BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 050078-EI

In the Matter of

PETITION FOR RATE INCREASE BY
PROGRESS ENERGY FLORIDA, INC.
______________________________/

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VOLUME 3

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PROCEEDINGS:	TECHNICAL HEARING
BEFORE:	CHAIRMAN BRAULIO L. BAEZ COMMISSIONER J. TERRY DEASON COMMISSIONER RUDOLPH "RUDY" BRADLEY COMMISSIONER LISA POLAK EDGAR
DATE:	Wednesday, September 7, 2005
TIME:	Commenced at 9:30 a.m.
PLACE:	Betty Easley Conference Center Room 148 4075 Esplanade Way Tallahassee, Florida
REPORTED BY:	JANE FAUROT, RPR Official FPSC Hearings Reporter (850) 413-6732
APPEARANCES:	(As heretofore noted.)

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DIRECT TESTIMONY OF JAMES H. VANDER WEIDE, PH.D.

I. Introduction and Summary.

Q. Please state your name, title, and business address for the record.

A. My name is James H. Vander Weide. I am Research Professor of Finance and Economics at the Fuqua School of Business of Duke University. I am also President of Financial Strategy Associates, a firm that provides strategic and financial consulting services to business clients. My business address is 3606 Stoneybrook Drive, Durham, North Carolina.

Q. Would you please describe your educational background and prior academic experience?

A. I graduated from Cornell University in 1966 with a Bachelor's Degree in Economics. I then attended Northwestern University where I earned a Ph.D. in Finance. In January 1972, I joined the faculty of the School of Business at Duke University and was named Assistant Professor, Associate Professor, and then Professor.

Since joining the faculty I have taught courses in corporate finance, investment management, and management of financial institutions. I have taught a graduate seminar on the theory of public utility pricing and lectured in executive development seminars on the cost of capital, financial analysis, capital budgeting, mergers and acquisitions, cash management, short-run financial planning, and competitive strategy. I have also served as Program Director of executive education programs at the Fuqua School of Business, including the Duke Advanced Management Program, the Duke Executive Program in Telecommunications, the Duke Competitive Strategies in Telecommunications Program, and the Duke Program for Manager Development for managers from the former Soviet Union.

I have conducted seminars and training sessions on financial analysis, financial strategy, cost of capital, cash management, depreciation policies, and short-run financial planning for a wide variety of U.S. and international companies, including ABB, Allstate, Ameritech, AT&T, Bell Atlantic, BellSouth, Carolina Power & Light, Contel, Fisons, Glaxo Wellcome, GTE, Lafarge, MidAmerican Energy, New Century Energies, Norfolk Southern, Pacific Bell Telephone, Progress Energy, Inc, The Rank Group, Siemens, Southern New England Telephone, TRW, and Wolseley Plc.

In addition to my teaching and executive education activities, I have written research papers on such topics as portfolio management, the cost of capital, capital budgeting, the effect of regulation on the performance of public utilities, the economics of universal service requirements, and cash management. My articles have been published in *American Economic Review, Financial Management, International Journal of Industrial Organization, Journal of Finance, Journal of Financial and Quantitative Analysis, Journal of Bank Research, Journal of Accounting Research, Journal of Cash Management,*

Management Science, The Journal of Portfolio Management, Atlantic Economic Journal, Journal of Economics and Business, and Computers and Operations Research. I have written a book titled *Managing Corporate Liquidity: an Introduction to Working Capital Management*, and a chapter for *The Handbook of Modern Finance*, "Financial Management in the Short Run."

Q. Have you previously testified on financial or economic issues?

A. Yes. As an expert on financial and economic theory, I have testified on the cost of capital, competition, risk, incentive regulation, forward-looking economic cost, economic pricing guidelines, depreciation, accounting, valuation, and other financial and economic issues in more than 350 cases before the U.S. Congress, the Canadian Radio-Television and Telecommunications Commission, the Federal Communications Commission, the National Telecommunications and Information Administration, the Federal Energy Regulatory Commission, the public service commissions of 40 states, the insurance commissions of five states, the Iowa State Board of Tax Review, the North Carolina Property Tax Commission, and the National Association of Securities Dealers. In addition, I have testified as an expert witness in proceedings before the U.S. District Court, District of Nebraska; U.S. District Court, Eastern District of North Carolina; Superior Court, North Carolina; the U.S. Bankruptcy Court, Southern District of West Virginia; and the U. S. District Court for the Eastern District of Michigan.

Q. What is the purpose of your testimony?

A. I have been asked by Florida Power Corporation d/b/a Progress Energy Florida (PEF) to prepare an independent appraisal of PEF's cost of equity, and to recommend a rate of return on equity that is fair, that allows PEF to attract capital on reasonable terms, and that allows PEF to maintain its financial integrity.

Q. How did you estimate PEF's cost of equity?

A. I estimated PEF's cost of equity in two steps. First, I applied several standard cost of equity methods to market data for proxy groups of comparable companies. Second, I adjusted the average cost of equity for my proxy groups for the difference in the perceived financial risk of my proxy companies in the marketplace and the financial risk implied by my recommended capital structure for PEF.

Q. Why did you apply your cost of equity methods to proxy groups of comparable companies rather than solely to PEF?

A. I applied my cost of equity methods to proxy groups of comparable companies because my methods require that a company's stock be publicly traded, and PEF does not meet this criteria. In addition, standard cost of equity methodologies such as the discounted cash flow (DCF), risk premium, and Capital Asset Pricing Model (CAPM) require inputs of quantities that are not easily measured. Since these inputs can only be estimated, there is naturally some degree of uncertainty surrounding the estimate of the cost of equity for each company.

However, the uncertainty in the estimate of the cost of equity for an individual company can be greatly reduced by applying cost of equity methodologies to a reasonably large sample of comparable companies. Intuitively, unusually high estimates for some individual companies are offset by unusually low estimates for other individual companies. Thus, financial economists invariably apply cost of equity methodologies to a group of comparable companies. In utility regulation, the practice of using a group of comparable companies is further supported by the regulatory standard that the utility should be allowed to earn a return on its investment that is commensurate with returns being earned on other investments of the same risk.[1]

Q. What average cost of equity did you find for your proxy companies?

A. On the basis of my studies, I find that the average cost of equity for my proxy companies is equal to 11.4 percent. This conclusion is based on my application of three standard cost of equity estimation techniques: (1) the discounted cash flow model; (2) the risk premium approach; and (3) the capital asset pricing model.

Q. Does the average cost of equity of your proxy companies depend on their average capital structure?

[1] See *Bluefield Water Works and Improvement Co. v. Public Service Comm'n.* 262 U.S. 679, 692 (1923) and *Federal Power Comm'n v. Hope Natural Gas Co.*, 320 U.S. 591, 603 (1944).

A. Yes. The cost of equity for a company depends on its financial risk, which is measured by the market values of debt and equity in its capital structure. Since PEF's recommended capital structure in this proceeding embodies greater financial risk than the financial risk embodied in the cost of equity estimates for my proxy companies, the cost of equity for my proxy companies will have to be adjusted upward so that investors in PEF will have an opportunity to earn a return on their investment in PEF that is commensurate with returns they could earn on other investments of comparable risk. On the basis of my studies, I have determined that PEF requires a cost of equity of 12.3 percent to compensate investors for the higher financial risk of PEF's capital structure.

Q. What is your recommendation regarding PEF's cost of equity?

A. I recommend that PEF be allowed a rate of return on equity equal to 12.3 percent.

Q. Do you have exhibits accompanying your testimony?

A. Yes. I have prepared or supervised the preparation of the following exhibits to my testimony:

- Exhibit No. ___ (JVW-1), Summary of Discounted Cash Flow Analysis for Electric Energy Companies.
- Exhibit No. ___ (JVW-2), Summary of Discounted Cash Flow Analysis for Natural Gas Companies.

- Exhibit No. ___ (JVW-3), Comparison of the DCF Expected Return on an Investment in Electric Companies to the Interest Rate on Moody's A-Rated Utility Bonds.
- Exhibit No. ____ (JVW-4), Comparison of the DCF Expected Return on an Investment in Natural Gas Companies to the Interest Rate on Moody's A-Rated Utility Bonds.
- Exhibit No. ___ (JVW-5), Comparative Returns on S&P 500 Stock Index and Moody's A-Rated Bonds 1937—2003.
- Exhibit No. ___ (JVW-6), Comparative Returns on S&P Utility Stock Index and Moody's A-Rated Bonds 1937—2003.
- Exhibit No. ___ (JVW-7), Using the Arithmetic Mean to Estimate the Cost of Equity Capital.
- Exhibit No. ___ (JVW-8), Calculation of Capital Asset Pricing Model Cost of Equity Using Ibbotson Associates' 7.2% Risk Premium.
- Exhibit No. ___ (JVW-9), Calculation of Capital Asset Pricing Model Cost of Equity Using DCF Estimate of the Expected Rate of Return on the Market Portfolio.
- Exhibit No. ___ (JVW-10), Derivation of the Quarterly DCF Model.
- Exhibit No. ___ (JVW-11), Adjusting for Flotation Costs in Determining a Public Utility's Allowed Rate of Return on Equity.
- Exhibit No. ___ (JVW-12), Ex Ante Risk Premium Method.
- Exhibit No. ___ (JVW-13), Ex Post Risk Premium Method.

These exhibits are true and accurate.

II. Economic and Legal Principles.

Q. How do economists define the required rate of return, or cost of capital, associated with particular investment decisions such as the decision to invest in electric generation, transmission, and distribution facilities?

A. Economists define the cost of capital as the return investors expect to receive on alternative investments of comparable risk.

Q. How does the cost of capital affect a firm's investment decisions?

A. The goal of a firm is to maximize the value of the firm. This goal can be accomplished by accepting all investments in plant and equipment with an expected rate of return greater than the cost of capital. Thus, a firm should continue to invest in plant and equipment only so long as the return on its investment is greater than or equal to its cost of capital.

Q. How does the cost of capital affect investors' willingness to invest in a company?

A. The cost of capital measures the return investors can expect on investments of comparable risk. The cost of capital also measures the investor's required rate of return on investment because rational investors will not invest in a particular investment opportunity if the expected return on that opportunity is less than the cost of capital. Thus, the cost of capital is a hurdle rate for both investors and the firm.

Q. **Do all investors have the same position in the firm?**

A. No. Debt investors have a fixed claim on a firm's assets and income that must be paid prior to any payment to the firm's equity investors. Since the firm's equity investors have a residual claim on the firm's assets and income, equity investments are riskier than debt investments. Thus, the cost of equity exceeds the cost of debt.

Q. **What is the overall or average cost of capital?**

A. The overall or average cost of capital is a weighted average of the cost of debt and cost of equity, where the weights are the percentages of debt and equity in a firm's capital structure.

Q. **Can you illustrate the calculation of the overall or weighted average cost of capital?**

A. Yes. Assume that the cost of debt is 7 percent, the cost of equity is 13 percent, and the percentages of debt and equity in the firm's capital structure are 50 percent and 50 percent, respectively. Then the weighted average cost of capital is expressed by .50 times 7 percent plus .50 times 13 percent, or 10.0 percent.

Q. **How do economists define the cost of equity?**

A. Economists define the cost of equity as the return investors expect to receive on alternative equity investments of comparable risk. Since the return on an equity investment of comparable risk is not a contractual return, the cost of equity is more difficult to measure than the cost of debt. However, as I have already noted, there is agreement among economists that the cost of equity is greater than the cost of debt. There is also agreement among economists that the cost of equity, like the cost of debt, is both forward looking and market based.

Q. How do economists measure the percentages of debt and equity in a firm's capital structure?

A. Economists measure the percentages of debt and equity in a firm's capital structure by first calculating the market value of the firm's debt and the market value of its equity. Economists then calculate the percentage of debt by the ratio of the market value of debt to the combined market value of debt and equity, and the percentage of equity by the ratio of the market value of equity to the combined market values of debt and equity. For example, if a firm's debt has a market value of $25 million and its equity has a market value of $75 million, then its total market capitalization is $100 million, and its capital structure contains 25% debt and 75% equity.

Q. Why do economists measure a firm's capital structure in terms of the market values of its debt and equity?

A. Economists measure a firm's capital structure in terms of the market values of its debt and equity because: (1) the weighted average cost of capital is defined as the return investors expect to earn on a portfolio of the company's debt and equity securities; (2) investors measure the expected return and risk on their portfolios using market value weights, not book value weights; and (3) market values are the best measures of the amounts of debt and equity investors have invested in the company on a going forward basis.

Q. Why do investors measure the return on their investment portfolios using market value weights rather than book value weights?

A. Investors measure the return on their investment portfolios using market value weights because market value weights are the best measure of the amounts the investors currently have invested in each security in the portfolio. From the point of view of investors, the historical cost or book value of their investment is entirely irrelevant to the current risk and return on their portfolios because if they were to sell their investments, they would receive market value, not historical cost. Thus, the return can only be measured in terms of market values.

Q. Is the economic definition of the weighted average cost of capital consistent with regulators' traditional definition of the average cost of capital?

A. No. The economic definition of the weighted average cost of capital is based on the market costs of debt and equity, the market value percentages of debt and equity in a company's capital structure, and the future expected risk of investing in the company. In contrast, regulators have traditionally defined the weighted average cost of capital using the embedded cost of debt and the book values of debt and equity in a company's capital structure.

Q. Does the required rate of return on an investment vary with the risk of that investment?

A. Yes. Since investors are averse to risk, they require a higher rate of return on investments with greater risk.

Q. Do economists and investors consider future industry changes when they estimate the risk of a particular investment?

A. Yes. Economists and investors consider all the risks that a firm might incur over the future life of the company.

Q. Are these economic principles regarding the fair return for capital recognized in any Supreme Court cases?

A. Yes. These economic principles, relating to the supply of and demand for capital, are recognized in two United States Supreme Court cases: (1) *Bluefield Water Works and Improvement Co. v. Public Service Comm'n.*; and (2) *Federal Power Comm'n v. Hope Natural Gas Co.* In the *Bluefield Water Works* case, the Court states:

> A public utility is entitled to such rates as will permit it to earn a return upon the value of the property which it employs for the convenience of the public equal to that generally being made at the same time and in

> the same general part of the country on investments in other business undertakings which are attended by corresponding risks and uncertainties; but it has no constitutional right to profits such as are realized or anticipated in highly profitable enterprises or speculative ventures. The return should be reasonably sufficient to assure confidence in the financial soundness of the utility, and should be adequate, under efficient and economical management, to maintain and support its credit, and enable it to raise the money necessary for the proper discharge of its public duties. [*Bluefield Water Works and Improvement Co. v. Public Service Comm'n.* 262 U.S. 679, 692 (1923)].

The Court clearly recognizes here that: (1) a regulated firm cannot remain financially sound unless the return it is allowed to earn on the value of its property is at least equal to the cost of capital (the principle relating to the demand for capital); and (2) a regulated firm will not be able to attract capital if it does not offer investors an opportunity to earn a return on their investment equal to the return they expect to earn on other investments of the same risk (the principle relating to the supply of capital).

In the *Hope Natural Gas* case, the Court reiterates the financial soundness and capital attraction principles of the *Bluefield* case:

> From the investor or company point of view it is important that there be enough revenue not only for operating expenses but also for the capital costs of the business. These include service on the debt and dividends on the stock... By that standard the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital. [*Federal Power Comm'n v. Hope Natural Gas Co.*, 320 U.S. 591, 603 (1944)].

Q. What practical difficulties arise when one attempts to apply the economic principles noted above to a regulated firm?

A. The application of these principles to the debt and preferred stock components of a regulated firm's capital structure is straightforward. Several problems arise, however, when the principles are applied to common equity. These problems stem from the fact that the cash flows to the equity investors, over any period of time, are not fixed by contract, and thus are not known with certainty. To induce equity investors to part with their money, a firm must offer them an expected return that is commensurate with expected returns on equity investments of similar risk. The need to measure expected returns makes the application of the above principles difficult. These difficulties are especially pronounced today for a firm like PEF, which is part of an industry that faces increased demand uncertainty, increased operating cost uncertainty, and increased uncertainty regarding the investments required to provide safe and reliable service.

Q. How do you address these difficulties in your testimony?

A. I address these difficulties by employing the comparable company approach to estimate PEF's cost of equity.

Q. What is the comparable company approach?

A. The comparable company approach estimates PEF's cost of equity by identifying a group of companies of similar risk. The cost of equity is then estimated for the companies in the proxy group.

III. Business and Financial Risks in Electric Energy Business.

Q. What are the primary factors that affect the business and financial risks of electric energy companies such as PEF?

A. The business and financial risks of investing in the electric energy business are affected by a number of factors, including:

1. Demand Uncertainty. The business risk of electric energy companies is increased by the high degree of demand uncertainty in the industry. Demand uncertainty is caused by: (a) the strong dependence of electric demand on the state of the economy and weather patterns; (b) the ability of customers to choose alternative forms of energy, such as natural gas or oil; (c) the ability of some customers to locate facilities in the service areas of competitors; (d) the ability of some customers to produce their own electricity under cogeneration or self-generation arrangements; and (e) the ability of municipalities to go into the energy business rather than renew the company's franchise. Demand uncertainty is a problem for electric companies because of the need to plan for infrastructure additions many years in advance of demand.

2. Operating Expense Uncertainty. The business risk of electric energy companies is also increased by the inherent uncertainty in the typical electric energy company's operating expenses. Operating expense uncertainty arises as a result of: (a) the prospect of rising employee health care and pension expenses; (b) variability in storm-related expenses due to severe weather; (c) the prospect of increased expenses for security related to the threat of

terrorist activities; (d) high volatility in fuel prices; and (e) uncertainty in the cost of purchased power.

3. Investment Uncertainty. The electric energy business requires very large investments in the generation, transmission, and distribution facilities required to deliver energy to customers. The future amounts of required investments in these facilities are highly uncertain as a result of: (a) demand uncertainty; (b) the prospect that Congress or state legislatures will pass stricter environmental regulations and clean air requirements; (c) the prospect of needing to incur additional investments to insure the reliability of the company's transmission and distribution networks; (d) uncertainty regarding the regulatory and management structure of the electric transmission network; and (e) uncertainty regarding future decommissioning costs. Furthermore, the risk of investing in electric energy facilities is increased by the irreversible nature of the company's investments in generation, transmission, and distribution facilities. For example, if an electric energy company decides to make a major capital expenditure in a coal-fired generation plant, and, as a result of new environmental regulations, energy produced by the plant becomes uneconomic, there is little the company can do to recover its investment.

4. High Operating Leverage. The electric energy business requires a large commitment to fixed costs in relation to the operating margin on sales, a situation known as high operating leverage. The relatively high degree of fixed costs in the electric energy business arises from the average electric

energy company's large investment in fixed generation, transmission, and distribution facilities. High operating leverage causes the average electric energy company's operating income to be highly sensitive to revenue fluctuations.

5. High Degree of Financial Leverage. The large capital requirements for building economically efficient electric generation, transmission, and distribution facilities, along with the traditional regulatory preference for the use of debt, have encouraged electric utilities to maintain highly debt-leveraged capital structures as compared to non-utility firms. High debt leverage is a source of additional risk to utility stock investors because it increases the percentage of the firm's costs that are fixed. The use of financial leverage also reduces the firm's interest coverage and increases vulnerability to variations in earnings.

6. Regulatory Uncertainty. Investors' perceptions of the business and financial risks of electric energy companies are strongly influenced by their views of the quality of regulation. Investors are painfully aware that regulators in some jurisdictions have been unwilling at times to set rates that allow companies an opportunity to recover their cost of service and earn a fair and reasonable return on investment. As a result of their perceived increase in regulatory risk, investors will demand a higher rate of return for electric energy companies operating in those states. On the other hand, if investors perceive that regulators will provide a reasonable opportunity for the

company to maintain its financial integrity and earn a fair rate of return on its investment, investors will view regulatory risk as minimal.

Q. Have any of these risk factors changed in recent years?

A. Yes. In recent years, the risk of investing in electric energy companies has increased as a result of greater uncertainty in demand, operating expenses, and investment costs. Since the risk factors that cause this increase in risk are unlikely to diminish in the foreseeable future, the Commission should recognize these additional risks in setting PEF's allowed rate of return in this proceeding.

Q. Can the risks facing PEF and other electric energy companies be distinguished from the risks of investing in companies in other industries?

A. Yes. The risks of investing in electric energy companies such as PEF can be distinguished from the risks of investing in companies in many other industries in several ways. First, the risks of investing in electric energy companies are increased because of the greater capital intensity of the electric energy business and the fact that most investments in electric energy facilities are irreversible once they are made. Second, unlike returns in competitive industries, the returns from investment in the electric energy business are largely asymmetric. That is, there is little opportunity for electric energy companies to earn more than their required return, and a significant chance that they will earn less than their required return.

Q. Has the investment community recognized that the risk of investing in electric energy companies such as PEF has increased in recent years?

A. Yes. The fact that the investment community recognizes the increased risk of investing in the utility sector, including electric energy companies, is apparent from the large number of bond down-grades over the last several years. As shown below in Table 1, the number of bond down grades has far exceeded the number of bond upgrades since 2000.

Table 1

Bond Rating Changes 2000 - 2004

Year	*Downgrade*	*Upgrade*
2000	65	20
2001	81	29
2002	182	15
2003	139	8
2004	33	18
Total	500	90

In addition, the bond rating agencies are using more stringent criteria to assess a company's suitability to be assigned a particular bond rating.

Q. What is PEF's current S&P bond rating?

A. PEF's current S&P bond rating is BBB with a business risk profile of 5. Since BBB- is the lowest investment-grade bond rating, PEF's current rating is only two notches above non-investment grade.

Q. Is a rating of BBB a reasonable target bond rating for PEF?

A. No. As noted above, electric energy companies such as PEF face significant challenges as they seek to respond to increased uncertainty in the industry. In the face of these uncertainties, PEF should have a target bond rating of A. An A bond rating would allow PEF to attract the capital required to maintain a highly reliable electric energy system and satisfy the potentially large capital expenditures that will be required by customer growth and more rigorous environmental standards.

Q. How do S&P's financial guidelines for an A rating differ from the financial guidelines for a BBB rating?

A. S&P's financial guidelines for an A rating compared to a BBB rating are shown below in Table 2. (These data relate to a company such as PEF with a business profile of 5.)

Table 2

S&P's Financial Guidelines for A-Rating vs. BBB-Rating

Ratio	*Rating* *A*	*BBB*
Funds from Operation/Interest Coverage	3.8x - 4.5x	2.8x - 3.8x
Funds from Operations/Total Debt	22%- 30%	15%– 22%
Total Debt/Total Capital	50%- - 42%	60%– 50%

Q. Does PEF currently satisfy S&P's criteria for an A rating?

A. No. S&P considers PEF's financial ratios to be weak for even a BBB rating. For PEF to increase its rating from BBB to A, its financial ratios must improve.

IV. Capital Structure.

Q. What capital structure do you recommend for the purpose of setting rates in this proceeding?

A. I recommend that PEF's forecasted capital structure for year-end 2006 be used to set rates in this proceeding. PEF's forecasted capital structure for year-end 2006 contains 45 percent debt and 55 percent common equity.

Q. Is PEF's forecasted capital structure at year-end 2006 sufficient to satisfy S&P's criteria for an A bond rating?

A. No. For the purpose of assessing bond ratings, S&P imputes a percentage of PEF's long-term purchased power and co-generation contract obligations as debt. Thus, S&P would consider that PEF had more debt and less equity in assigning a bond rating than PEF shows on its balance sheet.

Q. How does S&P calculate the specific amount of imputed debt they attribute to the company's purchased power and co-generation obligations?

A. S&P calculates the amount of imputed debt associated with the company's purchased power obligations in three steps. First, they calculate the company's capacity payments associated with purchased power and co-generation contracts over the life of the contracts. Second, they discount the total capacity payments in each year to a present value using a discount rate of 10 percent. Third, they assign a risk factor to the present value of the capacity payments to determine the imputed debt associated with the capacity payments.

Q. What risk factor does S&P use for PEF's purchased power and co-generation contracts at this time?

A. S&P assigns a risk factor of 30 percent to PEF's purchased power and co-generation contracts.

Q. Using this risk factor, what is the forecasted value of imputed debt for PEF's purchased power and co-generation contracts at year-end 2006?

A. The forecasted imputed debt using S&P's methodology for year-end 2006 is $757 million.

Q. Using this level of imputed debt, what capital structure ratios would S&P use to assess PEF's bond rating?

A. As shown below in Table 3, for the purpose of determining PEF's bond rating, S&P's methodology indicates that they would assign a capital structure to PEF containing 50.99 percent debt, 0.60 percent preferred, and 48.41 percent common equity.

Table 3
PEF's Recommended Capital Structure Adjusted for Imputed Debt ($ Millions)

Capital Source	Amount	Weight	PP Adjustment	Adjusted Amount	Adjusted Weight
Debt	2,111	43.37%	757	2,868	50.99%
Preferred	33	0.69%		33	0.60%
Common	2,722	55.94%		2,722	48.41%
Total Capital	4,866	100.00%		5,623	100.00%

Q. Is it important that the Commission recognize the implications of imputed debt when it determines the appropriate capital structure for use in setting rates in this proceeding?

A. Yes. The Commission should recognize that electric energy companies such as PEF are facing increased risk as a result of the greater uncertainty in operating expenses and capital investments required to provide safe and reliable service. In view of this greater risk, PEF should be encouraged to maintain financial ratios that increase the likelihood that its bond rating will be raised to the A level. If the Commission does not recognize the implications of imputed debt when it determines the appropriate capital structure for use in setting rates in this proceeding, it is unlikely that PEF's financial ratios can improve sufficiently to earn an A bond rating.

Q. How does your recommended capital structure for PEF compare to the capital structure the Florida Commission used to set rates in Florida Power & Light Company's (FPL) last rate proceeding?

A. In FPL's last rate proceeding, the Commission used a capital structure containing 41.69 percent debt, 2.31 percent preferred stock, and 56.00 percent common equity. Thus, my recommended capital structure is consistent with the capital structure the Commission has previously used to set rates for FPL.

V. Cost of Equity Estimation Methods.

Q. What methods did you use to estimate the cost of common equity capital for PEF?

A. I used three generally accepted methods for estimating PEF's cost of common equity. These are the Discounted Cash Flow (DCF), risk premium, and CAPM methods. The DCF method assumes that the current market price of a firm's stock is equal to the discounted value of all expected future cash flows. The risk premium method assumes that investors' required return on an equity investment is equal to the interest rate on a long-term bond plus an additional equity risk premium to compensate the investor for the risks of investing in equities compared to bonds. The CAPM assumes that the investors' required rate of return is equal to a risk-free rate of interest plus the product of a company-specific risk factor, beta, and the expected risk premium on the market portfolio.

VI. Discounted Cash Flow (DCF) Method.

Q. Please describe the DCF model.

A. The DCF model is based on the assumption that investors value an asset on the basis of the future cash flows they expect to receive from owning the asset. Thus, investors value an investment in a bond because they expect to receive a sequence of semi-annual coupon payments over the life of the bond and a terminal payment equal to the bond's face value at the time the bond matures. Likewise, investors value an investment in a firm's stock because they expect to receive a sequence of dividend payments and, perhaps, expect to sell the stock at a higher price sometime in the future.

A second fundamental principle of the DCF method is that investors value a dollar received in the future less than a dollar received today. A future dollar is valued less than a current dollar because investors could invest a current dollar in an interest earning account and increase their wealth. This principle is called the time value of money.

Applying the two fundamental DCF principles noted above to an investment in a bond leads to the conclusion that investors value their investment in the bond on the basis of the present value of the bond's future cash flows. Thus, the price of the bond should be equal to:

EQUATION 1

$$P_B = \frac{C}{(1+i)} + \frac{C}{(1+i)^2} + \ldots + \frac{C+F}{(1+i)^n}$$

where:

P_B	=	Bond price;
C	=	Cash value of the coupon payment (assumed for notational convenience to occur annually rather than semi-annually);
F	=	Face value of the bond;
i	=	The rate of interest the investor could earn by investing his money in an alternative bond of equal risk; and
n	=	The number of periods before the bond matures.

Applying these same principles to an investment in a firm's stock suggests that the price of the stock should be equal to:

EQUATION 2

$$P_s = \frac{D_1}{(1+k)} + \frac{D_2}{(1+k)^2} + \cdots + \frac{D_n + P_n}{(1+k)^n}$$

where:

P_S = Current price of the firm's stock;

$D_1, D_2 \ldots D_n$ = Expected annual dividend per share on the firm's stock;

P_n = Price per share of stock at the time the investor expects to sell the stock; and

k = Return the investor expects to earn on alternative investments of the same risk, i.e., the investor's required rate of return.

Equation (2) is frequently called the annual discounted cash flow model of stock valuation. Assuming that dividends grow at a constant annual rate, *g*, this equation can be solved for *k*, the cost of equity. The resulting cost of equity equation is $k = D_1/P_s + g$, where *k* is the cost of equity, D_1 is the expected next period annual dividend, P_s is the current price of the stock, and *g* is the constant annual growth rate in earnings, dividends, and book value per share. The term D_1/P_s is called the dividend yield component of the annual DCF model, and the term *g* is called the growth component of the annual DCF model.

Q. Are you recommending that the annual DCF model be used to estimate PEF's cost of equity?

A. No. The DCF model assumes that a company's stock price is equal to the present discounted value of all expected future dividends. The annual DCF model is only a correct expression for the present value of future dividends if dividends are paid annually at the end of each year. Since the companies in my proxy group all pay dividends quarterly, the current market price that investors are willing to pay reflects the expected quarterly receipt of dividends. Therefore, a quarterly DCF model must be used to estimate the cost of equity for these firms. The quarterly DCF model differs from the annual DCF model in that it expresses a company's price as the present value of a quarterly stream of dividend payments. A complete analysis of the implications of the quarterly payment of dividends on the DCF model is provided in Exhibit No. ___ (JVW-10), Appendix 1. For the reasons cited there, I employed the quarterly DCF model throughout my calculations.

Q. Please describe the quarterly DCF model you used.

A. The quarterly DCF model I used is described in Exhibit No. ___ (JVW-1) and in Exhibit No. ___ (JVW-10), Appendix 1. The quarterly DCF equation shows that the cost of equity is: the sum of the future expected dividend yield and the growth rate, where the dividend in the dividend yield is the equivalent future value of the four quarterly dividends at the end of the year, and the growth rate is the expected growth in dividends or earnings per share.

Q. How did you estimate the quarterly dividend payments in your quarterly DCF model?

A. The quarterly DCF model requires an estimate of the dividends, d_1, d_2, d_3, and d_4, investors expect to receive over the next four quarters. I estimated the next four quarterly dividends by multiplying the previous four quarterly dividends by the factor, (1 + the growth rate, g).

Q. Can you illustrate how you estimated the next four quarterly dividends with data for a specific company?

A. Yes. In the case of Alliant Energy, the first company shown in Exhibit No. ___ (JVW-1), the last four quarterly dividends are equal to .25, .25, .265, and .265. Thus dividends, d_1, d_2, d_3, and d_4 are equal to .2581 and .2736 [.25 x (1 + .0325) = .2581] and [.25 x (1 + .0325) = .2736]. (As noted previously, the logic underlying this procedure is described in Exhibit No. ___ (JVW-10), Appendix 1.)

Q. In Exhibit No. ___ (JVW-10), Appendix 1, you demonstrate that the quarterly DCF model provides the theoretically correct valuation of stocks when dividends are paid quarterly. Do investors, in practice, recognize the actual timing and magnitude of cash flows when they value stocks and other securities?

A. Yes. In valuing long-term government or corporate bonds, investors recognize that interest is paid semi-annually. Thus, the price of a long-term government or corporate bond is simply the present value of the semi-annual interest and principal payments on these bonds. Likewise, in valuing mortgages, investors recognize that interest is paid monthly. Thus, the value of a mortgage loan is simply the present value of the monthly interest and principal payments on the loan. In valuing stock investments, stock investors correctly recognize that dividends are paid quarterly. Thus, a firm's stock price is the present value of the stream of quarterly dividends expected from owning the stock.

Q. When valuing bonds, mortgages, or stocks, would investors assume that cash flows are received only at the end of the year, when, in fact, the cash flows are received semi-annually, quarterly, or monthly?

A. No. Assuming that cash flows are received at the end of the year when they are received semi-annually, quarterly, or monthly would lead investors to make serious mistakes in valuing investment opportunities. No rational investor would make the mistake of assuming that dividends or other cash flows are paid annually when, in fact, they are paid more frequently.

Q. How did you estimate the growth component of the quarterly DCF model?

A. I used the analysts' estimates of future earnings per share (EPS) growth reported by I/B/E/S Thomson Financial.

Q. What are the analysts' estimates of future EPS growth?

A. As part of their research, financial analysts working at Wall Street firms periodically estimate EPS growth for each firm they follow. The EPS forecasts for each firm are then published. Investors who are contemplating purchasing or selling shares in individual companies review the forecasts. These estimates represent five-year forecasts of EPS growth.

Q. What is I/B/E/S?

A. I/B/E/S is a firm that reports analysts' EPS growth forecasts for a broad group of companies. The forecasts are expressed in terms of a mean forecast and a standard deviation of forecast for each firm. Investors use the mean forecast as a consensus estimate of future firm performance.

Q. Why did you use the I/B/E/S growth estimates?

A. The I/B/E/S growth rates: (1) are widely circulated in the financial community, (2) include the projections of reputable financial analysts who develop estimates of future EPS growth, (3) are reported on a timely basis to investors, and (4) are widely used by institutional and other investors.

Q. Why did you rely on analysts' projections of future EPS growth in estimating the investors' expected growth rate rather than looking at past historical growth rates?

A. I relied on analysts' projections of future EPS growth because there is considerable empirical evidence that investors use analysts' forecasts to estimate future earnings growth.

Q. Have you performed any studies concerning the use of analysts' forecasts as an estimate of investors' expected growth rate, g?

A. Yes, I prepared a study in conjunction with Willard T. Carleton, Karl Eller Professor of Finance at the University of Arizona, on why analysts' forecasts are the best estimate of investors' expectation of future long-term growth. This study is described in a paper entitled "Investor Growth Expectations and Stock Prices: the Analysts versus Historical Growth Extrapolation," published in the Spring 1988 edition of *The Journal of Portfolio Management.*

Q. Please summarize the results of your study.

A. First, we performed a correlation analysis to identify the historically oriented growth rates which best described a firm's stock price. Then we did a regression study comparing the historical growth rates with the consensus analysts' forecasts. In every case, the regression equations containing the average of analysts' forecasts statistically outperformed the regression equations containing the historical growth estimates. These results are consistent with those found by Cragg and Malkiel, the early major research in this area (John G. Cragg and Burton G. Malkiel, *Expectations and the Structure of Share Prices*, University of Chicago Press, 1982). These results are also consistent with the hypothesis that investors use analysts' forecasts, rather than historically oriented growth calculations, in making stock buy and sell decisions. They provide overwhelming evidence that the analysts' forecasts of future growth are superior to historically-oriented growth measures in predicting a firm's stock price.

Q. Has your study been updated to include more recent data?

A. Yes. Researchers at State Street Financial Advisors updated my study using data through year-end 2003. Their results continue to confirm that analysts' growth forecasts are superior to historically-oriented growth measures in predicting a firm's stock price.

Q. What price did you use in your DCF model?

A. I used a simple average of the monthly high and low stock prices for each firm for the three-month period ending March 2005. These high and low stock prices were obtained from Thomson Financial.

Q. Why did you use the three-month average stock price in applying the DCF method?

A. I used the three-month average stock price in applying the DCF method because stock prices fluctuate daily, while financial analysts' forecasts for a given company are generally changed less frequently, often on a quarterly basis. Thus, to match the stock price with an earnings forecast, it is appropriate to average stock prices over a three-month period.

Q. Did you include an allowance for flotation costs in your DCF analysis?

A. Yes. I have included a five percent allowance for flotation costs in my DCF calculations.

Q. Please explain your inclusion of flotation costs.

A. All firms that have sold securities in the capital markets have incurred some level of flotation costs, including underwriters' commissions, legal fees, printing expense, etc. These costs are withheld from the proceeds of the stock sale or are paid separately, and must be recovered over the life of the equity issue. Costs vary depending upon the size of the issue, the type of registration method used and other factors, but in general these costs range between three and five percent of the proceeds from the issue [see Lee, Inmoo, Scott Lochhead, Jay Ritter, and Quanshui Zhao, "The Costs of Raising Capital," *The Journal of Financial Research*, Vol. XIX No 1 (Spring 1996), 59-74, and Clifford W. Smith, "Alternative Methods for Raising Capital," *Journal of Financial Economics* 5 (1977) 273-307]. In addition to these costs, for large equity issues (in relation to outstanding equity shares), there is likely to be a decline in price associated with the sale of shares to the public. On average, the decline due to market pressure has been estimated at two to three percent [see Richard H. Pettway, "The Effects of New Equity Sales Upon Utility Share Prices," *Public Utilities Fortnightly*, May 10, 1984, 35—39]. Thus, the total flotation cost, including both issuance expense and market pressure, could range anywhere from five to eight percent of the proceeds of an equity issue. I believe a combined five percent allowance for flotation costs is a conservative estimate that should be used in applying the DCF model in this proceeding.

Q. Is a flotation cost adjustment only appropriate if a company issues stock during the last year?

A As described in Exhibit No. ___ (JVW-11), Appendix 2, a flotation cost adjustment is required whether or not a company issued new stock during the last year. Previously incurred flotation costs have not been recovered in previous rate cases; rather, they are a permanent cost associated with past issues of common stock. Just as an adjustment is made to the embedded cost of debt to reflect previously incurred debt issuance costs (regardless of whether additional bond issuances were made in the test year), so should an adjustment be made to the cost of equity regardless of whether additional stock was issued during the last year.

Q. Does an allowance for recovery of flotation costs associated with stock sales in prior years constitute retroactive rate-making?

A. No. An adjustment for flotation costs on equity is not meant to recover any cost that is properly assigned to prior years. In fact, the adjustment allows PEF to recover only the current carrying costs associated with flotation expenses incurred at the time stock sales were made. The original flotation costs themselves will never be recovered, because the stock is assumed to have an infinite life.

Q. How did you apply the DCF approach to obtain the cost of equity capital for PEF?

A. I applied the DCF approach to the Value Line electric companies shown in Exhibit No. ___ (JVW-1), and to the Value Line natural gas companies shown in Exhibit No. ___ (JVW-2).

Q. How did you select your proxy group of electric companies?

A. I selected all the companies in Value Line's groups of electric companies that: (1) paid dividends during every quarter of the last two years; (2) did not decrease dividends during any quarter of the past two years; (3) had at least three analysts included in the I/B/E/S mean growth forecast; (4) have an investment grade bond rating and a Value Line Safety Rank of 1, 2, or 3; and (5) have not announced a merger.

Q. Why did you eliminate companies that have either decreased or eliminated their dividend in the past two years?

A. The DCF model requires the assumption that dividends will grow at a constant rate into the indefinite future. If a company has either decreased or eliminated its dividend in recent years, an assumption that the company's dividend will grow at the same rate into the indefinite future is questionable.

Q. Why did you eliminate companies that have fewer than three analysts included in the I/B/E/S mean forecasts?

A. The DCF model also requires a reliable estimate of a company's expected future growth. For most companies, the I/B/E/S mean growth forecast is the best available estimate of the growth term in the DCF model. However, the I/B/E/S estimate may be less reliable if the mean estimate is based on the inputs of very few analysts. On the basis of my professional judgment, I believe that at least three analysts' estimates are a reasonable minimum number.

Q. Why did you eliminate companies that have announced mergers that are not yet completed?

A. A merger announcement can sometimes have a significant impact on a company's stock price because of anticipated merger-related cost savings and new market opportunities. Analysts' growth forecasts, on the other hand, are necessarily related to companies as they currently exist, and do not reflect investors' views of the potential cost savings and new market opportunities associated with mergers. The use of a stock price that includes the value of potential mergers in conjunction with growth forecasts that do not include the growth enhancing prospects of potential mergers produces DCF results that tend to distort a company's cost of equity.

Q. Is your electric company proxy group comparable in risk to PEF?

A. Yes. Many investors use the Value Line Safety Rank as a measure of equity risk. As shown in Exhibit No. ___ (JVW-1), the average Value Line Safety Rank for my proxy group of electric companies is 2, on a scale where 1 is the most safe and 5 is the least safe, and the Value Line Safety Rank for PEF's parent is 2. The average S&P bond rating of the electric companies in my proxy group is approximately BBB+, with an average business risk profile of 5.7, on a scale from 1 to 10 where 1 is strong and 10 is weak. The S&P bond rating for PEF's parent is BBB with a business risk profile of 6.

Q. Please summarize the results of your application of the DCF model to the Value Line electric company proxy group.

A. As shown in Exhibit No. ___ (JVW-1), I obtain a DCF result of 9.4 percent. Given investors' perceptions that the risk of investing in electric utilities has increased in recent years, I believe that the DCF result for the Value Line electric companies understates PEF's true cost of equity. However, to be conservative, I will consider this result, along with my other cost of equity results, when I reach my conclusion regarding PEF's cost of equity.

Q. Does the DCF model produce an economically reasonable estimate of PEF's cost of equity at this time?

A. No. There are several reasons why the results of applying the DCF model to electric utilities do not make economic sense at this time. First, the DCF results for the electric utilities have displayed considerable volatility over the last several years. In contrast to the general pattern of equity costs varying within a more narrow range than interest rates, the DCF result for the electric utilities has varied within a much wider range than interest rates over the last five years, 445 basis points for DCF results versus 309 basis points for interest rates. Furthermore, the standard deviation of the DCF results is 152 basis points, as compared to the standard deviation of interest rates of just 83 basis points. The high volatility of DCF results for electric utilities compared to interest rates suggests that the DCF model is not providing an accurate indication of the electric utilities' cost of equity at this time.

Second, the DCF results for electric utilities deviate significantly from the cost of equity results obtained from other widely used cost of equity methodologies such as the risk premium and CAPM methodologies. The large deviation of the DCF results for electric utilities from the results of applying other cost of equity methods to the same companies suggests that the DCF model is not providing an appropriate indication of the electric utilities' cost of equity at this time.

Q. As noted above, you also applied the DCF model to a proxy group of natural gas companies. Why did you apply the DCF model to a proxy group of natural gas companies?

A. I applied the DCF model to a proxy group of natural gas companies in addition to a group of electric companies because the natural gas companies are similar in risk to the electric companies, and, as a group, are experiencing less industry restructuring than the electric companies.[2] In addition, it is useful to examine the cost of equity results for a group of similar companies from a closely associated industry in order to test the reasonableness of the results obtained by applying cost of equity methodologies to electric companies. Financial theory does not require that companies be in exactly the same industry to be comparable in risk.

Q. What natural gas companies did you include in your proxy group of natural gas companies?

A. I selected all the companies in Value Line's groups of natural gas companies that receive a significant percentage of revenues and income from regulated natural gas businesses and otherwise meet the same criteria as described above for the electric companies. The natural gas companies in my DCF group and the average DCF result are shown in Exhibit No. ___ (JVW-2).

Q. How are your proxy natural gas companies similar to PEF?

A. Like PEF, my proxy natural gas companies: (1) employ a capital-intensive physical network that connects the customer to the source of energy; (2) sell transmission and/or distribution services at regulated rates to customers whose energy demand is primarily dependent on the state of the economy and the

[2] The DCF model is based on the assumption that companies operate in a relatively stable environment. When companies are experiencing dramatic industry restructuring, the basic stability assumptions of the DCF model may not apply.

weather; (3) procure energy in energy markets with highly variable prices; and (4) are regulated by public utility commissions that have traditionally viewed electric and natural gas utilities as being comparable in risk.

Q. Do you have any empirical evidence that the natural gas companies in your proxy group are a conservative proxy for PEF?

A. Yes. The average Value Line Safety Rank for my proxy group of natural gas companies is 2, on a scale where 1 is the most safe and 5 is the least safe, compared to the Safety Rank of 2 for PEF's parent (see Exhibit No. ___ (JVW-2)). In addition, the average S&P bond rating and business profile of the natural gas companies in my proxy group is approximately A, with an average business profile of 4 (where 1 is least risky and 10 is most risky). In contrast, as noted above, PEF's parent has an S&P bond rating of BBB with a business profile of 6. These data provide evidence that the natural gas proxy group is somewhat less risky than the electric proxy group.

Q. Please summarize the results of your application of the DCF method to the Value Line natural gas companies.

A. My application of the DCF method to the Value Line natural gas companies produces an average DCF result of 9.9 percent, as shown in Exhibit No. ___ (JVW-2). I believe this result also understates PEF's true cost of equity because, as demonstrated above, the Value Line natural gas companies are less risky than both the electric proxy group and PEF.

VII. Risk Premium Method.

Q. Please describe the risk premium method of estimating PEF's cost of equity.

A. The risk premium method is based on the principle that investors expect to earn a return on an equity investment in PEF that reflects a "premium" over and above the return they expect to earn on an investment in a portfolio of bonds. This equity risk premium compensates equity investors for the additional risk they bear in making equity investments versus bond investments.

Q. Does the risk premium approach specify what debt instrument should be used to estimate the interest rate component in the methodology?

A. No. The risk premium approach can be implemented using virtually any debt instrument. However, the risk premium approach does require that the debt instrument used to estimate the risk premium be the same as the debt instrument used to calculate the interest rate component of the risk premium approach. For example, if the risk premium on equity is calculated by comparing the returns on stocks and the returns on A-rated utility bonds, then the interest rate on A-rated utility bonds must be used to estimate the interest rate component of the risk premium approach.

Q. Does the risk premium approach require that the same companies be used to estimate the stock return as are used to estimate the bond return?

A. No. For example, many analysts apply the risk premium approach by comparing the return on a portfolio of stocks to the return on Treasury securities such as long-term Treasury bonds. Clearly, in this widely-accepted application of the risk premium approach, the same companies are not used to estimate the stock return as are used to estimate the bond return, since the U.S. government is not a company.

Q. How did you measure the required risk premium on an equity investment in PEF?

A. I used two methods to estimate the required risk premium on an equity investment in PEF. The first is called the ex ante risk premium method and the second is called the ex post risk premium method.

1. Ex Ante Risk Premium Method

Q. Please describe your ex ante risk premium approach for measuring the required risk premium on an equity investment in PEF.

A. My ex ante risk premium method is based on studies of the DCF expected return on proxy groups of electric and natural gas companies compared to the interest rate on Moody's A-rated utility bonds. Specifically, for each month in my study period, I calculated the risk premium using the equation,

$$RP_{PROXY} = DCF_{PROXY} - I_A$$

where:

RP_{PROXY} = the required risk premium on an equity investment in the proxy group of companies,

DCF_{PROXY} = average DCF estimated cost of equity on a portfolio of proxy companies; and

I_A = the yield to maturity on an investment in A-rated utility bonds.

I then performed a regression analysis to determine if there were a relationship between the calculated risk premium and interest rates. Finally, I used the results of the regression analysis to estimate the investors' required risk premium. To estimate the cost of equity, I then added the required risk premium to the forecasted interest rate on A-rated utility bonds. A detailed description of my ex ante risk premium studies is contained in Exhibit No. ___ (JVW-12), Appendix 3, and the underlying DCF results and interest rates are displayed in Exhibit No. ___ (JVW-3).

Q. What cost of equity do you obtain from your ex ante risk premium method using the proxy group of electric companies?

A. To estimate the cost of equity using the ex ante risk premium method, one may add the estimated risk premium over the yield on A-rated utility bonds to the yield to maturity on A-rated utility bonds. At March 2005, the forecasted yield to maturity on A-rated utility bonds for 2006 is 6.94 percent. My analyses produce an estimated risk premium over the yield on A-rated utility bonds equal to 4.38 percent. Adding an estimated risk premium of 4.38 percent to the 2006 forecasted 6.94 percent average yield to maturity on A-rated utility bonds produces a cost of equity estimate of 11.3 percent using the ex ante risk premium method.

Q. Have you also applied your ex ante risk premium approach to a proxy group of natural gas companies?

A. Yes. Following the same procedure as described in Exhibit No. ___ (JVW-12), Appendix 3, I applied my ex ante risk premium approach to my proxy group of natural gas companies compared to the interest rate on A-rated utility bonds. The underlying DCF results and interest rates for this study are displayed in Exhibit No. ___ (JVW-4).

Q. What cost of equity do you obtain from your ex ante risk premium method using the proxy group of natural gas companies?

A. For the natural gas proxy group, my analyses produce an estimated risk premium over the yield on A-rated utility bonds equal to 4.69 percent. Adding an estimated risk premium of 4.69 percent to the 6.94 percent forecasted yield to maturity on A-rated utility bonds produces a cost of equity estimate of 11.6 percent using the ex ante risk premium method.

Q. What cost of equity do you obtain from your ex ante risk premium method?

A. The ex ante risk premium method using the electric proxy group produced a cost of equity estimate of 11.3 percent, and using the natural gas proxy group, a cost of equity estimate of 11.6 percent. Averaging these estimates produces a cost of equity estimate of 11.5 percent using the ex ante risk premium method.

2. Ex Post Risk Premium Method

Q. Please describe your ex post risk premium method for measuring the required risk premium on an equity investment in PEF.

A. I first performed a study of the comparable returns received by bond and stock investors over the last 67 years. I estimated the returns on stock and bond portfolios, using stock price and dividend yield data on the S&P 500 and bond yield data on Moody's A-rated utility bonds. My study consisted of making an investment of one dollar in the S&P 500 and Moody's A-rated utility bonds at the beginning of 1937, and reinvesting the principal plus return each year to 2004. The return associated with each stock portfolio is the sum of the annual dividend yield and capital gain (or loss) which accrued to this portfolio during the year(s) in which it was held. The return associated with the bond portfolio, on the other hand, is the sum of the annual coupon yield and capital gain (or loss) which accrued to the bond portfolio during the year(s) in which it was held. The resulting annual returns on the stock and bond portfolios purchased in each year between 1937 and 2004 are shown in Exhibit No. ___ (JVW-5). The average annual return on an investment in the S&P 500 stock portfolio was 11.67 percent, while the average annual return on an investment in the Moody's A-rated utility bond portfolio was 6.40 percent. The risk premium on the S&P 500 stock portfolio is, therefore, 5.27 percent.

I also conducted a second study using stock data on the S&P Utilities rather than the S&P 500. As shown in Exhibit No. ___ (JVW-6), the S&P Utility stock portfolio showed an average annual return of 10.57 percent per year. Thus, the return on the S&P Utility stock portfolio exceeded the return on the Moody's A-rated utility bond portfolio by 4.16 percent.

Q. Why is it appropriate to perform your ex post risk premium analysis using both the S&P 500 and the S&P Utility Stock indices?

A. I have performed my ex post risk premium analysis on both the S&P 500 and the S&P Utilities as upper and lower bounds for the required risk premium on an equity investment in PEF because I believe electric energy companies today face risks that are somewhere in between the average risk of the S&P Utilities and the S&P 500 over the years 1937 to 2004. Specifically, the risk premium on the S&P Utilities, 4.16 percent, represents a lower bound for the required risk premium on an equity investment in PEF because PEF is currently more risky than an investment in the average utility in the S&P Utilities index over the entire period 1936 to the present. On the other hand, the risk premium on the S&P 500, 5.27 percent, represents an upper bound because an investment in PEF is less risky than an investment in the S&P 500 over the period 1937 to the present. I use the average of the two risk premiums as my estimate of the required risk premium for PEF in my ex post risk premium method.

Q. Why did you analyze investors' experiences over such a long time frame?

A. Because day-to-day stock price movements can be somewhat random, it is inappropriate to rely on short-run movements in stock prices in order to derive a reliable risk premium. Rather than buying and selling frequently in anticipation of highly volatile price movements, most investors employ a strategy of buying and holding a diversified portfolio of stocks. This buy-and-hold strategy will allow an investor to achieve a much more predictable long-run return on stock investments and at the same time will minimize transaction costs. The situation is very similar to the problem of predicting the results of coin tosses. I cannot predict with any reasonable degree of accuracy the result of a single, or even a few, flips of a balanced coin; but I can predict with a good deal of confidence that approximately 50 heads will appear in 100 tosses of this coin. Under these circumstances, it is most appropriate to estimate future experience from long-run evidence of investment performance.

Q. Would your study provide a different risk premium if you started with a different time period?

A. Yes. The risk premium results do vary somewhat depending on the historical time period chosen. My policy was to go back as far in history as I could get reliable data. I thought it would be most meaningful to begin after the passage and implementation of the Public Utility Holding Company Act of 1935. This Act significantly changed the structure of the public utility industry. Since the Public Utility Holding Company Act of 1935 was not implemented until the beginning of 1937, I felt that numbers taken from before this date would not be comparable to those taken after.

Q. Why was it necessary to examine the yield from debt investments in order to determine the investors' required rate of return on equity capital?

A. As previously explained, investors expect to earn a return on their equity investment that exceeds currently available bond yields. This is because the return on equity, being a residual return, is less certain than the yield on bonds and investors must be compensated for this uncertainty. Second, the investors' current expectations concerning the amount by which the return on equity will exceed the bond yield will be strongly influenced by historical differences in returns to bond and stock investors. For these reasons, we can estimate investors' current expected returns from an equity investment from knowledge of current bond yields and past differences between returns on stocks and bonds.

Q. Has there been any significant trend in the equity risk premium over the 1937 to 2004 time period of your risk premium study?

A. No. Statisticians test for trends in data series by regressing the data observations against time. I have performed such a time series regression on my two data sets of historical risk premiums. As shown below in Tables 4 and 5, there is no statistically significant trend in my risk premium data. Indeed, the coefficient on the time variable is insignificantly different from zero (if there were a trend, the coefficient on the time variable should be significantly different from zero).

TABLE 4
REGRESSION OUTPUT FOR RISK PREMIUM ON S&P 500

Line No.		Intercept	Time	Adjusted R Square	F
1	Coefficient	0.015	0.001	0.002	1.124
2	T Statistic	0.354	1.060		

TABLE 5
REGRESSION OUTPUT FOR RISK PREMIUM ON S&P UTILITIES

Line No.		Intercept	Time	Adjusted R Square	F
1	Coefficient	0.007	0.001	0.002	1.136
2	T Statistic	0.195	1.066		

Q. **Do you have any other evidence that there has been no significant trend in risk premium results over time?**

A. Yes. The Ibbotson Associates' *2004 Yearbook* contains an analysis of "trends" in risk premium data. Ibbotson Associates uses correlation analysis to determine if there is any pattern or "trend" in risk premiums over time. They also conclude that there are no trends in risk premiums over time.

Q. **What is the significance of the evidence that historical risk premiums have no trend or other statistical pattern over time?**

A. The significance of this evidence is that the average historical risk premium is a good estimate of the future expected risk premium. As Ibbotson notes:

> The significance of this evidence is that the realized equity risk premium next year will not be dependent on the realized equity risk premium from this year. That is, there is no discernable pattern in the realized equity risk premium—it is virtually impossible to forecast next year's realized risk premium based on the premium of the previous year. For example, if this year's difference between the riskless rate and the return on the stock market is higher than last year's, that does not imply that next year's will be higher than this year's. It is as likely to be higher as it is lower. The best estimate of the expected value of a variable that has behaved randomly in the past is the average (or arithmetic mean) of its past values. [Ibbotson Associates' *Valuation Edition 2004 Yearbook*, page 75.]

Q. You noted that Ibbotson Associates also provides risk premium data. How do the Ibbotson Associates' risk premiums compare to your risk premiums?

A. Ibbotson Associates obtains a 7.2 percent risk premium on the S&P 500 versus long-term government bonds. Since the yield on long - term government bonds is currently approximately 100 basis points less than the yield on A - rated utility bonds, the Ibbotson Associates' data would indicate an approximate 6.2 percent risk premium on the S&P 500 over A - rated utility bonds. As shown on Exhibit Nos.___ (JVW-5) and (JVW-6) my studies produce a risk premium over A - rated utility bonds in the range of 4.16 percent to 5.27 percent.

Q. What conclusions do you draw from your ex post risk premium analyses about the required return on an equity investment in PEF?

A. My own studies, combined with my analysis of other studies, provide strong evidence that investors today require an equity return of approximately 4.16 to 5.27 percentage points above the expected yield on A-rated utility bonds. The

5.27 percentage points above the expected yield on A-rated utility bonds. The forecasted interest rate on Moody's A - rated utility bonds for the end of the test year as of March 2005 is 6.94 percent. Adding a 4.16 to 5.27 percentage point risk premium to an expected yield of 6.94 percent on A-rated utility bonds, I obtain an expected return on equity in the range 11.1 percent to 12.2 percent, with a midpoint of 11.7 percent. Adding a 25 basis-point allowance for flotation costs,[3] I obtain an estimate of 11.9 percent as the cost of equity for PEF using the ex post risk premium method.

3. Capital Asset Pricing Model (CAPM)

Q What is the CAPM?

A The CAPM is an equilibrium model of the security markets in which the expected or required return on a given security is equal to the risk-free rate of interest, plus the company equity "beta," times the market risk premium:

Cost of equity = Risk-free rate + Equity beta x Market risk premium.

The risk-free rate in this equation is the expected rate of return on a risk-free government security, the equity beta is a measure of the company's risk relative to the market as a whole, and the market risk premium is the premium investors require to invest in the market basket of all securities compared to the risk-free security.

[3] I determined the flotation cost allowance by calculating the difference in my DCF results with and without a flotation cost allowance.

Q How do you use the CAPM to estimate the cost of equity for your proxy companies?

A The CAPM requires an estimate of the risk-free rate, the company-specific risk factor or beta, and the expected return on the market portfolio. For my estimate of the risk-free rate, I use the Blue Chip forecasted yield to maturity on 20-year Treasury bonds for 2006, 5.70%. For my estimate of the company-specific risk, or beta, I use the average Value Line beta for my proxy companies. For my estimate of the expected risk premium on the market portfolio, I use two approaches. First, I estimate the risk premium on the market portfolio from the difference between the arithmetic mean return on the S&P 500 and the income return on 20-year Treasury bonds as reported by Ibbotson Associates' *2004 Yearbook*. Second, I estimate the risk premium on the market portfolio from the difference between the DCF cost of equity for the S&P 500 and the yield to maturity on 20-year Treasury bonds.

Q. Why do you recommend that the risk premium on the market portfolio be estimated using the difference between the arithmetic mean return on the S&P 500 and the income return on 20-year Treasury bonds?

A. I recommend that the long-run historic arithmetic mean risk premium be used to estimate the cost of equity because the arithmetic mean is the best estimate of the expected risk premium on a forward-looking basis. As Ibbotson Associates explains in *Stocks, Bonds, Bills, and Inflation Valuation Edition 2004 Yearbook*, the arithmetic mean return is the best approach for calculating the return investors expect to receive in the future:

> The equity risk premium data presented in this book are arithmetic average risk premia as opposed to geometric average risk premia. The arithmetic average equity risk premium can be demonstrated to be most appropriate when discounting future cash flows. For use as the expected equity risk premium in either the CAPM or the building block approach, the arithmetic mean or the simple difference of the arithmetic means of stock market returns and riskless rates is the relevant number. This is because both the CAPM and the building block approach are additive models, in which the cost of capital is the sum of its parts. The geometric average is more appropriate for reporting past performance, since it represents the compound average return. [Ibbotson Associates, *op. cit.*, p. 71.]

A discussion of the importance of using arithmetic mean returns in the context of CAPM or risk premium studies is contained in Exhibit No. ___ (JVW-7).

Q. What CAPM result do you obtain when you estimate the expected return on the market portfolio from the arithmetic mean difference between the return on the market and the yield on 20-year Treasury bonds?

A. I obtain a CAPM estimate of 11.8 percent, as shown in Exhibit No. ___ (JVW-8).

Q. What CAPM result do you obtain when you estimate the market risk premium on the market portfolio by applying the DCF model to the S&P 500?

A. I obtain a CAPM result of 12.0 percent when forecasted interest rates are used to estimate the risk-free rate (see Exhibit No. ___ (JVW-9)).

Q. Is there any evidence that a reasonable application of the CAPM may produce higher cost of equity results than you have just reported?

A. Yes. There are several reasons why a reasonable application of the CAPM may produce higher results than I have just reported. First, there is substantial evidence that the CAPM tends to underestimate the cost of equity for companies whose equity beta is less than 1.0 and to overestimate the cost of equity for companies whose equity beta is greater than 1.0. Second, there is strong evidence that a size premium should be added to the CAPM result for some of my electric and natural gas proxy companies.

Q. What evidence do you have that the CAPM tends to underestimate the cost of equity for companies with betas less than 1.0?

A. The original evidence that the unadjusted CAPM tends to underestimate the cost of equity for companies whose equity beta is less than 1.0 and to overestimate the cost of equity for companies whose equity beta is greater than 1.0 was presented in a paper by Black, Jensen, and Scholes, "The Capital Asset Pricing Model: Some Empirical Tests." Numerous subsequent papers have validated the

Black, Jensen, and Scholes findings, including those by Litzenberger and Ramaswamy, Banz, Fama and French, and Fama and MacBeth.[4]

Q. Do you have any evidence that the CAPM equation must be adjusted to account for a company's size as measured by market capitalization?

A. Yes. Chapter 7 of the Ibbotson Associates' *2004 Yearbook, Valuation Edition*, provides evidence that investors in smaller capitalization companies require a higher rate of return than is indicated by the unadjusted CAPM equation. In addition, Ibbotson Associates provides estimates of the size premium required to be added to the basic CAPM cost of equity, shown below in Table 6.

Table 6

Ibbotson Estimates of Premiums for Company Size

Size	Smallest Mkt. Cap. ($000s)	Premium
Large-Cap (No Adjustment)	4,794,027	-
Mid-Cap	1,167,040	0.91%
Low-Cap	330,797	1.70%
Micro-Cap	0.332	4.01%

[4] Fischer Black, Michael C. Jensen, and Myron Scholes, "The Capital Asset Pricing Model: Some Empirical Tests," in *Studies in the Theory of Capital Markets*, M. Jensen, ed. New York: Praeger, 1972; Eugene Fama and James MacBeth, "Risk, Return, and Equilibrium: Empirical Tests," *Journal of Political Economy* 81 (1973), pp. 607-36; Robert Litzenberger and Krishna Ramaswamy, "The Effect of Personal Taxes and Dividends on Capital Asset Prices: Theory and Empirical Evidence," *Journal of Financial Economics* 7 (1979), pp. 163-95.; Rolf Banz, "The Relationship between Return and Market Value of Common Stocks," *Journal of Financial Economics* (March 1981), pp. 3-18; and Eugene Fama and Kenneth French, "The Cross-Section of Expected Returns," *Journal of Finance* (June 1992), pp. 427-465.

B. Fair Rate of Return on Equity

Q. Based on your application of several cost of equity methods to your proxy companies, what is your conclusion regarding your proxy companies' cost of equity?

A. Based on my application of several cost of equity methods to my proxy companies, I conservatively conclude that my proxy companies' cost of equity is 11.4 percent. As shown in Table 7 below, 11.4 percent is the simple average of the cost of equity results I obtain from my cost of equity models.

TABLE 7
Cost of Equity Model Results

Method	*Cost of Equity*
DCF	9.6%
Ex Post Risk Premium	11.9%
Ex Ante Risk Premium	11.5%
DCF CAPM	12.0%
Historical CAPM	11.8%
Average All Cost of Equity Methods	11.4%

Q. Does your 11.4 percent cost of equity conclusion for your proxy groups depend on the percentages of debt and equity in your proxy companies' average capital structure?

A. Yes. The 11.4 percent cost of equity for my proxy groups reflects the financial risk associated with my proxy companies' average capital structures, where the capital structure weights are measured in terms of market values. Since financial leverage, that is, the use of debt financing, increases the risk of investing in the proxy companies' equity, the cost of equity would be higher for a capital structure containing more leverage.

Q. **What are the average percentages of debt and equity in your proxy companies' capital structures?**

A. As shown below in Table 8, my electric proxy company group has an average capital structure containing 40.70 percent debt, 1.34 percent preferred stock, and 57.97 percent common equity. My natural gas proxy company group has an average capital structure containing 33.90 percent debt, 0.24 percent preferred equity, and 65.86 percent equity, as shown in Table 9.

Q. **How does PEF's projected capital structure at December 31, 2006 compare to the average capital structure of your proxy companies?**

A. PEF's projected capital structure at December 31, 2006, contains 45 percent long-term debt and 55 percent common equity. Although this capital structure contains an appropriate mix of debt and equity and is a reasonable capital structure for ratemaking purposes, from an investors' viewpoint, PEF's capital structure embodies greater financial risk than the average market value capital structures of my proxy company groups.

Q. **You noted earlier that the cost of equity depends on a company's capital structure. Is there any way to adjust the 11.4 percent cost of equity for**

your proxy companies to reflect the higher financial risk embodied in PEF's recommended capital structure in this proceeding?

A. Yes. Since my proxy groups are comparable in risk to PEF, PEF should have the same weighted average cost of capital as my proxy companies. It is a simple matter to determine what cost of equity PEF should have in order to have the same weighted average cost of capital as my proxy companies.

Q. Have you performed such a calculation?

A. Yes. I adjusted the 11.4 percent average cost of equity for my proxy groups by recognizing that to attract capital, PEF must have the same weighted average cost of capital as my proxy group. As shown in Table 8, the weighted average cost of capital for my proxy group of electric companies is 8.433 percent. The weighted average cost of capital for my proxy group of natural gas companies is 8.962 percent, as shown in Table 9. The average cost of capital for both proxy groups is 8.697 percent. As shown in Table 10, PEF would require a 12.35 percent cost of equity in order to have the same weighted average cost of capital as the proxy groups.

TABLE 8

Weighted Average Cost of Capital Electric Proxy Group

Line No.	Capital Source	Percent	After-tax Cost Rate	Weighted Cost
1	Long-term Debt	40.70%	4.23%	1.723%
2	Preferred Stock	1.34%	7.64%	0.102%
3	Common Equity	57.97%	11.40%	6.608%
4		100.00%		8.433%

TABLE 9

Weighted Average Cost of Capital Natural Gas Company Proxy Group

Line No.	Capital Source	Percent	After-tax Cost Rate	Weighted Cost
1	Long-term Debt	33.90%	4.23%	1.435%
2	Preferred Stock	0.24%	7.64%	0.018%
3	Common Equity	65.86%	11.40%	7.508%
4		100.00%		8.962%

TABLE 10

Weighted Average Cost of Capital PEF

Line No.	Capital Source	Percent	After-tax Cost Rate	Weighted Cost
1	Long-term Debt	45.00%	4.23%	1.905%
2	Preferred Stock	0.00%	7.64%	0.000%
3	Common Equity	55.00%	12.35%	6.792%
4		100.00%		8.697%

Q. What is your recommendation as to a fair rate of return on common equity for PEF?

A. I recommend that PEF be allowed a fair rate of return on common equity equal to 12.3 percent.

Q. Does this conclude your testimony?

A. Yes, it does.

DIRECT TESTIMONY
OF
CHARLES J. CICCHETTI, Ph.D.

I: <u>Introduction and Qualifications</u>

Q. Please state your name, business and address.

A. My name is Charles J. Cicchetti. My address is Pacific Economics Group, 201 South Lake Street, Suite 400, Pasadena, California 91101.

Q. What is your position with Pacific Economics Group?

A. I am a Co-Founding Member of Pacific Economics Group.

Q. What are your duties as a member of Pacific Economics Group?

A. I actively consult with clients on price, costs, environmental, natural gas and electricity market issues and antitrust policies, particularly as those policies relate to regulated industries.

Q. Do you hold any other positions?

A. I hold the Jeffrey J. Miller Chair in Government, Business and the Economy at the University of Southern California.

Q. What is your educational background?

A. I attended the United States Air Force Academy, and I received a B.A. degree in Economics from Colorado College in 1965 and a Ph.D. degree in Economics from Rutgers University in 1969. From 1969 to 1972, I engaged in post-doctoral research on energy and environmental matters at Resources for the Future.

Q. Please summarize your professional experience.

A. I served as chief economist for the Environmental Defense Fund from 1972 to 1975, and was a faculty member at the University of Wisconsin from 1972 to 1985, ultimately earning the title of Professor of Economics and Environmental Studies. From 1975 through 1976, I served as the Director of the Wisconsin Energy Office and as Special Energy Counselor for the Governor. In 1977, I was appointed by the Governor as Chairman of the Public Service Commission of Wisconsin and held that position until 1979, and served as a Commissioner until 1980. In 1980, I co-founded the Madison Consulting Group, which was sold to Marsh & McLennan Companies in 1984. In 1984, I was named Senior Vice President of National Economic Research Associates and held that position until 1987. From 1987 until 1990, I served as Deputy Director of the Energy and Environmental Policy Center at the John F. Kennedy School of Government at Harvard University, and from 1988 to 1992, I was a Managing Director and ultimately Co-Chairman of the economic and management consulting firm, Putnam, Hayes & Bartlett, Inc. In 1992, I formed Arthur Andersen Economic Consulting, a division of Arthur Andersen, LLP. In late 1996, I left Arthur Andersen to co-found Pacific Economics Group, L.L.C.

Q. Have you published any papers or articles?

A. Yes. I have published articles on energy and environmental issues, public utility regulation, competition and antitrust. A complete listing of my publications is included in Exhibit No. ___ (CJC-1).

Q. Have you ever given expert testimony in a court or administrative proceeding?

A. Yes. A list of the proceedings in which I have provided expert testimony since 1980 is also included in Exhibit No. ___ (CJC –1).

Q. Who retained you for this testimony?

A. I have been retained to present testimony on behalf of Progress Energy Florida, Inc. (PEF or the Company).

II. Purpose and Summary of My Testimony

Q. How is the balance of your testimony organized?

A. In Section III, I discuss general rate relief topics. In this section, I discuss why it is important to treat PEF in a fair regulatory manner. I explain why this is important given the tremendous benefits that have been achieved for both customers and shareholders since the consummation of the merger and the last rate case, including the $125 million annual rate reduction for the period ending January 1, 2006 resulting from the last rate case settlement. Under the terms of the 2002 Settlement, there was a general rate reduction of 9.25% and the typical residential customer's monthly bills fell from $91.65 per 1000 KWH to $80.25, which is according to Mr. Lyash's Testimony, a reduction of about 16%. These 2002 reductions came after nearly a ten year base rate freeze from November 1993 until May 2002.

Customers are best served by encouraging PEF to continue its recent successes. Indeed, customers have already reaped many benefits since the last rate case. Much of the recent run-up in energy prices that are affecting other jurisdictions have, in effect, been paid for out of these efficiency and synergy savings that flowed from PEF's merger in late 2000. It is important to recognize PEF's efforts and not remove or restrict PEF's incentives to continue with its efforts.

In Section IV, I review the results of both internal and external benchmarking that demonstrate PEF's exceptional performance. The first is internal benchmarking data discussed in more detail by Messrs. Lyash, McDonald, DeSouza, Williams, and Young and Mrs. Morman-Perry that shows how PEF has been working to reduce its costs and to accommodate system growth. In effect, these activities inure to the benefit of current and future ratepayers.

The second analysis is a statistical analysis based on a proprietary econometric model of electricity production using a sample of 99 electric companies in the U.S. over a period of nine years (from 1995 through 2003). This analysis shows that for the period 2001 through 2003, ignoring its storm damage and undergrounding requirements, PEF's actual total costs are 12.7% below what would be expected for a utility with its specific requirements, circumstances, and drivers. The 12.7% difference represents statistically significant superior performance.

In Section V, I review Dr. Vander Weide's recommended capital structure. In this section, I also explain why, if the Commission sets an equity share below the 55% that Dr. Vander Weide recommends, it would be necessary for the Commission to simultaneously increase PEF's authorized Return on Equity (ROE). I also discuss the effect that purchase power agreements have on the risk factors associated with the debt component of the equity structure.

In Section VI, I review Dr. Vander Weide's ROE analysis and capital structure. I conclude that his approach results in a just and reasonable floor for ROE and Rate of Return (ROR) using traditional approaches. I then discuss several important reasons that support my conclusion that the Commission should add 50 basis points to the ROE recommended by Dr. Vander Weide. These include: (1) precedent in Florida; (2) regulatory judgment; (3) the need to reward PEF for superior service quality and controlling costs; (4) 50 basis points effectively splits the difference between PEF's storm adjusted ROE and the ROE recommended by Dr. Vander Weide; and (5) a 12.8% ROE will enable PEF to maintain its superior service quality and cost control.

In Section VII, I restate my conclusions and summarize my policy recommendations.

Q. Please summarize your testimony.

A. My testimony covers four primary areas, each of which contains several related sub-topics. First, I discuss global rate relief policy issues and how those apply to PEF. Within this general topic, I discuss several matters that affect the context in which the Florida Public Service Commission (the Commission or FPSC) should decide the appropriate level of revenues and, in that regard, the rate of return for PEF. Here, I explain that while PEF has made recent improvements in attaining merger related synergies and implementing cost cutting measures, and that customers have already received in rate cuts from the Company's efficiency and synergy gains, the process is not yet completed. I explain why the Commission, in this hearing, should recognize PEF for its successes and take steps to encourage PEF to do more of the same by rewarding it with an additional 50 basis point bump to its authorized ROE. This proceeding should seek an outcome that is truly a win/win for customers and shareholders.

Second, to demonstrate the gains made by PEF, I discuss an external statistical analysis that I performed. This analysis demonstrates that PEF's costs are 12.7% below what I would have expected based on the statistical analysis of PEF's cost relative to the industry. I will also review the Company's internal benchmarking analyses to demonstrate the improvements that the Company has made relative to its pre-merger performance.

The third area in my testimony discusses Dr. Vander Weide's recommended capital structure for PEF. Here I discuss the targeted capital structure that he proposes and explain why: (1) it is just and reasonable to use a

45/55 debt-to-equity structure for PEF; (2) how this capital structure benefits consumers by improving the quality of PEF's debt, and (3) how this will result in lower long-term interest payments for decades to come, easing the burden and increasing the value of PEF's purchase power requirements. I also explain why and how purchase power contract costs affect capital structure and how at least a portion of these costs should be included in the debt component of capital structure.

The fourth area I discuss is Dr. Vander Weide's ROE analysis. It is well established that an ROE must be determined that is sufficient to enable the utility to (1) discharge its service obligations in a safe and reliable manner; (2) maintain its financial integrity; (3) attract the capital necessary for capital improvements required to maintain safe and reliable service; and (4) adequately compensate investors for their assumption of risk. I use these inter-related objectives as a backdrop to put Dr. Vander Weide's analysis in context and explain why I think the Commission should add 50 basis points to Dr. Vander Weide's recommended authorized ROE to reward PEF for its exemplary performance.

Q. Please summarize your conclusions.

A. I conclude that PEF's commitments in the 2002 Settlement, coupled with its performance since the last rate case, merit a positive consideration here. The Commission should continue to encourage PEF and not establish the wrong incentives for the future. I recommend setting the factors that affect ROR, such as the authorized ROE, near the top end of the ranges proffered in this rate case. PEF competes against other utilities for capital, and its ROE should be set at a level high enough so that PEF can attract the required capital it will require in the near future. Thus, I conclude that adding 50 basis points to the authorized ROE is a reasonable way for the Commission to reward PEF for its exemplary performance and is consistent with precedent in Florida and other jurisdictions.

My overall conclusion is that a just and reasonable ROE for PEF is 12.8%, including the 50 basis point adder I discussed above. This ROE should be combined with a 45/55 debt/equity capital structure. Further, if the Commission establishes a different debt/equity capital structure, the ROE should be adjusted accordingly.

III: <u>Policy Issues</u>

Q. Do you have any general policy observations before you get into the details of your evidence?

A. Yes, I do. Particularly, I will discuss: incentives, PEF's successes and performance, and its special circumstances and needs.

Q. How should the Commission evaluate PEF and set rates?

A. The Commission should consider how the Company has performed in the past and the degree to which it has met its commitments to improve and achieve its goals. The Commission should also consider the Company's current financial condition, its current quality of service, and general financial and economic factors affecting the utility industry and cost of capital. Finally, the Commission should be cognizant of future customer needs and the degree to which capital attraction is important in order to meet those needs.

Q. What do you mean by PEF's "past" performance?

A. PEF completed a merger in 2001. The Company put forward a rate case and set some significant post merger goals. As this current case demonstrates, PEF has essentially met or beaten its projections, achieving what it promised to do. As a result, customers have received a $125 million annual rate reduction and have reaped the benefits of improved safety, reliability, customer service, and increased cost effective power supply production.

These past efforts to improve efficiency and productivity should not be used, as some would likely propose, in a manner that takes away the incentive of utility success and passes it on to ratepayers. Such a policy would be tantamount to undermining much of the incentives for utility cost cutting and service enhancement. Here, PEF has used much of the past reduction to insulate its customers from a good portion of the recent energy price run-up and growing customer demand. The storm damages, continuing mounting energy costs, and need to add generation supply, among other things, have grown to be too strong.

PEF continues to seek further productivity and customer service gains. In this proceeding, current customers benefit in three ways under PEF's rate plan and proposal. These are:

- Customers capture specific cost savings, both fixed and variable, in PEF's current cost of service filing.

- Customer growth adds revenue that helps to retire rate base and pay for the carrying cost of capital. This revenue requirements gain is also reflected in PEF's rate filing.
- PEF proposes to reduce its current ROE to 12.8%, which would inure to the ratepayers' benefit.

Q. What would you propose?

A. I favor a middle ground form of cost-of-service regulation in which shareholders and customers both participate or share in the benefits of productivity and efficiency gains.

When sharing is adopted, utilities will reap rewards from past success, and customers, as they have here, will share in those achievements. Moreover, continuing to provide incentives to the utility to do more will typically mean a "win/win" situation for shareholders and ratepayers.

If a person works hard and achieves his/or her goals only to have the benefits of that hard work stripped away, it would not be unexpected if in the future that person did not work as hard or achieve as much. Incentives and rewards for hard work and accomplishments are important.

Some witnesses in this case will likely try to convince the Commission that PEF should cut its rates. They will likely propose that it is time to cut PEF's authorized ROE and equity share. The Commission should not follow such poor advice for several reasons, foremost of which is that the process that led to the success should be encouraged, not punished.

Q. Please summarize the settlement that was reached in the Company's last rate case.

A. When the Company's last rate case was filed, the merger that created Progress Energy had been recently completed. Testimony was presented as to the total merger savings that could be achieved and the costs necessary to achieve those savings. A plan was proposed that would equitably share the merger savings and benefits between customers and shareholders, a plan that would encourage and provide incentives to PEF to achieve these savings. Ultimately, a settlement was reached that accomplished these goals and customers received a $125 million annual rate reduction in 2002 after a nearly ten year base rate freeze. They also received $45.9 million in revenue sharing refunds.

Q.` **What is significant about the timing of this rate case?**

A. There are several interrelated factors that make the timing of this rate filing significant. First, it is important to recognize that PEF has been very successful in achieving the savings promised by this merger. The improvements made by the Company are impressive. Second, it is important to realize that the position in which the Company is in today does not represent the end game. Nevertheless, as I outlined above, the consumers are capturing much of PEF's recent cost cutting and revenue gains in this case, and PEF is proposing to set its authorized ROE below its current earnings. Further, the Company intends to continue on its quest to provide superior performance. Third, and perhaps crucial, these efforts can be short-circuited if the Commission attempts to reduce the Company's ROE and capital structure based solely on the Company's current cost-of-service. Fourth, the Company is planning major infrastructure investments to accommodate the residential customer growth on its system and to continue to provide superior service quality, safety, and reliability, and is facing required capital expenditures to comply with new EPA environmental requirements that will total hundreds of millions of dollars starting in 2005. Part of the requested rate increase is due to putting the Hines 2 power plant into rate base rather than recovering it through the fuel clause under the 2002 Rate Stipulation, and putting the Hines 3 generating plant, used to provide service to a growing customer base, into service in 2005. Additionally rates need to be increased to replace the storm reserve fund. Higher pension and other benefit costs are also pushing up rates.

Q. What role do current conditions play in this rate proceeding?

A. There are three types of relevant conditions: (1) customer satisfaction and service quality; (2) PEF's current financial condition and needs; and (3) the overall financial market and economic conditions in the utility industry.

First, when I was a regulator, I graded utility performance and service quality. I explicitly admitted that success and good service would be rewarded, while the laggards would be hurt financially. In fact, the first opportunity I had to change the rate of return for a major utility after I assumed the role as Chair of the Public Service Commission of Wisconsin was in 1979. In that case, I awarded Wisconsin Electric Power Company a 25 basis point bump to its authorized ROE to reward it for achieving superior performance that benefited its customers. I noted that utilities that did not meet these goals would be "punished" with lower

ROEs.[1] Subsequently, I rewarded the "best" utility with a 13.5% ROE, the very highest end of the then just and reasonable range. I kept the lower performers at 13%, the prior unofficial floor, or some 50 basis points below the "best" performer. To this day, some twenty-six years later, I continue to believe this is a sound regulatory principle. PEF has performed well with actual costs that are 12.7% lower than predicted by the statistical comparison of PEF and the industry. Moreover, this Commission has also recognized the incentives provided by rewarding a utility for superior performance.[2] In the 1999 Gulf Power earnings case, the Commission, in effect, awarded Gulf Power a 50 basis point reward to its authorized ROE. PEF is, among other things, cooperative, innovative, and pro-consumer. These and other factors that I discuss below should warrant a 50 basis point performance reward to be added to PEF's authorized ROE.

Second, interest rates are increasing. Capital markets are becoming highly interdependent and integrated. Florida is in a relatively unique position as a state that retains a traditional cost-of-service regulatory approach, while its utilities, such as PEF, are continuing to grow and need to attract significant capital in order to build needed infrastructure and meet new EPA environmental requirements.

There is an external group of analysts and large investment groups that purchase large blocks of utility equity and debt. These analysts will grade Florida's regulatory treatment of PEF. Specific issues such as ROE, equity share,

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[1] *Findings of Fact and Order re Application of Wisconsin Electric Power Company for Authority to Increase its Electric Rates*, 1979 Wisc. PUC Lexis 45 (March 6, 1979).

[2] *In re: Investigation into the Earnings and Authorized Return on Equity of Gulf Power Company*, 1999 Fla. PUC LEXIS 915, 99 FPSC 5:305 (May 24, 1999).

the likely achievement of authorized revenues, the use and funding of reserve accounts, among others, will affect this external grade.

As a former regulator, I understand this. A good grade meant lower capital costs for consumers. Since my state at the time was adding significant new utility investments, much as PEF will be doing, I recognized that treating utilities justly and relatively well (*i.e.,* at the high end of the reasonable range of ROE) would inure to the benefit of ratepayers.

Q. Why shouldn't the Commission reset PEF's ROE to 12.3% along with other savings in its current cost of service?

A. To do so would ignore the ongoing efficiency and customer service improvements. As I testified at the Company's last proceeding, the merger related synergy savings are real and achievable. However, the savings are not achievable without some cost. In order to provide the Company with the correct incentives to continue on its current path, which has already yielded $125 million in annual benefits to customers, the Commission must recognize that these savings achieved by the Company should be encouraged by erring in the direction of establishing a financially sound and healthy utility. It would be to the customers' detriment if PEF is, in effect, discouraged from adding to its good work since its last rate case. There should be some modest sharing between customers, which have three beneficial drivers in this proceeding (cost reduction, growth, and a lower ROE) and shareholders.

Q. Are you suggesting that the Commission continue to try to quantify merger related savings?

A. No. As time goes forward, it becomes increasingly difficult to identify synergy related merger savings. Progress Energy has completed the merger, the companies have been combined, in effect scrambling the eggs. The 2002 Settlement resulted in a 9.25% levelized reduction in base rate unit costs that reduced retail rates by $125 million and cut residential rates up to 16% for a typical 1000 kwh customer. (See Testimony filed by Mr. Lyash). This eased much of the "pain" caused by the run-up in worldwide energy prices. It would be a largely futile task to attempt, at this juncture, to identify what the previous unmerged companies' costs would have been absent the merger and compare those "but-for-the-merger" costs with current post merger costs. Such an exercise would be time-consuming, costly, and dependent on assumptions that would likely differ between parties. Ultimately, the resulting savings numbers could only be assigned with a high degree of subjectivity. It would be akin to trying to identify the individual eggs in an omelet.

Q. Please summarize your key points.

A. My overriding point is that the Company's achievements to date are strong and at the same time incomplete. These efforts should be rewarded. The Company should be encouraged to continue to improve performance, build up its equity, and improve its bond ratings. This is especially important for a company like PEF that is located in a non-restructuring state and is facing substantial costs to expand its infrastructure to accommodate residential growth. These improvements will benefit both customers and shareholders alike.

In this proceeding, particularly, I strongly urge the Commission to favor a combination of high equity share and the highest possible just and reasonable ROE (plus a 50 basis point adder) to determine an ROR on rate base. I do this for three reasons: (1) PEF's success in increasing efficiency, its cooperation, innovation, and its pro-consumer stance; (2) PEF's current capital needs for new infrastructure and generation relative to other jurisdictions in the nation that have no significant growth; and (3) market expectation. Thus I support adding 50 basis points to the Commission's authorized ROE. Starting with Dr. Vander Weide's 12.3% recommended ROE, this would mean and I would propose a 12.8% ROE, as well as a 45%/55% debt to equity capital structure.

IV. Benchmarking Analysis

Q. Has the Company performed any internal analysis that compares its performance today with its pre-merger performance?

A. Yes. The Company has performed an internal analysis that compares PEF to its prior self. The results are summarized in Mr. Portuondo's Testimony, which I describe below. The various components are described in detail in his testimony, as well as the testimony filed by various other PEF witnesses. This comparison or inter-temporal internal benchmarking analysis shows that since the time the merger was completed, the Company has improved its efficiency and its performance in several key areas.

Q. What do you conclude after reviewing these testimonies?

A. I conclude that PEF's performance has been outstanding and its improvements have met or exceeded expectations. For example:

- Employee safety improved by over 50%, moving the Company to almost the top quartile (See Mr. Lyash's testimony);
- PEF's System Average Interruption Duration Index (SAIDI) (a measure of system reliability) was improved by 23%, dropping from 100.6 in 2000 to 77 in 2004. This bettered the Company's commitment of 80 minutes. (See Mr. Lyash's testimony);
- Residential base rates were reduced by up to 16% for a typical 1000 kwh customer, placing PEF in the top quartile of Florida electric utility companies. (See Mr. Lyash's testimony);
- Customer service improved, moving PEF from the third quartile to the first quartile, as reported by J.D. Powers and Associates 2004 Electric Utility Residential Customer Satisfaction Service. (See Mr. Lyash's Testimony). Progress Energy ranked number one in the J.D. Powers Customer Service component of the survey for the Southern Region. (See Mrs. Morman-Perry's Testimony);
- At the eighth annual Customer Service Awards program at Edison Electric Institute's Spring National Accounts Workshop, Progress Energy (along with American Electric Power, Cleco Power, and Oklahoma Gas & Electric) was named as one of the electric companies offering the best overall customer service in 2004. (See Mrs. Morman-Perry's Testimony);

- Installation cost for new service was reduced, from $120 per customer to $102 per customer, placing PEF in the second quartile of peer utilities. (See Mr. Lyash's testimony);
- A recent Florida Public Service Commission Report ("Review of Florida's Investor-Owned Electric Utilities' Distribution Reliability") reported that PEF improved on seven of eight performance metrics. (See Mr. McDonald's Testimony);
- Transmission reliability improved by 37% since 2002. Transmission related SAIDI dropped from 16.26 minutes in 2002 to 10.23 minutes in 2004. (See Mr. DeSouza's Testimony);
- Fossil steam units bested the national average availability for 2004 (85.8% based on NERC data) by improving from 86.9% in 2002 to 89.7% in 2004. When adjusted for hurricane related events, the availability increases to 90.2%. (See Mr. William's Testimony).
- The forced outage rate for fossil fuel units was 2.27% when adjusted for hurricane related events, comparing favorably to the 2003 industry average of 5.04%. (See Mr. William's Testimony).
- Similarly, PEF's combustion turbine and combined cycle fleet beats industry reliability averages, with combustion turbine reliability at 99.5% for 2004 (compared to the industry average of 80% based on NERC data). (See Mr. William's Testimony);
- The Hines combined cycle units completed 2004 with an equivalent availability factor of 90.9%, easily beating the industry average of 79.8%. (See Mr. William's Testimony).

- PEF's nuclear unit (CR-3) ranks in the top quartile of all U.S. nuclear plants in most key performance areas. This is all the more impressive when one considers that CR-3 is ranked in the top quartile of all nuclear facilities in terms of plant safety. (See Mr. Young's Testimony).

Q. What are your conclusions with respect to PEF's internal benchmarking studies?

A. I conclude that PEF has made remarkable progress in improving its service quality and reliability while continuing to aggressively manage and reduce its costs. PEF is now consistently ranked in the top quartile of all utilities in the country and is poised to continue its improvement in these areas. PEF should be recognized and commended for its excellent work on behalf of its customers.

Q. You stated that you also performed a statistical benchmarking study of PEF's cost performance. Please describe that statistical analysis.

A. PEG has developed a proprietary econometric model of electricity production. I directed my colleagues to use this model to analyze PEF's costs over the period 2001-2003. The analysis utilizes publicly available cost data for 99 utilities over the period 1995-2003, the last period for which data is currently available. This analysis uses rigorous econometric methods that are needed to develop holistic performance assessments.

Q. Please describe the statistical analysis of PEF's cost performance.

A. First, it is very important when conducting an analysis of a utility's cost performance that care is taken to account for any differences between utilities or over time. For example, one fact that seems particularly important is that PEF has a relatively high component of residential customers in its customer mix. If PEF's performance is measured, without making statistical adjustments, against a utility that has a relatively large industrial component to its customer mix, the results are likely to be misleading. Another factor is weather variability and uncertainty, which also needs to be accounted for statistically. PEG's econometric model significantly makes these statistical adjustments so that meaningful comparisons can be made.

Q. Please explain, in layperson's terms, what your model does.

A. The econometric model reflects the effect of various variables on the production of electricity. The unadjusted percent of the variation in the dependent variables in this model explained about 98% of the variation in total cost across the electricity industry. Some of the key cost drivers in the model are:

- Labor prices
- Capital prices
- Energy and fuel prices
- Residential and business sales volume
- Peak demand
- Number of natural gas customers (synergy)
- Growth in customers
- Share of residential and other customers

- Transmission and distribution
- Probability of tropical storm activity
- Time period

These data are combined into a Total Cost Function. The theory is that the cost for company *i* (C_i) is a function of the minimum industry-wide achievable costs (C_i*) and its specific efficiency level. The minimum achievable cost depends upon labor, capital, and other inputs. Age of plant and capital mix also matter, as do the volume and type of products, type of customers served, and specific market or locational conditions. These various explanatory factors are incorporated into a natural logarithm model, which adds complexity but facilitates the interpretation of the apportionment of cost responsibility to the various cost determinants contained in the model.

The statistical approach was developed theoretically and empirically in the 1970s. Its full technical name is "Transcending Logarithmic," or Translog for short. This approach uses the economic theories of how firms efficiently produce the products they sell, and as a consequence, minimize their corresponding total production costs.

Total cost is the focus of this extensive econometric research, which has been applied extensively for many different industries across the world and over time. Perhaps one of the most extensively analyzed industries is electric power. Indeed, the analyses of electricity production functions and total cost functions are where much of this modern-day marriage of economic theory and advanced econometric applications began.

Q. What were the results of this econometric analysis of PEF's costs?

A. I found that PEF's actual costs for the period studied were 12.7% below the costs the model predicted for PEF for a three-year composite period. This is an extraordinary achievement and indicates the depth of PEF's cost level efficiency on a statistical basis.

Q. What are the annual savings for the three-year period for which you compared PEF's total costs to the efficient industry prediction?

A. The three-year composite score translates to an industry total cost prediction of $3,323,121,000 and an actual composite score for PEF of $2,926,784,000. This represents an annual equivalent savings for PEF of $396.3 million. Therefore, this 12.7% advantage saved PEF's ratepayers about $396.3 million per year compared to the efficient industry benchmark utility.

Q. How did you approach the task of determining PEF's performance relative to the industry?

First, I estimated the Total Cost function for the industry, omitting the firm that analysts seek to score or compare relative to the industry. This refinement is widely accepted for performing such comparisons. The firm being analyzed is <u>not</u> included in the sample used to estimate econometrically the industry-wide total cost, segment cost, and share functions.

Second, I compared the predicted score of the firm in question using the industry model to the actual score of the firm in question.

Q. Please explain your Total Cost comparison of PEF's performance relative to the industry.

A. Table 1 shows PEF's actual Total Cost scores relative to the corresponding scores based upon the industry model of how efficient firms in the U.S. would produce electricity. These scores are stated in natural logarithmic form. The difference between the logarithm of predicted total cost for an efficient firm and PEF represents PEF's total cost advantages or savings relative to the industry. This means that if PEF's unique characteristics (*e.g.* ,residential sales volume, purchase power prices, labor prices, etc.) were assigned to a firm of average efficiency in the electric industry, the percentage advantages shown in Table 1 would be the percentage savings that PEF has achieved since its merger.

TABLE 1

PEF'S TOTAL COST SCORES RELATIVE TO INDUSTRY

YEAR	ACTUAL SCORE	PREDICTED SCORE	PERCENTAGE ADVANTAGE PEF TO INDUSTRY
2001	17.165	17.277	-11.20%
2002	17.162	17.313	-15.10%
2003	17.248	17.367	-11.80%
Three Year Composite Score	17.192	17.319	-12.70%

In 2001, PEF had an 11.2% cost advantage, or relative savings. This percentage increased in 2002, and returned to 11.8% in 2003 as fuel and purchase power cost increases began to hit PEF relatively more than others.

Over the three-year period, I determined that PEF's corporate advantage relative to a firm with average efficiency with PEF's requirements and characteristics was a negative 12.7%. PEF's actual total cost savings beats the industry prediction by 12.7%.

Q. Did you also review separately PEF's capital cost segment?

A. Yes. Here, I examined the same sort of logarithm score for an economist's measure of capital cost in which current replacement cost dollars are imputed. Based upon this approach, Table 2 shows that PEF has about a 39.6% capital cost advantage over a comparable "efficient firm in the industry" with PEF's requirements.

TABLE 2

PEF'S CAPITAL COST SCORES RELATIVE TO INDUSTRY

YEAR	ACTUAL SCORE	PREDICTED SCORE	PERCENTAGE ADVANTAGE PEF TO INDUSTRY
2001	16.121	16.474	-35.30%
2002	16.093	16.510	-41.70%
2003	16.146	16.562	-41.60%
Three Year Composite Score	16.120	16.516	-39.60%

Two other facts are important. First, PEF's scores have also declined by 7% between 2001 and 2003. This is also very beneficial for PEF's consumers. Second, PEF purchases long-term power. This would partially offset these very impressive PEF capital cost advantages, but not PEF's three-year improvement of 7% relative to itself.

Q. Have you broken out or isolated the distinction between PEF's energy and non-energy scores relative to the industry?

A. Yes. Table 3 shows that PEF outperforms the industry by 32.5% for the composite score over a three-year period when I remove energy (purchase power and fuel).

TABLE 3

PEF's 'NON" PURCHASE POWER AND FUEL COST SCORES RELATIVE TO THE INDUSTRY

YEAR	ACTUAL SCORE	PREDICTED SCORE	PERCENTAGE ADVANTAGE PEF TO INDUSTRY
2001	16.560	16.852	-29.20%
2002	16.551	16.884	-33.30%
2003	16.588	16.938	-34.90%
Three Year Composite Score	16.567	16.891	-32.50%

In contrast to PEF's very favorable scores in Tables 2 (capital) and 3 (non-energy), Table 4 shows that PEF has 16.2% higher fuel and purchase power costs.

TABLE 4

PEF'S COMBINED PURCHASE POWER AND FUEL COST SCORES RELATIVE TO INDUSTRY

YEAR	ACTUAL SCORE	PREDICTED SCORE	PERCENTAGE ADVANTAGE PEF TO INDUSTRY
2001	16.374	16.216	15.90%
2002	16.379	16.260	12.00%
2003	16.521	16.313	20.80%
Three Year Composite Score	16.425	16.263	16.20%

These results reflect a combination of clean fuel and increased purchase power regulatory policies in Florida. Nevertheless, together, the net gain for Florida over all four tables, as well as discussed below, represents a distinct advantage.

This means that PEF's current and long-term business and investment strategies and performance exceed the best prediction for PEF using the efficient industry model.

Q. Have you considered other cost categories?

A. Yes. Table 5 shows the "other" costs comparison. Economists typically think of these "other "costs as items such as material costs and outsourcing.

TABLE 5

PEF'S "OTHER" COST SCORES RELATIVE TO INDUSTRY

YEAR	ACTUAL SCORE	PREDICTED SCORE	PERCENTAGE ADVANTAGE PEF TO INDUSTRY
2001	15.148	15.335	-18.70%
2002	15.114	15.353	-23.90%
2003	15.076	15.419	-34.20%
Three Year Composite Score	15.113	15.369	-25.60%

"Other" means non-labor, non-capital, and non-energy (fuel and purchase power)

PEF has reduced these other costs relative to itself by 7.2% over three years; while the industry has been increasing these other costs by 8.4%. PEF has outperformed the efficient firm in the industry standard by 25.6% over the same three-year composite basis.

Q. How do PEF's O&M costs compare to the industry?

A. Table 6 shows that over the three-year composite time period, PEF has rather consistently outperformed the efficient firm industry standard by 18.5%.

TABLE 6

PEF'S O&M COST SCORES RELATIVE TO THE INDUSTRY

YEAR	ACTUAL SCORE	PREDICTED SCORE	PERCENTAGE ADVANTAGE PEF TO INDUSTRY
2001	15.526	15.698	-17.20%
2002	15.551	15.719	-16.80%
2003	15.559	15.776	-21.70%
Three year Composite Score	15.545	15.731	-18.50%

Q. How does PEF's labor cost compare to the industry?

A. Table 7 shows a modest advantage of 4.5% for PEF relative to the industry using the three-year composite score.

TABLE 7

PEF'S LABOR COST SCORES RELATIVE TO INDUSTRY

YEAR	ACTUAL SCORE	PREDICTED SCORE	PERCENTAGE ADVANTAGE PEF TO INDUSTRY
2001	14.370	14.508	-13.80%
2002	14.513	14.537	-2.40%
2003	14.600	14.573	2.70%
Three Year Composite Score	14.494	14.539	-4.50%

The biggest advantage in labor cost savings occurred in the first year after the merger was completed. Since then, the Company has added labor to enhance customer service quality and reliability. This often involved training and other new labor costs.

Regardless, in the context of an 12.7% overall superior performance relative to the best industry model prediction for PEF with respect to Total Cost, PEF has consistently outperformed the efficient industry performance standard and saves ratepayers about $396.3 million per year.

Q. What are the limitations of this analysis if the last full year for which data is available is the end of the year 2003?

A. PEF handily beats the industry benchmark for an efficient electric utility. These results are relatively long-term in nature because electric utilities do not typically make major changes in the way they conduct their business and provide energy from year to year.

That said, I did perform two additional tests. This was to compare PEF's actual 2004 total operations and maintenance expenses to its own internal budget in order to determine if PEF was staying its course and continuing to perform well for the last full calendar year of this rate cycle.

Q. Have you analyzed PEF's performance in 2004 using the econometric model?

A. Yes. I analyzed PEF's actual and predicted costs in 2004 on a preliminary basis because I do not have the full industry sample for 2004. Accordingly, I predicted PEF's performance out of the time period of the sample in 2004 and compared these estimated costs to PEF's actual 2004 performance. I found that PEF continues to have superior performance relative to the utility industry. PEF's relative cost and productivity performance continue to be impressive compared to the industry.

Q. What additional benchmarking data did you consider?

A. I have reviewed Mr. Javier Portuondo's data used for PEF's Minimum Filing Requirements (MFRs) in order to bring the benchmarking analysis beyond the period for which national data is available. I specifically analyzed PEF's Total Other O&M Expenses since the merger in 2002 and as projected for 2006 on a comparable accounting or per book financial basis for these two years.

Q. What expenses are included in Total Other O&M Expenses?

Table 8		
PEF's Total Other O&M Expenses		
	Dollars Per Customer	
Expenses	**2002**	**2006 (Projected)**
Power Production	$126.47	$131.33
Transmission	$21.33	$17.24
Distribution	$55.51	$50.43
Customer Account	$34.82	$31.70
Customer Service	$2.57	$2.74
Sales	$3.58	$2.29
Administrative & General	$103.69	$132.05
TOTAL OTHER O&M	**$347.97**	**$367.78**

Q. How do the changes in PEF's Other O&M costs per customer from 2002 to 2006 compare to PEF's fundamental cost drivers over this five-year period?

A. There are three fundamental cost drivers. Two effectively are outside PEF's ability to control. Those are inflation and customer growth. In addition, while PEF is committed to conservation, it does not fully control the third cost driver: the MWHs that it has a duty to provide.

Over these five years, these three cost drivers have increased as follows: (1) the Consumer Price Index (CPI) from 179.9 to 193.1, or 7.34% over five years; (2) Customer Growth of 8.67% over five years; and combined with the CPI, a 16.65% increase in inflation and customers; and (3) MWHs sold growth of 8.73%.

During this same five-year time period, PEF's Total Other O&M Expenses per customer increased by 5.69%. This means use per customer has remained relatively constant. During this same five-year period, the relatively small increase in dollars per customers is less than inflation. This represents a gain for consumers, especially since utilities often find new customers and growing use can increase average or unit operating costs. PEF has beaten inflation, which alone would have put unit costs per customer in 2006 at $373.51, which is above PEF's projection of $367.78. PEF has done this while adding customers and increasing MWHs sold by about 8.7%, without adding to the unit costs per customer.

Q. What do you conclude from these internal and external analyses?

A. I conclude that PEF is delivering on its promise to ratchet up its cost and service performance both relative to itself and to its peers. Quality of service and reliability have improved. My comparison with the rest of the industry shows that PEF has a significant degree of efficiency and performance advantage based upon the most recent industry data. Finally, PEF's MFR data show that it is on track to continue to improve through 2006.

As I have said earlier in this testimony, this good work is not yet complete. In effect, sharing 50 basis points of ROE with PEF for its achievements and success to date would tend to cause these efforts to continue. Customers would benefit more and for a longer period of time if PEF is rewarded for its performance and encouraged or incented to continue its service quality improvement and cost cutting efforts. The Commission can accomplish this by authorizing returns and setting revenue targets towards the high end of their respected ranges, and including a 50 basis point adder to PEF's authorized ROE. I explain this in greater detail in Section VI. This progress would be further enhanced by establishing a 45/55 debt to equity structure as recommended by Dr. Vander Weide. I explain this in greater detail in Section V.

V. Capital Structure

Q. What capital structure is PEF preparing for this filing?

A. The Company has targeted a capital structure that is 55% equity and 45% debt. I support PEF's intentions and purpose, as discussed in Dr. Vander Weide's testimony. I support Dr. Vander Weide's recommendation. I would also recommend thickening the equity share of PEF's capital structure if the Commission sets the ROE below Dr. Vander Weide's recommended 12.3%.

Q. How do you approach the debt/equity structure issue?

A. Reviewing the debt/equity structure issue requires a combination of regulatory judgment, financial and business reasons, and considering current facts. My personal bottom line is "do what is best for consumers" in the long-run.

Q. What do you mean by the regulatory judgment component of the analysis?

A. The regulator's role is to determine a just and reasonable rate of return (ROR).[3] This often requires considering many factors, some of which might be offsetting. Nevertheless, most authorities, including the U.S. Supreme Court, accept a standard that produces a reasonable "end result." I consider this to mean that some factors may be low, others high, and others just right. Regardless, when combined, the outcome can often be deemed just and reasonable.

[3] ROR can be defined as: ROR = Percent Debt (Interest Rate) + Percent Equity (Authorized ROE).

The "end result" necessarily considers the effect on both customers and shareholders. This is a second type of balancing that takes place in a rate case. This overarching principle is relatively simple. While lower RORs would mean lower regulated prices in the short run, understating RORs will hurt consumers in the long run. RORs should be set at a level sufficient to attract new capital that is needed for necessary investment in infrastructure. Without such investments, the gains and improvements made by PEF will be threatened.

Customers could face a future marked by reduced service quality, service disruptions, and higher costs for replacement energy and/or long-term purchase power agreements. Customers have as great a stake in the outcome of a rate case as do shareholders. The customers, for example, need assurance that the ROR is set at a level that is sufficient to allow PEF to continue on its current course of improving its performance, to the benefit of customers. The key is that, all other things equal, an ROR that is sufficient to attract capital at a low cost will benefit customers. This conclusion is extremely important for a utility like PEF that is located in a state that is not restructuring its electricity industry and that needs to attract capital in financial markets to finance its planned infrastructure investments, including necessary environmental upgrades required by the new EPA regulations. Florida needs a good financial outcome in a rate case to achieve both shareholder expectations and to satisfy customer needs at a reasonable cost.

Q. What are the specific financial and business components to the debt/equity ratio and how do these affect consumers?

A. First, consider the formula used to express ROR and the fact that interest rates on debt (ROD) are a component of ROR and typically less than the expected ROE. Since ROD is less than ROE, it would seem, from a mathematical perspective, that a business could lower its overall ROR by borrowing more of its capital and eschewing equity finance. However, this is too simplistic for several reasons. First, as the debt to equity ratio increases, the ROD will begin to increase as bond ratings are lowered, raising the overall ROR.

Second, financial risk of the firm is higher as the debt-to-equity ratio increases, particularly relative to other firms with comparable requirements and with similar business, economic, and regulatory risks.

Third, there are valid business reasons for a business not to borrow 100% of its capital. A business has an obligation to make interest and debt reduction payments before paying dividends, retaining earnings, or repurchasing outstanding shares. As debt increases, business risk and cost also increase. An all debt firm would live in the constant shadow of bankruptcy. Any unexpected event could push it into failure. Accordingly, the risk adjusted cost of capital, also known as ROR, would increase for highly leveraged firms. Thus, a reasonable and well reasoned balance must be struck for setting a regulated firm's capital structure.

Q. But didn't you just state that debt is less expensive than equity?

A. Yes, other things equal, debt is less costly than equity. Nevertheless, as I discussed above, regulators and financial markets recognize that too much debt is inherently risky. A firm with a significant degree of indebtedness also has lower quality debt, and therefore, higher fixed financing costs, greater interest payments, and/or liabilities. Such firms generally have lower debt ratings and, as a result, higher interest costs. Moreover, a more highly leveraged firm (*i.e.,* one with more debt) will have more expensive equity, in part because investors view highly leveraged firms as risky investments.

In addition, with more debt, operating income or margins must cover significantly greater annual interest payments before equity investors can receive any earnings per share and/or dividends. This increases equity risk. These combine to increase financing costs for necessary new investments. These factors also increase the costs of long-term supply contracts and, in the extreme, could reduce a utility's access to debt, equity, and long-term purchase power agreements (PPAs).

Several utilities now purchase a disproportionate share of their electricity for resale. These utilities are often located in fully restructured states in which some utilities now purchase 100% of their customers' energy needs. These states and their share of energy purchases are not comparable to PEF, which effectively remains the sole provider of retail energy requirements.

A second difference is that some utilities purchase a large share of their retail needs in short or intermediate term spot and forward or futures markets. These utilities are not comparable to PEF with its long-term fixed cost recovery PPAs. As PEF uses more PPAs, it is very similar to increasing the risk inherent in carrying more debt.

High debt shares or ratios work against retail customers by increasing the risk of both debt and equity, thereby increasing their respective cost. Regulators traditionally have sought to regulate stand-alone utilities that are making significant new investments in the future based on a capital structure with a thick, or relatively high, equity share. This permits regulators to eschew financial risk, improve debt ratings, hold down long-term debt payments, and target authorized RORs at levels that provide the utility with necessary capital while protecting customers in terms of least cost financing principles.

The Company has committed itself to attaining a capital structure of 55% equity by the end of the rate year. I view this as an important step. However, PEF likely needs to go further, and grow equity in the future as it continues to grow and make necessary capital additions. This is why I support Dr. Vander Weide's recommended capital structure.

Q. You stated that PEF's long-term contractual commitments for purchase power add a debt-like fixed cost recovery requirement to PEF's cash flow from operations. How does PEF compare to other companies with respect to this purchase power component?

A. In Table 9, I show the purchase power component for the various utilities around the country that are included in Dr. Vander Weide's peer group for his traditional ROE analyses. The information contained in this table is culled from the FERC 1 filings made by each company. The information on the S&P bond ratings is from Dr. Vander Weide's Testimony.

Table 9
Purchase Power vs Generated Power

Utility	Nov '04 S&P Bond Rating	% Generated	% Purchased
Ameren	A-	60	40
Cinergy	BBB+		
Cincinnati Gas & Electric		82	18
Union Light		0	100
PSI Energy		85	15
Consolidated Edison	A		
The Consolidated Edison of New York		3	97
Orange and Rockland Utilities		0	100
Constellation Energy	BBB+		
Baltimore Gas & Electric		0	100
Dominion Resources	BBB+		
North Carolina Power		N/A	N/A
Virginia Power		76	24
DTE Energy	BBB+		
Detroit Edison		88	12
Duke Energy	BBB	98	2
Energy East	BBB+		
NYSE&G		21	79
Rochester Gas & Elect		64	36
Central Maine Power		0	100
Entergy	BBB		
Entergy Arkansas		68	32
Entergy Louisiana		54	46
Entergy Mississippi		38	62
Entergy New Orleans		28	72
Entergy Gulf States		52	48
Entergy Power		73	27
Exelon	A-		
PECO		0	100
ComEd		0	100
FirstEnergy	BBB-		
Pennsylvania Power		50	50
Jersey Central		0	100
Cleveland Electric		37	63
Ohio Edison		24	76
Metropolitan Edison		0	100
Toledo Edison		34	66
Pennsylvania Electric		1	99
FPL Group	A	80	20
Great Plains Energy	BBB		
Kansas City P&L		94	6
Hawaiian Electric	BBB		
HECO		59	41
Maui Electric		94	6
MDU Resources	A-	72	28
Northeast Utilities	BBB+		
Connecticut Power & Light		0	100
Public Service Co. New Hamp		72	28
Western Massachussetts	0	0	100
NSTAR	A		
Boston Edison Company		16	84
Cambridge Electric Light Company		9	91
Commonwealth Electric Company		15	85
OGE Energy	BBB+	83	17
Otter Tail	A-	63	37
Pepco Holdings	BBB+		
Potomac Electric Power Company		0	100
Conectiv			
Atlantic City Electric Company		19	81
Delmarva Power & Light Company		0	100
Pinnacle West Capital	BBB		
Arizona Public Service Company		44	56
PPL	BBB		100
Progress Energy	BBB		
Carolina Power & Light		93	7
Progress Energy Florida		79	21
Public Service Enterpricse	BBB		
PSEG Energy Resources		0	100
PSEG Fossil		100	0
PSEG Nuclear		100	0
Public Service Electric and Gas Company		0	100
Puget Energy	BBB-	27	73
SCANA	A-		
South Carolina Electric		76	24
South Carolina Generating Company		100	0
Sempra	BBB+		
SDG&E		34	66
Southern Co.	A		
Alabama Power		90	10
Georgia Power		78	22
Gulf Power		90	10
Mississippi Power		78	22
Savannah Electric		47	53
Southern Electric Generating Company		100	0
Vectren Corp	A-		
Southern Indiana Gas and Electric		61	39
Wisconsin Energy	BBB+		
Wisconsin Electric		86	14
Edison Sault Electric		21	79
WPS Resources	A		
Wisconsin Public Service		82	15
Upper Penninsula Electric		15	85
Xcel Energy	BBB		
Northern States Power (Minn)		76	24
Northern State Power (WI)		17	83
Public Service CO Colorado		56	44
Southwestern PSC		81	19

Information from FERC Form 1 for 2003

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It can be seen that in those states that have retained a traditional regulatory framework, PEF has a relatively high percentage of purchase power and most of PEF's purchases are long-term purchases, not spot purchases, which is unlike many other utilities. Thus, the 45% debt/55% equity capital structure recommended by Dr. Vander Weide is not as free of debt related risk once the purchase power contracts, which are akin to a long-term debt commitment, are considered. Mr. Sullivan discusses this in his Testimony, specifically how off balance sheet debt obligations increase PEF's projected 2006 leverage ratio from 45% to 52.29%.

Q. Do you have an opinion as to whether purchase power contract costs should be included in the debt component of the capital structure?

A. Yes, I do. I have reviewed Mr. Sullivan's testimony and concur with him that PEF's rates should reflect the effect of imputed debt associated with long-term PPAs. Purchase power contracts are an alternative method for a utility to secure the generation needed to serve its customers. Consider the fact that if PEF did not enter into purchase power contracts, it would need to build new generation facilities to serve its native load. There is no question that PEF would need to borrow money to secure outside power. The debt component associated with new generation stations would be included in the capital structure calculation. PPAs are an alternative long-term financial liability, much like seeking new rate base with secured first mortgage debt. In these ways, PPAs are equivalent to and serve a similar purpose (*i.e.,* providing electricity to serve native load). Therefore, a portion of the purchase power contract costs should also be included in the debt component of PEF's capital structure. In addition, any fixed long-term payment is a source of higher financial risk for equity holders because, as with bonds, these fixed cost PPAs need to be repaid before any money is available to shareholders.

Q. What are you recommending?

A. I recommend in this proceeding that the Commission should accept Dr. Vander Weide's capital structure at 55% equity and 45% debt and approve the Company's consideration of PPA's in its request for rate relief. PEF has about $3 billion in debt when off-balance sheet debt is included.

VI. <u>ROE</u>

Q. What is your role in the ROE portion of this proceeding?

A. Dr. Vander Weide is the Company's ROE witness in this proceeding. My role is to put Dr. Vander Weide's authorized ROE recommendations into a broader context and to explain, as I have been doing, why an additional 50 basis points should be added to Dr. Vander Weide's recommended 12.3%, raising the ROE to 12.8%, which is just and reasonable here.

Q. Please summarize traditional regulatory treatment of ROE.

A. The first step in authorizing the ROE is to review various cost of capital estimation approaches, using formulae and historical information. The core principle in sorting through these often differing estimates is the *Hope Natural Gas* and *Bluefield Water Works*[4] criterion that recognizes a utility's need to attract capital. Dr. Vander Weide finds that PEF requires a 12.3% (12.8% with the 50 basis point adder) ROE to do this. I agree with his conclusion. I take it another step, however, and urge an approach where this Commission would move to the very high end of the "just and reasonable" range in setting ROE for PEF.

Q. Why do you support 12.8% ROE in this proceeding?

A. There are several lines of reasoning that guide my recommendation.

First, consumers benefit when utility companies are financially healthy and, as a result, they can finance necessary investments at reasonable or relatively low long-term costs.

Second, just as performance and capital structure targets are important, I believe that other utility companies and regulatory jurisdictions should be analyzed. When I examine other utility companies and regulatory jurisdictions, I find that both PEF and Florida do quite well. That said, aiming high at superior performance often helps us achieve additional beneficial results. Here, I explain how I would look outside to set a higher bar for achievement. I do this to encourage more productivity improvements and greater future consumer benefits.

Third, PEF has not had a base-rate price increase since 1993, and in fact provided residential customers with a $125 million annual rate reduction in the last

[4] *FERC v. Hope Natural Gas Co.*, 320 US 591 (1944); *Bluefield Water Works and Improvement Co. v. Public Service Commission*, 262 US 679 (1923).

rate case settlement. This means that PEF will have gone more than a dozen years since its last base rate increase, but with some decreases, when the new rates would be applicable in 2006. In fact, base rates today for the typical 1,000 kwh customer under the current rate freeze are about what they were in 1983. Adjusting for inflation, the current base rate is $41.18 per month for 1,000 kWh, or about 4.18¢ per kWh, at the end of 2004. This is equivalent to about 2.171¢ per kWh in 1983. This is nearly a 90% decline in inflation-adjusted base rate prices.

Consumers and the Florida economy have benefited and continue to benefit from this achievement. PEF is, therefore, one of the successful utility companies in the nation and quite distinct from the gaggle of utilities whose inability to hold down base rates caused their states to restructure and essentially deregulate the electricity industry.

After some 23 years, PEF is, in effect, seeking to raise base rates to about 5.01¢ per kWh related to adding new generation and replenishing storm reserve funds. This is a small fraction of the inflation-adjusted decline of 90% that consumers have enjoyed. In fact, in 1983 dollars, the new proposed base rate would still be below 2.4¢ per kWh.

Fourth, PEF has several specific reasons why it seeks to add approximately $206 million to revenue requirements for base rates. The following components of the need for an adjustment combine to exceed the requested increase, which means cost cutting and growth are reducing some of the need for a rate increase.

Specifically, PEF has the following needs for more revenue:

(1) The 516 MW Hines 2 and 516 MW Hines 3 power plants need to be

added to rate base.

(2) Fossil fuel dismantlement expenses have increased.

(3) PEF needs to add about $50 million per year to its depleted storm reserve fund, while current base rates provide for only about $6 million per year.

Q. These factors justify more revenue. How does this affect your views related to authorized ROE?

A. As I have explained, the final result is what matters. Higher ROEs, thickening the equity share, improved recovery of capital expenses and other reserves are all factors that combine to determine the need and size of a revenue increase.

In that respect, there is not much gained by using any of these factors to increase the target levels of the others. If we get them each right, we would have a reasonable combined result. That seldom happens. Therefore, I find it useful to discuss them collectively.

More important, investors and utility analysts review and effectively grade states and utilities. One factor is often paramount. That factor is the authorized ROE. For this reason, I believe that PEF's significant and important reasons for rate relief need to be considered when this Commission sets a new ROE for PEF.

Furthermore, authorized ROEs need to be considered in the context of how likely the authorized ROE will be achieved. Here, utility performance and the regulatory cost recovery of these other factors become important. In effect, ROE cannot be divorced and isolated from these other significant revenue requirements and related factors.

Q. How might consumers benefit by setting PEF's ROE at the high end of just and reasonable?

A. This would help to hold or improve PEF's financial position. This would help to control PEF's cost of long-term debt. A strong investment grade status means a lower cost of debt, a better chance of attracting capital, and could make other cost savings available to PEF. Lower debt interest rates benefit consumers. This is especially true when one considers the capital costs that PEF will be incurring to meet the needs of a growing customer base, maintaining superior service that customers have come to expect and demand, and meeting its obligations under the EPA's new environmental requirements. Any reduced cost of financing these capital costs will benefit customers for decades to come.

Q. How does the restructured versus non-restructured states dichotomy affect authorized ROEs?

A. In the past decade, many states, such as California, restructured and moved from traditional cost of service regulation to a competitive environment. The impetus to restructure was a perceived failure of traditional cost of service regulation to keep prices to reasonable levels. When California began its restructuring efforts in 1996, its prices were about twice the national average. Today, average electricity prices in California are three times the national average. Other states, such as

Florida, adopted a "wait and see" strategy. Unlike California, these states did not jettison traditional cost-of-service approaches despite external pressures to do so. Nevertheless, investor impression of the utility sector, as a whole, is colored by the failed attempts at restructuring, even in jurisdictions, such as Florida, that retained traditional cost-of-service approaches.

Q. What are you suggesting?

A. First, I think that it is important that, when setting PEF's authorized ROE, the Commission should focus on utilities located in jurisdictions that, like Florida, have retained traditional cost-of-service approaches and where utilities are expected to continue to make large scale infrastructure investments to serve their native load customers. In particular, states like Georgia and Wisconsin are most similar to Florida in regulatory approach. Utilities located in these states, like PEF, continue to invest in rate base generation and enter into long-term PPAs to reduce customer risk and hedge volatile energy markets. Consequently, PEF will be competing with these utilities for the capital needed to build that new generation and infrastructure. Thus, the way in which the public utilities commissions in these other non-restructuring states are setting ROEs for the utilities within their respective jurisdictions, including incentive programs and accounting treatment, should be very relevant to this Commission in deciding the authorized ROE and capital structure that will allow PEF to effectively compete and attract limited capital at a reasonable cost to finance infrastructure investments for the benefit of its customers.

Q. Do other non-restructuring jurisdictions typically have performance-based or other incentive ratemaking plans?

A. Performance-based and incentive plans are fairly common in other non-restructuring jurisdictions. For example, Georgia Power for several years has had a sharing plan that authorizes it to earn an ROE within a specified band. This band has been capped at 12.95%.[5] This 12.95% is, in effect, its authorized ROE target. If Georgia Power earns above that authorized 12.95%, it shares the excess earnings with its customers. The sharing mechanism provides Georgia Power with the incentive to cut costs so as to increase its earnings. The Georgia Public Utilities Commission has frozen Georgia Power's retail rates within an ROE band with the very real potential for Georgia Power to exceed that ROE, thereby benefiting both customers (through rate reductions) and shareholders. Consider Table 10, below. Here, I show that the average top of the neutral band ROE is 13.35% for states that retain traditional utility investments and have a strong positive performance-based rate (PBR) incentive to invest and keep costs under control.

TABLE 10
PBR POST-2001

COMPANY	STATE	OPERATION SUBJECT TO PBR	RATE ADJ. PROVISIONS AND INCENTIVES	ROE NEUTRAL BAND	RESTRUCTURING
Alabama Power	Alabama	Electric	Rate Stabilization	13.0-14.5	No
Georgia Power	Georgia	Electric	Rate Freeze	10.25-12.25	No
Mid American	Iowa	Electric	Rate Freeze	12.0-14.0	No
Northern States	North Dakota	Electric	Rate Freeze	11.0-13.0	No
Otter Tail	North Dakota	Electric	Rate Freeze	11.0-13.0	No
		Average Top of Neutral Band ROE	**13.35**		

[5] The Georgia Commission in 2004 reset the earnings band with a range of 10.25% to 12.25%, as shown in Table 2.

While PEF is not suggesting a performance based sharing mechanism be implemented at this time, the 50 basis point adder for PEF's superior performance accomplishes the same incentives, and as I described above, would be a good approach for PEF.

Q. Why is it necessary to add incentives in the form of a 50 basis point adder to the ROE to traditional regulation?

A. It has been my experience that people respond to challenges and seek rewards, as well as work to avoid losses. More important, it has been shown to yield benefits that exceed inherent costs. It is something I have advocated and practiced since my days on the Public Service Commission of Wisconsin. In this case, there are six specific reasons that support my conclusion that adding 50 basis points to Dr. Vander Weide's recommended 12.3% ROE is justified. Those several reasons are:

- There is precedent in Florida to consider significant factors that are <u>not</u> reflected in the traditional formulistic methods used to determine the cost of capital.
- As a former regulator, I used such regulatory judgment to select the authorized ROE for a specific utility. The precise point along a just and reasonable range (12% to 13.5% at the time and a tighter 13.0% to 13.5% ROE for electric utilities since they had greater additional capital requirements) is based upon non-traditional factors related to specific utility performance and its degree of cooperation with the Commission.
- PEF's overall performance with respect to controlling costs and

accommodating growth, its innovation, and pro-consumer stance place it in a position that fully justifies an additional 50 basis points for ROE and a thicker equity ratio.

- Adjusting for storm damage and other developments, PEF has been earning about 13.3% on equity on a corrected basis. Dr. Vander Weide proposes a 12.3% rate using traditional cost of capital methods. In states that split or share savings, it would be typical for half of the 100 basis point differential between the just and reasonable target of 12.3% and 13.3% adjusted to be split 50/50 between shareholders and consumers. This reasoning would also support the 50 basis point adder that I recommend in this proceeding.
- In effect, agreeing to a 12.8% ROE and thicker equity structure would generate cash and earnings at the PEF level. This would enable PEF to improve the quality of service, to expand efficiency, to accommodate growth, and to continue to provide superior performance.

Q. What precedent is there in Florida for considering factors that are not reflected in the traditional formulistic methods used to determine the cost of capital?

A. In approving a regulatory incentive plan for Gulf Power Company, the Commission set the midpoint of the sharing band at 11.5%, 50 basis points higher than the midpoint it set for FPL. The Commission took this action, which it said "fairly considers Gulf's performance" to reflect Gulf Power's "lower rates, reliability, customer satisfaction and its relatively low equity ratio."[6] In that decision, the Commission also discussed early actions taken in 1990 where it had penalized Gulf Power 50 basis points on its ROE for mismanagement.[7] The Commission has both rewarded and penalized utilities based on factors outside the traditional cost of capital analysis. In fact, when I was sitting on the PSCW, I took similar action.

Q. What actions did you take as a regulator on the PSCW?

A. Just as this Commission has done in Florida, when I was the Chair of the Public Service Commission of Wisconsin, I firmly believed that utilities with superior performance should be rewarded and provided with incentives to continue their superior efforts. I also believed in symmetric regulation. Thus, I penalized utilities whose performance was inferior. At the time, ROEs in Wisconsin were routinely set at 13.0%. I broke this tradition when I first rewarded Wisconsin Electric Power Company's superior performance (which included embracing tariff reforms that benefited consumers, cooperation with the Commission and its Staff, reduction and elimination of unnecessary costs, and a well managed and healthy utility) by adding 25 basis points to its authorized ROE.[8] I subsequently "rewarded" Wisconsin Power and Light with an ROE of 13.5%, representing 50

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[6] *In re: Investigation into the earnings and authorized return on equity of Gulf Power Company,* 1999 Fla. PUC Lexis 915, 99 FPSC 5:305 (May 24, 1999).

[7] *In re: Petition of Gulf Power Company for an Increase in its Rates and Charges,* 1990 Fla. PUC LEXIS 1320, 120 PUR 4th 1, (October 3, 1990).

[8] *Findings of Fact and Order re Application of Wisconsin Electric Power Company for Authority to Increase its Electric Rates,* 1979 Wisc. PUC LEXIS 45, (March 6, 1979).

basis points over the previous 13% floor.[9] Subsequently, I set the ROE for Madison Gas & Electric at 13%[10], reflecting no adder for superior performance. Consequently, I wholeheartedly endorse the approach taken by the Commission here in Florida. I think that rewarding exemplary utility performance is an extremely effective way in which to encourage the utility to continue with its efforts for the customers' benefit. Thus, I conclude that PEF should be at the higher end of the just and reasonable range for ROE, which I estimate to be 12.8% using Dr. Vander Weide's starting point of 12.3% and adding 50 basis points for superior performance.

Q. Were your efforts successful?

A. Yes. When I left the Public Service Commission of Wisconsin, the major electric utilities were AAA rated. The Wisconsin utilities still maintain A ratings to this day, twenty-five years later. Further, compared to neighboring states, Wisconsin customers enjoyed the lowest cost of service and some of the highest quality of service.

Q. How does PEF's record with respect to controlling costs while accommodating the growth in its service territory affect your recommendations?

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[9] *Application of Wisconsin Power and Light Company, as an Electric and Water Utility, to Increase Electric and Water Rates,* 64 Wis PSC 57, (Decision No. 6680-WR-5) (February 8, 1980).

[10] *Application of Madison Gas & Electric Company for Authority to Increase its Electric and Natural Gas Rates*, 64 Wis PSC 115 (Decision No. 3270-UR-9) (February 14, 1980).

A. I have discussed how PEG's econometric analysis demonstrated that PEF's actual costs are 12.7% lower than the costs predicted by PEG's proprietary model. PEF's internal benchmarking analysis also demonstrated PEF's superior performance in controlling and reducing its costs while still accommodating the growth in its customer base. It accomplished all of this while maintaining safe and reliable service. These are the types of extraordinary performance that warrant the type of reward that the Commission provided to Gulf Power and that I authorized for superior utilities when I was a Commissioner in Wisconsin.

Q. Please review your reasoning on adding a 50 basis point adder in this conservative state context based on PEF's actual current return on equity.

A. Dr. Vander Weide recommends an ROE based on a traditional cost of capital analysis and a typical regulatory approach. By traditional regulatory approach, I mean that there is no built-in sharing mechanism as in some states, like Georgia, that have retained a traditional regulatory structure. In those states, there is typically a 100 basis point deadband around the ROE that is authorized. The utility will typically keep any earnings that are within 50 basis points above its authorized ROE. Any earnings above that deadband will typically be shared between the customers and shareholders based on a formula. Here, Dr. Vander Weide's analysis suggests a just and reasonable ROE of 12.3%. The Company is currently earning a storm adjusted ROE of 13.3%. It would be reasonable to split the difference between the authorized and actual between customers and shareholders on a 50/50 basis. This split is equal to 50 basis points. Further, the cost associated with such a 50 basis point adder amounts to $15-$20 million (based on a rate base of $4 billion). This is a small portion of the cost savings associated with PEF's performance in achieving costs that were 12.7% below or nearly $400 million below those predicted for PEF using our proprietary model of the utility industry.

VII. Conclusions

Q. How would consumers benefit from the proposals you support?

A. I propose that the Commission authorize an ROE of 12.8% and capital structure with (55% equity). This Commission action would likely enable PEF to reduce financial risk and would likely save consumers money in the long run.

PEF also purchases power under long-term contracts. This is likely to expand. Favorable terms and conditions for consumers are more likely when the buyer has relatively strong financial health.

These are just some of the reasons why successful utilities often have superior financial health and efficient performance. Qualitatively, treating shareholders well can often inure to the benefit of consumers.

Q. Have you quantified these benefits to consumers?

A. Yes. Although I focused primarily on qualitative benefits, I described the quantitative benefits to customers that are achieved when PEF beats its predicted costs (in the econometric analysis) by 12.7%, to be about $396.3 million in savings for ratepayers based upon the three-year composite comparison.

Q. Please review your conclusions.

A. I have reached several conclusions. First, it is crucial that PEF's outstanding job since the merger in achieving merger related savings and other cost cutting efforts be recognized. The effects of these efforts are demonstrated by both the internal and external statistical benchmarking analyses. PEF has improved when measured against itself (in pre-merger guise) or against its peer companies. However, this effort is mid-stream. PEF must be provided with the necessary incentives to continue with its efforts. Customers have already reaped the benefits of the merger through a $125 million annual rate reduction. A rate increase is now needed to account for new generation being placed in rate base and to restore the storm reserve fund.

With that overarching policy matter firmly in mind, I conclude that the 12.3% ROE recommended by Dr. Vander Weide is a reasonable floor, to which the Commission should add 50 basis points to reward PEF for its superior performance and encourage it to continue its efforts. Thus, I conclude that an ROE of 12.8% is appropriate.

Further, in keeping with the general regulatory flavor of providing an incentive for the Company to continue along its current path, I support Dr. Vander Weide's recommended 45/55 equity ratio. Further, I conclude that PEF's approach to include purchase power costs as part of the debt component should be implemented here because these costs are analogous to debt that would be incurred if PEF financed and built power plants to provide the power received under these purchase power contracts.

It is important to keep in mind the fact that PEF is located in a traditional state that has eschewed deregulation. As my statistical analysis demonstrates, PEF is a superior performer with respect to cost levels and also needs to invest in infrastructure to serve its expanding, primarily residential, customer base. PEF, as others have shown, has also improved the quality of its service and its reliability performance. PEF should be rewarded with an authorized ROE at the higher end of the range of reasonable ROEs. Further, PEF's superior performance should be recognized by adding 50 basis points to the ROE authorized by the Commission. This should be coupled with a 45% debt, 55% equity capital structure.

By doing these forward looking things, the Commission can help ensure that PEF is able to attract capital at reasonable prices to finance its infrastructure improvements. By so doing, the Commission will be providing long-term customer benefits that will last 30 years or longer. Such regulatory treatment will also ensure that savings associated with the merger, other cost cutting benefits, and safety and reliability improvements will continue to be made. In adopting such a reasonable regulatory treatment, the Commission will provide benefits to both customers and shareholders, a symmetry that is required for the continued success of the Company and the welfare of its customers.

Q. Does this conclude your testimony?

A. Yes.

DIRECT TESTIMONY OF
WILLIAM C. SLUSSER, JR.

I. Introduction.

Q. Please state your name and business address.

A. My name is William C. Slusser, Jr. My business address is 16550 Gulf Boulevard, No. 342, North Redington Beach, Florida 33708.

Q. What is your occupation?

A. I am an electric utility rate consultant.

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

A. I am testifying on behalf of Progress Energy Florida ("PEF" or the "Company") on allocated cost of service and rate design issues.

Q. Please describe your educational background and professional experience.

A. I graduated in 1967 from the University of Florida with a Bachelor of Science Degree in Electrical Engineering and in 1970 from the University of South Florida with a Master's Degree in Engineering Administration. I have been a registered Professional Engineer in the state of Florida during my career until recently when I acquired a retired status. I retired from Florida Power Corporation in January 2001, after 36 years of service where I devoted most of my career to allocated cost of service and rate design matters. I have been retained by PEF since my retirement as a consultant on allocated cost of service and rate design matters in the Company's prior base rate proceeding, Docket No. 000824-EI, and now in this proceeding.

II. Purpose and Summary of Testimony

Q. Mr. Slusser, what is the purpose of your testimony?

A. My testimony serves three main purposes. First, I present a Jurisdictional Separation Study for the projected 2006 test period. This study provides the basis for determining the Company's total costs and revenue requirements subject to the jurisdiction of this Commission. Second, I present two retail Allocated Class Cost of Service and Rate of Return studies for the test period, each study differing primarily as to the method for allocating fixed production capacity costs among the Company's retail rate classes. The first study employs a method that allocates production capacity costs based on each class's 12 monthly coincident peak demands weighted by 12/13th and its average demand, or energy usage, weighted by 1/13th which is called the "12 CP and 1/13 AD" method. I have provided a study employing this method to satisfy the study specified by the Commission's Minimum Filing Requirements ("MFRs"). However, I am recommending that the Commission rely upon my second study, which allocates production capacity costs using what I call the "12 CP and 25% AD" method, for establishing each rate class's cost of service and, thus, the amount of revenues each class should produce as a result of this proceeding. Third, I present the Company's proposed tariff schedules of rates and charges which, when applied to test period billing determinants, produce the Company's total retail revenue requirements.

Q. Do you have an exhibit to your testimony?

A. Yes, I have prepared or supervised the preparation of the following exhibits which are attached to my direct testimony:

- Exhibit No. ___ (WCS-1), a list of the MFR schedules I sponsor or co-sponsor.
- Exhibit No. ___ (WCS-2), Summary Development of Functional Unit Costs with Proposed Revenue Credits.
- Exhibit No. ___ (WCS-3), Estimate of Alternative Resource Investment Required to Serve Peak Demand Only.
- Exhibit No. ___ (WCS-4), Comparison of Class Allocated Cost of Service Study Results.
- Exhibit No. ___ (WCS-5), Development of Target Revenue Increase by Rate Class.
- Exhibit No. ___ (WCS-6), Summary of Proposed Rates and Class Rates of Return.

These exhibits are true and correct.

Q. What Minimum Filing Requirement (MFR) schedules do you sponsor?

A. I sponsor all or portions of the MFR schedules listed in my Exhibit ___(WCS-1). These schedules are true and accurate, subject to their being updated in the course of this proceeding.

Q. Are PEF's Jurisdictional Separation Study, Allocated Class Cost of Service Studies, and proposed rate schedules provided as a part of the Company's MFRs?

A. Yes, they are provided within the portion of the MFRs designated Section E - Rate Schedules. I should mention, however, that the Jurisdictional Separation Study and the two Allocated Class Cost of Service Studies are provided in separate bound volumes apart from the main volume of Section E because of the voluminous output reports included with these studies.

Q. Would you please provide a summary of your testimony?

A. Certainly. My role in this proceeding has been to develop, and to now support, the tariff rates and charges that produce sufficient revenues to (i) recover the Company's total retail jurisdictional cost of service from its rate classes as a whole, and (ii) recover from each rate class to the extent practicable the portion of the Company's total retail cost of service properly and fairly allocated to that class. To accomplish this objective, I have prepared and sponsor two types of cost studies.

The first of these cost studies is entitled "Jurisdictional Separation Study". This type of study allocates the various items comprising the Company's total system costs between the Company's two jurisdictional businesses; its wholesale business and its retail business. This separation of costs between the two businesses is based on accepted mathematical factors representing appropriate customer, capacity, and energy cost responsibilities. The allocation of costs to the retail business that results from the application of these factors is the basis for determining the Company's revenue requirements subject to the jurisdiction of this Commission.

The second type of cost study is called an "Allocated Class Cost of Service and Rate of Return Study". This study is a further allocation of the costs initially allocated to the retail jurisdiction among the individual retail rate classes. The results of this further retail allocation form the cost basis for establishing revenue requirements attributable to each rate class. One of the most important considerations in undertaking this type of study arises from the fact that the costs allocated to each rate class are heavily dependent upon the method employed by the study for the allocation of fixed production capacity costs. The production capacity cost allocation method recommended by PEF is called the "12 CP and 25% AD" method. Simply stated, this method allocates 75 percent of the Company's production capacity costs based on the 12 monthly coincident peak demands of a rate class and 25 percent of these costs based on the class's annual energy usage. As I explain later in my testimony, allocating 25 percent of production capacity costs on the basis of energy usage, instead of about 8 percent under the 12 CP and 1/13 AD method previously employed by the Commission, is intended to provide a better recognition of the enormous investment made in generation plant to achieve lower operating costs, *i.e.*, fuel savings. The Company's recommended method represents a reasonable middle ground between competing cost allocation approaches that allocates little or no production capacity based on energy responsibility at one extreme, and at the other extreme, that allocates the full amount of capacity investment made to achieve fuel savings on an energy basis, which in PEF's case is estimated to be approximately 50 percent.

With respect to rate design, PEF is not proposing any major rate structure or rate design changes. In keeping with Commission policy, the Company has proposed to limit the percentage revenue increase for a number of rate classes to 1-1/2 times the overall percentage increase. In addition, the Company has proposed the elimination of its Rate Schedules' IS-1 and IST-1, Interruptible General Service, and CS-1 and CST-1, Curtailable General Service, which have been closed to new customers since early 1996. The customers taking service under these rate schedules would be transferred to the Company's corresponding cost-effective interruptible or curtailable rate schedule, IS-2, IST-2, CS-2, or CST-2, which were established in the first place to accommodate new interruptible and curtailable customers when the grandfathered rates were closed to new customers almost 10 years ago.

III. <u>Jurisdictional Separation Study</u>

Q. What is a Jurisdictional Separation Study?

A. Most of the costs incurred by an electric utility to serve its customers are of a "joint" or "common use" nature. For example, a generating plant is ordinarily not constructed to serve any one customer or even one class of customers, but is part of a total generating system designed to serve the aggregate load requirements of all customers on the system. The investment in this plant is recorded on the Company's books and records as a joint cost for which all customers receiving electric service should share. A Jurisdictional Separation Study is an allocation of the Company's joint costs between those customers served under the jurisdiction of the

Federal Energy Regulatory Commission (FERC) and those customers served under the jurisdiction of this Commission, or, in other words, between the Company's wholesale and retail jurisdictions. The study consists of allocations for all rate base and operating expense items comprising the Company's total system cost of service for the test period. Allocations are performed using mathematical formulas that best represent each jurisdiction's cost responsibility.

Q. What sources of information have been used to prepare the Company's Jurisdictional Separation Study?

A. The accounting data, particularly the data provided in MFR Schedules B, C, and D, sponsored by Company witness Javier Portuondo provides the basic system cost of service information. This data is organized by primary FERC accounts and is classified or assigned into functional groupings for allocation purposes. The data represents the fully adjusted data for the test period. The factors developed for allocating system costs are predominately based on load data at the time of the Company's projected system monthly peaks. This load data, which is sponsored by Company witness John B. Crisp, is projected for each individual wholesale customer and the total retail class.

Q. Are the procedures and methodologies employed in the preparation of the Jurisdictional Separation Study in this proceeding consistent with those used in separation studies submitted in prior regulatory filings before both this Commission and the FERC?

A. Yes. I consider it extremely important to utilize procedures and methodologies that are consistent with the regulatory practices of both this Commission and the FERC, and have endeavored to do so for each of the many separation studies I have prepared for the Company over the years. The use or adoption of different costing procedures by either commission can result in an under- or over-recovery of costs by the Company on a total system basis. Both commissions employ similar embedded cost ratemaking practices and develop rate base and rates of return to determine test year revenue requirements in a comparable manner. Significantly, both commissions have relied upon the use of the "Average of the 12 Monthly Coincident Peak Demands," or the "12CP" methodology to allocate fixed power supply costs for jurisdictional separation purposes.

The FERC staff provides a computerized cost allocation model which is intended to be utilized for rate filings before the FERC. The Company has elected to use this same model in this proceeding. The FERC model is somewhat limited in the number of line items it can accommodate, and therefore it is necessary to group certain FERC accounts for input into the model. This grouping process is referred to as "Cost Assignments to Allocation Categories" and is fully included in the MFR volume containing the Jurisdictional Separation Study.

Q. What type customers comprise the Company's separated wholesale business during the test period?

A. The Company provides full requirements service to the Cities of Bartow, Mt. Dora, Quincy, Chattahoochee, and Williston. Partial requirements service is provided to the Florida Municipal Power Agency, New Smyrna Beach Utilities Commission, and the City of Tallahassee. Stratified production sales, which are sales specifically from a particular type of production resource, such as base, intermediate, or peaking, are made to Seminole Electric Cooperative, Inc., the City of Homestead, and Reedy Creek Improvement District.

Q. Have you developed a specific treatment in your Jurisdictional Separation Study for assigning fixed production costs to those wholesale customers purchasing stratified production services?

A. Yes. It warrants mentioning, however, that the cost responsibilities for the wholesale full requirements and partial requirements sales, and for that of the retail business, are based on average, overall production embedded costs. By comparison, the cost responsibilities for stratified wholesale sales are based on the average embedded costs of the particular resource type or types of production resources, i.e. base, intermediate, or peaking, used to make these sales. The costing treatment that has been established in the Jurisdictional Separation Study is intended to be consistent with the treatment of stratified sales by the Company in its fuel cost recovery proceedings that establish the fuel charge on the bills of retail customers. That is, cost responsibilities are first determined and assigned to the stratified sales customers based on their respective type of production resource or resources. These costs are then subtracted from the Company's total costs to derive the average rate customers cost responsibility.

In addition, when developing the capacity portion of production costs to be assigned to the stratified rate customers, ratios for each stratification are calculated by dividing the average 12 CP load of stratified customers by the total average monthly system stratified resource capability adjusted for reserves. These ratios result in a specific capacity cost responsibility, expressed as a percentage for the type of generation resource required by each of the stratified customers. The remaining cost responsibility for the stratified resources is allocated to the average rate customer classes based on their 12 CP demands. This development is contained in the "Development of Input Allocation Factors" section of the separate MFR volume entitled "Jurisdictional Separation Study."

When developing the energy portion of production non-fuel costs to be assigned to stratified customers, direct assignments are calculated for stratified customers by applying per-unit energy costs by resources to stratified customer sales. These assignments are contained in the production O&M cost assignments section of the Jurisdictional Separation Study.

Similarly, all the various system production costs (plant-in-service, accumulated depreciation, fuel inventories, operation and maintenance expenses, and depreciation expenses) have been stratified within the separation study in order to appropriately assign the appropriate cost responsibility to the stratified customers.

Q. Have you applied any other different costing treatments to the wholesale jurisdiction?

A. Yes. In accordance with Commission Order No. PSC-99-1741-PPA-EI in Docket No. 990771-EI, specific amounts of plant and expense related to a sale to the City of Tallahassee have been assigned to the wholesale business. These costs, of course, have not been included in the balance of production costs assigned or allocated to any other customers.

Q. Would you summarize the wholesale business's proportional requirements of the Company's investment in production, transmission, distribution, and general plant that result from the Jurisdictional Separation Study?

A. Yes. The wholesale business is responsible for 7.5% of the production, 28.6% of the transmission, 0.2% of the distribution, and 7.6% of the general plant investment of the Company. The wholesale business requires a proportionally higher investment in transmission plant relative to production plant due to the fact that (1) certain wholesale customers embedded in the system have acquired production resources from suppliers other than PEF which are delivered to these customers utilizing the Company's transmission system, and (2) certain wholesale transactions represent a transmission of power out of, into, or through the Company's system. The wholesale business requires very little distribution investment since most wholesale power is either received or delivered at points connected to the Company's transmission system.

IV. Class Allocated Cost of Service and Rate of Return Studies

Q. What is a retail Allocated Class Cost of Service and Rate of Return Study?

A. This study is an extension of the Jurisdictional Separation Study in which the retail jurisdictional costs are further allocated to the various rate classes within the retail jurisdiction. The study provides: (1) class realized rates of return at present and proposed rates, (2) class revenue surplus or deficiencies from full cost of service, and (3) functional unit cost information for rate design consideration. Factors for allocating the jurisdictional costs to rate classes are based on billing determinants and class load characteristics derived from the Company's sales forecast and latest load research.

As with the separation study, the FERC cost model was utilized to perform the cost allocations to retail rate classes. To obtain the functional cost information required by the Commission's MFRs, additional model runs were made utilizing each class's cost results and allocating this data to functional categories.

Q. How did you establish the customer rate classes or rate groups that were used as costing entities in your Allocated Class Cost of Service Studies?

A. Each regular rate schedule in the Company's present tariff has been established as a rate group in the cost of service studies. Rate schedules serving either, (i) optional time of use, (ii) load management service, or (iii) standby service, have been combined with its corresponding or related rate schedule. The resultant rate groups are described as:

(1) Residential Service (RS)

(2) General Service Non-Demand (GS-1)

(3) General Service 100% Load Factor (GS-2)

(4) General Service Demand (GSD)

(5) Curtailable General Service (CS)

(6) Interruptible General Service (IS), and

(7) Lighting Service (LS), consisting of sub-groups for the costs of

 (a) Lighting Energy

 (b) Lighting Facilities (Fixtures and Poles).

Q. You indicated that an Allocated Class Cost of Service Study provides functional cost information for rate design purposes. What functional components are provided in the cost of service studies?

A. The cost of service for each of the Company's rate classes, which ultimately translates into the classes' revenue requirements for rate design purposes, is allocated or assigned to the following functional cost components:

(1) Production Capacity

(2) Production Energy

(3) Transmission Capacity

(4) Distribution Capacity - Primary

(5) Distribution Capacity - Secondary

(6) Distribution Services

(7) Metering

(8) Interruptible General Service Equipment

(9) Lighting Facilities (Fixtures & Poles) and

(10) Customer Billing, Information, etc.

Unit costs are developed in the allocated cost of service studies by dividing the class's component cost of service by the appropriate billing units, *i.e.*, the number of customer bills, energy sales, or billing demands. This type of information is then used as a consideration in rate design when establishing the level of customer charges, demand charges, energy charges, etc. I have provided a summary of the functional cost of service for each rate class and their respective unit costs in my Exhibit No. _____ (WCS-2). The production capacity costs in this exhibit are based on the 12 CP and 25% AD allocation method that I will describe below. All cost of service amounts shown have been reduced by an allocation of revenue credits from other operating revenues, including the additional revenue credits from proposed increases in service charges that I describe later in the rate design section of my testimony.

Q. What costing treatment is utilized in the class cost of service studies for those rate groups that contain non-firm service provisions?

A. PEF's residential service and general service rate groups include optional load management provisions that permit the interruption of certain specified customer equipment, while the interruptible service and curtailable service rate groups require that all or a significant portion of the customer's load be subject to interruption or curtailment as a condition for service. However, the development of costs for these rate groups is based on the premise that all of the groups' load requirements are firm. This is because the Company's various forms of non-firm service are elements of its demand side management (DSM) program and, therefore, the value of each rate group's load subject to interruption or curtailment is not a consideration in setting base rates, but instead is recognized separately by the payment of billing credits that are established in and recovered through PEF's Energy Conservation Cost Recovery clause.

Q. Mr. Slusser, you indicated that two allocated class cost of service studies were prepared for this proceeding which differ primarily by the method employed to allocate production capacity costs. Would you describe the two production capacity cost allocation methods that you have employed?

A. Yes. The Commission's MFRs require at least one cost of service study to be provided that allocates production and transmission plant using the average of the twelve monthly coincident peaks and 1/13 weighted average demand (the "12 CP and 1/13th AD" method). This has been the method most often relied upon by the Commission in previous rate cases involving the four major investor-owned electric utilities in Florida. It allocates 12/13, or about 92 percent, of production capacity costs on the basis of class average monthly coincident peak demands, and 1/13, or about 8 percent of production capacity costs on the basis of class average hourly demands, which is the equivalent of class annual energy consumption. PEF believes that an energy weighted allocation of only 8 percent under this method gives too little recognition to the important role energy considerations play in determining production capacity costs. For this reason, I have prepared an additional study to recognize the greater extent that energy responsibility should bear in allocating the Company's total production capacity costs among the rate classes. I have chosen 25 percent as a reasonable allocation of these costs to be made on the basis of class energy responsibility in this additional study, which I refer to as the 12 CP and 25% AD method.

Q. Does your additional study utilizing the 12 CP and 25% AD method incorporate any other differences from the retail Class Allocated Cost of Service Study required by the MFRs?

A. Yes, there is one other allocation difference related to transmission costs. The study required by the MFRs allocates both production and transmission capacity costs using the 12 CP and 1/13 AD method. The Company's recommended study applies the 12 CP and 25% AD method only to the allocation of production capacity costs; transmission capacity costs are allocated fully on the average of the classes' 12 monthly coincident peaks, the 12 CP method. Unlike production costs, the Company does not believe that energy requirements are a significant consideration or factor in determining the costs of transmission plant. Furthermore, in the event a Regional Transmission Organization is developed for Florida participation, it is expected that the transmission users' cost responsibility will be assessed on a 12 CP basis. The Company believes and supports this method as an appropriate measure for transmission cost responsibility and therefore has employed this method in its recommended study in this proceeding.

Q. Mr. Slusser, would you explain why PEF believes that energy utilization should be given a greater weighting than 8 percent for allocating production capacity cost responsibility among its retail rate classes?

A. Yes. The primary reason is because PEF has made a considerable investment in production plant for reasons other than simply meeting peak demand. I have prepared Exhibit No.___(WCS-3) that provides an estimate of the additional investment expended by PEF in this regard for its existing generating fleet. If meeting peak demand had been the sole consideration, the Company would have installed less expensive, simple-cycle combustion turbine units. Instead, as can be seen from this exhibit, PEF has invested approximately twice the cost of peaking units in order to incur lower operating costs for those generating units that will need to remain online well beyond peak demand periods. Allocating more than 8 percent of production capacity costs on an energy basis assigns more of this additional investment to classes with relatively high energy usage in recognition of the fact that these classes receive more of the benefit produced by the additional investment, in the form of lower fuel charges for each unit of energy consumed.

PEF also believes that this proceeding provides an especially timely opportunity to recognize the consideration that energy usage has had in the Company's generation decisions. The most recent capacity additions on the Company's system consist of two combined-cycle units at its Hines Energy Complex with a total capacity of approximately 1,000 MW. Another 500 MW combined-cycle unit is scheduled for commercial operation at the Hines site in December 2005. These combined-cycle units are complex, state-of-the-art technology types of generating plants which provide considerably more benefits, and require considerably more investment, than the capacity needed to simply meet the Company's reliability requirements; they provide tremendous improvements in generating efficiency and substantial fuel savings that result from this efficiency. These units were justified as the Company's next capacity additions by satisfying its reliability criteria while providing the lowest revenue requirements. PEF considers it to be both fair and consistent with sound allocation principles for its customers to pay for the higher capital costs invested in these units to achieve operating efficiencies in the same proportion that customers benefit from the fuel savings these efficiencies provide.

Q. Why is PEF proposing that average demand be weighted specifically by 25 percent?

A. Although PEF could justify an average demand weighting of as much as 50% based on the estimate of the additional investment shown in Exhibit No.__(WCS-3), the use of a 25 percent energy allocation factor is intended to represent a reasonable middle ground between the inadequate recognition of energy responsibility in the 12 CP and 1/13 AD method and a full recognition under capital substitution principles. As such, an increase in the weighting of energy usage to 25 percent is a significant improvement toward the allocation of energy-driven capacity costs to classes in closer proportion to the energy-based benefits the classes receive from those costs.

Q. Do you have an exhibit that compares the results of the two allocated class cost of service studies which you have prepared?

A. Yes. My Exhibit No. ____(WCS-4) provides a summary comparison that shows the allocated class cost of service resulting from each study and calculates the difference between the two studies for each rate class. The exhibit also quantifies the effect on allocated costs of the two allocator differences employed in these studies, i.e. the production allocation factor difference and the transmission allocation factor difference.

Q. Has the Commission previously deviated from the 12 CP and 1/13 AD method for establishing class production capacity cost responsibility in a base rate proceeding?

A. Yes. The Commission relied upon the so called Equivalent Peaker method in Docket No. 850246-EI, a Tampa Electric Company base rate proceeding. This method is comparable to PEF employing a 50% average demand weighting in this proceeding.

In addition, when the allocation of costs for new nuclear units placed in service by PEF and Florida Power and Light Company were considered in Docket Nos. 770316-EU and 830465-EI, respectively, the Commission decided to allocate a portion of each unit's fixed costs equal to its fuel savings on an energy basis to recognize the magnitude of the savings afforded by the investment in such units. The Commission reasoned that since the fuel cost savings of a nuclear unit flow through to customers on an energy basis through the fuel clause, at least that amount of fixed costs should be recovered in base rates on a similar energy basis.

V. Development of Target Class Revenues

Q. Please describe generally the procedure used to determine the portion of the Company's total proposed base rate revenue increase assigned to each rate class.

A. The starting point in determining the portion, or percentage, of the Company's proposed base rate revenue increase to be assigned to each rate class is the class cost of service study. For this purpose, the cost of service study utilizing the 12 CP and 25% AD production capacity allocation method was relied upon. Ideally, the rates developed in a proceeding such as this will produce revenues from each of the rate classes that equal the costs allocated to that class by the cost of service study.

Therefore, the first step in determining how much each rate class should share in the Company's total revenue increase, *i.e.*, the shortfall between total revenue requirements and total revenues under current rates, is to determine for each rate class the shortfall between the costs allocated to that class and the revenues produced by applying current rates to the class's test year billing determinants. The next step is to determine how much of each class's revenue shortfall will be offset by additional revenues from any increase in other operating revenues, such as the increase in certain service charges proposed by the Company in this proceeding. Once the net revenue deficiency of each rate class has been determined, the final step is to identify whether any ratemaking policy considerations should limit the amount of any rate class's revenue increase. In this proceeding, several rate classes fall within the scope of the Commission's established policy of limiting the increase to any individual rate class to 150% of the overall percentage increase in the Company's total revenues.

The completion of this three-step procedure produces what we refer to as the target revenues for each rate class. These are the total class revenues the Company will attempt to produce through its revised base rate charges, which are determined by applying test year billing determinants to these total class revenues.

Q. How did the Company derive the projected billing determinants for the test year that were used in this procedure to determine the rate classes' current revenues and proposed rates?

A. The projected rate class billing determinants rely on the relationships between the actual number of bills, kWh sales, and kW billing demand recorded for each rate schedule during calendar year 2003. These actual relationships were applied to the Company's projected 2006 sales forecast by major rate class to derive the projected test year billing determinants for each rate schedule. The 2006 kWh sales forecast is described in the testimony of John B. Crisp. Billing determinants from 2003 were relied upon rather than those from 2004 due to the distorted and abnormal usage characteristics that resulted from the extraordinary hurricane season in 2004. The test year billing determinants derived from this process are included in MFR Schedule E-13c.

Q. Have you prepared an exhibit that sets out the procedure you have described to develop the target revenue increases for each of the Company's rate class?

A. Yes. My Exhibit No. _____(WCS-5) was prepared for this purpose.

Q. Would you explain this exhibit?

A. Certainly. The exhibit lays out the procedure I described numerically from left to right in columns (A) through (I). The rate classes' allocated cost of service developed in the 12 CP and 25% AD cost study is shown in column (A). This is compared to the classes' revenues under current rates in column (B), which yields the class revenue deficiency by difference in column (C). These revenue deficiencies are then reduced by crediting the additional revenues allocated to each class from the Company's proposed increases in service charges shown in column (D), resulting in the classes' net revenue deficiencies expressed monetarily in column (E) and as a percentage in column (F). This column also shows that the average of all class revenue deficiencies, *i.e.*, the overall revenue increase required, is 13.83%, with all rate classes exceeding the average revenue deficiency except residential and general service non-demand. The next two columns, (G) and (H), show the effect of the Commission's policy of limiting increases to individual rate classes to no more than 1½ times the system average increase. In the Company's case, this policy equates to a limitation of 20.74 percent (13.83% x 1.5). Column (H) shows that this limitation applies to all of the rate classes except for the Residential and General Service Non-Demand classes. For reasons I will discuss below, the Company has incorporated another constraint which further limits the class percentage revenue increase for the Lighting Facilities class. The target revenue increases for the Residential and General Service Non-Demand classes were raised above their stand-alone net revenue deficiencies to 10.71%. This was the result of allocating to these two classes, consistent with the Commission's increase limitation policy, the portion of the other classes' revenue deficiency that could not be targeted because of the policy. The final effect of the target increase procedure is the total revenue requirements to be collected from each rate class, which are shown in Column (I).

Q. What were the service charge increases that provided the additional revenue credits to the target revenue increases for the rate classes?

A. The Company has identified the need for an increase in three of its service charges, which would produce additional revenues of $8.2 million. These additional revenues will serve as a credit to offset a corresponding revenue requirement that would otherwise increase the Company's base rates.

The first increase relates to charges for providing temporary service connections. Currently, a customer is assessed a service charge of $104.00 for the cost of installing and removing a temporary service extension where such extension is requested and can be provided by a service drop or connection point to the Company's existing distribution system. The Company's analysis has determined that the actual cost to provide such an extension is currently $227.00. The Company has therefore proposed that the temporary service charge be adjusted to this amount, which will produce an additional annual revenue credit estimated to be $1.9 million.

The second concerns the returned check service charge. The proposed increase is based on the same level of increase for returned checks in other circumstances provided by a recent revision to Section 68.065, Florida Statutes. The Company estimates this increase will result in an additional annual revenue credit of approximately $300,000.

The third service charge which the Company proposes to revise is its late payment charge. The Company currently assesses a 1.5% charge on past due unpaid account balances, except on the accounts of governmental entities. The Company's proposal would include a minimum charge of $5.00 to provide a more meaningful deterrent to late payments, which the Commission has previously authorized for other utilities. This revision will increase the annual revenue credit by an estimated $6.0 million.

The Company believes its other service charges, which were adjusted in the 2002 rate settlement approved by the Commission in Docket No. 000824-EI, remain at a reasonable and compensatory level.

VI. Rate Design

Q. What were PEF's rate design objectives in developing the proposed rates and charges submitted in this proceeding?

A. The first objective, of course, is to establish proposed charges for each rate schedule such that their application to the test year billing determinants produces the target class revenues. Second, the Company does not intend to make any major rate design or rate structure changes to its tariff. The Company believes its rate structure is reasonable, equitable, and generally acceptable by its customers. Third, the Company seeks to continue the historically developed methodologies of establishing the charges for affiliate and optional rate schedules consisting of Time-of-Use and Stand-by Rate Schedules. Fourth, the Company finds that it is appropriate in this proceeding to propose the elimination of particular "closed" and "grandfathered" General Service Interruptible and Curtailable rate schedules and transfer the customers under these schedules to an applicable "open" Interruptible or Curtailable rate schedule. Lastly, the Company is pursuing some changes in the offerings and terms and conditions of its Lighting Service Rate Schedule and limiting the magnitude of the proposed increases of certain facility offerings.

Q. What changes are being proposed for the Company's residential rate schedules, RS-1, RST-1, RSL-1, RSL-2, and RSS-1?

A. The changes being proposed for residential service are simply increases to the per kWh energy and demand charges in order to derive the residential class's proposed target revenues. These changes are consistent with the

Company's objective to make no major rate design revisions. That is, the Company is proposing to maintain for its regular rate the same two-step inverted rate design with the 1000 kWh inversion point and one cent price differential. In addition, the Time of Use (TOU) rate design is intended to be the same design as historically developed.

The customer charges in the residential rate schedules remain at the existing level with two exceptions. First, regarding the TOU customer charge in Rate Schedule RST-1, with on-going changes and capabilities of electronic metering, the Company finds it is no longer necessary to distinguish the cost of single-phase and three-phase TOU metering in the charge. This distinction has been eliminated for the secondary delivery customer charges with the existing single-phase charge now applying to both single and three-phase secondary delivery.

The second proposed change relates to the customer charge for optional seasonal service Rate Schedule, RSS-1. The customer charge for this service is intended to provide an incentive for a seasonal customer to maintain active service during their absence by setting the accumlated customer charges at a level below the cost of the reconnection charge the customer would otherwise incur upon return. The desired relationship between the cost of this customer charge and the cost of the Company's reconnect charge was not maintained when the Company increased its reconnection charge from $15 to $28 in Docket No. 000824-EI. To re-establish the intended relationship with the reconnection charge, the monthly seasonal customer charge has been set at $4.20.

Q. What changes are proposed for Rate Schedules GS-1 and GST-1, the Company's General Service Non-Demand rates?

A. Since the kWh energy charges in these rate schedules are intended to be equivalent to the levelized energy kWh charges for residential service, the revisions proposed in this proceeding track those of the residential class.

Q. What changes are proposed for Rate Schedule GS-2, the Company's General Service 100% Load Factor rate?

A. The only change in this rate schedule is an increase in the energy and demand charge to produce the proposed target class revenues.

Q. What changes are proposed for Rate Schedules GSD-1 and GSDT-1, the Company's General Service Demand rates?

A. The energy and demand charges for these rate schedules were revised to produce the class's target revenues determined after taking into account (1) the amount of revenues from the proposed Firm Standby Service charges established by the cost of service study, and (2) the effect on revenues from proposed cost of service-based changes in delivery voltage credits, power factor credits and charges, and premium distribution charges. The existing customer charges and equipment rental charges were determined to be adequate compared with cost of service.

Q. Will the Company's proposed rate changes to its general service rate schedules result in any customers being transferred from one general service rate schedule to another?

A. Yes. Under the Company's proposed rates in this proceeding, about 2,000 General Service Demand (GSD) customers would receive lower billings under the General Service Non-Demand (GSND) rates. This is because the proposed GSND rates will receive a lower percentage increase than the proposed GSD rates. Currently, GSD rates are advantageous compared to GSND rates at load factors of 22% or greater. With the GSND rate's lower percentage increase, this break-point has risen to 25%, which means that the approximately 2,000 GSD customers with a load factor between 22% and 25% will benefit from service under the GSND rate. Since the Company will automatically transfer these customers to the lower GSND rate, this transfer has been simulated in the revenue billing calculations included in the MFRs.

If further rate revisions to the general service rates are given consideration in this proceeding, I would request that the Company be allowed to test any such revisions for similar migration effects. Where migration is likely to occur, the billing determinants for the affected rate schedules should be revised to reflect the post-migration effect. This can sometimes involve a laborious iterative process, but it is nonetheless essential to undertake this effort before the final general service rate charges are established in order to avoid potentially serious unintended consequences.

Q. What changes are proposed by the Company for its General Service Interruptible and Curtailable rate schedules?

A. In general, the Company revised the charges in these schedules in the same manner as it has proposed for its General Service Demand rate schedules. The major change to the tariff for these rate classes is the proposed elimination of the curtailable and interruptible rate schedules that have been closed to new customers since April 1996. Also, as a housecleaning item, the Company proposes to revise the language of the following items to achieve consistency with the wording of comparable provisions contained in other of the Company's rate schedules: (1) Special Provision No. 4 of Rate Schedules IS-2 and IST-2, and (2) the Metering Voltage Adjustment and Power Factor clauses of Rate Schedules CS-3 and CST-3.

Q. Please elaborate on your reference to the Company's proposal for eliminating certain curtailable and interruptible rate schedules.

A. The Company has proposed to complete the closure and withdrawal of its general service interruptible and curtailable Rate Schedules IS-1, IST-1, CS-1, and CST-1, and transfer the remaining customers served under these rate schedules to the applicable IS-2, IST-2, CS-2, or CST-2 rate schedule. These rate schedules were closed by the Commission in April 1996 to all but existing customers because they were no longer cost-effective. The Commission allowed the customers then served under the rate schedules to be grandfathered to avoid the possibility of hardship from their immediate transfer to comparable, but cost-effective rate schedules.

The affected customers will continue to have the same quality of service and subject to the same base rates as they would have otherwise.

The primary difference is that they will be subject to a lesser value of interruptible or curtailable demand credit provided for under their transferred rate schedule. The Company believes that those customers under the closed tariff have had ample notice that the demand credits they have been receiving are not justified and that it is now time for their grace period to finally be ended.

There are some differences and possible modifications required to the applicable schedule which the affected customers will be transferred to accommodate them. The first relates to the time period of a required notice provision by a customer who may desire to transfer to a firm rate schedule. The new notice for the customer is actually less restrictive, that being 36 months, than the withdrawn rate schedule which requires 60 months. The Company proposes to permit these customers the less restrictive provision that is in the open rate schedules.

The second difference relates to the requirement of a minimum billing demand of 500 kW under the applicable rate to which the customer is being transferred. The Company has found that loads of less than 500 kW posed administrative problems and, in many instances, required customized interruptible equipment and metering installations which were not practical or cost effective. The Company is proposing that any affected customer that has a demand less than the desired minimum would not be subject to the billing demand minimum in the event that the customer exercises the 36-month notice provision to transfer to a firm rate. This is the same mitigating offer that was adopted by the Commission in Docket

No. 000824-EI when the Company sought to incorporate the 500 kW billing demand minimum in the Rate Schedules IS-2, IST-2, CS-2, and CST-2.

A third difference relates to a limitation incorporated in the Applicability Clause of the IS-2, IST-2, CS-2, and CST-2 rate schedules for customer accounts established under any of these schedules after June 3, 2003. The customers establishing service after this date are limited to those premises at which an interruption or curtailment will not significantly affect members of the general public, not interfere with functions performed for the protection of public health or safety. The Company is aware that certain of those customers proposed to be transferred to one of these schedules may not satisfy this limitation and proposes that the limitation not apply.

A final difference relates to the exclusion of curtailment or interruption of an affected customer's facility during periods of use as a public shelter. This exclusion is proposed to be added to the open tariffs as it applies only to these transferred customers.

Q. Has the Company revised the Interruptible and Curtailable Capacity Credits contained in Rate Schedule SS-2, Interruptible Standby Service, and Rate Schedule SS-3, Curtailable Standby Service?

A. Yes. The credits provided under these existing tariffs correspond with the credits provided for under the grandfathered IS-1, IST-1, CS-1 and CST-1 rate schedules. With the proposed elimination of these rate schedules, the credits should be revised to correspond with the credits provided for under the "open" IS-2, IST-2, CS-2, and CST-2 rate schedules.

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

A. The Company has proposed that the energy and demand charges be revised to the level which produces the proposed target revenues for this rate class.

Q. You indicated earlier that the Company placed a further constraint on the total revenue increases for the Lighting Facilities rate class. Why did the Company choose to do this?

A. The Company would like to have individual lighting charges reflect their current embedded cost. However, this would require substantial increases in a number of commonly utilized facilities. As was done in the Stipulation approved by the Commission in Docket No. 000824-EI, the Company has proposed in this proceeding to take another significant step toward correcting these deficiencies by setting the fixture and pole charges to reflect their current embedded cost, but limiting any particular fixture charge to a 15 percent maximum increase and limiting any particular pole charge to a maximum of a 20% increase.

Q. Has the Company proposed any other changes to lighting service provided under Rate Schedule LS-1?

A. Yes. In addition to revising the facility charges, PEF is proposing the following revisions to this schedule and its related standard contract forms.

1. PEF is proposing to increase its maintenance charges for light fixtures to a level reflective of current maintenance cost.

2. In the form of housecleaning, certain facility offerings have been proposed to be added, deleted, or restricted, and certain format changes are being proposed. Format changes include: (a) the elimination of what is considered a not fully inclusive "Total" column for the indicated component charges for a fixture; (b) the re-sequencing of "Poles" offerings by billing type number; and (c) a more descriptive header and footnote regarding the description for "Lumens" and "Watts" for a fixture type.
3. Due to the increasing capital nature of many facilities, PEF is proposing to increase the minimum term of service from six years to ten years.
4. Clarifications and additions were made in the Special Provisions regarding reference to appropriate sections of the Company's Rules which apply.
5. The special provision in the rate schedule and its related standard contract form regarding an option for an up-front lump sum payment for lighting facilities has been proposed to be eliminated due to the non-use of any customer for this option.
6. The standard contract form for service application of the metal halide pilot program is proposed to be eliminated. Metal halide lighting service is no longer a pilot program and the standard contract form for application of lighting service is proposed to be modified and used for any application for lighting service.

VII. Other Tariff Revisions

Q. Is the Company seeking revisions to any riders to its rate schedules?

A. Yes. The Company asks that Rate Schedule CISR-1, its Commercial/Industrial Service Rider pilot program be made permanent. The pilot program's tariff provides for its termination forty-eight months from the initial effective date, which will occur in August 2005. Renewed interest in the Rider has led the Company to conclude that the program should remain in effect.

VIII. Summary of Class Proposed Rates of Return

Q. Do you have an exhibit that summarizes the amount and change in class revenues, as a result of the Company's proposed rates, and the class rates of return which would be realized under the proposed rates?

A. Yes. My Exhibit No. _____(WCS-6) shows this information. The classes' proposed rates of return, of course, vary from parity primarily due to the limitations placed by the Company on the proposed class increases.

Q. Does this conclude your testimony?

A. Yes, it does.

STATE OF FLORIDA)

: CERTIFICATE OF REPORTER

COUNTY OF LEON)

I, JANE FAUROT, RPR, Chief, Office of Hearing Reporter Services, FPSC Division of Commission Clerk and Administrative Services, 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' attorney or counsel connected with the action, nor am I financially interested in the action.

DATED THIS 12th day of September, 2005.

JANE FAUROT, RPR
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