT FAIR, JUST AND REASONABLE?

A: No. Each of the cost projections and requested revenue items that I mentioned above would result in rates that are too high, and, therefore, unfair, unjust, and unreasonable. I will address each of these issues in my testimony.

CUSTOMER FORECAST

Q: PLEASE EXPLAIN YOUR CONCERNS WITH THE CUSTOMER FORECAST USED TO DERIVE THE TEST YEAR REVENUES.

A: FPL Witness Mr. Green prepared the Company's customer and load forecasts for 2006. He then adjusted the forecasts to reflect a significant reduction in customer growth for 2005, 2006, and 2007 on the assumption that the 2004 hurricanes would have a significant impact on the number of new customers. As shown on Exhibit LEG-2, page 1 of 1, FPL has experienced customer growth of over 2% for each year since 1999. The average annual customer growth on FPL's system was 2.38% from 1999 through 2004. Growth was increasing, with 2003 and 2004 growth rates of 2.4% and 2.6%, respectively. However, FPL assumed customer growth for 2005 and 2006 of only 1.7%. This is a lower percentage of growth than experienced over the past 11 years, including years following Hurricane

Andrew, which devastated South Florida, and the September 11, 2001 terrorist attacks.

Q: HOW MANY NEW CUSTOMERS WERE ADDED TO FPL'S SYSTEM IN 2003 AND 2004?

A: As shown on Exhibit__(LEG-2), FPL added 97,416 customers in 2003 and 107,289 in 2004.

Q: HOW MANY NEW CUSTOMERS IS FPL PROJECTING WILL BE ADDED IN 2005 THROUGH 2007?

A: Prior to making his hurricane adjustments, Mr. Green was projecting an annual increase of 80,000 new customers in 2005 and 82,000 new customers in 2006. After the hurricane adjustments, the projections were reduced to only 72,488 new customers in 2005 and 74,999 new customers in 2006. Mr. Green indicates that he is projecting a "return to a trend of 80,000 in 2007" and that "the impact of the 2004 hurricanes will be short-lived and customer growth will return to a more normal level in a couple of years as opposed to the impact of Hurricane Andrew which lasted six years." (Green Direct Testimony, pages 7 and 8)

Q: IS THE CUSTOMER GROWTH FORECAST REASONABLE IN LIGHT OF RECENT EXPERIENCE?

A: No. First, FPL has added over 80,000 new customers each year from 1999 through 2004. Even at the base forecast of 80,000 new customers for 2005, the growth rate would be 1.9%, while the average annual growth rate experienced from 1999 through 2004 has been 2.4%. Further decreasing the forecast of new customers to 72,448 reduces the growth rate to 1.7%. Mr. Green applied this lower growth rate to FPL average 2004 customers for both 2005 and 2006 to derive total average customers of 4,371,957 in 2006. Using the actual annual average growth rate from 1999 through 2004 would indicate a 2006 customer base of 4,429,718, or 57,761 additional customers than forecasted by FPL.

Q: HAS FPL'S ASSUMPTION BEEN REALIZED IN ACTUAL CUSTOMER GROWTH?

A: No. FPL's actual customer growth to date in 2005 has been significantly greater than that assumed by FPL. In response to OPC's Interrogatory No. 88, the Company provided the actual number of customers for each month from March, 2004 through February, 2005. The 12-month customer growth for each month through May, 2005 was provided in the response to FRF Interrogatory No. 20. From this data, the monthly customer growth for each month from January through May, 2005 can be developed. A review of historical customer growth, by month, from Table 32 of the statistics filed annually with the FPSC shows that average customer growth for January through May of the previous four-year period was 42,534. Actual customer growth for January through May of 2004 was 51,083. Actual customer growth for January through May of 2005 was 56,985—outstripping both 2004 growth and the average growth experienced over the previous four year period.

Q: HOW DOES THE ACTUAL GROWTH COMPARE TO FPL'S CUSTOMER FORECAST?

A: As shown in the response to FRF Interrogatory No. 20, the actual annual customer growth for the 12 months ending May, 2005 was 95,836. This is 23,388 greater than the 2005 growth projection of 72,448 as shown on Document No. LEG-2—even though the period ending May, 2005 includes the months immediately following the 2004 hurricanes in which customer growth was adversely impacted.

Q: HOW DOES THE ACTUAL NUMBER OF TOTAL CUSTOMERS IN THE FIRST QUARTER OF 2005 COMPARE TO THE FORECASTED NUMBER OF TOTAL CUSTOMERS IN THE FIRST QUARTER OF 2005?

A: MFR Schedule F-7 shows the total customers on an actual basis through December, 2004 and projected thereafter. As shown on Schedule F-7, FPL is projecting a decrease in customers from December, 2004 to January, 2005. At the end of the May, 2005, FPL projected total customers of 4,290,144 as compared to actual customers of approximately 4,313,996. FPL's projections of annual customer growth for the months ending January, February, March, April, and May, 2005 are understated by 20% to 25%. This is an unacceptable forecasting error.

Q: HAVE YOU CALCULATED THE IMPACT OF THE COMPANY'S UNDERSTATEMENT OF CUSTOMERS ON THE TEST YEAR REVENUES?

A: Yes. Exhibit__(SLB-1) provides calculations of the impact of the forecasting error on the Test Year revenues. Even *with* the impact of the hurricanes, FPL experienced 2.6% in average customer growth from 2003 to 2004. Given the actual reductions experienced in the fall of 2004 associated with the hurricanes, the actual 2.6% growth rate for the year implies an even higher growth rate, absent the storms. In 2003, customer growth was 2.4%. Further, as explained above, the average annual growth rate from 1999 through 2004 was 2.4%. To assure that the adverse impacts on customer growth that occurred during the last quarter of 2004 were recognized, I escalated the 2004 year-end customers by 2.4% for 2005 and 2006. The average of the year-end 2005 and 2006 customers is thus 4,411,489. This represents 39,532 more customers than FPL is assuming for the Test Year. FPL estimated present base revenues of $3,757,025,000 for the Test Year, with billing energy of 106,226,417 MWhs, resulting in an average rate of $0.03537 per kWh. As shown on Schedule F-6, FPL is assuming that a change in customers has a corresponding percentage change in net energy for load. Applying FPL's average use per customer to the revised customer base provides Test Year billing energy of 107,186,945 MWhs. Using the average rate per kWh produces Test Year revenues of $3,790,997,000, or an increase of $33.972 million over FPL's projected Test Year revenues. The revised Test Year revenue of $3.791 billion is only a 1.56% increase in retail revenues per year when compared to FPL's reported 2004 base revenues of $3.676 billion, as reported in its December, 2004 surveillance report. The Company's requested increase should be reduced by the $33.972 million in additional revenue that would be recovered under present rates.

Q: DOES FPL'S UNDERSTATEMENT OF CUSTOMER GROWTH AND SALES HAVE ANY IMPACT ON THE RATES THAT WILL BE DETERMINED AT THE CONCLUSION OF THIS CASE?

A: Yes. Aside from reducing the need for a base rate revenue increase, the final rates that result from whatever total revenue requirement is approved by the Commission should be calculated using the additional billing determinants, i.e.

the additional kWh sales and associated billing demands, over which the Test Year revenue requirement will be collected.

<u>Labor Expenses</u>

Q: WHAT IS THE LEVEL OF LABOR AND BENEFITS EXPENSES INCLUDED IN THE TEST YEAR REVENUE REQUIREMENT?

A: The Company's MFRs do not include a breakdown of labor and benefit expenses included in the Test Year revenue requirement. However, by "piecing together" data from numerous responses to interrogatories, it appears that the Test Year revenue requirement include $766.4 million in labor and benefit expenses. The derivation of the labor and benefit expenses included in the Test Year revenue requirement is as follows:

Table 1. Estimates of FPL Labor and Benefits Expense, 2006

Payroll Item		($000)
Gross Payroll (MFR Schedule C-35)	$	808,940
Fringe Benefits (MFR Schedule C-35)		154,241
Long-term Incentive Payments (OPC 43)[a]		29,717
Less:		
Gross Payroll Capitalized (OPC 50)		(194,196)
Payroll Taxes Capitalized (OPC 116)		(11,904)
Other Benefits Capitalized (OPC 247) [b]		(20,402)
Payroll and Benefits included in the Test Year Revenue Requirement	$	766,396

[a] Per OPC 49, Long-term Incentive Payments are included in MFR C-1, but not in C-35.

[b] Per OPC 247, $20,402,000 was credited to O&M expense for capitalized benefits. OPC 247 does not state whether this amount includes the $11.9 million capitalized payroll taxes.

In addition to the above amounts, the Test Year revenue requirement includes labor and benefit expenses billed to the Company from its affiliates. It appears that additional deferred compensation is also included in the Test Year revenue requirement.

Q: DO YOU HAVE ANY CONCERNS WITH RESPECT TO FPL'S TEST YEAR REVENUE REQUIREMENT ASSOCIATED WITH LABOR AND BENEFITS?

A: Yes. FPL has overestimated the number of employees for the Test Year, and, therefore, has overstated the Test Year labor and benefit expenses.

Q: PLEASE EXPLAIN HOW THE COMPANY HAS OVERSTATED THE NUMBER OF EMPLOYEES PROJECTED FOR THE TEST YEAR.

A: As shown on MFR Schedule C-35, the Company has estimated that there will be an average of 10,558 employees during the Test Year. In the Company's response to OPC Interrogatory No. 256, FPL explained that the 10,558 positions in the Test Year included part-time positions as 1 position, whereas part-time positions in previous years were counted as one-half of a position. Further, the 2006 projected headcount is a greater percentage of projected year-end positions than would be expected based on actual company experience.

Q: WHAT IS THE COMPANY'S ACTUAL EXPERIENCE?

A: As shown in FPL's response to OPC's Interrogatory No. 44, the Company's actual average annual employee headcount has been approximately 97% of its year-end budget projections.

Q: WHAT WAS THE COMPANY'S TEST YEAR END BUDGET PROJECTION FOR EMPLOYEE HEADCOUNT?

A: As shown on the response to OPC Interrogatory No. 44, the Company projected 10,628 employees for the end of the Test Year.

Q: BASED ON THE YEAR-END BUDGET PROJECTION, WHAT LEVEL OF EMPLOYEES SHOULD BE EXPECTED DURING THE TEST YEAR?

A: Applying the historical average actual headcount percentage of 97% to the year-end budget of 10,628 employees gives an expected employee count of 10,335 for the Test Year.

Q: HAVE YOU ADJUSTED THE TEST YEAR PAYROLL AND BENEFITS EXPENSES TO REFLECT THIS REVISED HEADCOUNT?

A: Yes. Exhibit__(SLB-2) provides a breakdown of the adjustment to FPL's Test Year payroll and benefits expenses. The payroll and benefits expenses were adjusted to reflect a reduction in the estimated headcount from 10,558 employees to 10,335 employees. Based on information obtained in FPL's responses to OPC Interrogatories 50, 116, and 247, FPL is capitalizing approximately 23.5% of its payroll costs in the Test Year. A 76.5% expense ratio was thus applied to the total revised payroll and benefits expense to derive the amount of expense to include in the Test Year total system revenue requirement. The adjustment reduces Test Year payroll and benefits expenses (exclusive of Long-term Incentive Payments) from $736.729 million to $720.059 million, or $16.670 million.

Q: WHAT IS THE IMPACT OF THIS ADJUSTMENT ON THE RETAIL JURISDICTIONAL REVENUE REQUIREMENT?

A: In the response to OPC Interrogatory 116, the Company claimed that it does not know in which accounts the labor and benefit costs were included; therefore, to date, the information has not been provided to accurately determine the jurisdictional impact of the labor and benefit adjustment. However, in its response to OPC's Interrogatory No. 116, the Company based its jurisdictional allocation on the Company's retail administrative and general allocator of 99.5437%. Using this allocation factor, the impact of the combined adjustment on the retail jurisdiction is a reduction of $16.594 million in revenue requirement. Further adjusting this to remove amounts that will be recovered through pass-through clauses, results in an adjustment to the retail jurisdiction Test Year base rate revenue requirement of $16.2 million.

Q: DO YOU HAVE OTHER CONCERNS WITH THE COMPANY'S TEST YEAR LABOR COSTS?

A: Yes. As shown above, the Company has included approximately $29.9 million in the Test Year revenue requirement associated with the Long-Term Incentive Plan. This plan is a stock-based compensation plan. Under the plan, the Company has 13 million shares authorized. Under new rules established by the Financial Accounting Standards Board in Statement of Financial Accounting Standard No. 123-Revised (December, 2004), the fair value of share-based payments is recognized for financial statement reporting purposes. Stock-based compensation is treated as an expense based on the market value of the stock at the date of the grant. A corresponding entry is then made to equity. This treatment essentially treats the transactions as two steps: the award of compensation to the employee-shareholders, then the return of the cash in the form of equity payments. While this program is true compensation to the employee-shareholders, the actual cost of such compensation to the Company is questionable. If the Company issues additional stock and values it at market value, the ratepayers are being charged for the market value, while the Company avoids an actual cash expense.

Q: DO YOU HAVE SUFFICIENT INFORMATION TO QUANTIFY THE ACTUAL AMOUNT OF TEST YEAR LONG-TERM INCENTIVE PAYMENTS ASSOCIATED WITH STOCK-BASED COMPENSATION?

A: No. In its response to OPC's Interrogatory No. 43, the Company provided a breakdown of its Long-term Incentive Plan into "stock options" and "other long-term" incentives. The actual out-of-pocket costs associated with these incentives may include cash payments made to allow executives to pay taxes on the stock compensation and potential purchases of treasury stock to include in the program. However, as shown in FPL's response to OPC's Interrogatory No. 43, the stock options and other long-term incentives budgeted for 2004 were approximately $29 million, while the amount of stock-based compensation actually distributed for these programs in 2004 was $16.8 million. In FPL's 2004 FERC Form 1, the stock-based employee compensation expense reported in the notes to the financial statements for the "total stock-based employee compensation expense determined under fair value based method, net of related income tax effects" was $17 million. The amount of stock-based employee compensation expense under the fair value based method for 2003 and 2002 was $19 million and $21 million, respectively. The Commission should require FPL to demonstrate the actual out-of-pocket costs of the Long-Term Incentive Plan before allowing the recovery of any such costs in retail rates. However, absent such demonstration, it would be reasonable to reduce the Test Year revenue requirement by $17 million to reflect the potential value of share-based compensation included in the Test Year Long-Term Incentive Plan expenses of $29.9 million which were included in Schedule C-1.

REGIONAL TRANSMISSION ORGANIZATION

Q: HAS THE COMPANY INCLUDED COSTS ASSOCIATED WITH THE ESTABLISHMENT AND OPERATION OF A REGIONAL TRANSMISSION ORGANIZATION IN THE TEST YEAR REVENUE REQUIREMENT?

A: Yes. The Company has included $104 million ($102.6 million retail jurisdiction) in the Test Year revenue requirement for recovery of costs associated with the proposed GridFlorida RTO.

Q: HOW DID THE COMPANY DETERMINE THE RTO COSTS THAT IT INCLUDED IN ITS TEST YEAR REVENUE REQUIREMENT?

A: As explained by FPL's witness, Mr. Mennes, the RTO costs included in the Test Year include start-up costs, operating costs, and cost-shifting. The start-up and operating costs were developed from estimates provided by the Accenture Group in Docket No. 020233-EI on March 20, 2002. These costs were then escalated using cost information from other RTOs. The cost-shifting estimates were developed from data provided by the "GridFlorida pricing workgroup". (Mennes Direct Testimony, page 22)

Q: WHAT IS THE CURRENT STATUS OF THE GRIDFLORIDA RTO?

A: While the FERC approved GridFlorida as the RTO for peninsular Florida, the FPSC determined that the RTO, as established by FERC, was not in the best interest of Florida customers and required revisions to the proposed structure. The Commission held a series of workshops to address GridFlorida issues.

Ultimately, a study was commissioned to determine the costs and benefits of the proposed GridFlorida RTO. Preliminary results from that study, which was performed by ICF Consulting, were presented to the Commission on May 23, 2005. As shown in that study, the costs of the RTO were estimated at $1.253 billion, while the benefits were expected to reach only $968 million. The estimated costs thus exceed the benefits by $285 million. Thus, at this time, the status of the GridFlorida RTO is uncertain.

Q: DOES GRIDFLORIDA HAVE TARIFFS IN EFFECT?

A: No.

Q: HAS THE GRIDFLORIDA RTO BEEN IMPLEMENTED?

A: No. In fact, as I understand it, the implementation date for the RTO, if it is ever implemented at all, is unknown.

Q: TO THE BEST OF YOUR KNOWLEDGE, WHAT IS THE STATUS OF THE GRIDFLORIDA RTO AT THIS TIME?

A: At this time, the GridFlorida RTO is not operational and its future status is uncertain.

Q: IS IT REASONABLE TO INCLUDE $104 MILLION OF RTO COSTS IN THE TEST YEAR REVENUE REQUIREMENT?

A: No. First, given the uncertainty of the RTO, which is compounded by the tentative finding that costs are anticipated to exceed benefits, including the GridFlorida costs in the Test Year revenue requirement is speculative, at best. FPL has not demonstrated that it will, in fact, incur any of the projected RTO costs at all. Further, any benefits that may be derived from the RTO would not be realized until actual implementation and, therefore, the timing of cost recovery from ratepayers should coincide with the ratepayers' receipt of any associated benefits. In addition, without final approval of the RTO structure and timing, the costs and benefits may change substantially from those projected by the Company based on a study performed in 2002.

Q: WHAT IS YOUR SPECIFIC RECOMMENDATION WITH REGARD TO FPL'S CLAIMED COSTS ASSOCIATED WITH THE GRIDFLORIDA RTO?

A: The Commission should disallow all such costs from FPL's authorized revenue requirement in this case. FPL will, of course, have the option of petitioning for rate relief to recover costs it actually incurs.

Q: DO YOU HAVE ANY OTHER BASES AND INFORMATION THAT SUPPORT YOUR RECOMMENDATION?

A: Yes. PEF, another of the GridFlorida RTO applicants, recently filed a petition asking the Commission for an increase in rates to take effect on January 1, 2006, just as FPL has requested. PEF, however, did not include any RTO costs in its proposed revenue requirement for its 2006 Test Year. As stated in PEF's petition in FPSC Docket 050078-EI at page 10:

> By this Petition, PEF has not requested the recovery of any post commercial in service costs resulting from its participation in the GridFlorida regional transmission organization...The timing and nature of GridFlorida has not enabled PEF to determine when and the extent to which contributions will be required and, therefore, Company has not included any such costs in its MFRs. The Company reserves the right to

seek recovery of such costs at a later time and in any manner appropriate for recovery, including this proceeding if necessary, when the Company is better able to identify and quantify the costs.

Q: IF THE COMMISSION WERE TO DISAGREE WITH YOU AND DETERMINE THAT FPL'S RATES SHOULD INCLUDE SOME ESTIMATED RTO COSTS, IS THE COMPANY'S $104 MILLION ESTIMATE AN APPROPRIATE TEST YEAR EXPENSE?

A: No. While I believe all of the RTO costs should be excluded from the Test Year revenue requirement for the reasons previously stated, I am also concerned with FPL's proposal to increase the Test Year revenue requirement to reflect a 5-year average cost estimate. FPL's claimed RTO costs are not representative of its 2006 Test Year costs, even as represented by FPL, and are, therefore, inappropriately included in the Test Year revenue requirement. This tactic increased FPL's Test Year RTO cost estimate from $59 million to $104 million. Extending the estimates out to 2010 further increases the speculative nature of the RTO costs.

Q: DOES THE COMMISSION NORMALLY ESTIMATE REVENUE REQUIREMENTS BASED ON COST PROJECTIONS OVER A 5-YEAR PERIOD?

A: No. Normal expenses are typically projected for the single Test Year. While the Commission may amortize certain expenses over the time period in which benefits are received, the GridFlorida expenses are not subject to such amortization because they are annual expenses, similar to other transmission or distribution expenses. It is thus inappropriate to isolate this one expense to capture future cost increases without considering a host of other changes to FPL's costs of providing service over the same period of time. Therefore, even if the Commission were to allow some GridFlorida costs to be included in base rates in 2006, only the Company's actual documented, incremental 2006 expenses should be included. At a minimum, FPL's $45 million "adder" should be denied.

Q: DO YOU HAVE ANY OTHER CONCERNS WITH FPL'S INCLUSION OF RTO COSTS IN THE TEST YEAR?

A: Yes. In addition to including the overstated, speculative expenses in the Test Year revenue requirement, the Company's proposed averaging would result in a prepayment from ratepayers, yet the Company has not included a regulatory liability as an offset to rate base for the amount of the prepayment.

Q: WHAT IS THE IMPACT ON THE TEST YEAR REVENUE REQUIREMENT ASSOCIATED WITH ESTABLISHING A REGULATORY LIABILITY FOR THE RTO COSTS?

A: Assuming that FPL actually incurred $59 million of costs in the Test Year, the regulatory liability would be $22.5 million on an average Test Year basis. Including the impact of the regulatory liability and the associated deferred income taxes, the revenue requirement would be reduced by $1.84 million.

RATE OF RETURN ADDER

Q: PLEASE DESCRIBE THE COMPANY'S REQUEST FOR A RATE OF RETURN ADDER AND QUANTIFY THE IMPACT OF THE ADDER.

A: The Company has requested a 50 basis point adder to its proposed rate of return on equity as a supposed performance incentive. This adder increases the Test Year revenue requirement by $49.2 million, or 11.4% of the total requested increase in base rates.

Q: WHAT IS THE COMPANY'S JUSTIFICATION FOR THIS ADDER?

A: FPL's witness, Mr. Dewhurst, explained that "the purpose of the incentive is to recognize FPL's past superior performance and to encourage continued strong operational performance over the long-term." (Dewhurst Direct Testimony, page 20, lines 5-7) Mr. Dewhurst further noted, at page 25 of his testimony, that "a performance incentive should be large enough to motivate FPL's continued performance improvement over the long-term."

Q: WHAT IS FPL'S PROPOSAL?

A: As explained by FPL's witness, Mr. Dewhurst:

> I have reviewed the analysis performed by Dr. Avera and concur with his recommended fair rate of return on equity of 11.8%. In addition, we request that the Commission approve a performance incentive of 50 basis points to recognize the Company's superior performance and to provide an incentive for future superior performance. (Dewhurst Direct Testimony, page 11)

Q: IS THE RATE OF RETURN ADDER A REASONABLE COST OF PROVIDING SERVICE?

A: No. As noted by FPL in its Petition:

> ....FPL is obligated by statute to provide such service in a reasonable, "sufficient, adequate, and efficient" manner. Section 366.03, F.S., 2004. In return, FPL's shareholders must be provided the opportunity to earn a reasonable and adequate return on their investment. (Petition, page 6)

As explained by Mr. Avera at page 3 of his Direct Testimony:

> Investors commit capital only if they expect to earn a return on their investment commensurate with returns available from alternative investments with comparable risks.

FPL has not shown how the rate of return adder will provide an incentive for better future performance or why investors need a return greater than the "fair" return in order to invest their capital in FPL.

Regulated utilities operating in a monopolistic market have an obligation to serve their customers at the lowest possible costs. However, unlike entities operating in a competitive environment, regulated utilities are insulated from a large portion of the normal operating risks faced by unregulated entities. The customer base is not at risk due to poor performance and the recovery of a large percentage of operating costs is essentially guaranteed through cost recovery clauses (subject to prudency review) or through tax adders to customer bills.[1] Further, in exchange for the obligation to serve, the regulated utilities are provided with an opportunity to earn a fair return on their investments in assets used to serve customers.

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[1] In FPL's case, without any consideration of FPL's requested Storm Restoration Surcharge in Docket No. 041291-EI, over 64.1% of its operating expenses is recovered through recovery clauses on a pass-through basis or specific tax adders to customer bills. These pass-through costs made up over 64.1% of FPL's operating expenses and 57% of FPL's total revenue in 2004. (December, 2004 Surveillance Report)

The discounted cash flow and risk premium analyses used by Mr. Avera and other cost of capital witnesses are used to determine a "fair rate of return." These methodologies already reflect the relative risk of the Company and the markets in which it is operating. The Company's proposal for a rate of return adder provides additional "upside" for the Company, while still providing the protections inherent in regulation. This adder is not a reasonable cost of providing service, is not necessary to attract capital, and does not provide any additional incentives for improved performance. In fact, Mr. Dewhurst noted that Dr. Avera's recommended rate of return on equity, before the performance reward adder, would:

> ...fairly account for the exposures that investors attribute to FPL, while ensuring the Company's ability to attract capital even under adverse circumstances... (Dewhurst Direct Testimony at page 19)

FPL's proposed adder would, therefore, be a windfall to shareholders at customer expense.

Q: WHAT INCENTIVES DO REGULATED UTILITIES HAVE UNDER CURRENT REGULATED RATEMAKING TREATMENT?

A: Utilities, like any other business, seek to maximize profits. Profits can be maximized by increasing revenues or reducing costs. For utilities, however, revenues are generally not controllable, so utilities focus on cost reductions as a means to maximize profit. Under current regulated ratemaking treatment, there are essentially three components to the development of rates. These three components include costs that are passed-through directly to consumers through adjustment clauses, costs that are included in the development of rates with no markup to the utility, and the fair return on assets invested to serve customers. I will address each of these components.

First, in Florida, a significant portion of a utility's costs is recovered through cost recovery clauses, which essentially guarantee the Company recovery of prudently incurred costs. For FPL, 52.3% of its jurisdictional revenue in 2004 was recovered through cost recovery clauses and another 5.1% was recovered through direct tax adders to customer bills. Therefore, 57.4% of FPL's revenues were received through cost recovery clauses and adders. Excluding FPL's return on rate base, approximately 64.1% of its total operating expenses were collected through cost recovery clauses and rate adders. This does not provide incentives for the utility to reduce costs, but does protect against volatility of expenses, thereby reducing risks of losses to shareholders.

The remaining expenses are included on a dollar-for-dollar basis in the development of base rates using a proforma Test Year. Once those rates are established, the utility's profitability is dependent upon the actual costs incurred (which is controllable by the utility) and the level of revenues received (which is not controllable by the utility). This portion of the ratemaking process thus gives the utility two incentives: the first is to overestimate expenses and underestimate sales and revenues when seeking a change in base rates, and the second is to reduce expenses between rate proceedings in order to maximize profits.

The last component of the utility's rate structure is the return on rate base. Since rates are set to include a fair return on the utility's investment in assets used to serve customers, the incentive is to maximize investment and to persuade the regulatory authority to set its "fair return" as high as possible.

After the rates are set, the utility will attempt to maximize its profits by reducing its costs. Although it cannot control sales, the utility will also reap the benefit of higher sales if its rates are set based on an unrealistically low sales estimate.

Q: HOW WOULD A RATE OF RETURN ADDER CHANGE THE COMPANY'S INCENTIVES?

A: Since actual returns are not based on the rate of return set in a rate proceeding, an "incentive" rate of return adder would not change the Company's incentives. Once rates are set, the Company will still have the incentive to maximize returns by reducing expenses between rate cases. The adder is thus not really an incentive to promote future performance, but is rather a requested reward for what FPL claims is superior past performance.

Q: ARE RATEPAYERS PAYING FOR OTHER PERFORMANCE INCENTIVES?

A: Yes. The Company is providing substantial performance incentives to employees, many of whom are employee-shareholders, through its short-term and long-term incentive pay programs. The cost of these programs is estimated to be $73 million for the Test Year, as shown in FPL's response to OPC's Interrogatory No. 43. In 2004, the performance-based pay was $52.8 million, as shown in FPL's response to OPC's Interrogatory No. 255. Even with this level of performance-based compensation, the Company still earned a 12.68% rate of return on equity on an FPSC adjusted basis (12.81% when adjusted for weather normalization due to the hurricanes).

Q: SHOULD THE COMMISSION APPROVE FPL'S PROPOSED ROE ADDER OR SOME OTHER ADDER AT A LOWER LEVEL?

A: No. As demonstrated above, any adder as proposed by FPL, whether at 50 basis points or any level greater than zero, is not a legitimate or reasonable cost of providing service and is not an appropriate or meaningful incentive for future performance.

Q: WHAT IS THE IMPACT OF ELIMINATING THE 50 BASIS POINT ADDER TO FPL'S REQUESTED RETURN ON EQUITY?

A: Eliminating the 50 basis point adder reduces FPL's requested rate of return from 8.22% to 7.975%. This adjustment reduces the Test Year revenue requirement by $49.2 million[2].

Q: SHOULD THE COMMISSION CONSTRUE YOUR TESTIMONY AS SUPPORTING OR AGREEING THAT FPL'S PROPOSED ROE OF 11.8% IS REASONABLE?

A: No. While I am not specifically opining on a recommended ROE for FPL, I believe the Commission should recognize that there are several significant factors that mitigate risks when evaluating an appropriate ROE for FPL. For example, the Commission should recognize a) the fact that more than 64% of FPL's operating expenses and 57% of its revenue are recovered through pass-through clauses and tax adders, b) FPL operates in a regulated environment and there is no threat of retail deregulation in the foreseeable future, c) that FPL has also

[2] Rate Base of $12,410,522 x (.0822-.07975) x 1.61971.

modified its capital structure to mitigate the risks of adverse rating agency actions, and d) that FPL enjoys high rates of customer growth and associated growth in sales, with less exposure to industrial load than its counterparts.

Q: DOES FPL'S PRIOR RATE HISTORY SUPPORT ITS REQUEST FOR A BASE RATE INCREASE IN THIS CASE?

A: No. While FPL makes a point of the fact that it has not raised its base rates since 1985 and has actually provided base rate reductions, this fact has nothing to do with the establishment of rates in this proceeding. Ratemaking is prospective and should be based on what FPL's legitimate, reasonable, and prudent costs will be for the Test Year. In addition, even with the earlier rate reductions, FPL's rates have been more than sufficient to provide it with generous profits. In fact, over the last four years, FPL has earned after-tax returns of between 12.21% and 13.58%.

BAD DEBT EXPENSE

Q: WHAT IS THE LEVEL OF BAD DEBT EXPENSE THE COMPANY IS CLAIMING FOR THE TEST YEAR?

A: The Company is using a bad debt factor of 0.168% for the Test Year. When applied to the Test Year revenues at current rates of $8,722,657,950, the Test Year write-offs are $14,691,374.

Q: IS THIS AN APPROPRIATE, FAIR, AND REASONABLE VALUE TO BE USED IN SETTING RATES IN THIS CASE?

A: No. It is inconsistent with FPL's historical bad debt experience and FPL has not justified its claims.

Q: HOW DOES THE TEST YEAR BAD DEBT FACTOR COMPARE TO THE COMPANY'S PREVIOUS WRITE-OFF HISTORY?

A: The Test Year bad debt factor is higher than the level of bad debt incurred during any of the last four years. As shown on Schedule C-11, the bad debt factor ranged from 0.128% to 0.144% from 2001 through 2003 and rose to 0.158% in 2004, the year in which the Company's customers experienced the impact of the hurricanes.

Q: HAS THE COMPANY JUSTIFIED THIS INCREASE IN WRITE-OFFS FOR THE TEST YEAR?

A: No. The Company's witness, Ms. Santos, commented on the increase in the bad debt factor experienced in 2004, asserting that the change between 2003 and 2004 was attributable to the increase in fuel charges. She indicated that "all other things being equal", higher bills produce an added difficulty in bill payment. She did not directly address the increase in bad debt expense for the Test Year.

Q: DOES THE INCREASE IN FUEL CLAUSE REVENUES JUSTIFY THE INCREASE IN BAD DEBT EXPENSE FOR THE TEST YEAR?

A: No. A review of FPL's bad debt history shows that the bad debt factor does not always vary based on revenues. Exhibit__(SLB-3) provides a calculation of the revenues per customer for each year shown on Schedule C-11. As shown on Exhibit__(SLB-3), the bad debt factor rose in 2002, although revenues per customer decreased. Then, in 2003, the bad debt factor decreased, although revenues per customer increased. The level of revenues, then is not the only factor impacting the level of bad debt expense incurred by the Company.

Q: HAS THE COMPANY PROVIDED ANY OTHER JUSTIFICATION FOR THE INCREASE IN BAD DEBT EXPENSE PROJECTED FOR THE TEST YEAR?

A: No. In fact, Ms. Santos' testimony discusses the Company's improvements in billing and revenue recovery operations which would lead to an expectation of decreases in bad debt expenses, rather than the projected increase. For example, the Company has initiated numerous billing options to make it easier for customers to make payments, including credit card payments, automatic bank withdrawals, budget billing, and the FPL 62 Plus Payment Plan. Ms. Santos also notes that FPL has assisted customers experiencing financial difficulty by working with social service agencies and explains that, in 2004, assistance payments were received representing approximately $11.7 million towards customers' bills.

Q: WHAT IS AN APPROPRIATE LEVEL OF BAD DEBT EXPENSE TO INCLUDE IN THE TEST YEAR REVENUE REQUIREMENT?

A: Due to the uncertainties associated with the hurricanes in 2004, the bad debt expense factor should be based on the history from 2001 through 2003. Based on that experience, the bad debt factor would be 0.135%. The use of this factor reduces the Test Year write-offs from $14,691,374 to $11,775,588, reducing the Test Year revenue requirement by $2,915,786.

Q: DOES THE REDUCTION IN THE BAD DEBT FACTOR IMPACT ANY OTHER COMPONENTS OF FPL'S REVENUE REQUIREMENT?

A: Yes. The bad debt factor is included in the development of the revenue expansion factor. The revised bad debt factor results in a reduction in the revenue expansion factor from 1.61971 to 1.61917. When applied to the Company's claimed net operating income deficiency, the revenue increase is reduced by an additional $120,133. The total impact of this adjustment is thus $3,035,919.

POSTAGE INCREASE

Q: MS. SANTOS ALSO SUPPORTS AN INCREASE OF $2.2 MILLION IN BILLING EXPENSES ASSOCIATED WITH A PROJECTED POSTAGE INCREASE. IS THIS INCREASE JUSTIFIED?

A: No. Ms. Santos explains that her $2.2 million increase in billing expenses is based on a projected increase in postage of $.04 per piece. However, this increase in postage rates is overstated by over 100%. On April 8, 2005, the United States Postal Service ("USPS") filed its requested increase in postage rates in Postal Rate Commission Docket R2005-1. A review of the USPS requested increase reveals that a first class stamp is increasing from $.37 to $.39, for an increase of only $.02.

Q: IS FPL USING FIRST CLASS POSTAGE?

A: No. Ms. Santos explains that the Company has achieved cost savings on mailings by implementing systems and processes that "allow FPL to receive the greatest USPS discounts for bulk mails, zip code optimization and reduction in return mail. (Santos Direct Testimony, page 30) In its response to FRF's Interrogatory No. 51, FPL indicated that it was paying for bulk-metered postage at rates ranging from $0.275 to $0.309 for Automation Carrier Route, Automation 5-Digit, Automation 3-Digit, Automation AADC, and Automation MAADC mail.

Q: WHAT IS THE USPS REQUESTED INCREASE FOR THESE SERVICES?

A: Based on the rate and fee schedules filed in Postal Service Commission Docket R2005-1, the increase for these services is as follows:

Automation Carrier Route	$.015
Automation 5-Digit	$.015
Automation 3-Digit	$.016
Automation AADC	$.016
Automation MAADC	$.017

Q: WHAT IS THE APPROPRIATE LEVEL OF INCREASE IN POSTAGE EXPENSES TO INCLUDE IN THE TEST YEAR REVENUE REQUIREMENT?

A: At a minimum, the postage increase of $2.2 million claimed by the Company should be reduced to reflect an increase of only $.016 per piece, as opposed to $.04 per piece. The appropriate increase for postage expense is thus $880,000 million, resulting in a reduction in jurisdictional Test Year revenue requirement of $1.32 million.

RATE CASE EXPENSES

Q: WHAT IS THE TOTAL REVENUE REQUIREMENT INCLUDED IN THE TEST YEAR FOR RATE CASE EXPENSES?

A: The Company has estimated total rate case expenses of $8.4 million which it claims it will incur over the 2004-2005 time frame, with an additional $550,000 that it claims it will incur in 2006. The Company is proposing to defer these costs to the Test Year and amortize the costs over a 2-year period. The Test Year expenses thus include $4.475 million in rate case expenses. In addition, the

Company is proposing to include the Test Year average deferred expenses of $6.438 million in rate base.

Q: SHOULD THE COMPANY BE ALLOWED TO DEFER AND AMORTIZE THE RATE CASE EXPENSES IN THE TEST YEAR?

A: No. While the Commission has allowed utilities to defer rate case expenses in the past, FPL is already recovering its rate case expenses and its request for deferral and amortization of the rate case expenses should be denied. In FPSC Docket 001148-EI, the Company estimated total rate case expenses of $10.848 million and amortized the expenses over a 2-year period, resulting in an annual expense of $5.4 million. Actual rate case expenses associated with that Docket were only $4.5 million. Thus, any level of rate case expenses included in the development of present rates has been recovered over 44 months, rather than 24 months over which those costs were spread. By the end of 2005, this will have resulted in a fairly significant over-recovery of rate case expenses over the past 3 ½ years. I am not suggesting that FPL be required to refund any amount of over-recovery, but rather, I am making the obvious point that FPL is recovering rate case expenses during the period in which it is actually incurring rate case expenses in this docket and, accordingly, FPL's request to defer such costs should be denied. Further, review of the Company's surveillance report for the year ending December 31, 2004 shows that the Company has an earned return of 12.68% on equity on an FPSC adjusted basis. This is in excess of even the 12.3% return on equity requested by the Company in the current case. Even if the full rate case expense of $8.95 million ($5.50 million net of tax) is subtracted from the actual net operating income shown on the December 31, 2004 surveillance report, FPL's earnings would still be 12.71%, which is well in excess of the 11.83% return on equity FPL included in its MFRs in Docket 001148-EI and the 12.3% return on equity requested in this proceeding.

FPL cannot reasonably claim to be entitled to defer these costs for future recovery in order to have had a fair return for 2004 and 2005, accordingly, there is no legitimate basis for the requested deferral.

In determining whether to allow FPL to defer costs for future recovery in this proceeding, the Commission should take into consideration the level of earnings FPL is already enjoying, in conjunction with the extremely high level of rate increases that would be imposed on ratepayers in this proceeding if FPL's positions are adopted. Taking these factors into consideration, the Commission should deny FPL's request to defer the rate case expenses for recovery in the Test Year. As shown on Exhibit__(SLB-4), elimination of rate case expenses and the associated rate base and cost of capital components would reduce Test Year revenue requirement by $5.001 million.

Q: IF THE COMMISSION CHOOSES TO ALLOW DEFERRAL OF FPL'S RATE CASE EXPENSES BASED ON PAST COMMISSION POLICY, SHOULD THE COMMISSION MAKE ANY ADJUSTMENTS TO FPL'S RATE CASE EXPENSE PROPOSAL?

A: Yes. First, while the Commission has allowed deferral of rate case expenses for recovery during the time period in which the rates would be in effect, the amortization period allowed has not been limited to two years. In PSC Order No.

22224, the Commission approved a 5-year amortization period for FPUC-Fernandina Beach since it had been 15 years since its last rate case. In other dockets, longer amortization periods were used as well. FPL's last rate case was Docket No. 001148-EI, which was filed in 2001; however, that case was filed on the request of the Commission and did not include a request for a change in FPL's rates. FPL's last rate case in which it requested a change in rates was Docket No. 830465-EI, which was filed on November 23, 1983. Therefore, at a minimum, the Commission should require FPL to amortize the rate case expenses over a 4-year period.

Further, if FPL does not seek a base rate change at the end of the amortization period allowed in this proceeding, it should be required to continue accruing the annual rate case expense accrual, thereby creating a regulatory liability to be used against rate case expenses in the next proceeding.

Q: HAVE YOU CALCULATED THE IMPACT OF USING A 4-YEAR AMORTIZATION PERIOD?

A: Yes. Revising the amortization period from two years to four years results in a reduction in the Test Year revenue requirement of $2.146 million as shown on Exhibit__(SLB-4), including the impacts of modifying the Company's proposed regulatory asset for the smaller Test Year expense.

Q: DO YOU HAVE ANY OTHER CONCERNS WITH RESPECT TO FPL'S RATE CASE EXPENSE REQUEST IN THIS PROCEEDING?

A: Yes. The Company has requested inclusion of the unamortized rate case expenses in rate base as a component of working capital. In PSC Order No. 23573, the

Commission explained that "Commission policy is to exclude unamortized rate case expense from working capital." Removal of the unamortized rate case expense from working capital reduces the Test Year revenue requirement by $526,500.

Q: PLEASE SUMMARIZE YOUR RECOMMENDATIONS ON RATE CASE EXPENSES.

A: Due to the over-recovery of prior rate case expenses and the the fact that FPL does not need to defer its 2004-2005 rate case expenses associated with this docket in order to have a fair return, as evidenced by the level of FPL's 2004 and 2005 earnings under the Stipulation and Settlement in Docket No. 001148-EI, the Commission should deny FPL's request for deferral and recovery of rate case expenses in the Test Year. This adjustment would reduce the Test Year revenue requirement by $5.001 million. If the Commission chooses to allow deferral, the costs should be amortized over a 4-year period, with no return on the unamortized balance. This would reduce rates by $2.764 million ($2.238 million expense and $.526 million elimination of the regulatory asset from rate base). The following table summarizes the impacts of eliminating or extending the rate case expense amortization with and without including the regulatory asset in rate base.

Table 2. FPL Rate Case Expense – Regulatory Treatment Revenue Impacts

Rate Case Expense	Rate Base	Revenue Impact	
Eliminate	Eliminate	$	(5,001,498)
Amortize over 4	Include	$	(2,146,071)
Amortize over 4	Eliminate	$	(2,763,998)
Amortize over 2 per Company	Eliminate	$	(526,498)

STORM DAMAGE ACCRUALS

Q: WHAT IS THE COMPANY REQUESTING FOR STORM DAMAGE ACCRUALS IN THIS CASE?

A: Based on the testimony of Mr. Steven Harris, the Company is requesting an annual accrual to the storm damage reserve of $120 million. This represents an increase of $100 million per year from the $20 million per year that FPL is presently accruing to its storm damage reserve.

Q: HAS MR. HARRIS PERFORMED ANALYSES OF THE EXPECTED ANNUAL UNINSURED COSTS TO FPL'S SYSTEM?

A: Yes. Mr. Harris has analyzed the average expected annual uninsured costs based on an analysis of historical and random storms to determine the average expected level of damage. He has then applied estimates from the 2004 storm restoration costs to determine the costs associated with the average expected level of damage. Based on this analysis, Mr. Harris has concluded that the "expected" annual uninsured cost to FPL's system is estimated to be $73.7 million.

Q: IF THE ANNUAL AVERAGE EXPECTED STORM DAMAGES ARE ESTIMATED TO BE $73.7 MILLION, WHY IS THE COMPANY RECOMMENDING A $120 MILLION STORM DAMAGE ACCRUAL?

A: As explained by Mr. Dewhurst, the $120 million storm damage accrual includes the $73.7 million expected amount of annual storm losses and the remainder would "contribute towards replenishment of the storm reserve." (Dewhurst Direct Testimony, page 34)

Q: WHAT IS THE LEVEL OF STORM RESERVE BALANCE THAT FPL IS TARGETING?

A: FPL is targeting $500 million. Based on a $120 million annual accrual and Mr. Harris' probability analyses, FPL estimates that there is a 39% chance that the storm reserve balance will be greater than $500 million at the end of the five-year period. Mr. Harris indicates that the expected balance would be $367 million with recovery of negative storm balances over a two-year period and $256 million without such recovery.

Q: DO YOU HAVE ANY CONCERNS WITH FPL'S PROPOSED $120 MILLION ANNUAL ACCRUAL TO THE STORM DAMAGE RESERVE FUND?

A: Yes. While Mr. Harris has used sophisticated modeling techniques to determine the expected annual storm damage costs and the probability of insolvency of the fund during a five-year period based on various storm accruals, his results are significantly greater than the level of FPL's actual experience and frequency of major Category 3 through 5 storms. Further, I have several concerns with the ratemaking treatment proposed by FPL.

Q: WHAT ARE YOUR CONCERNS WITH THE RATEMAKING TREATMENT PROPOSED BY FPL?

A: First, in calculating the expected annual storm damage costs, Mr. Harris apparently did not segregate storm damage costs that would be expensed from those costs that would be capitalized. This aggregation would overstate the costs that would be expected to be expensed when actual storm damage occurs. Second, as experienced in the 2004 hurricane damage case, Docket No. 041291-

EI, FPL has the opportunity to seek quicker recovery of storm damage costs that exceed the balance in the storm damage account, either through a special Commission-approved surcharge or through a surcharge pursuant to the Securitization Bill. Further, the Commission has allowed the utilities to recover interest on the unrecovered balance. FPL's proposed increase in the annual accrual is thus duplicative insurance, when coupled with the ability to seek recovery for storm costs that result in a negative balance in the reserve.

Q: IN ESTABLISHING THE CURRENT ACCRUAL LEVELS, DID THE COMMISSION RECOGNIZE THE POTENTIAL FOR NEGATIVE RESERVE BALANCES?

A: Yes. In its response to OPC's Interrogatory No. 145, FPL described the Commission's decision in establishing the current accrual level.

> In Order Nos. 95-0264, issued February 27, 1995, and 98-0953, issued July 14, 1998, the Commission decided it would not set the annual accrual in base rates at a level equal to the expected annual damage. Instead, the Orders set up a three part regulatory framework which was described in question 142 that allowed FPL "to petition the Commission for emergency relief" to address any insufficiencies. (Response to OPC Interrogatory No. 145)

Although FPL notes the Commission's past decision to establish an accrual that is less than expected annual damage, in conjunction with the ability to seek additional recovery in the event that storm damages are incurred in excess of the reserve, it has taken this opportunity to (i) seek full recovery of storm damage costs incurred in the 2004 hurricanes through a special cost recovery clause and (ii) increase its storm damage accrual to 163% of its calculated average annual storm damage. This added level of protection against storm damage costs is unnecessary and is unfair and unjust to ratepayers, who are already dealing with large increases in costs due to the 2004 hurricane damage recovery, coupled with their own hurricane damages.

Q: DOES THE RECENT SECURITIZATION LEGISLATION AFFECT THE NEED FOR FPL TO MAINTAIN A STORM DAMAGE RESERVE?

A: Yes. The securitization legislation provides FPL with the ability to securitize storm damage costs, i.e. to issue bonds pursuant to a financing order issued by the Commission to recover storm damage costs, and potentially storm damage reserve replenishment costs. The costs of the associated debt service would then be recovered from ratepayers over the term of the bonds. Thus, in addition to the Commission's previous policy of allowing FPL to seek recovery of negative storm reserve balances, including interest, the Securitization Bill provides still another layer of protection for storm damages.

Q: WHAT IS THE HISTORY OF THE FREQUENCY OF CATEGORY 3 THROUGH 5 HURRICANES?

A: On FPL's website, www.FPL.com/storm, FPL notes the major storms that have occurred in the last century, affecting its service territory. Based on the noted storms, it would be reasonable to expect a Category 3 to Category 5 storm on average once every 10 years.

Q: WHAT LEVEL OF HURRICANE DAMAGE COSTS DID FPL EXPERIENCE AS A RESULT OF HURRICANE ANDREW AND THE 2004 STORMS?

A: If the storm damage costs incurred in Hurricane Andrew are escalated to 2006 dollars and averaged with the storm damage costs incurred from the 2004 hurricanes, the average damage would be approximately $363.79 million per Category 3 through 5 storm. Based on the expectation of a Category 3 through 5 storm once every 10 years, the annual average cost of storm damage for a Category 3 through 5 storm would be 1/10 of $363.79 million, or $36.38 million.

Q: WHAT IS THE ANNUAL LEVEL OF STORM DAMAGE EXPENSES EXPERIENCED BY FPL FOR CATEGORY 1 AND 2 STORMS?

A: In its response to OPC's Interrogatory No. 78, the Company provided the annual charges to the reserve for storm damages. Beginning with Hurricane Andrew and ending with the 2004 season, the Company experienced storm damage in 10 of the 13 years. To calculate the annual level of storm damage expenses experienced by FPL for Category 1 and 2 storms, the actual Category 1 and 2 storm damage expenses incurred for 1992 through 2004 were escalated to 2006 dollars and averaged over the 13 year period. The result is an average of $15.26 million.

Q: BASED ON FPL'S HISTORY AND STORM FREQUENCY, WHAT IS THE TOTAL AVERAGE ANNUAL STORM DAMAGE COSTS THAT WOULD BE EXPECTED OVER TIME?

A: The total average annual storm damage costs would be $51.64 million, including $36.38 million for larger storms occurring approximately once every 10 years and $15.26 million for the smaller storms which occur more frequently.

Q: WHAT PRINCIPLES SHOULD GOVERN THE COMMISSION'S DECISION IN ESTABLISHING THE APPROPRIATE STORM DAMAGE RESERVE ACCRUAL FOR THE TEST YEAR?

A: The Commission should ensure that FPL's rates, in total, are fair, just, and reasonable to ratepayers and the Company. As explained earlier, the ratepayers are already burdened with the high costs of the 2004 storm damages, in conjunction with higher fuel costs and any increase granted by the Commission in this docket. The ratepayer interests must be balanced with the Company's need to be able to recover costs associated with any storm damages that may occur. This principle does not require the Company to have extraordinary reserves on hand, rather, it requires that the utility and its investors be able to recover reasonable and prudent storm restoration costs at levels that are sufficient to allow the Company to continue to achieve a fair return on investment.

Q: BASED ON THESE PRINCIPLES, WHAT IS YOUR RECOMMENDED STORM DAMAGE ACCRUAL FOR THE TEST YEAR?

A: Based on these principles, I believe it would still be advisable for FPL to maintain a storm reserve fund for covering the costs of damage associated with smaller, Category 1 and 2, storms. This would prevent the Company from having to resort to numerous bond issues to handle smaller, ongoing storm damage. Based on FPL's history of damages from these smaller storms, the current $20 million annual accrual is sufficient to recover these costs.

Q: WHAT IS THE REVENUE IMPACT OF MAINTAINING THE STORM DAMAGE ACCRUALS AT THE CURRENT $20 MILLION LEVEL?

A: If the storm damage accruals are limited to the amounts needed to recover damage from the smaller storms, the Test Year revenue requirement would be reduced by $100 million ($99.5 million retail jurisdiction).

Q: DO YOU HAVE ANY OTHER CONCERNS WITH FPL'S TREATMENT OF STORM DAMAGES?

A: Yes. FPL is funding the payments from ratepayers for storm damages on a net-of-tax basis. This treatment recognizes that FPL has to pay taxes on the revenue it receives from ratepayers. However, in removing the associated deferred income taxes from the capital structure, FPL has treated the adjustment as a "prorata" adjustment, rather than a specific adjustment to accumulated deferred income taxes. Since the accumulated deferred income taxes associated with the storm damages are a debit balance, the elimination of such balances from the capital structure on a prorata basis, rather than a specific adjustment to accumulated deferred income taxes unfairly understates the zero cost accumulated deferred income taxes that should be included in the capital structure.

Q: PLEASE EXPLAIN.

A: FPL's average balance in the storm damage reserve for the Test Year is $81.342 million. The storm damage fund is funded on a net-of-tax basis; therefore, the average fund balance for the Test Year is $49.964 million ($81.342 million less $31.378 million taxes). The return earned on the fund is thus already "penalized" by the lost return on the accumulated deferred income taxes.

In making its adjustment to equalize the capital structure with rate base, FPL added the $81.342 million storm damage reserve and deducted the $49.964

million storm damage fund, for a net addition to the capital structure of $31.378 million. This adjustment is shown on Schedule D-1b. The effect of this adjustment is to eliminate the accumulated deferred income taxes from the capital structure. However, as shown on Schedules D-1b and D-1a, FPL eliminated these accumulated deferred income taxes as a prorata adjustment, which was spread to all components of the capital structure. The result is an increase in all components of the capital structure, rather than an increase to only the accumulated deferred income tax component on which FPL earns a zero return.

Q: HAVE YOU QUANTIFIED THE IMPACT OF THIS ERROR?

A: Yes. Exhibit__(SLB-5), page 2 of 2, provides the weighted average cost of capital as calculated by FPL and as adjusted to eliminate the accumulated deferred income taxes associated with the storm damage fund from only the accumulated deferred income tax component of the capital structure. As shown on Exhibit__(SLB-5), page 2 of 2, the impact of this error is $4.071 million in Test Year revenue requirement. The Commission should note that this capital structure treatment is erroneous and should be corrected regardless of the level of storm damage accrual approved in this docket.

LAST CORE NUCLEAR FUEL

Q: WHAT IS THE CURRENT ACCRUAL FOR LAST CORE NUCLEAR FUEL?

A: As shown on Schedule B-21, the Company is accruing $5.51 million a year for Last Core Nuclear Fuel. This amount was established by the Company in FPSC Docket No. 001148-EI.

Q: WHAT IS "LAST CORE NUCLEAR FUEL"?

A: Last Core Nuclear Fuel is the amount of nuclear fuel that is expected to be left in the unit at the time it is shut down for decommissioning. Last Core Nuclear Fuel, then, is like an additional cost of decommissioning that the Company will incur at the time of shut-down.

Q: HOW DID THE COMPANY DETERMINE THE LEVEL OF ACCRUAL FOR LAST CORE NUCLEAR FUEL?

A: In Docket No. 001148-EI, the Company determined that the total unamortized last core costs would be $71.224 million. This amount was broken down by unit, then each unit's last core costs were amortized over the remaining life of the unit. The result was an annual accrual of $5.51 million.

Q: DID THE COMPANY MODIFY THE ACCRUAL FOR THE TEST YEAR BASED ON THE LICENSE EXTENSIONS?

A: No. Although the Company received 20-year license extensions on all four of its nuclear units, the Test Year amortization of Last Core Nuclear Fuel was not adjusted to reflect the extensions.

Q: WHAT IS THE EXPECTED BALANCE IN THE LAST CORE OPERATING RESERVE AS OF DECEMBER 31, 2005?

A: As shown on Schedule B-21, the expected balance in the Last Core Operating Reserve as of December 31, 2005 is $20,203,000.

Q: SHOULD THE ACCRUAL TO THE LAST CORE RESERVE BE MODIFIED TO REFLECT THE LIFE EXTENSION?

A: Yes. As noted on page 26 of Order No. PSC-02-0055-PAA-EI, "outages, capacity factor, plant life extension, future fuel contracts, the change in mix of generating assets owned by the company as the industry further evolves, market conditions, and technology" are all factors that can affect the Last Core estimate.

Q: WHAT IS YOUR RECOMMENDATION FOR THE TREATMENT OF LAST CORE NUCLEAR FUEL EXPENSES IN THIS PROCEEDING?

A: In its response to FRF Interrogatory No. 42, FPL indicated that it would address this issue in its upcoming decommissioning study. The Commission should suspend accruals to the Last Core Nuclear Fuel reserve until FPL files its decommissioning study and justifies continued accruals to the reserve.

Q: HAVE YOU CALCULATED THE REVENUE IMPACT OF THE SUSPENSION OF THE AMORTIZATION FOR THE TEST YEAR?

A: Yes. As shown on Exhibit__(SLB-6), the total jurisdictional Test Year revenue impact associated with the suspension of the Last Core Nuclear Fuel amortization is $5.263 million, including the impacts on expense, rate base, and capital structure.

NUCLEAR END-OF-LIFE MATERIALS AND SUPPLIES INVENTORY

Q: WHAT IS THE LEVEL OF AMORTIZATION OF END-OF-LIFE NUCLEAR MATERIALS AND SUPPLIES THAT THE COMPANY HAS INCLUDED IN THE TEST YEAR REVENUE REQUIREMENT?

A: As shown on Schedule B-21, the Company has included $2.444 million in the Test Year revenue requirement for amortization of End-of-Life Nuclear Materials and Supplies.

Q: WHAT ARE END-OF-LIFE NUCLEAR MATERIALS AND SUPPLIES?

A: As with the Last Core Nuclear Fuel, End-of-Life Nuclear Materials and Supplies are materials and supplies that will be on-hand at the end of the service life of the nuclear units.

Q: HOW DID THE COMPANY DETERMINE THE LEVEL OF AMORTIZATION?

A: In FPSC Docket 001148-EI, the Company provided workpapers showing the calculation of the amortization. The End-of-Life Materials and Supplies were estimated for each nuclear station, then amortized over the remaining life of the station. The amortization was approved in FPSC Docket No. 990324-EI.

Q: DID THE COMPANY ADJUST THE AMORTIZATION IN THE TEST YEAR TO REFLECT THE 20-YEAR LICENSE EXTENSIONS FOR THE NUCLEAR UNITS?

A: No. Although Footnote (B) of Schedule B-21 indicates that the costs are amortized over the remaining life span at each nuclear site, the amortization has not been changed to reflect the 20-year license extensions.

Q: WHAT IS THE EXPECTED BALANCE IN THE END-OF-LIFE MATERIALS AND SUPPLIES INVENTORY AT DECEMBER 31, 2005?

A: As shown on Schedule B-21, the balance in the End-of-Life Materials and Supplies Inventory is expected to be $8.961 million at December 31, 2005. This balance reflects 44 months of amortization, beginning with the implementation of the rates under the Stipulation and Settlement in Docket No. 001148-EI.

Q: HOW SHOULD THE COMMISSION TREAT THE EXCESS END-OF-LIFE MATERIALS AND SUPPLIES INVENTORY RESERVE?

A: As with the Last Core Nuclear Fuel accruals, it would be reasonable to suspend any further accruals to the End-of-Life Materials and Supplies Inventory reserve until such time as the Company justifies continued accruals.

Q: HAS THE COMPANY INDICATED ITS INTENT TO UPDATE ITS END-OF-LIFE MATERIALS AND SUPPLIES INVENTORY?

A: Yes. In its response to FRF Interrogatory No. 55, FPL indicated that it "intends to file a decommissioning study later this year and would support an adjustment, as necessary, to nuclear decommissioning costs in the MFRs once the new study has been reviewed and approved." In Order No. PSC-02-0055-PA-EI, the Commission determined that End-of-Life Materials and Supplies Inventory was not decommissioning, but should be treated as nuclear maintenance expense. The Commission asked FPL to address the End-of-Life Materials and Supplies Inventory in subsequent decommissioning studies. If FPL does address the End-of-Life Materials and Supplies Inventory in its upcoming decommissioning study and its analyses indicate the need for continued accruals, the Commission could adjust rates at that time, along with changes to decommissioning and Last Core Nuclear Fuel accruals.

Q: HAVE YOU CALCULATED THE TEST YEAR REVENUE IMPACT OF SUSPENDING THE END-OF-LIFE MATERIALS AND SUPPLIES INVENTORY ACCRUAL?

A: Yes. As shown on Exhibit__(SLB-7), the jurisdictional Test Year revenue impact of this adjustment is $2.334 million, including the impact on expenses, rate base and capital structure.

CHARITABLE CONTRIBUTIONS

Q: HAS THE COMPANY INCLUDED AN ADJUSTMENT FOR CHARITABLE CONTRIBUTIONS IN THE TEST YEAR REVENUE REQUIREMENT?

A: Yes. The Company has requested that $1.545 million ($1.538 million retail jurisdiction) in charitable contributions be included in the Test Year revenue requirement.

Q: SHOULD THIS ADJUSTMENT BE ALLOWED?

A: No. Following past Commission practice, this adjustment should not be allowed. Charitable contributions are discretionary and should be made at shareholder expense. Further, ratepayers should not be required to support FPL's choice of charitable donations.

CONSTRUCTION WORK IN PROGRESS

Q: HAS THE COMPANY INCLUDED CWIP IN RATE BASE?

A: Yes. As shown on Schedule B-1, the Company has included $522.6 million of CWIP in rate base.

Q: SHOULD CWIP BE REMOVED FROM RATE BASE?

A: Yes. No CWIP should be allowed in FPL's rate base. Based on prior Commission decisions, CWIP is only included in rate base when needed to maintain financial integrity. The Commission has historically measured the need for CWIP in rate base by evaluating interest coverage with and without CWIP in rate base. In this case, FPL has indicated Test Year interest coverage ratios (excluding AFUDC) of 4.03 times at present rates and 5.68 times at proposed rates. Removing CWIP from rate base, and reducing revenues and net income accordingly, results in a reduction in Test Year interest coverage ratios of .255 times, reducing the coverage at proposed rates from 5.68 times to 5.42 times and at present rates from 4.03 times to 3.77 times. This reduction is not sufficient to warrant inclusion of CWIP in the Test Year rate base.

Q: WHAT IS THE REVENUE IMPACT OF REMOVING THE CWIP FROM THE TEST YEAR RATE BASE?

A: The revenue impact of removing CWIP from rate base is $69.585 million. ($522.642 million x 8.22% x 1.61971)

<u>NUCLEAR MAINTENANCE EXPENSE ACCRUAL</u>

Q: PLEASE EXPLAIN HOW THE COMPANY HANDLES ITS ACCRUALS FOR NUCLEAR MAINTENANCE.

A: The Company estimates its nuclear maintenance outage costs for the next anticipated outage at the end of each outage period. The outage costs are then accrued monthly from the time of the current nuclear maintenance outage through the end of the next anticipated outage period. The nuclear maintenance reserve is a regulatory liability and is treated as a reduction to rate base.

Q: HAS THE COMPANY CORRECTLY CALCULATED THE RATE BASE REDUCTION ASSOCIATED WITH THE NUCLEAR MAINTENANCE RESERVE?

A: No. The Company has charged (debited) the nuclear maintenance reserve with the anticipated costs of the next nuclear maintenance outage at the time the accruals begin, rather than at the time the actual expenditures are made. For example, the accruals for the St. Lucie 2 October 2007 outage begin in May,

2006. The Company will not actually incur the costs associated with this outage until 2007; however, in determining the nuclear maintenance reserve balances, the Company has reduced the regulatory liability account by the October 2007 costs in May, 2006. This practice overstates the actual regulatory liability, resulting in an overstatement of rate base and the Test Year revenue requirement.

Q: WHAT IS THE IMPACT OF THIS OVERSTATEMENT?

A: Exhibit__(SLB-8) provides a recalculation of the nuclear maintenance reserve balances with charges to the reserve properly timed with the actual expenses. As shown on Exhibit__(SLB-8), this correction reduces the jurisdictional revenue requirement by $7.161 million.

Q: DOES THIS CONCLUDE YOUR TESTIMONY?

A: Yes, it does.

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

IN RE: PETITION FOR RATE INCREASE BY FLORIDA POWER & LIGHT COMPANY) DOCKET NO. 050045-EI

DIRECT TESTIMONY OF STEPHEN J. BARON

I. QUALIFICATIONS AND SUMMARY

Q. Please state your name and business address.

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

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

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

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

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

Q. Please state your educational background.

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

Q. Please describe your professional experience.

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

Following the completion of my graduate work in economics, I joined the staff of the Florida Public Service Commission in August of 1974 as a Rate Economist. My responsibilities included the analysis of rate cases for electric, telephone, and gas utilities, as well as the preparation of cross-examination material and the preparation of staff recommendations.

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

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

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

During the course of my career, I have provided consulting services to more than thirty utility, industrial, and Public Service Commission clients, including three international utility clients.

I have presented numerous papers and published an article entitled "How to Rate Load Management Programs" in the March 1979 edition of "Electrical World." My article on "Standby Electric Rates" was published in the November 8, 1984 issue of "Public Utilities Fortnightly." In February of

1984, I completed a detailed analysis entitled "Load Data Transfer Techniques" on behalf of the Electric Power Research Institute, which published the study.

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

Q. **Do you have previous experience in FPL regulatory proceedings?**

A. Yes. I have been involved in a number of FPL rate proceedings during my career. This includes participation as a Florida Public Service Commission Staff member in a 1975 FPL rate case, a generic DSM proceeding in 1993 and an FPL rate case in 2002.

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

A. I am testifying on behalf of the South Florida Hospital and Healthcare Association, Inc. ("SFHHA" or the "hospitals"). SFHHA members take service on FPL general service and CILC rate schedules throughout the Company's service area.

Q. What is the purpose of your testimony?

A. I will address issues associated with FPL's proposed allocation of its requested base rate revenue increase of $385 million to rate schedules. FPL witness Rosemary Morley provides testimony on these issues, including the Company's proposed methodology to utilize the results of its class cost of service study ("parity study") to assign increases to each rate schedule. I will discuss the Company's approach and recommend an improved allocation based on alternative cost of service analyses, as well as the application of a "1.5 times average increase cap" approach.

With regard to the class cost of service study, I will address the Company's filed 12 CP and 1/13th average demand methodology and offer an alternative approach that focuses on the key summer and winter peaks that drive the

Company's generation resource decisions. As I will discuss, it is growth in the summer and winter peak demands that will require the Company to obtain almost 6000 mW of additional generating capacity over the next ten years. Customers should, through the cost of service and rate design process, be provided price signals reflecting the "cost" of their decisions to use and cause the construction of additional scarce generation resources during the summer and winter peak periods. The Company's use of a 12 CP cost allocation methodology does not adequately reflect the Company's planning decisions. As a result, FPL will overbuild capacity, customers will receive the wrong message about the actual cost of their consumption patterns, resources will be misallocated, and pollution may be increased by virtue of running additional generation.

Finally, I will address the proposal by the Company to recover the fixed costs associated with Turkey Point 5 on a kWh basis, within rate schedules. Since these costs are demand related, they should be recovered by increasing the kW billing demand charge (or charges) of rate schedules that include a demand charge as part of the rate.

Q. Would you summarize your conclusions and recommendations?

A. Yes.

- **FPL has proposed increases to some rate schedules that are substantially in excess of 1.5 times the average retail base rate increase requested by the Company. Some rate schedules will receive increases of as much as 21% under the Company's proposals in this case. In consideration of the impact and the potential for "rate shock" with such large increases, no rate schedule should receive an increase greater than the "1.5 times" cap applied to the average base rate increase, excluding adjustment clauses.**

- **FPL has based its proposed rate schedule increases on the results of its 12 CP and 1/13th average demand cost of service study and an objective to bring each rate schedule to within +/- 10% of the system average rate of return. A more efficient cost of service study for FPL is a method based on a summer/winter average CP methodology, coupled with consideration of a "minimum distribution system" approach to the classification of secondary distribution facilities. The parity results using this corrected cost of service study supports an equal percentage increase to rate schedules in this case, which should be adopted by the Commission.**

- **The Company's proposal to offer a high load factor time of use rate (HLFT) should be adopted by the Commission. The methodology used by the Company to develop this rate, which is directly tied to the underlying costs for serving general service customers, is reasonable. In the event that the Commission adjusts the revenue increases proposed by FPL for general service rates, either because of a reduction in the overall FPL revenue requirement increase or an alternative allocation of the approved increase, the proposed HLFT rate should be adjusted accordingly (as described subsequently in this testimony).**

- **If the Commission approves the Company's proposed 2007 Turkey Point Unit 5 recovery in this case, the allocated revenue to demand metered rate schedules should be recovered on a kW demand basis, rather than on a kWh basis as proposed by FPL. These are demand related costs and, to the extent that a rate schedule incorporates a demand charge in the rate, the Turkey Point Unit 5 charges should be recovered from the kW demand charge.**

II. ALLOCATION OF THE AUTHORIZED REVENUE INCREASE

Q. Would you please briefly describe the methodology that FPL is proposing to use to allocate its requested $385 million increase to rate schedules?

A. FPL has used the results of its cost of service "parity" study to assign the increase to rate schedules such that each rate schedule produces a rate of return on rate base (premised upon the Company's recommended cost allocation study) within a "+/- 10%" band. Essentially, FPL claims it is adjusting its rates in this case to bring each of its rates schedules to within 10% of the system rate of return. The Company is not proposing to limit the increases to any specific rate schedule to "1.5 times" the average increase. In fact, FPL is proposing increases to some rate schedules at a much higher percentage than the level that would be produced had the Company adhered to a "1.5 times" constraint.

Q. What are the specific increases recommended by FPL, assuming that it is authorized its full $385 million rate increase in this case?

A. Table 1 below summarizes the increases recommended by the Company for most of the general service and CILC rate schedules. These rate schedules, as can be

Table 1
FPL Proposed Revenue Increases

Rate		Base Rev (Present)	Base Rev (Proposed)	Percent	Excess Over "1.5 x Avg."
CILC-1D		45,594,194	54,970,753	20.6%	**6.09%**
CILC-1T		13,609,695	16,140,110	18.6%	**4.11%**
CS1		3,479,708	4,272,915	22.8%	**8.32%**
CST1		1,758,579	2,136,289	21.5%	**7.00%**
CS2		1,273,351	1,542,219	21.1%	**6.64%**
CST2		1,279,726	1,550,869	21.2%	**6.71%**
GSD1	Non-Migrate	554,457,645	637,058,916	14.9%	**0.42%**
GSLD1	Non-Migrate	120,481,295	144,231,946	19.7%	**5.23%**
GSLDT1	Non-Migrate	17,325,850	20,308,479	17.2%	**2.74%**
GSLDT1	Migr-HLFT	65,347,245	76,061,539	16.4%	**1.92%**
GSLD2	Non-Migrate	10,152,158	12,120,591	19.4%	**4.91%**
GSLDT2	Non-Migrate	6,617,515	7,780,602	17.6%	**3.10%**
GSLDT2	Migr-HLFT	14,052,762	16,250,410	15.6%	**1.16%**
GSLD3		450,776	523,553	16.1%	**1.67%**
GSLDT3		2,561,176	2,857,992	11.6%	
Total Retail				**9.7%**	
"1.5 Times Cap"				**14.5%**	

seen in the table, reflect general service classes (on which the hospitals are served) that will receive substantially greater increases than "1.5 times the average 9.7% retail increase" in base rates being proposed by FPL. In particular, customers taking service on rate schedule CILC-1D, and the non-migrating customers on schedules GSLD-1 and GSLDT-1 will receive base rate increases of 20.6%, 19.7% and 17.2% respectively. CILC-1D customers will receive an increase of 212% of the system average (2.12 times the average increase of 9.7%).

Q. Has FPL provided sufficient support to justify an increase to these (and other) rate schedules of such magnitude?

A. No. Even if one were to agree with the Company's cost of service results without exception, which I do not, it is unreasonable to increase some customer rates by more than a "1.5 times" system average base rate cap. Given the magnitude of the increase requested by the Company in this case and its impact on ratepayers, including general service customers, such a limitation by rate schedule is appropriate. This is further warranted by the additional proposed increases requested by FPL in 2007. The Commission should limit the increase in base rates to 1.5 times the system average for each rate schedule.

Q. Why do you believe that the "1.5 times" cap should apply to the system average base rate increase?

A. This proceeding involves a substantial increase to base rates. The appropriate metric to measure the impact and assess "rate shock" is the impact on the base rates at issue. Because the base rate represents less than half the overall bill for most, if not all of FPL's customers, the reasonableness of a proposed base rate increase should not be obscured and clouded by including fuel costs and other adjustment clause revenues in the evaluation of rate shock. The component of the rate here at issue and which can be adjusted is the base rate.

This is particularly problematic for higher load factor general service rate schedule customers who have a relatively greater proportion of fuel revenues included in their total costs. If the rate shock "test" is applied to the impact of a proposed base rate increase on total revenues, including fuel, higher load factor rate schedules are penalized, all else being equal. If all rate schedules had the same proportion of adjustment clause revenues, then it would not matter whether the "1.5 times" cap was applied to assess the impact of an increase in base rates or whether it is applied to as a cap on the percentage increase in total revenues, including adjustment clauses. However, this is not the case and it is more reasonable and fair to cap the increases using a "1.5 times" cap applied to base rates.

Q. You indicated in a previous answer that you did not agree with FPL's cost of service results. Would you please address your concerns with the Company's study?

A. Yes. As I will discuss in more detail later in my testimony, the Company's cost of service study and the related "parity" results on which FPL has relied to establish its proposed increases to each rate schedule are not reasonable and should not be used to set rates in this case. The cost of service methodology is of particular significance in this case because of the extent of the reliance being placed on the results to establish rate schedule revenue targets. Though I support the use of a cost of service study to set rates (subject to some type of limitation to address potential rate shock concerns, such as the "cap" limitation that I discussed above to limit the increase to any rate schedule to 1.5 times the system average increase), the necessary pre-condition to such an analysis is to utilize a reasonable cost of service study that allocates costs in a manner that reflects cost causation. Though the Company has used a methodology that has been previously found by the Commission to be appropriate for FPL and other Florida electric utilities, I am recommending that the Commission consider an alternative approach in this case to assign cost responsibility. Specifically, as I will discuss, I am recommending that the Commission adopt a summer/winter average production demand methodology. I will discuss the support for such a study in the next section of my testimony. I am also recommending that the Commission consider an alternative approach to the classification of distribution plant. I present the basis for such an approach and the cost of service and parity implications of classifying a portion of the Company's secondary distribution facilities using a customer component, in addition to a demand component. As I will discuss, FPL has classified 100% of secondary lines (underground and overhead), secondary poles and secondary line transformers as demand related. I believe that there is strong support to classify a portion of these costs as both customer and demand related. I will present an alternative cost of service study that illustrates the potential impact on class parity results from such a change in the Company's study.

Q. What are the parity results using your alternative cost of service studies?

A. Table 2 below presents the results of the parity analyses using the two alternative cost of service studies that I discuss later in my testimony. These studies show that general service and CILC-1D customers should receive revenue increases much closer to the system average increase than recommended by FPL. The rate schedule increases approved by the Commission may be in place for many years, if history is a guide. Given the large disparity between the parity results presented by FPL in this case (see Table 3) and the parity results shown in Table 2, using what I believe are more reasonable assumptions, I recommend that the Commission apply an equal percentage increase to all rate schedules in this case. For general service rate schedules, GSD, GSDT, GSLD-1, GSLD-2, GSLDT-1 and GSLDT-2 that include both non-migrating and migrating (to HLF and SDTR) customers, the equal percentage increase should be applied to all of the customers on the rate (e.g., GSLDT-1) in a first step. As I discuss subsequently, the second step would then develop the individual increases to the non-migrating and migrating customers within the rate schedule such that the same relative relationships among the general service rates and the HLF and SDTR rates are preserved.

Table 2
Comparison of Parity Index Results

Rate Class	Sum/Win CP	S/W CP w/Min Dist
CILC-1D	108%	114%
CILC-1G	175%	187%
CILC-1T	108%	108%
CS1	89%	96%
CS2	84%	91%
GS1	179%	171%
GSD1	115%	124%
GSLD1	81%	89%
GSLD2	86%	93%
GSLD3	127%	127%
MET	66%	66%
OL-1	-16%	-15%
OS-2	68%	77%
RS1	93%	90%
SL-1	33%	35%
SL-2	290%	305%
SST-TST	618%	618%
SST1-DST	-54%	-54%
SST2-DST	86%	98%
SST3-DST	143%	143%

Q. Does your recommendation for the Commission to adopt an alternative cost of service study and use these results to allocate the revenue increases in this case result in "cost shifting"?

A. No. As I will more fully discuss subsequently in my testimony, the Company's 12 CP & 1/13th average demand cost of service methodology does not adequately reflect cost responsibility. FPL is proposing substantial increases in this proceeding based on the assumption that certain rate classes have under-contributed to their share of the system's costs (e.g., rate schedule CILC-1D). However, using a more reasonable measure of cost responsibility, these same classes are actually over-contributing to their share of costs. Likewise, some rate schedules (RS-1, for example) are shown to be over-contributing to their share of costs under FPL's cost study, while under a more reasonable measure, these same classes are under-contributing to their share of costs (i.e., producing a parity less than 100%). As a result, when the contribution to costs by the various rate classes is analyzed in a more appropriate and logical basis than is reflected in the Company's cost of service study, it is apparent that an equal percentage increase is reasonable and would not unduly burden the residential class or general service schedules.

Q. The Company is proposing to a new tariff, HLF (high load factor), for some general service customers who are able to migrate to the new rate. How should the proposed target revenue level for rate HLF be adjusted,

if the Commission adopts your recommendations to change the allocation of the increase to general service rates?

A. First, as I will discuss later in my testimony, the Hospitals support the Company's proposal to introduce rate schedule HLF. If the Commission adjusts the allocation of the increase to general service schedules, as I am recommending, there should be a corresponding decrease to proposed rate schedule HLF so that the relationships established among the general service feeder rates to HLF and HLF remain essentially the same. I recognize that because customers from a number of general service rate schedules will migrate to rate HLF, the process of adjusting rate HLF, following a change in one or more general service schedules, will require an iterative approach in compliance filings with the Commission. The objective, however, should be that the relative relationship between the various general service rates and rate HLF should remain the same (within a reasonable bound) as exists under the Company's proposed tariffs.

Q. Are there any additional issues that you would like to address regarding the allocation of any authorized revenue increase to rate schedules?

A. Yes. In presenting summary proposed increases by rate schedule in Schedule E-8 of the MFR, the Company included "other operating revenue", which includes not only connection and reconnection fees and other retail customer miscellaneous revenues, but also the allocated share of other revenue credits (for example, transmission) that are not even at issue in this case. These other revenues should be excluded from the presentation of the proposed increases at issue in this case since they are not tied to the sale of electricity governed by the tariffs being adjusted in this case. Though it is reasonable to consider the proposed changes, if any, in connection fees (for example), it is not appropriate to include any such amounts in the calculation of the proposed increases to rate schedule. In sum, this presentation obscures and conceals the full effects of FPL's proposals.

More significantly, FPL has included "imputed" CILC incentives in the computation of the rate increase proposed for the three CILC rate schedules. It is appropriate to include these incentives in the cost of service study, as FPL has done. However, it is completely inappropriate to include the imputed incentives in the "presentation" of FPL's proposed increase to these rates. The CILC rates do not include these incentive revenues in customer charges and it is thus incorrect to calculate a rate impact using an "imputed" amount of additional revenues that are not actually part of a customer's bill.

III. COST ALLOCATION ISSUES

Q. Would you please discuss the issue of the allocation of demand related production costs?

A. Yes. As required by the MFR, FPL has filed a 12 CP and 1/13th average demand based cost of service study in this case. The Company has not filed any alternative studies and supports the 12 CP and 1/13th method in this case.

In the past, based upon circumstances then in effect, FPL used and the Commission accepted this methodology. However, circumstances now in effect and compelling public policy reasons suggest alternative methodologies for FPL cost allocation. This issue is not an academic exercise in this case, since FPL is proposing to assign its requested $385 million base rate increase to rate schedules on the basis of the class cost of service study ("parity" results).

Q. What is your understanding of the underpinning for the use of the 12 CP and 1/13th average demand method?

A. This methodology, which is primarily a 12 CP method, allocates production demand costs under the assumption that customer (and ultimately rate schedule) kW demand contributions to each of the 12 monthly coincident peaks have equal "cost responsibility" for the Company's generating units and power purchases (the capacity portion thereof). Thus, for example, the 12 CP method presumes that a residential or general service customer's incremental demand at the time of the August or January system coincident peak is no more "costly" to the system than the same amount of incremental demand at the time of the October or April FPL peak. This method sends price signals to customers that adding demand during any of the monthly peaks throughout the year costs the same to the Company. Correspondingly, if residential loads are being added more rapidly in the summer and winter peak months than in the off-peak months, the impact on class revenue requirements is much less (under FPL's cost methodology) than if a group of general service customers added the identical load during the summer and winter peaks, but also added a like amount of load in the off-peak months. In that case, general service class cost responsibility would increase much more under the Company's cost of service study allocation approach, even though such responsibility was spread throughout the year and not concentrated during the summer and winter peak months.

A numerical example will help illustrate this point. Assume that both the residential and general service class peak demands increased by 1000 mW during July, August, January and February. Further assume that during the other eight months of the year, the residential class coincident peak demand increased by only 500 mW, while the general service peaks increased by 800 mW, reflecting the higher load factor for this class. The 12 CP demands for each of the two classes would increase by 8000 mW and 10,400 mW respectively for the residential and general service classes. Despite the fact that both rate classes contributed identical amounts to the summer and winter peaks that drive the capacity needs of the FPL system, the general service class would be assigned 30% more cost responsibility for this incremental demand than the residential class. Since rates ultimately will be impacted from the results of the cost of service study, residential customers will receive a "discounted" price signal on the cost associated with its behavior. The opposite will occur for general service customers.

Q. Have you prepared any analyses that show the changes in residential and general service customer coincident peak demands during the past six years, compared to the expectations of FPL for the test year?

A. Yes. Figures 1 and 2 that follow contain charts for the RS-1 and GSLDT-1 rate schedules comparing each the 12 CP demands and the average of the summer and winter CP demands for the period 1998 through 2003, together with the Company's test year 2006 estimate.

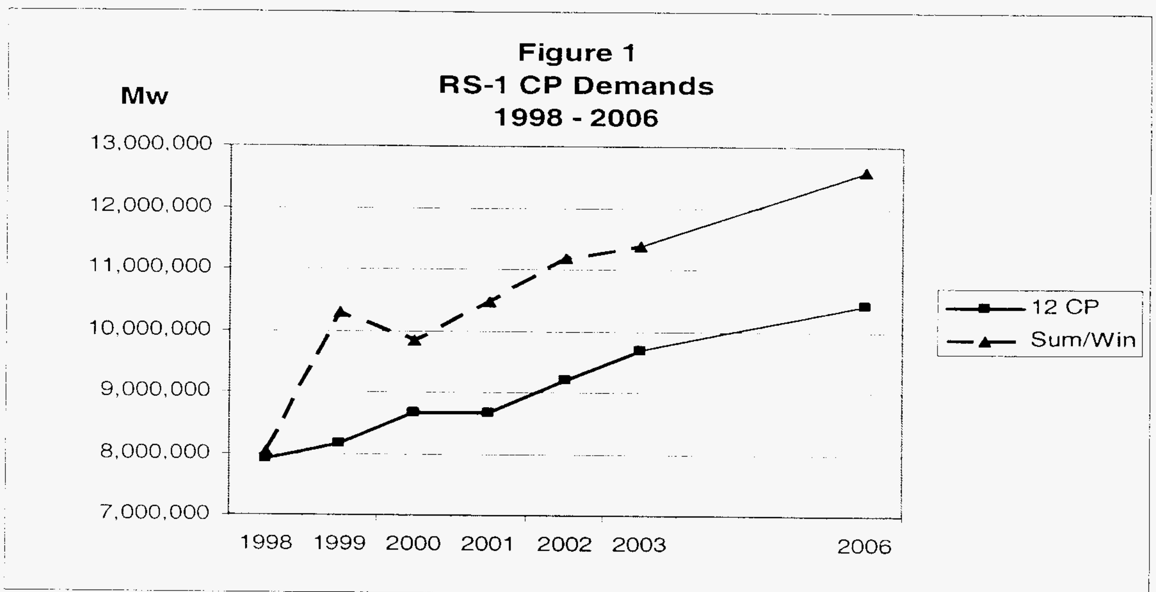

Figure 1
RS-1 CP Demands
1998 - 2006

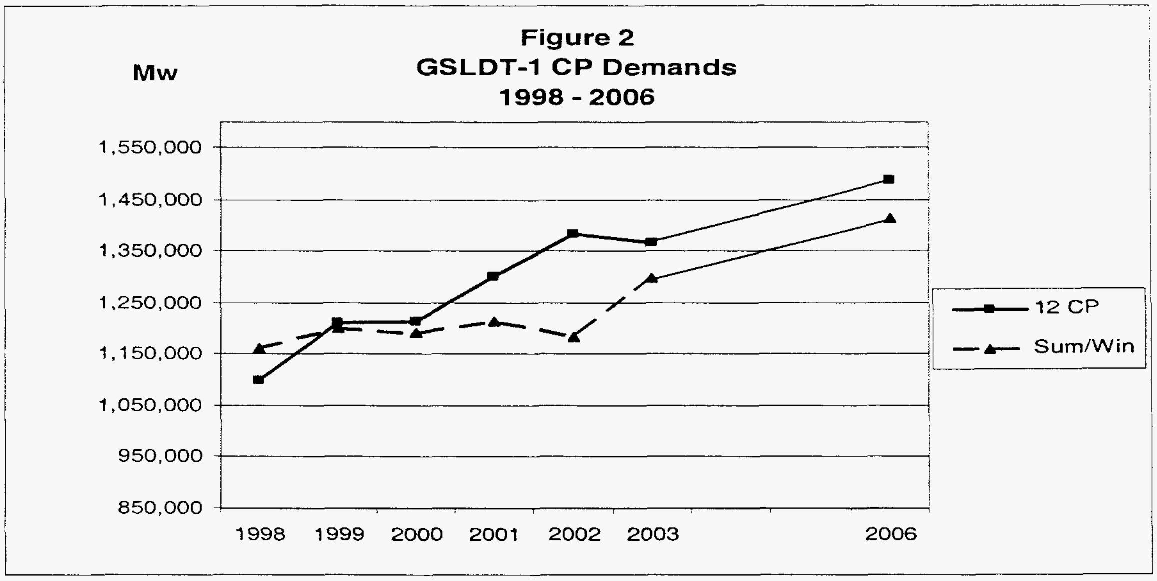

Figure 2
GSLDT-1 CP Demands
1998 - 2006

The charts show that the growth in the residential contribution to the summer/winter average has been growing much faster than its 12 CP contribution. For the GSLDT-1 rate, the two measures of coincident peak have been growing at a much closer rate. More significantly, for the RS class, the summer/winter average CP demand is substantially above the 12 CP level, while for the GSLDT-1 class, the two measure of CP are similar, with the 12 CP level being the higher value. Because the FPL cost allocation study is driven in large part by a rate schedule's contribution to 12 CP demand, rather than the important summer and winter peak contributions that are driving capacity additions on the FPL system, GSLDT-1 customers are being assigned a relatively larger share of the system's fixed production costs. All else being equal, this results in higher rates to these customers simply because they have relatively higher demands in the off-peak months.

This is also problematic because these higher load factor general service customers contribute a relatively greater amount of revenues during the off-peak (non-summer and winter peak periods), which helps defray the capital costs of capacity additions, while classes that have more concentrated demands during the summer and winter peak periods provide proportionately less contribution to these capacity costs because of their lower non-summer/winter consumption.

Q. Does FPL's current 10 year site plan support the general assumptions in your illustration that the growth in summer and winter peak demands is driving the need for capacity additions on the system?

A. Yes, I believe that it does. Baron Exhibit__(SJB-2), schedules 1 and 2 contain copies of FPL's projected summer and winter peak capacity, load and reserves. These schedules are copies of Schedules 7.1 and 7.2 from FPL's 2004 Ten Year Power Plant Site Plan. As can be seen, the Company is projecting substantial capacity additions over the next ten years to meet growing summer and winter peak demand and to maintain a 20% reserve margin during the summer. It is clear that the requirement to meet the summer and winter peak demand is driving the capacity resource addition on the system.

Q. Don't the generation resources also meet the demands during the other months of the year?

A. Yes. Clearly, all of FPL's generating resources (except seasonal purchases, if any) are designed to meet the loads of the Company's customers, regardless of when they occur. However, these loads in other months do not drive the incurrence of generation resource costs on the system. This is true, even if planned maintenance is considered. Because, by its very nature, planned maintenance is "planned", it is not the driver of the need to obtain additional generation resources. This need is driven by the summer and winter peaks projected in the ten year site plan.[1] This is further confirmed in a December 2004 report by The Division of Economic Regulation of the Florida Public Service Commission at page 13, which states:

> **FRCC studies currently show that a 15% reserve margin correlates to LOLP values that are well below 0.1 days per year. These low LOLP values are the result of two factors: high unit availabilities and low forced outage rates typical of new, efficient generating units; and, enhanced maintenance practices on older generating units. <u>As a result, reserve margin continues to be the primary criterion driving a utility's capacity needs</u>. In the late 1990's, the Commission was increasingly concerned with the declining reserve margins forecasted by Florida's utilities and the impact of such declines on reliability. In response to these concerns, PEF, FPL and TECO agreed to adopt a 20% reserve margin planning criterion starting in Summer 2004.** (emphasis added).

Q. How do the monthly peak loads compare to the summer and winter peaks on the FPL system?

A. The following graph (figure 3) shows the actual 2003 and projected 2005 monthly peak loads on the FPL system. As can be seen from the graph, there is a significant system peak in the summer and the winter period. Since the 2005 data is projected, it reflects a weather normalized result and it is clear that <u>two seasonal peaks</u> rise above the coincident peaks in the remaining months.

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[1] FPL also employs a maximum loss-of-load probability ("LOLP") criterion of "0.1 day per year" in its planning. However, based on the Company's resource plan, FPL is generally adding capacity that maintains a 20% reserve margin in the summer.

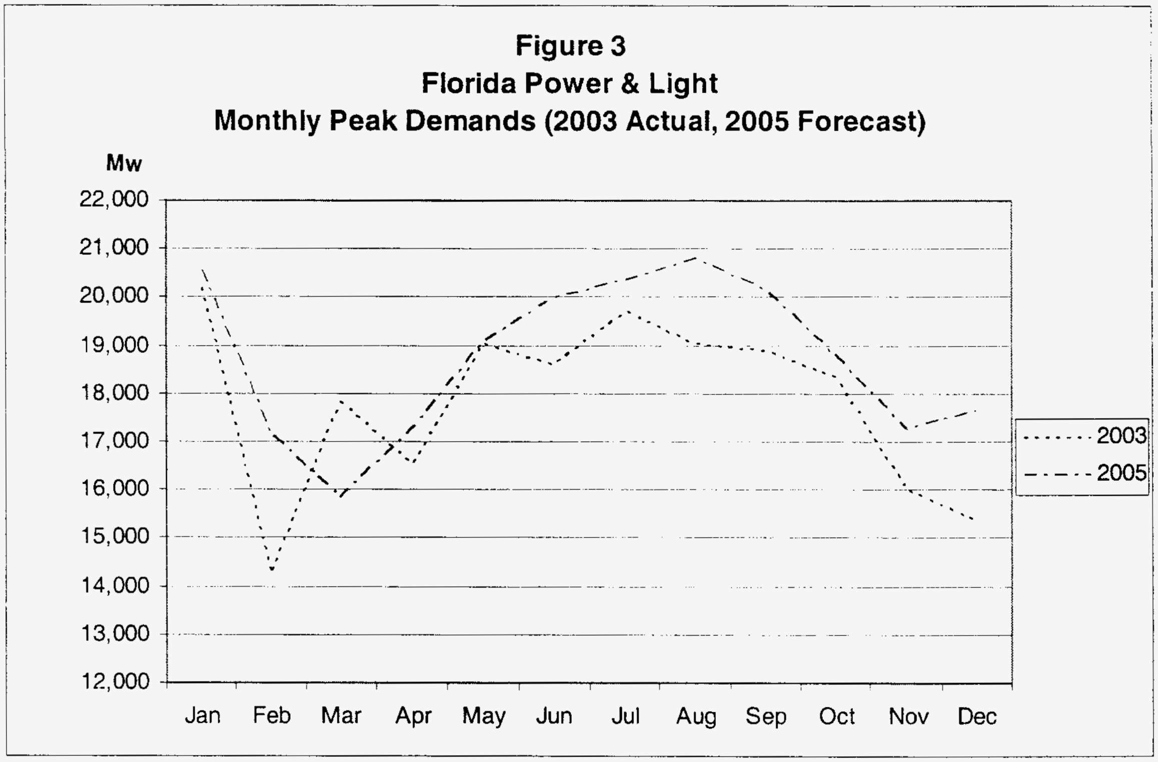
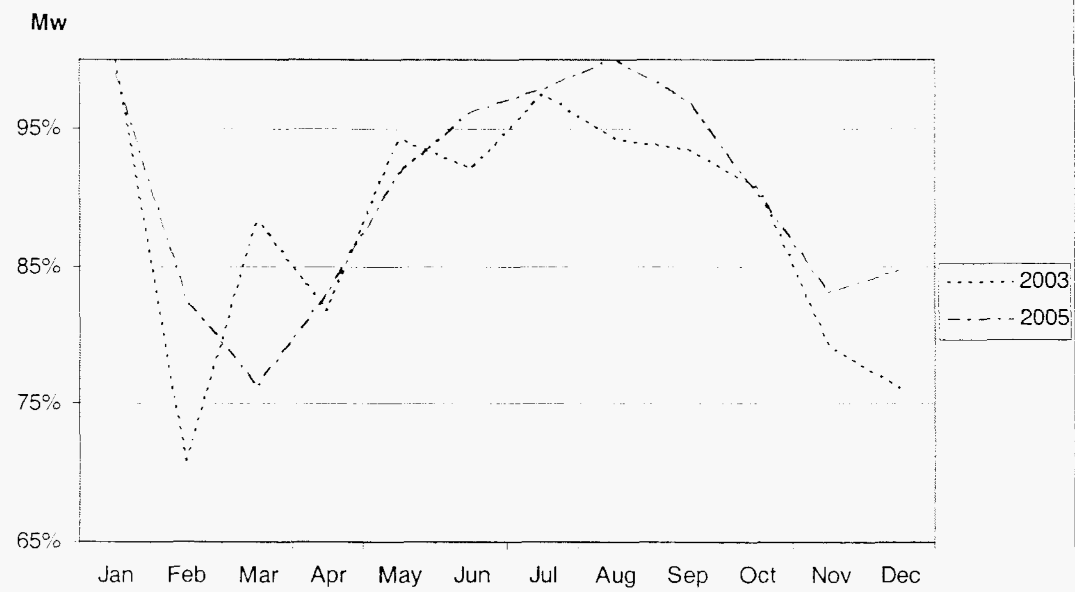


Figure 3
Florida Power & Light
Monthly Peak Demands (2003 Actual, 2005 Forecast)

Figure 4, below, shows the same data in terms of the percentage of each month's peak to the annual peak. As can be seen, coincident peak demands in most months fall far short of the load during the key summer and winter peak months. In half the months, the peak demand falls below 90% of the annual system peak. This represents more than a 2000 mW difference from the peak month demand.

Figure 4
Florida Power & Light
Monthly "% to Peak" Demands (2003 Actual, 2005 Forecast)



Q. What are the implications of this for pricing using the Company's proposed 12 CP and 1/13th average demand methodology?

A. The main implication is that customers are being provided price signals through rates that FPL is indifferent as to whether customers use demand in say March or in August or January. According to FPL's 2004 Ten Year Power Plant Site Plan, the Company will be acquiring almost 6000 mW of new generating capacity over the next 10 years to meet additional summer and winter customer peak loads on the system. Baron Exhibit__(SJB-3), page 1 of 2 presents a copy of "Schedule III.B.1" from the Site Plan. This capacity is expected to cost the Company and its ratepayers in the range of $500 to $600 per kW (see "Schedule 9, Page 5 of 7 of the Site Plan", a copy of which is included on page 2 of 2 of Exhibit__(SJB-3)). That amounts to additional investment (or purchase equivalent) in new generation facilities in the range of $3 billion over the next ten years. Yet, despite this expectation, FPL continues to argue in its rate filing that customer behavior during any of the 12 months during the year is equally responsible for the Company's need to acquire new generating facilities to meet demand.

Q. What about the argument that the fuel savings associated with base load generating units support an allocation method that recognizes customer usage in non-peak months or even in the off-peak period?

A. Though it is certainly true that a base load nuclear unit produces energy at a lower fuel cost than a gas fired combined cycle unit, this does not change the fact that the Company is adding thousands of mW of additional generating capacity to meet its summer and winter peak demand. At the same time, FPL is "telegraphing" its customers through cost allocation and rate design that the "cost" of customer decisions associated with the next unit of consumption during March or October is equally responsible for this new capacity cost as the next unit of consumption during August or January at the time of the system peak.

Q. What conclusions do you draw from this analysis?

A. I believe that it is now appropriate for the Commission to consider an alternative cost allocation method in this case and I recommend a summer/winter coincident peak method using class coincident demand contributions to the August and January test year peaks to allocate production demand costs. Baron Exhibit__(SJB-4) presents summary schedules of the results of such a cost of service study.

Table 3 below shows a comparison of the parity results using the filed 12 CP and 1/13th average demand method and the summer/winter CP method. As can be seen, there are significant differences in the reported parity results using the two methodologies.

Table 3 Comparison of Parity Index Results		
Rate Class	12 CP & 1/13th As Filed	Sum/Win CP
CILC-1D	77%	108%
CILC-1G	141%	175%
CILC-1T	82%	108%
CS1	72%	89%
CS2	69%	84%
GS1	151%	179%
GSD1	93%	115%
GSLD1	60%	81%
GSLD2	65%	86%
GSLD3	85%	127%
MET	64%	66%
OL-1	-21%	-16%
OS-2	42%	68%
RS1	106%	93%
SL-1	25%	33%
SL-2	252%	290%
SST-TST	279%	618%
SST1-DST	-53%	-54%
SST2-DST	91%	86%
SST3-DST	112%	143%

Q. Would you please discuss the methodology used by FPL to allocate distribution plant investment and expenses to retail rate classes?

A. Yes. As discussed in Ms. Morley's testimony, the Company has classified all distribution plant as demand related except account 369 Services and account 370 meters, which are classified as customer related. The Company's approach does not give any recognition to a customer component of any primary or secondary line, pole or transformer. All of these costs are assigned on the basis of relative class kW demand. FPL, in its response to Commercial Group's interrogatory No. 3 cites a number of prior Commission orders as precedent for its treatment of these costs.

Q. Do you agree with the Company's classification of these distribution costs?

A. No. Despite the Commission's prior decision's rejection of a customer component for these distribution facilities, I believe that there is credible evidence to support a classification of some portion of these facilities as customer related. Given the significant reliance that the Company has placed on the results of its cost of service study in assigning its requested revenue increase to rate schedules in this case, it is reasonable for the Commission to consider evidence on alternative methods of classifying distribution costs in this case. FPL has, to a very significant degree, relied on the "parity" results from its cost of service study to assign increases to rate schedules. In particular, the proposed increases to general service (GSD, GSLD, GSLDT-1, GSLDT-2) and CILC rate schedules are substantially higher than the system average increase due to the parity results. These parity results are driven to a large extent by the methodology used by FPL to classify and allocate costs to rate schedules. This is not purely an argument of academic interest. The impact of this issue for commercial and industrial rate schedules is $30 million, based on a comparison of allocated distribution costs under the FPL methodology and the cost of service results using the minimum secondary distribution system analysis that I have developed and present subsequently.

Q. What is the central argument underlying a classification of some portion of distribution costs (other than services, meters and "primary pull-offs") as customer related?

A. As described in the NARUC Electric Utility Cost Allocation Manual, the underlying argument in support of a customer component is that there is a minimal level of distribution investment necessary to connect a customer to the distribution system (lines, poles, transformers) that is independent of the level of demand of the customer. To the extent that this component of distribution cost is a function of the requirement to interconnect the customer, regardless of the customer's size, it is appropriate to assign the cost of these facilities to rate schedules on the basis of the number of customers, rather than on the kW demand of the class. As stated on page 90 of the NARUC cost allocation manual:

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

Q. In the recent Gulf Power rate case, the Commission considered and rejected a customer component methodology to classify distribution related costs. Have you reviewed the Commission's decision in that case (Docket No. 010949-EI, Order No. PSC-02-0787-FOF-EI)?

A. Yes. I have reviewed the portion of the Order that addresses the allocation and classification of distribution costs. Though the Order speaks for itself, the Commission rejected the conceptual basis of a "zero load cost" that underlies the two methodologies ("zero-intercept" and "minimum size") that have been used to estimate the customer component of various distribution plant accounts (e.g., poles, primary lines, secondary lines, line transformers, etc.). Each of the two methods (the zero-intercept method, for example) is designed to estimate the component of distribution plant cost that is incurred by a utility to effectively interconnect a customer to the system, as opposed to providing a specific level of power (kW demand) to the customer. Though arithmetically, the zero-intercept method does produce the cost of say "line transformers" associated with "0" kW demand, the more appropriate interpretation of the zero-intercept is that it represents the portion of cost that does not vary with a change in size or kW demand and thus <u>should not</u> be allocated on NCP demand (as FPL has done). Essentially, the "zero-intercept" represents the cost that would be incurred, irrespective of differences in the kW demand of a distribution customer. It is this cost-invariant component that is used in the zero-intercept method to identify the portion of distribution costs that should be allocated to rate classes based on the number of primary and secondary distribution customers taking service in the class.

Conceptually, this analysis is designed to estimate the behavior of costs statistically, as the Company meets growth in both the number of distribution customers and the loads of these customers. This is in contrast to FPL's analysis that is premised on an assumption that all distribution costs (except services and meters) vary directly with kW demand, without any fixed component that should be allocated on the basis of the number of customers in each class

Q. Do you have any specific examples that could illustrate this point?

A. Yes. In this rate case, FPL has classified all costs in account No. 368, line transformers, as demand related and allocated these costs to rate schedules on the basis of rate class NCP demand. This account would include equipment ranging from residential pole and pad mounted transformers rated at say 20 kVa to 160 kVa that might serve one or two residential customers (in the case of the smaller size units, to a larger group of residential customers (in the case of a larger pad mounted single phase transformer). For commercial customers, both pole and pad mounted transformers would also be used, including larger sizes rated at say 300 kVa to 500 kVa or greater that might serve a food market, hospital facility or retail store.

To explain why it is inappropriate to allocate the costs of all of these line transformers on the basis of relative class kW demand, it is necessary to examine the cost of this equipment. An analysis of FPL data indicates that the cost per kVa for line transformers decreases as the size of the transformer increases. Table 4 below summarizes some of the line transformer cost data in Account No. 368 on a per kVa basis.

kVa Block	Units	Cost	Avg. Cost	Unit @ Midpoint
< 37	405,131	284,704,516	$ 702.75	$ 37.99
50 - 75	137,779	154,349,814	$1,120.27	$ 17.92
100 - 167	19,153	35,914,215	$1,875.12	$ 14.05
< 75	172,844	272,479,653	$1,576.45	$ 42.04
100 - 300	43,463	168,710,966	$3,881.71	$ 19.41

Table 4
Account No. 368 Line Transformer Data

Based on my experience, this is consistent with industry data. It simply reflects the economies of scales of this type of equipment. Also, the labor associated with the installation of line transformers is a much larger percentage of the cost per kVa for smaller size units, than for larger size units. Again, this represents the economies of scales associated with this investment.

Q. Does FPL's cost allocation study give any recognition to this cost/size relationship?

A. No. Baron Exhibit__(SJB-5) shows the average cost per customer maximum kW demand for line transformer plant in service (the line transformer portion of FERC account No. 368) for both residential and GSLDT-1 customers. This summary is based directly from the Company's cost of service study, as filed in this case. As can be seen, thought the average size of a residential (RS-1) customer is 9.5 kW compared to the average size GSLDT-1 customer of 730 kW, the allocated cost of line transformers to these two rate schedules, on a per kW basis, is identical ($28.90 per kW). The Company's cost allocation study, because it does not recognize a customer component in the allocation of Account No. 368 costs, over-assigns costs to the GSLDT-1 customers.

In FPL's cost of service study, which assigns line transformer costs to rate schedules on the sole basis of kW demand, the underlying assumption is that if a secondary customer on rate schedule GSLD has an average NCP demand of 730 kW and a residential class customer has an average NCP demand of 10 kW, then the cost responsibility of the GSLD customer for line transformer costs is 73 times greater than for an RS-1 customer. This is contrary to the costs of line transformers serving these customers. If a portion of the cost had been classified as customer related so that line transformer costs would be allocated on a demand and a customer basis, the resulting allocation to rate schedules would more reasonably reflect that cost to serve these classes. Again, because the Company is proposing to set rates in this case on the basis of the cost of service study and the resulting parities, it is critical to develop a cost study that accurately reflects the cost to serve each rate schedule. The current method means that commercial class customers pay a distinct subsidy through their rates.

Q. **Can similar arguments be made for other distribution facilities?**

A. Yes. As I noted previously, the Commission has previously rejected this "no-load" conceptual argument. However, as I discussed earlier, the rationale for assigning some distribution facilities on the basis of both a customer and demand component can be supported by examining the nature of the cost for these facilities, rather than a strict reliance on a "no-load" hypothetical construct. I showed this to be the case for line transformers and it can also be logically argued for distribution poles (Account 364). If, for example, the minimum size pole that FPL might install is a 25/30 foot wood pole (which appears to be the FPL minimum), then this "cost" (or at least some portion of it) is incurred to simply interconnect the customer to the system and is not influenced by the level of the customer's demand. Essentially, there is a fixed component of the cost related to the requirement to connect the customer to the system and a variable component related to the size of the customer's load. Sending an FPL customer a "price signal" that relates the incurrence of this cost by FPL to only the level of the customer's kW demand is simply not realistic. Yet, that is the message being sent by way of FPL's cost of service study.

Q. Can you illustrate why the Company's allocation of poles is unreasonable?

A. Yes. FPL's cost of service study classifies all "25/30 foot" wooden poles and all "30 foot" concrete poles as secondary and allocates these facilities to rate schedules on the basis of "secondary group coincident peak demand" (allocation factor FPL105). Based on the Company's workpapers that support the primary/secondary split of account 364 (poles, towers and fixtures), there were 172,403 "25/30 foot" wooden poles in 2003 and 2,719 "30 foot" concrete poles. FPL's allocation of these 175,122 secondary poles to rate schedules is shown in Table 5. Also shown, is the average number of secondary poles assigned per customer for each of these rate schedules.[2]

Table 5
FPL's Assignment of Secondary Poles Per Customer

Total Secondary Poles: 175,122

Rate Class	Allocation Factor*	Poles Allocated to Rate	Poles Per Customer	**Poles Per Every 50 Customers**
CILC-1D	1.302%	2,281	7.84	**391.9**
CILC-1G	0.159%	278	2.28	**113.8**
GS1	6.151%	10,771	0.03	**1.4**
GSD1	19.215%	33,650	0.35	**17.5**
GSLD1	8.233%	14,417	4.95	**247.6**
GSLD2	0.920%	1,610	20.65	**1,032.4**
RS1	63.063%	110,436	0.03	**1.4**

* FPL105

As can be seen from the analysis, the results show that the average number of secondary poles assigned by FPL to CILC-1D customers is 7.84, while for residential customers, it is 0.03. To help place this in perspective, the last column of the table shows the average number of poles for every 50 customers on the rate schedule. For the residential class, the Company's

[2] To illustrate this point, only residential, general service and CILC rates have been included.

study assumes that there are 1.4 secondary poles for every 50 residential customers. These results speak for themselves as regards the reasonableness of the Company's distribution plant analysis. The presumption that the average GSLD-2 customer relies on over 20 ("secondary voltage") poles would appear to be unsupportable.

Q. What about other distribution plant accounts?

A. A traditional distribution plant classification analysis would normally perform a classification analysis on most distribution plant accounts, including Account 364 (poles, towers, fixtures), Account 365 (overhead conductors), Account 366 (underground conduit), Account 367 (underground conductors) and Account 368 (line transformers). Accounts 369 and 370 (services and meters) are usually always classified as customer related, as FPL has done in this case. The result of such a study would be a classification of each of these accounts into both customer and demand components, using either a minimum system or, more commonly, a "zero-intercept" method.

The conceptual basis for the zero-intercept method is that it reflects a classification of the distribution facilities that would be required to simply interconnect a customer to the system, irrespective of the kW load of the customer. From a cost causation standpoint, the argument supporting this approach is that all of these minimal facilities would be required simply due to the requirement to interconnect the customer, including meeting minimum safety standards set forth in the National Electric Safety Code ("NESC"), which the FPSC requires be adhered to for all Florida electric utilities.

Q. Are there other reasons why a customer classification of some portion of distribution plant is appropriate for FPL's system?

A. Yes. There are a significant number of "second homes" or vacation homes on the FPL system. Consider a residential single family home that is used for say 50 days per year as a vacation home. FPL, in connecting this dwelling to its system, does not know that this customer's contribution to the residential class "secondary group coincident peak demand" is likely to be very low, given the probability that the customer will not occupy the dwelling on the day and hour of the group peak. Because the Company does not know this, and to meet standard reliability requirements for distribution facilities, FPL will install secondary conductors to meet or exceed the expected maximum load of this customer and the other customers than may be served from the secondary line segment. In its cost of service study, FPL classifies secondary lines (the secondary component of accounts 365 and 367) as demand related and allocates the cost to rate schedules on allocation factor "FPL105" (secondary group coincident peak demand). The obvious problem with FPL's approach is that very little of the cost of this distribution line will be assigned to the residential class, even though it is in place to serve the customer. Only in the low probability event that the vacation home is being occupied on the day and hour of the residential class peak would the cost of this secondary line be assigned to the customer and the residential class. By failing to recognize that a fixed "customer related" component of this cost exists, the Company's study is understating the cost of service to residential customers and, by definition, overstating the cost of service to general service customers.

Q. Have you develop any estimate of the potential impact of this distribution classification issue on the rate schedule cost of service parity results presented by FPL in this case?

A. Yes. To illustrate the impact of this distribution plant classification issue in this case, I have developed two alternative cost of service analyses using the cost classification percentages presented by Gulf Power Company in its cost study. I have only applied these customer/demand classification to the secondary portion distribution accounts 364, 368 (poles and line transformers) and the secondary portion of accounts 365, 366 and 367 (overhead and underground lines and underground conduit). Though I believe that the primary portion of all of these facilities should also reflect a "customer component", I have not reclassified FPL's costs for these primary facilities. The purpose of this analysis is to illustrate the impact of this issue on the parity results presented by the Company and used to establish the rate schedule revenue increases in this case.

The first analysis, shown in Baron Exhibit__(SJB-6) is a modification of the FPL 12 CP and 1/13th average demand methodology cost study presented in the Company's filing. The modification made to this study is to classify the secondary portions of accounts 364, 365, 366, 367 and 368 using the customer/demand ratios for these accounts developed in the Gulf Power cost study. Though I acknowledge that an FPL specific analysis of these two plant accounts would likely produce different classification ratios, since the equipment used by Gulf Power (for example, line transformers, poles) would be similar in nature and cost, the use of the Gulf Power classification data should provide indicative impacts to illustrate the significance of this issue on parity results.

The second analysis that I developed (Baron Exhibit__(SJB-7) uses the summer/winter CP allocation methodology from production demand related costs, together with the modified classification for the secondary portion of accounts 364, 365, 366, 367 and 368.

Q. What are the results of the alternative analyses?

A. Table 6 below shows the rate schedule parity results of the two alternative cost of service studies, compared to FPL's filed results.

Table 6
Comparison of Parity Index Results

Rate Class	12 CP & 1/13th w/Min Dist	S/W CP w/Min Dist
CILC-1D	82%	114%
CILC-1G	152%	187%
CILC-1T	82%	108%
CS1	79%	96%
CS2	74%	91%
GS1	145%	171%
GSD1	101%	124%
GSLD1	67%	89%
GSLD2	70%	93%
GSLD3	85%	127%
MET	64%	66%
OL-1	-21%	-15%
OS-2	48%	77%
RS1	103%	90%
SL-1	26%	35%
SL-2	266%	305%
SST-TST	281%	618%
SST1-DST	-54%	-54%
SST2-DST	104%	98%
SST3-DST	112%	143%

As can be seen, the parity results for the general service and CILC rate schedules based on my recommended study (summer/winter CP, minimum distribution system for secondary facilities) are significantly closer to 1.00 than under the Company's filed study for the major rate classes. These results support the allocation of approved revenue increases on an equal percentage increase for all rate schedules.

Q. Are there any additional issues that you would like to address?

A. Yes. The Company is proposing to recover the fixed costs associated with Turkey Point Unit 5 on a kWh basis, within rate schedules. If the Commission approves the Company's proposed 2007 Turkey Point Unit 5 recovery in this case, the allocated revenue to demand metered rate schedules should be recovered on a kW demand basis, rather than on a kWh basis as proposed by FPL. These are demand related costs and, to the extent that a rate schedule incorporates a demand charge in the rate, the Turkey Point Unit 5 charges should be recovered from the kW demand charge.

Q. Does that complete your testimony at this time?

A. Yes.

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

IN RE: PETITION FOR RATE INCREASE BY FLORIDA POWER & LIGHT COMPANY) DOCKET NO. 050045-EI

DIRECT TESTIMONY OF RICHARD A. BAUDINO

I. QUALIFICATIONS AND SUMMARY

Q. Please state your name and business address.

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

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

A. I am a utility rate and economic consultant holding the position of Director of Consulting with the firm of Kennedy and Associates.

Q. Please describe your education and professional experience.

A. I received my Master of Arts degree with a major in Economics and a minor in Statistics from New Mexico State University in 1982. I also received my Bachelor of Arts Degree with majors in Economics and English from New Mexico State in 1979.

I began my professional career with the New Mexico Public Service Commission Staff in October of 1982 and was employed there as a Utility Economist. During my employment with the Staff, my responsibilities included the analysis of a broad range of issues in the ratemaking field. Areas in which I testified included cost of service, rate of return, rate design, revenue requirements, analysis of sale/leasebacks of generating plants, utility finance issues, and generating plant phase-ins.

In October 1989 I joined the utility consulting firm of Kennedy and Associates as a Senior Consultant where my duties and responsibilities covered substantially the same areas as those during my tenure with the New Mexico Public Service Commission Staff. I became Manager in July 1992 and was named to my current position in January 1995.

Exhibit ____(RAB-1) summarizes my expert testimony experience.

Q. On whose behalf are you testifying?

A. I am offering testimony on behalf of the South Florida Hospital and Healthcare Association ("SFHHA") and individual healthcare institutions (collectively, the "Hospitals") taking electric service on the Florida Power & Light Company ("FPL" or "Company") system .

Q. What is the purpose of your Direct Testimony?

A. The purpose of testimony is to address the investor required return on equity for Florida Power and Light Company.

Q. Please summarize your recommendation.

A. I conclude that the investor required return on equity for FPL is 8.70%.

Q. How is your testimony organized?

A. Section II provides a summary of past and current economic conditions, which sets the backdrop for my rate of return analysis. Section III contains a discussion of my approach to estimating the cost of equity and the results of the methodologies that I utilize. Section IV contains my response to the Direct Testimony of Dr. William Avera, witness for FPL.

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II. REVIEW OF ECONOMIC AND FINANCIAL CONDITIONS

Q. Please describe the general economic trends that have affected utilities in the last few years.

A. The trend for the stock and bond markets was quite positive through the '90s. Although there was a recession in late 1990 through early 1991, the markets continued to post strong, above average gains through 1999. During the period from 1990 - 1999, the S&P 500 posted an average annual gain of 18.2%, still well above the long-term average stock market return of 12.4%[1]. Long-term government bonds also provided excellent returns during the '90s, averaging 8.8% per year compared to the long-run average of 5.8%. During the 1990s, inflation remained moderate, averaging 2.9%.

In 2000, the stock and bond markets substantially diverged. The total return for the S&P 500 was –9.11%, while the return for small company stocks was –3.59%. Bond prices, however, staged a strong rally despite two interest rate increases by the Federal Reserve. The total return for long-term government bonds for the year was 21.48%, with the yield falling from 6.82% at the end of 1999 to 5.58% at the end of December 2000. The inflation rate rose to 3.39% for the year.

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1 *Stocks, Bonds Bills, and Inflation 2004 Yearbook*, Ibbotson Associates, pages 19 and 33.

During 2001, the economy slowed considerably and was affected drastically by the terrorist attacks of September 11. The unemployment rate rose to 5.8% and GDP growth slowed to only 1.1% for the year. Stock and bond markets again showed divergent returns. The Standard and Poor's 500 returned –11.88% for the year, while small company stocks actually did quite well, posting a total return of 22.77%. Long-term government bonds returned 3.70% during 2001. For 2002, Ibbotson Associates reported that the unemployment rate rose to 6.0% and GDP grew at an inflation-adjusted rate of 2.4%. This compares to the 0.3% growth rate for GDP in 2001. The S&P 500 returned –22.10% for the year, the third straight yearly loss for large-company stocks. However, long-term government bond returned 17.84%, well above the long-run average yearly return. 2003 was a much better year for the stock market in general as the U.S. economy staged a recovery. Ibbotson Associates reported that GDP grew at an inflation-adjusted rate of 3.1% and the unemployment rate fell to 5.7%. In a huge rebound from the losses sustained in 2002, the S&P 500 gained 28.70%, while small-company stocks surged to a total return of 60.70%. Long-term government bonds only returned a modest 1.45% for the year. Utility stocks also did well during 2003, with prices staging a significant rally during the year. The Dow Jones Utility Average began the year at 215.16 and closed the year at 266.9, an increase of 24%.

In 2004, the stock market has had somewhat mixed results. Ibbotson Associates reported that the S&P 500 index produced a total return for the year of 10.87%. Value Line's *Selection and Opinion* for January 14, 2005 indicated that the Dow Jones Utility Average gained 25.5% and the Value Line Utilities index increased 10.1%. Long-term government and corporate bonds also did quite well in 2004. Ibbotson Associates reported that the total returns for long-term government and corporate bonds were 8.51% and 8.72%, respectively. These returns were significantly higher than the average annual returns for long-term bonds. The U.S. unemployment rate eased to 5.4% for December, according to the U.S. Department of Labor's Bureau of Labor Statistics.

Q. What has the trend in capital costs been over the last few years?

A. Exhibit____(RAB-2) presents a graphic depiction of the trend in interest rates from January 1995 through May 2005. The interest rates shown are for the 20-year U.S. Treasury Bond and the average public utility bond from the Mergent Bond Record. Exhibit____(RAB-2) shows that the yields on long-term treasury and utility bonds have declined significantly since early 1995, although rates have been quite volatile. Increased bond market volatility actually began in the early 1970s, when inflation became more of a sustained long-term concern.

Yields have trended downward from 2002 through 2005, with the 20-year bond yield declining from 5.69% to 4.56% at the end of May 2005. The yield on the average public utility bond also decreased significantly over the last two years, falling from 7.83% in March 2002 to 5.60% in May 2005, a decline of over 220 basis points. Public utility bond yields fell far more than long-term Treasury yields over this two-year period.

Moody's reported that as of June 10, 2005, the average public utility bond yield was 5.34%.

Current bond yields are either at or near their lowest levels in recent history. Exhibit____(RAB-2) shows that since 1995 public utility bond yields are at their lowest level over that ten-year historical period. I also reviewed the Mergent *Public Utility Manual* and found that average public utility bond yields have not been as low as they are now since the 1968 – 1969 time period, almost 36 years ago.

Q. Mr. Baudino, in your opinion what effect does the current interest rate environment have on utility stocks?

A. In my view, the currently low bond yields strongly suggest lower return on equity requirements on the part on the investing public. The results of my return on equity analysis in the subsequent section of my Direct Testimony are consistent with these historically low bond yields.

Q. In 2003, Congress enacted a change in tax policy that lowered the tax rate on dividends and capital gains. Please explain the effect of this tax change on utility common stocks and on investor required returns for utilities.

A. Other things being equal, the dividend tax rate reduction means that investors should require lower pre-tax rates of return for utilities. This is because the after-tax dividend streams have now become more valuable due to the reduction in federal taxation. Thus, for a given stock price investors will discount the future dividend payments at a lower return on equity. The stock prices that I use in my cost of equity analyses fully incorporate the effects of this change in tax rates and on the expected returns for utilities. This also means that investors require *lower* risk premiums for stocks compared to utility bonds.

Q. How does the investment community regard the electric utility industry as a whole?

A. The Value Line Investment Survey reported the following in its October 1, 2004 report on the electric utility industry (central):

"The Electric Utility Industry's finances have undergone dramatic changes since the start of the 21st century. Through the 1990s, returns on total capital, share equity, and common equity showed relatively little change. But starting with the year 2000, as retail competition spread, many utilities were confronted with reduced earnings from basic operations. This induced company managements to look for investments elsewhere to shore up profits. Though many of these investments were initially successful, several eventually turned sour. That led to a weakening of finances and a reduction in earnings.

* * * * *

The power glut in 2002 resulted in a slowdown in new plant construction the following year. This reduced borrowing needs and lowered interest expense. In turn, it led to a rise in common equity ratios and fixed charge coverages. Company managements initiated additional steps to improve finances by selling unprofitable assets, canceling acquisitions, and focusing on core business operations.

* * * * *

By the end of the current year, industry finances will probably recover to the level attained at the start of the century. Over the next 3 to 5 years, further progress is likely. Based on our projection of steady profit growth for the industry to 2007 to 2009, we look for solid improvement in free cash flow."

Value Line also noted that available funds could be used by utilities to buy back stock, increase dividend payments, or both.

The March 4, 2005 Value Line profile of the electric utility industry (east) noted the following:

> **"For a period of several years, beginning in the mid-1990s, many electric utilities eschewed dividend increases in favor of investing in nonregulated operations or M&A activity with another utility ... Many of these nonregulated investments turned sour, or time proved that some of the acquiring utilities in mergers had overpaid. As a result, some companies had little choice but to cut or suspend their common dividends.**
>
> **Utilities began to take another look at raising the dividend after the federal government cut the tax rate on dividends in 2003. Some were still getting their finances in order as part of their "back to basics" strategies, so noteworthy dividend boosts didn't start to occur until 2004.**

* * * *

The good news of dividends has continued in early 2005. A few companies that cut or suspended the dividend in the late 1990s or early 2000s have reinstated it, increased it, or stepped up the growth rate."

The April 1, 2005 Value Line profile of the electric utility industry (central) noted the following:

"...utility profits slumped in 2002. This was due largely to unsuccessful investments abroad and overbuilding domestically. These missteps resulted in heavy write-offs, weakened capital structures, and debt rating reductions by major rating organizations. Starting in 2003, managements began taking steps to reverse course. Overseas assets were sold and plant construction was scaled back. That began a profit rebound. By the end of 2004, most previous mistakes had been overcome, and 2005 began with a relatively clean slate."

On May 2, 2005, Standard and Poor's published an article entitled "U.S. Utility Rating Actions Continued Their Slow-Down In First Quarter 2005". This article covered ratings actions for the utility industry as a whole (electric, gas, pipeline, and water companies). S&P noted that for the investor-owned utility industry, ratings activities moderated in the first quarter of 2005 and were balanced between negative and positive actions. The article noted that the "main drivers of negative rating actions were continued erosion in financial credit measures, increasing business risk, aggressive financial policies, and uncertainty regarding funding of accelerating capital programs." S&P noted in this article that the outlook for the utility industry was relatively stable and that the average rating for the industry was BBB. Looking ahead at the utility industry, S&P noted that "[t]raditional, nondiversified utilities should remain relatively stable, with little of the downside pressure experienced elsewhere in the industry."

Q. What conclusions do you draw from Value Line's and S&P's comments regarding the state of the electric industry today?

A. In my opinion, it appears that the electric industry is entering a more stable, less risky environment than it experienced during the last few years. Companies that focus on core electric operations will be lower risk than those with unregulated and/or deregulated operations and investments.

Q. How does the investment community view FPL?

A. FPL carries senior secured debt ratings of A from Standard and Poor's and Aa3 from Moody's.

S&P published its most recent detailed research report on FPL on April 1, 2005. S&P noted in this report that the Company's strengths are as follows:

- FPL adds stability to FPL Group Inc.'s consolidated cash flow.
- FPL's strong customer growth with a primarily residential base.
- Parent FPL Group's adequate financial performance.

FPL's weaknesses are as follows:

- *Higher risk unregulated generation portfolio at FPL Energy contributes less certain cash flow* (italics added).
- FPL's increased exposure to natural gas to serve its load.
- Uncertainty regarding several regulatory issues at FPL.
- FPL Group's high consolidated leverage.

My review of S&P's report on FPL indicates that the Company adds a stable, lower risk financial profile to FPL Group compared to the higher risk and less stable FPL Energy subsidiary. S&P currently assigns a negative outlook to FPL Group and its subsidiaries due mostly to pending resolution of regulatory issues, such as the current rate proceeding. However, despite the negative outlook, FPL's current bond ratings of Aa3/A are higher than the average utility bond rating of BBB. This indicates that FPL is a lower risk company than the average regulated utility company.

For purposes of estimating the cost of equity for FPL in this case, it is important to note that the Company's cost of equity would be lower than FPL Group as a whole. This is because the more risky and highly leveraged unregulated operations of FPL Energy increase the risk and the required rate of return of FPL Group. Florida ratepayers should not have to support the higher cost of capital associated with FPL Group's unregulated operations. The fair rate of return granted to FPL by the Florida Public Service Commission should only consider the lower risk regulated electric operations of the Company.

III. DETERMINATION OF FAIR RATE OF RETURN

Q. Please describe the methods you employed in estimating a fair rate of return for FPL.

A. I employed a Discounted Cash Flow ("DCF") analysis for a group of comparison electric companies to estimate the cost of equity for FPL's regulated electric operations. I also employed two Capital Asset Pricing Model ("CAPM") analyses, although I did not incorporate these results into my recommendation.

Q. What are the main guidelines to which you adhere in estimating the cost of equity for a firm?

A. Generally speaking, the estimated cost of equity should be comparable to the returns of other firms with similar risk structures and should be sufficient for the firm to attract capital. These are the basic standards set out in Federal Power Comm'n v. Hope Natural Gas Co., 320 U.S. 591 (1944) and Bluefield W.W. & Improv. Co. v. Public Service Comm'n., 262 U.S. 679 (1922).

From an economist's perspective, the notion of "opportunity cost" plays a vital role in estimating the cost of equity. One measures the opportunity cost of an investment equal to what one would have obtained in the next best alternative.

For example, let us suppose that an investor decides to purchase the stock of a publicly traded electric utility. That investor made the decision based on the expectation of dividend payments and perhaps some appreciation in the stock's value over time. However, that investor's opportunity cost is measured by what she or he could have invested in as the next best alternative. That alternative could have been another utility stock, a utility bond, a mutual fund, a money market fund, or any other number of investment vehicles.

The key determinant in deciding whether to invest, however, is based on comparative levels of risk. Our hypothetical investor would not invest in a particular electric company stock if it offered a return lower than other investments of similar risk. The opportunity cost simply would not justify such an investment. Thus, the task for the rate of return analyst is to estimate a return that is equal to the return being offered by other risk-comparable firms. Failing this, the subject firm will be impaired in its ability to attract capital.

Q. What are the major types of risk faced by utility companies?

A. In general, risk associated with the holding of common stock can be separated into three major categories: business risk, financial risk, and liquidity risk. Business risk refers to risks inherent in the operation of the business. Volatility of the firm's sales, long-term demand for its product(s), the amount of operating leverage, and quality of management are all factors that affect business risk. The quality of regulation at the state and federal levels also plays an important role in business risk for regulated utility companies.

Financial risk refers to the impact on a firm's future cash flows from the use of debt in the capital structure. Interest payments to bondholders represent a prior call on the firm's cash flows and must be met before income is available to the common shareholders. Additional debt means additional variability in the firm's earnings, leading to additional risk.

Liquidity risk refers to the ability of an investor to quickly sell an investment without a substantial price concession. The easier it is for an investor to sell an investment for cash, the lower the liquidity risk will be. Stock markets, such as the New York and American Stock Exchanges, help ease liquidity risk substantially. Investors who own stocks that are traded in these markets know on a daily basis what the market prices of their investments are and that they can sell these investments fairly quickly. Many electric utility stocks are traded on the New York Stock Exchange and are considered liquid investments.

Q. Are there any indices available to investors that quantify the total risk of a company?

A. Yes. Published measures exist that categorize companies based on various measures of risk. One of the best-known and most widely available sources is from Value Line. Each company on which Value Line reports is assigned a Safety Rank. The Safety Rank consists of a number from 1 to 5, with 1 being the highest - meaning least risky - and 5 being the lowest - meaning most risky. The Safety Rank measures the total risk of a stock and encompasses a wide array of factors that affect financial and business risk. These factors include:

- Stock price volatility
- Fixed charge coverage ratio
- Quality of earnings
- Capitalization ratio
- Earnings on common stock
- Payout ratio
- Regulatory risk

By selecting companies with the same Safety Rank, investors may rely upon a widely-read third party assessment of which investments are similarly risky.

Bond ratings are another good tool that investors may utilize to determine the risk comparability of firms. Bond rating agencies such as Moody's and Standard and Poor's perform detailed analyses of factors that contribute to the business and financial risk of a particular investment. The end result of their analyses is a bond rating that reflects these risks.

<u>Discounted Cash Flow Method</u>

Q. Please describe the basic DCF approach.

A. The basic DCF approach is rooted in valuation theory. It is based on the premise that the value of a financial asset is determined by its ability to generate future net cash flows. In the case of a common stock, those future cash flows take the form of dividends and appreciation in price. The value of the stock to investors is the discounted present value of future cash flows. The general equation then is:

$$V = \frac{R}{(1+r)} + \frac{R}{(1+r)^2} + \frac{R}{(1+r)^3} + \ldots \frac{R}{(1+r)^n}$$

Where: *V = asset value*
R = yearly cash flows
r = discount rate

This is no different from determining the value of any asset from an economic point of view. However, the commonly employed DCF model makes certain simplifying assumptions. One is that the stream of income from the equity share is assumed to be perpetual; that is, there is no salvage or residual value at the end of some maturity date (as is the case with a bond). Another important assumption is that financial markets are reasonably efficient; that is, they correctly evaluate the cash flows relative to the appropriate discount rate, thus rendering the stock price efficient relative to other alternatives. Finally, the model I employ also assumes a constant growth rate in dividends. The fundamental relationship employed in the DCF method is described by the formula:

$$k = \frac{D_1}{P_0} + g$$

Where: D_1 = *the next period dividend*
P_0 = *current stock price*
g = *expected growth rate*
k = *investor-required return*

It is apparent that the "k" so determined must relate to the investors' expected return. Use of the discounted cash flow method to determine an investor-required return is complicated by the need to express investors' expectations relative to dividends, earnings, and book value over an infinite time horizon. Financial theory suggests that stockholders purchase common stock on the assumption that there will be some change in the rate of dividend payments over time. We assume that the rate of growth in dividends is constant over the assumed time horizon, but the model could easily handle varying growth rates if we knew what they were. Finally, the relevant time frame is prospective rather than retrospective.

Q. What was your first step in conducting your DCF analysis for FPL?

A. My first step was to construct a comparison group of companies that has a risk profile that is reasonably similar to FPL. Since FPL is a wholly owned subsidiary of FPL Group and does not have publicly traded common stock, FPL's cost of equity cannot be estimated directly using the DCF model. As a result, it is necessary to construct a group of comparison companies that has a risk profile that is reasonably similar to FPL.

Q. Please describe your approach for selecting a comparison group of electric companies.

A. As my starting point in this proceeding, I reviewed the group of companies used by FPL witness William Avera in his cost of equity analysis. On page 33 of his

Direct Testimony, Dr. Avera explained that his electric utility proxy group was comprised of electric utilities that had an S&P corporate credit rating of BBB+ or higher and total revenues exceeding $1.0 billion. After excluding ALLETE, Dr. Avera's proxy group consisted of 21 companies that are presented on his Document WEA-3.

My review of Dr. Avera's group indicates that a significant number of companies should be excluded.

First, CINergy Corp. recently agreed to a merger with Duke Energy and Exelon recently announced a proposed merger with Public Service Enterprise Group. The CINergy/Duke merger was announced after Dr. Avera filed his Direct Testimony. However, the Exelon/PSEG merger was announced in December 2004, which was before Dr. Avera filed his testimony. Companies that have pending mergers are not appropriate candidates for a cost of equity analysis since their corporate profiles are subject to significant future changes, which influence investors' expectations, stock prices, and future dividends and earnings. CINergy's and Exelon's mergers would render their historical stock price and earnings forecasts irrelevant for purposes of a cost of equity analysis. Thus, CINergy and Exelon should be eliminated from the proxy group.

Second, Dr. Avera included numerous companies that derive a minority of their revenues from regulated utility operations. For example, Constellation Energy and MDU Resources are involved in significant unregulated operations. MDU

Resources also operates an interstate natural gas pipeline that is regulated by the FERC. *AUS Utility Reports* indicated that the percentage of total revenues from regulated electric operations for these companies was only 15% and 6%, respectively. Unregulated operations are likely fueling higher expected earnings growth rates for both of these companies. On Document WEA-4, Dr. Avera presented forecasted earnings growth rates for Constellation Energy that ranged from 7.09% to 13.0%. For MDU Resources, his earnings growth forecasts ranged from 7.5% to 8.0%. These rates are greatly in excess of the average growth rates for his proxy group of 4.9% to 5.3%. Inclusion of these companies would inflate the investor required return calculation for FPL.

Based on my review of the June 2005 issue of *AUS Utility Reports*, the following companies in Dr. Avera's group have less that half of their revenues coming from regulated utility operations. The percentage after each company's name represents the percentage of total revenues from regulated electric operations.

1. Constellation Energy – 15%
2. Dominion Resources – 35%
3. DTE Energy – 18%
4. MDU Resource Group – 6%
5. OGE Energy Group – 30%
6. SCANA – 43%
7. Sempra Energy – 48%
8. Vectren Corporation – 22%
9. WPS Resources – 18%

In my opinion, companies that have significant unregulated operations or other operations that are not related to regulated electric utility services are not appropriate candidates for inclusion in a proxy group. One of the criteria I have used in constructing a comparison group of companies is to include companies that have at least 50% of their operations coming from regulated electric utility services. Of course, even at that level unregulated activities can have a significant effect on a company's financial profile, but at least that effect is reduced. On this basis, the nine companies I listed above should be excluded from the proxy group.

Using Dr. Avera's proxy group as a starting point, the resulting group of comparison electric companies I used in my analysis is:

1. Alliant Energy
2. Ameren Corp.
3. Consolidated Edison
4. Energy East Corp.
5. FPL Group, Inc.
6. Northeast Utilities
7. NSTAR
8. Pepco Holdings
9. Southern Company
10. Wisconsin Energy

Q. Are the bond ratings of the companies in your comparison group comparable to FPL's bond ratings?

A. Yes. Please refer to Exhibit____(RAB-3), which lists the bond ratings for each of these companies. These bond ratings were taken from the June 2005 issue of *AUS Utility Reports*. As a group, the average bond rating is around a mid to low A. These bond ratings suggest that the comparison group of companies that I have selected provides a reasonable basis for estimating the cost of equity for FPL.

Q. What was your first step in determining the DCF return on equity for the comparison group?

A. I first determined the current dividend yield, D_0/P_0, from the basic equation. My general practice is to use six months as the most reasonable period over which to estimate the dividend yield. The six-month period I used covered the months from December 2004 through May 2005. I obtained historical prices and dividends from Yahoo! Finance. The annualized dividend divided by the average monthly price represents the average dividend yield for each month in the period.

The resulting average dividend yield for the group is 4.12%. These calculations are shown in Exhibit____(RAB-4).

Q. Having established the average dividend yield, how did you determine the expected growth rate for the electric comparison group?

A. "Expected" refers to the investor's expected growth rate. The task, in theory, is to use a growth rate that will correctly forecast the constant rate of growth in dividends. We refer to a perpetual growth rate since the DCF model has no arbitrary cut-off point. The obvious fact is that there is no way to know with absolute certainty what investors expect the growth rate to be in the short term, much less in perpetuity. The dividend growth rate is a function of earnings growth and the payout ratio, neither of which is known precisely for the future.

In this analysis, I relied on three major sources of analysts' forecasts for growth. These sources are Value Line, Zacks Investment Research ("Zacks"), and First Call/Thomson Financial.

Q. Please briefly describe Value Line, Zacks, and First Call/Thomson Financial.

A. Value Line is an investment survey that is published for approximately 1,700 companies, both regulated and unregulated. It is updated quarterly and probably represents the most comprehensive and widely used of all investment information services. It provides both historical and forecasted information on a number of important data elements. Value Line neither participates in financial markets as a broker nor works for the utility industry in any capacity of which I am aware.

According to Zacks' website, Zacks "was formed in 1978 to compile, analyze, and distribute investment research to both institutional and individual investors." Zacks gathers opinions from a variety of analysts on earnings growth forecasts for numerous firms including regulated electric utilities. The estimates of the analysts responding are combined to produce consensus average and median estimates of earnings growth.

Like Zack's, First Call/Thomson Financial also provides detailed investment research on numerous companies. Thomson also compiles and reports consensus analysts' forecasts of earnings growth.

Q. Why did you rely on analysts' forecasts in your analysis?

A. The finance literature has shown that analysts' forecasts provide better predictions of future growth than do estimates based on historical growth alone[2].

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2 See Rozeff (Journal of Forecasting, Volume 2, Issue No. 4, 1983), Brown and Rozeff (Journal of

Q. How did you utilize your data sources to estimate growth rates for the comparison group?

A. Exhibit____(RAB-5), pages 1 and 2, presents the details of the calculations for the Value Line, Zacks, and Thomson Financial forecasted growth estimates. The Value Line growth estimates are based on five-year forecasts for dividend growth and six-year forecasts for earnings growth. The Zacks and First Call/Thomson Financial earnings growth estimates are forecasts for the next three to five years. These earnings and dividend growth estimates for the comparison group are summarized on Columns (1) through (4) of page 1 of Exhibit____(RAB-5).

I also utilized the sustainable growth formula in estimating the expected growth rate. The sustainable growth method, also known as the retention ratio method, recognizes that the firm retains a portion of its earnings fuels growth in dividends. These retained earnings, which are plowed back into the firm's asset base, are expected to earn a rate of return. This, in turn, generates growth in the firm's book value, market value, and dividends.

The sustainable growth method is calculated using the following formula:

Finance, March 1978), Moyer, Chatfield and Kelley (International Journal of Forecasting, 1985), and a study by Vander Weide and Carleton that was incorporated as part of the Edison Electric Institute's comments in the Federal Energy Regulatory Commission's generic cost of capital proceedings.

$$G = B \times R$$

Where: *G = expected retention growth rate*
B = the firm's expected retention ratio
R = the expected return

In its proper form, this calculation is forward-looking. That is, the investors' expected retention ratio and return must be used in order to measure what investors anticipate will happen in the future. Data on expected retention ratios and returns may be obtained from Value Line.

The expected sustainable growth estimates for the comparison group are presented in Column (5) on page 1 of Exhibit____(RAB-5). The data came from the Value Line forecasts for the comparison group.

Q. How did you proceed to determine the DCF cost of equity for the electric comparison group?

A. To estimate the expected dividend yield (D_1) for the group, the current dividend yield must be moved forward in time to account for dividend increases over the next twelve months. I estimated the expected dividend yield by multiplying the current dividend yield by one plus one-half the expected growth rate.

I then added the expected growth rate ranges to the expected dividend yield for the comparison group. The calculation of the resulting DCF returns on equity is presented on page 3 of Exhibit____(RAB-5). The expected growth rates I utilized in this proceeding range from 4.19% to 4.80%. The retention growth method resulted in a growth rate of 3.87%, slightly below the low end of this range.

Q. Please explain how you calculated your DCF cost of equity estimates.

A. Page 3 of Exhibit____(RAB-5) shows four alternative DCF cost of equity calculations using the four growth estimates shown on page 1. The growth rates I used were the Value Line forecasts for dividend and earnings growth and the analysts' forecasts from Zack's and First Call/Thomson Financial.

The DCF returns range from 8.39% to 9.02%. The DCF return on equity utilizing the average of all four growth rates is 8.70%.

Capital Asset Pricing Model

Q. Briefly summarize the Capital Asset Pricing Model ("CAPM") approach.

A. The theory underlying the CAPM approach is that investors, through diversified portfolios, may combine assets to minimize the total risk of the portfolio. Diversification allows investors to diversify away all risks specific to a particular company and be left only with market risk that affects all companies. Thus, CAPM theory identifies two types of risks for a security: company-specific risk and market risk. Company-specific risk includes such events as strikes, management errors, marketing failures, lawsuits, and other events that are unique to a particular firm. Market risk includes inflation, business cycles, war, variations in interest rates, and changes in consumer confidence. Market risk tends to affect all stocks and cannot be diversified away. The idea behind the CAPM is that diversified investors are rewarded with returns based on market risk.

Within the CAPM framework, the expected return on a security is equal to the risk-free rate of return plus a risk premium that is proportional to the security's market, or nondiversifiable risk. Beta is the factor that reflects the inherent market risk of a security. It measures the volatility of a particular security relative to overall market for securities. For example, a stock with a beta of 1.0 indicates that if the market rises by 15.00%, that stock will also rise by 15.00%. This stock moves in tandem with movements in the overall market. Stocks with a beta of 0.5 will only rise or fall 50.00% as much as the overall market. So with an increase in the market of 15.00%, this stock will only rise 7.50%. Stocks with betas greater than 1.0 will rise and fall more than the overall market. Thus, beta is the relevant measure of the risk of individual securities vis-à-vis the market.

Based on the foregoing discussion, the equation for determining the return for a security in the CAPM framework is:

$$K = Rf + \beta(MRP)$$

Where: K = *Required Return on equity*
Rf = *Risk-free rate*
MRP = *Market risk premium*
β = *Beta*

This equation tells us about the risk/return relationship posited by the CAPM. Investors are risk averse and will only accept higher risk if they receive higher returns. These returns can be determined in relation to a stock's beta and the market risk premium. The general level of risk aversion in the economy determines the market risk premium. If the risk-free rate of return is 3.00% and the required return on the total market is 15.00%, then the risk premium is 12.00%. Any stock's required return can be determined by multiplying its beta by the market risk premium. Stocks with betas greater than 1.0 are considered riskier than the overall market and will have higher required returns. Conversely, stocks with betas less than 1.0 will have required returns lower than the market as a whole.

Q. In general, are there concerns regarding the use of the CAPM in estimating the return on equity?

A. Yes. There is considerable controversy surrounding the use of the CAPM[3]. There is strong evidence that beta is not the primary factor in determining the risk of a security. For example, Value Line states that its Safety Rank is a measure of total risk, not its calculated beta coefficient. Beta coefficients usually describe only a small amount of total investment risk. Also, recent finance literature has questioned the usefulness of beta in predicting the relationship between risk and required return. Finally, a considerable amount of judgment must be employed in determining the risk-free rate and market return portions of the CAPM equation. The analyst's application of judgment can significantly influence the

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3 For a more complete discussion of some of the controversy surrounding the use of the CAPM, refer to *A Random Walk Down Wall* Street by Burton Malkiel, pages 229 – 239, 1999 edition.

results obtained from the CAPM. My past experience with the CAPM indicates that it is prudent to use a wide variety of data in estimating returns. Of course, the range of results may also be wide, indicating the difficulty in obtaining a reliable estimate from the CAPM.

Q. **How did you estimate the market return portion of the CAPM?**

A. The first source I used was the Value Line Investment Survey for Windows for May 2005. Value Line provides a summary statistical report detailing, among other things, forecasted growth in dividends, earnings, and book value for the companies Value Line follows. I have presented these three growth rates and the average on page 2 of Exhibit ____(RAB-6). The average growth rate is 12.70%. Combining this growth rate with the average expected dividend yield of the Value Line companies of 1.18% results in an expected market return of 13.88%. The detailed calculations are shown on page 1 of Exhibit ____(RAB-6).

I also considered a supplemental check to this market estimate. Ibbotson Associates published a study of historical returns on the stock market in its *Stocks, Bonds, Bills, and Inflation 2005 Yearbook.* Some analysts employ this historical data to estimate the market risk premium of stocks over the risk-free rate. The assumption is that a risk premium calculated over a long period of time is reflective of investor expectations going forward. Exhibit ____(RAB-7) presents the calculation of the market return using the Ibbotson historical data.

Q. Please address the use of historical earned returns to estimate the market risk premium.

A. The use of historic earned returns on the Standard and Poor 500 to estimate the current market risk premium is rather suspect because it naively assumes that investors currently expect historical risk premiums to continue unchanged into the future forever regardless of present or forecasted economic conditions. Brigham, Shome and Vinson noted the following with respect to the use of historic risk premiums calculated using the returns as reported by Ibbotson and Sinquefield (referred to in the quote as "I&S"):

> **"There are both conceptual and measurement problems with using I&S data for purposes of estimating the cost of capital. Conceptually, there is no compelling reason to think that investors expect the same relative returns that were earned in the past. Indeed, evidence presented in the following sections indicates that relative expected returns should, and do, vary significantly over time. Empirically, the measured historic premium is sensitive both to the choice of estimation horizon and to the end points. These choices are essentially arbitrary, yet can result in significant differences in the final outcome."**[4]

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4 Brigham, E.F., Shome, D.K. and Vinson, S.R., "The Risk Premium Approach to Measuring a

In summary, the use of historic earned returns should be viewed with a great deal of caution. There is no real support for the proposition that an unchanging, mechanistically applied historical risk premium is representative of current investor expectations and return requirements.

Q. How did you determine the risk free rate?

A. I used the average yields on the 20-year Treasury bond and five-year Treasury note over the six-month period from December 2004 through May 2005. The 20-year Treasury bond is often used by rate of return analysts as the risk-free rate, but it contains a significant amount of interest rate risk. The five-year Treasury note carries less interest rate risk than the 20-year bond and is more stable than three-month Treasury bills. Therefore, I have employed both of these securities as proxies for the risk-free rate of return. This approach provides a reasonable range over which the CAPM may be estimated.

Q. What is your estimate of the market risk premium?

Utility's Cost of Equity", *Financial Management*, Spring 1985, pp. 33-45.

A. Exhibit ____(RAB-6), line 9 of page 1, presents my estimates of the market risk premium based on a DCF analysis applied to current market data. The market risk premium is 9.14% using the 20-year Treasury bond and 10.03% using the five-year Treasury bond.

Utilizing the historical Ibbotson data on market returns, the market risk premium ranges from 5.20% to 7.20%. This is shown on Exhibit ____(RAB-7).

Q. How did you determine the value for beta?

A. I obtained the betas for the companies in the electric company comparison group from most recent Value Line reports. The average of the Value Line betas for the electric group is .75.

Q. Please summarize the CAPM results.

A. Please refer to line 14 of page 1 of Exhibit ____(RAB-6) for the CAPM results for the 20-year and five-year Treasury bond yields. For the electric comparison group, the CAPM returns are 11.32% (five-year bond) and 11.55% (20-year bond).

The CAPM results using the historical Ibbotson data range from 8.62% to 10.11%. These results are shown on Exhibit ____(RAB-7).

<u>Conclusions and Recommendations</u>

Q. Please summarize the cost of equity estimates you have developed up to this point in your testimony.

A. Utilizing the DCF model, I developed cost of equity estimates for a comparison group of electric utility companies. The results for the electric company comparison group using the constant-growth DCF model ranged from 8.39% to 9.02%. The results using the CAPM ranged from 8.62% to 11.55%.

Q. What is your recommendation for a fair rate of return on equity for FPL?

A. My recommended rate of return on equity for the Company is 8.70%. This recommendation is based on the average of the four DCF cost of equity estimates. Given current market conditions, I believe this value is the most representative of the investor-required return on equity for an Aa3/A-rated company such as FPL.

I also believe that my recommended fair rate of return of 8.70% reflects the investor required returns for the regulated electric operations of FPL. As I mentioned earlier in my testimony, FPL Group's more risky unregulated operations should not be included in the consideration of the cost of equity for FPL.

Q. Your CAPM results are higher than your DCF results. Why didn't you take this into account in your recommended return on equity for FPL?

A. It is my opinion that the CAPM results for the comparison group may be overstated at this time. This is due, in part, to the application of Value Line's beta for the group of .75. Value Line determines its betas based on five years of historical price data. Over the last five years, utility share prices in general have been quite volatile due to restructuring, deregulation, and the increase of unregulated investments that were more risky than core electric operations. These factors likely increased the historical betas for electric utilities, other things being equal. It now appears that the industry will be more stable going forward and, in my opinion, historical betas are therefore likely to fall from their current level.

Second, the expected return on the market based on Value Line's most recent forecasts appears to be quite volatile at this time. In a piece of return on equity testimony I filed in 2004 for Aquila Networks – WPC, the expected return on the market was 11.70%. Later that year, I filed return on equity testimony for Southwestern Electric Power Company ("SWEPCO") in which the market return jumped substantially to 13.38%. Now in this proceeding, the Value Line market return jumped once again to 13.88%. This change substantially increased the CAPM results in this proceeding compared to my Aquila and SWEPCO testimonies. However, my DCF results have remained fairly stable and are consistent with interest rates trends throughout 2004 and 2005.

Thus, I believe the CAPM results will likely overstate the investors' required return for FPL in this proceeding.

Q. In Section II of your Direct Testimony, you mentioned the passage of the 2003 tax bill that reduced taxes on qualifying dividends to 15%. Do you believe that this reduced tax rate on dividends has affected the investor required returns for electric utilities companies?

A. Yes. As I stated earlier, I believe that the new favorable tax rate on dividends has reduced the investors' required pre-tax cost of equity for electric utilities. Basic economic theory supports this proposition.

Prior to the passage of the 2003 tax bill, dividends were taxed at the normal tax rates, which could be as high as 35%. These same dividends are now being taxed at a much lower 15% rate. What this means is that for a given after-tax rate of return, such as 7% for example, an investor would now require a lower pretax return in order to earn that 7% after-tax return. In the realm of regulation, experts must estimate, and commissions must set, a pretax rate of return on equity that will be applied to a company's rate base. With lower tax rates on dividends, these pretax returns will inevitably decline.

In conclusion, other things being equal, the reduction in dividend taxation should lead to lower required returns for investors. When viewed from this perspective, an 8.70% return on equity for FPL is quite reasonable.

Q. **Have you reviewed Mr. Kollen's Direct Testimony with respect to the appropriate capital structure for FPL?**

A. Yes. I reviewed Mr. Kollen's testimony regarding the appropriate capital structure for FPL. For ratemaking purposes, Mr. Kollen recommended that FPL's equity ratio be set at the midpoint of the S&P range for a single A utility, with the capital structure reflecting the imputed value of the purchased power agreements as an increase in debt.

Q. Do you agree with Mr. Kollen's recommended adjustment to FPL's capital structure?

A. Yes. Mr. Kollen's recommended capital structure is reasonable in light of the excessive equity ratio being requested by the Company in this proceeding. Further, Mr. Kollen's recommendation is consistent with FPL's current bond ratings and with the bond ratings of the companies in my comparison group.

IV. RESPONSE TO DR. WILLIAM AVERA

Q. Have you reviewed the Direct Testimony and Exhibit of FPL witness Avera?

A. Yes.

Q. Please summarize your conclusions with respect to Dr. Avera's testimony and return on equity recommendation.

A. My conclusions regarding Dr. Avera's testimony and return on equity recommendation are as follows.

Dr. Avera's recommended 11.8% return on equity is grossly overstated. Further, Dr. Avera recommended the adoption of a 50 basis point "incentive" adder that further inflates his recommendation to 12.30%. Dr. Avera's return on equity recommendation should be rejected.

Dr. Avera included a number of inappropriate companies in his proxy group. Two companies are engaged in pending merger activity, while nine other companies have a minority of their revenues derived from regulated electric operations. These companies should be excluded from his proxy group for the purpose of estimating the return on equity for FPL regulated electric utility operations.

Dr. Avera improperly used forecasted interest rates in his risk premium analyses. These forecasted interest rates significantly overstated his cost of equity results. For the reasons I discussed earlier in my testimony, risk premium methods are less reliable than the DCF model, which employs current market data in the estimation of the current cost of equity. Thus, I recommend that the FPSC place primary reliance on the DCF model in setting a fair rate of return for FPL in this proceeding.

Dr. Avera's discussion of the current economic environment for electric utilities is overly pessimistic and heavily laden with detailed descriptions of how risky regulated electric operations are. I believe that an objective reading of current market information suggests that the regulated electric utility industry is stabilizing. Further, it should be noted that FPL's Aa3/A bond rating exceeds the average S&P utility bond rating of BBB. This suggests that in comparison to the average utility, FPL is a less risky company.

Dr. Avera's recommended 11.80% return on equity, before the addition of a 50 basis point "incentive adjustment", was taken from the high end of his range of estimates. This unsubstantiated judgment further overstates Dr. Avera's return on equity recommendation.

Dr. Avera's recommended adder of 50 basis points for an incentive adjustment should be rejected. Such an adjustment is inappropriate, merely inflates the investor required return on equity, and harms ratepayers by unjustly increasing rates. Of course, if FPL operates efficiently and reduces costs below test period levels, it will in fact receive an "incentive adjustment" because the Company and its shareholders will be able to keep all such cost reductions.

<u>**DCF Analyses**</u>

Q. Please summarize Dr. Avera's approach to the DCF model and its results.

A. Dr. Avera utilized the constant growth form of the DCF model to estimate the fair return on equity. He employed analysts' forecasts from Value Line, First Call, IBES, and Zack's to estimate the growth component of the model. In calculating forecasted dividend growth from Value Line, Dr. Avera omitted zero growth rates as not meaningful. After calculating all the forecasted growth estimates, Dr. Avera concluded that the expected growth rate for his proxy group fell within a range of 4.9% to 5.6%.

On page 41 of his Direct Testimony, Dr. Avera concluded that the implied cost of equity using a 5.3% midpoint of his growth rate range resulted in a DCF cost of equity of 9.4%.

Q. Are the results and recommendations from Dr. Avera's DCF analyses reasonable?

A. No. Dr. Avera's DCF results are significantly overstated.

Q. Please explain why Dr. Avera's DCF results are overstated.

A. First, as I mentioned in Section III of my Direct Testimony, Dr. Avera's proxy group contains eleven companies that should not be included. Two companies have recently announced mergers and nine companies have a minority of their revenues derived from regulated electric operations. My analysis of Dr. Avera's DCF results indicates that including these companies overstated Dr. Avera's results.

Exhibit ____(RAB-8) presents the results of Dr. Avera's DCF analyses excluding the eleven companies that I discussed in Section III of my Direct Testimony. For the remaining ten companies, the dividend yield is 4.2% and the growth rates range from 4.25% to 5.33%. The DCF cost of equity results range from 8.48% to 9.56%, with an average of all results of 8.81%. This result is almost 60 basis points lower than Dr. Avera's DCF cost of equity recommendation.

My review of Dr. Avera's DCF analysis indicates that excluding Constellation Energy and MDU Resources made a significant difference in the DCF results. Both of these companies have extensive unregulated operations that appear to be driving high expected growth rates. Inclusion of these companies overstated Dr. Avera's DCF results.

Q. Dr. Avera omitted dividend growth rates of zero from his analysis. Is this appropriate?

A. No. Dr. Avera selectively excluded zero growth rates but failed to consider excluding unsustainably high dividend growth rates for certain companies. For example, forecasted earnings growth rates suggest that dividend growth rates of 9.5% for Northeast Utilities and 13.5% for Pepco Holdings are not expected to hold for the longer term. Yet, Dr. Avera gave no consideration to excluding these high near-term dividend growth rates.

If both the high (13.5%) and low (0.0%) dividend growth rates are excluded from the analysis, the average dividend growth rate for the proxy group is 4.93%, with a resulting cost of equity using forecasted dividend growth of 9.16%.

<u>Risk Premium Analyses</u>

Q. Please summarize Dr. Avera's risk premium analyses.

A. Dr. Avera used three different risk premium approaches. The first approach employed allowed returns from regulatory commissions. The second approach estimated an equity risk premium from historical utility stock and bond returns. The third approach utilized the CAPM. Dr. Avera's CAPM models employed both current and historical market risk premiums and an average beta from his proxy group.

In each of his three risk premium approaches, Dr. Avera used both current and projected interest rates to determine the risk premium cost of equity. Projected interest rates were taken from interest rate forecasts for 2006.

Using current interest rates, Dr. Avera's risk premium results ranged from 9.7% to 11.8%. Using forecasted interest rates, his results ranged from 10.9% to 12.0%.

Q. **Was it appropriate for Dr. Avera to use projected interest rates in his risk premium analyses?**

A. No. In my opinion it is more appropriate to use current interest rates than forecasted rates. This is because current interest rates incorporate all information available in the marketplace, including investor expectations on the course of future interest rates. Those expectations carry some weight in terms of the price investors are currently willing to pay for bonds. Interest rates may be forecasted to rise, as they indeed were at the beginning of 2005. However, interest rates declined through May of this year, highlighting the fact that there are great uncertainties associated with those forecasts. That uncertainty is discounted in current bond prices and interest rates.

In my view, if investors knew for a fact that utility bond yields were going to rise to the 7.0% level contained in Dr. Avera's analysis, then they already would have adjusted the prices they are currently willing to pay for those bonds and yields would quickly rise to 7.0%. That is because with certain knowledge, it is unlikely a rational investor today would knowingly accept a certain future capital loss and not discount the price of his or her utility bond. Thus, current bond yields are the best measure of investors' expectations of economic trends since they reflect all currently available market information.

Q. What is your response to Dr. Avera's historical risk premium studies?

A. The problem with Dr. Avera's historical risk premium analysis is similar to the problem with using historical earned returns in the CAPM analysis, which I described earlier in my testimony. This approach naively assumes that earned returns and the resulting risk premiums in an historical period are reflective of current investor expectations. Such an assumption should be viewed with a good deal of skepticism. Given changing investor expectations over time, it is somewhat risky to assume that investors base their current required returns on an unchanging historical risk premium. Finance literature has shown that historical risk premiums change over time. Although historical risk premiums may provide rough guides to estimating current required returns, I believe that it is preferable to place greater weight on DCF calculations that employ current, rather than historic data.

It should also be noted that the recent change in dividend taxation should reduce the expected risk premium of stocks over bonds going forward, other things being equal. As I stated earlier in my testimony, reduced taxation on dividends should lower the investor's required pretax return on equity, other things being equal. Since there was no change in the tax treatment of bond income, the required equity premium over bonds should decline going forward. Thus, historical risk premiums could overstate the current required risk premiums of utility stocks over bonds.

Q. Please comment on Dr. Avera's allowed risk premium analysis which he presented beginning on page 43 of his Direct Testimony.

A. Dr. Avera employed a risk premium approach by using Commission-allowed returns during the period from 1974 through 2004. In addition to the aforementioned weaknesses associated with the risk premium approach in general, using Commission-allowed returns implies that the FPSC should base its return on equity award on what commissions have done in years past in other jurisdictions. The problem here is that other Commissions may include adjustments in their allowed returns on equity such as incentive mechanisms, performance rewards and/or penalties, and other items that are unique to the individual cases in other jurisdictions and may have nothing to do with a straight return on equity. Further, these equity returns may reflect utilities that are more leveraged than FPL, faced greater business risks than FPL (e.g., restructuring or deregulation), or had other circumstances that are not comparable to FPL. Using allowed returns also implies that the FPSC should rely on decisions in other jurisdictions rather than evaluate the specific evidence on return on equity in this proceeding. I recommend that the FPSC reject Dr. Avera's allowed risk premium approach.

<u>**Implications for Financial Integrity**</u>

Q. Beginning on page 73 of his Direct Testimony, Dr. Avera discusses his views on an adequate rate of return and the implications for financial integrity. Please summarize your position with respect to this section of Dr. Avera's testimony.

A. Dr. Avera has included a number of extreme examples of situations with troubled utilities to bolster his position that FPL should be allowed to earn a fair return on equity. In his discussion, Dr. Avera cites the following examples:

- The California energy crisis.
- The "plight" of PG&E and Sierra Resources.
- The financial problems of El Paso Electric Company in the late 1970s.

The problem with these extreme examples cited by Dr. Avera is that none of these situations pertain in any way to FPL. FPL is a below average risk regulated electric utility as I have pointed out elsewhere in my Direct Testimony. Florida regulation has been supportive to its electric utilities and FPL has an above average Aa3/A bond rating. FPL's financial profile looks nothing like the profiles of the troubled utilities Dr. Avera chose to cite in his Direct Testimony. Thus there is little basis for the concerns Dr. Avera expressed on pages 73 through 75 of his Direct Testimony.

I agree with Dr. Avera that FPL should be allowed the opportunity to earn a fair rate of return. However, I do not believe that the Company's allowed return should be inflated in order to protect against risks that FPL does not face.

Dr. Avera's ROE Range and Recommendation

Q. Please summarize the basis of Dr. Avera's recommended return on equity for FPL.

A. Dr. Avera described how he reached his conclusion as to a fair return on equity for FPL on page 82 of his Direct Testimony. Dr. Avera based his 11.8% recommendation on the upper end of his range. He chose the upper end of the range after considering "the potential exposures faced by FPL and the economic requirements necessary to maintain access to capital even under adverse circumstances."

Q. Is it reasonable for Dr. Avera to base his recommended return on equity on the upper end of his ROE range?

A. No. Dr. Avera's selection of the upper end of his ROE range as the basis for his fair rate of return is unreasonable and should be rejected by the Commission.

FPL's bond ratings of Aa3/A are higher than S&P's average rating for the utility industry, which currently stands at BBB. This means that FPL is a lower risk company than the average utility company. Since Dr. Avera used a proxy group of A-rated utility companies to estimate the cost of equity, it is inappropriate for him to select a rate of return from the upper end of his range. FPL's regulated electric operations do not constitute a high-risk investment, in fact quite the contrary. Even with the Company's current regulatory uncertainties, FPL's regulated electric operations contribute financial stability and steady cash flows to FPL Group. FPL's rate of return does not need unnecessary padding going forward.

Dr. Avera's recommendation has the effect of harming ratepayers because they would have to support unreasonably high rates associated with his overstated cost of equity. I recommend that the FPSC reject his proffered cost of equity because it is not a fair rate of return.

50 Basis Point "Incentive" Adder

Q. **On page 82 of his Direct Testimony, Dr. Avera stated that an incentive to recognize exemplary performance and efficient and economic management should be included in his cost of equity recommendation. On page 83, Dr. Avera recommended that the FPSC adopt a 50 basis point adder to recognize these factors. Please address the inclusion of a 50 basis point adder to FPL's cost of equity.**

A. The 50 basis point adder proposed by Dr. Avera and Mr. Dewhurst should be rejected by the Commission.

The Commission and FPL's ratepayers are already entitled to "exemplary performance and efficient and economic management" from the Company. FPL has a duty to provide reliable service to customers at just and reasonable rates as part of the "regulatory compact" between the Commission, the Company, and ratepayers. This 50 basis point adder proposed by Dr. Avera and Mr. Dewhurst would merely enrich the Company's shareholders at the expense of ratepayers.

It should also be noted that the Company's management has apparently provided excellent service and cost reductions in the past without an explicit incentive adder to its return on equity. Thus, management already had all the incentive it required to provide such service. FPL's witnesses have provided no foundation to suggest that such service would cease if the Commission does not provide the requested 50 basis point adder.

Q. Does this conclude your direct testimony?

A. Yes.

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

I, LINDA BOLES, RPR, CRR, Official Commission Reporter, do hereby certify that the foregoing prefiled testimony was assembled under my direct supervision.

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' attorneys or counsel connected with the action, nor am I financially interested in the action.

DATED THIS 24TH DAY OF AUGUST, 2005.

Linda Boles

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