BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

In the Matter of:

REVIEW OF 2007 ELECTRIC INFRASTRUCTURE STORM HARDENING PLAN FILED PURSUANT TO RULE 25-6.0342, F.A.C., SUBMITTED BY FLORIDA PUBLIC UTILITIES COMPANY. — DOCKET NO. 070300-EI

PETITION FOR RATE INCREASE BY FLORIDA PUBLIC UTILITIES COMPANY. — DOCKET NO. 070304-EI

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VOLUME 2

Pages 153 through 351

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PROCEEDINGS: HEARING

BEFORE: CHAIRMAN MATTHEW M. CARTER, II
COMMISSIONER LISA POLAK EDGAR
COMMISSIONER KATRINA J. McMURRIAN
COMMISSIONER NANCY ARGENZIANO
COMMISSIONER NATHAN A. SKOP

DATE: Wednesday, February 27, 2008

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

REPORTED BY: JANE FAUROT, RPR
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APPEARANCES: (As heretofore noted.)

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P R O C E E D I N G S

(Transcript follows in sequence from Volume 1.)

CHAIRMAN CARTER: We are back on the record with our hearing. In our last episode we had tied Sweet Polly Purebred to the railroad track, but we let her go.

Ms. Christensen, we took care of your issue before?

MS. CHRISTENSEN: Yes, I believe we have moved my exhibit into the record, so I think I'm finished as far as Witnesses Martin and Mesite are concerned on direct testimony.

CHAIRMAN CARTER: Okay.

Mr. Horton, call your next witness.

MR. HORTON: I would call Mr. Camfield.

And, Mr. Chairman, I would note, as Mr. Camfield is coming up, that Mr. Camfield and Ms. Cox were part of a panel, and Ms. Cox, of course, has been excused. As soon as I qualify Mr. Camfield and get him to adopt his portion of the testimony, I will move both Ms. Cox and Mr. Camfield's testimony.

CHAIRMAN CARTER: Was that the understanding of the parties?

MS. CHRISTENSEN: Yes. That Ms. Cox's testimony has been stipulated? Yes.

CHAIRMAN CARTER: Okay.

ROBERT J. CAMFIELD

was called as a witness on behalf of Florida Public Utilities Company, and having been duly sworn, testified as follows:

DIRECT EXAMINATION

BY MR. HORTON:

Q State your name and address for the record, please, sir.

A My name is Robert J. Camfield, and my business address is 4610 University Avenue, Madison, Wisconsin.

Q And by whom are you employed, and in what capacity are you appearing in this proceeding, Mr. Camfield?

A I am with the consulting group Christensen Associates Energy Consulting, that is a subsidiary of Christensen Associates, or Laurits R. Christensen as we are sometimes referred to. And I hold the position of Vice President with the consulting group, and I am appearing here before the Florida Public Service Commission on behalf of Florida Public Utilities Company on the topic of cost of capital. Specifically the cost rate appropriate for short-term debt within the overall capital structure, and then, secondly, the return on equity.

Q Mr. Camfield, did you as part of a panel with Ms. Doreen Cox cause to be prepared and prefiled direct testimony consisting of 21 pages in this docket?

A I did.

Q And that was presented as panel testimony, was it not?

A That's correct.

Q Do you have any additions or corrections to make to your portion of the testimony at this time?

A I do. There is one small change, and that is that -- over the course of printing, it seems that a footnote has been left out. It is a reference footnote to Appendix 2, and that footnote should read, "Investment Science, David Leuenberger, 1998."

CHAIRMAN CARTER: Again, please. Would you restate that, please.

THE WITNESS: It should read, "Investment Science, by David Leuenberger, 1998." It is a reference.

BY MR. HORTON:

Q And, Mr. Camfield, you said that was to Appendix 2?

A That's correct.

Q Which is one of your exhibits, right?

A It's attached to the prefiled testimony.

Q All right, sir. As far as your prefiled testimony, do you have any additions or corrections to make to the prefiled testimony?

A Line 9 of Page 46 should read the word "four" in lieu of "five".

Q Thank you. With that change, if I were to ask you the questions contained in your direct testimony, would your answers be the same today?

A They would.

MR. HORTON: Thank you.

Mr. Chairman, at this time I would like to ask that the prefiled testimony of Mr. Camfield and Ms. Cox be inserted into the record as though read.

CHAIRMAN CARTER: The prefiled testimony will be entered into the record as though read.

DIRECT TESTIMONY

DOREEN COX
ROBERT CAMFIELD

COST OF EQUITY AND RATE OF RETURN REQUIREMENTS
of
FLORIDA PUBLIC UTILITIES COMPANY

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

A. Witness Cox. My name is Doreen Cox. I am a Financial Analyst with Florida Public Utilities Company. My business address is 401 South Dixie Highway, West Palm Beach, Florida, 33401.

Witness Camfield. My name is Robert Camfield. I am Vice President with Christensen Associates Energy Consulting LLC, and my business address is Suite 700, 4610 University Avenue, Madison, Wisconsin, 53705.

Q. What is the scope of your testimony?

A. The scope of our testimony is twofold. First, we address the issue of the cost of common equity to Florida Public Utilities Company. Estimates of the equity cost rate underlie our common equity rate of return recommendation. Second, we integrate the equity rate of return with the other financial components of Florida Public Utilities Company's capital structure to determine the weighted average cost of capital and accompanying overall rate of return recommendation. Our rate of return recommendation should be used by the

Commission to set retail electricity prices of Florida Public Utilities Company in the current docket.

Q. Please review your professional background and experience that qualifies you to provide such recommendations.

A. Witness Cox. I received a Bachelor of Science Degree in Management from the University of the West Indies in 1979, with a concentration in Accounting. In 1990, I earned a Master of Science Degree in Accounting, also from the University of the West Indies. I am a member of the Jamaican Institute of Chartered Accountants.

I joined Florida Public Utilities Company in 1999, and I hold the position of Financial Analyst, which reports to the Chief Financial Officer (CFO). In this position, I support the CFO as well as the Accounting and Finance Divisions of Florida Public Utilities Company. My position covers a variety of operating and planning responsibilities including project assessment, budget and financial projections, and cash flow analysis. I assist in the preparation of quarterly reports to our Board of Directors, and the compliance monitoring with respect to the Financial Covenants of Florida Public Utilities Company's long- and short-term sources of external funds. In was a witness in the Natural Gas rate relief proceedings before the FPSC, Docket Number 040216-GU.

Witness Camfield. I joined the Michigan Public Service Commission in 1976 as a staff economist. During my tenure with the Michigan Commission, I was involved in several retail electricity and natural gas pricing issues, and I testified in rate case proceedings regarding cost of capital and retail gas tariff design. I joined the New Hampshire Public Service Commission in 1979 as Senior Economist, and held the position of Chief Economist beginning in 1981. As Chief Economist, I was responsible for the administration of the Economics Department of the Commission Staff. I oversaw the analysis of regulatory issues, the coordination and guidance of Staff participation in regulatory proceedings, the preparation and development of testimony, and I provided policy advice to the Commission on a variety of issues such as construction work in progress, financial planning, and the determination of PURPA Section 133 rates. I joined Southern Company in 1983, and held positions in several departments including Pricing and Economic Analysis at Georgia Power Company, Costing Analysis of Southern Company Services, and Southern Company's Strategic Planning Group. In 1994, I joined Laurits R. Christensen Associates, Inc. ("Christensen Associates") as a senior economist, and currently hold the position of Vice President with Christensen Associates Energy Consulting LLC., a subsidiary consulting group of Christensen Associates.

My experience covers a gamut of issues facing regulated industries. I have been involved in the negotiation of power supply contracts and the terms of franchise licenses. My overseas assignments are several, and I have managed a large market restructuring project in Central Europe. I have served on national and regional advisory panels, and I have advised integrated electric utilities, independent power producers, transmission and distribution companies, utility associations, offices of consumer advocate, and regulatory agencies on numerous policy and technical issues. Innovations include two-part tariffs for transmission services, web-based self-designing retail electric products, marginal cost-based cost-of-service methods, and principles for efficient pricing of distribution services. I have published chapters in technical books, reports, and articles in noted journals such as *The Electricity Journal, IEEE Transactions on Power Systems*, and *CIGRE*. Currently, I serve as Program Director of the Edison Electric Institute's Market Design and Transmission Pricing School.

Q. **Would you please review the statutory mandates that guide the determination of rate of return for public utilities?**

A. Yes, the statutory principles of rate of return for public utilities substantially rest with two decisions of the Supreme Court of the United States. In the Bluefield Water Works and Improvement Co. v. Public Service Commission of West Virginia case (262 U.S. 679, 1923), the U.S. Supreme Court set forth its view on fair rate of return, as follows:

> "...A public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding risks and uncertainties; 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. A rate of return may be reasonable at one time and become too high or too low by changes affecting opportunities for investment, the money market and business conditions generally."

A second landmark decision of U.S. Supreme Court echoed, fortified, and expanded upon the fair return standard established by the "Bluefield" decision cited above for capital committed to public utilities. This second decision is the Federal Power Commission v. Hope Natural Gas Company case (320 U.S. 391, 1944). A relevant passage of this latter decision is as follows:

> "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 return 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 attract capital."

These longstanding decisions provide the recognized framework for the fair rate of return on capital committed by investors to public service. In these decisions, the U.S. Supreme Court codified, in clear and readily understandable terms, a statutory benchmark that serves as the basis to set fair and equitable prices for retail public services such as natural gas, while also providing a fair rate of return on the capital provided by investors. Though they reach back many years, these decisions remain to this day the cornerstone for the determination of rate of return requirements. The challenge for regulators, regulated utilities, and interested parties to regulatory proceedings is to operationalize these principles in contemporary regulatory processes.

Q. Please provide an overview of your approach to the determination of the rate of return requirements for Florida Public Utilities Company.

A. Our approach follows the prescribed methodology of the Florida Public Service Commission to determine the overall weighted average cost of capital ("WACC") and the overall rate of return, for regulatory purposes. Specifically, we develop a forward-looking consolidated capital structure for the year 2008 with the exclusion of capital structure balances associated with the Company's propane subsidiary, Flo-Gas. For determining retail prices in the instant docket, the recommended capital structure is determined on the basis of the 13-month average balances of the components that comprise the capital structure of the Company. We develop a traditional capital structure including the key elements of long-term debt, short-term debt, preferred stock, and common shareholder equity. Similarly, we develop a regulatory capital structure that contains, in addition to these components, balances for customer deposits, accumulated deferred taxes and accumulated investment tax credits of the Company dedicated to providing retail electricity services. Traditional elements of the capital structure are scaled pro rata, such that the regulatory capital structure, in total, matches the rate base attributable to the provision of electricity services.

It is good regulatory policy to accurately capture the means by which Florida Public Utilities Company underwrites its assets and rate within the regulatory capital structure, providing that such structure contains an appropriate balance of equity and debt, given the regulatory and operational business risks facing the Company. Contemporary business, regulatory, and financial risks confronting energy utilities are higher than in past years. Consequently, and consistent with the business objectives of providing low-cost and reliable service, Florida Public Utilities will fund its assets with larger equity participation in total capital than in years past and, to this end, the year-end 2008 capital structure is a better representation of the expected capital structure of the Company. This is because the year-end balances capture the prospective weight, on average, that common equity will assume within the Company's capital structure. Furthermore, the year-end balances of the components of capital provide a better balance of debt and equity for the purpose of minimizing the weighted average cost of capital. Accordingly, the adoption of the projected year-end capital structure to determine retail prices, which would constitute a departure of the Florida PSC from its general policy of using the 13-month average capital structure, would be in the long-term interests of retail consumers and the Company as well. Accordingly, we offer the year-end capital structure as an alternative to the 13-month average approach.

The cost rates applied to the 13-month 2008 balances of long-term debt and preferred stock include the interest rate on the face amount and issuance costs unique to each individual issue, and related debt expenses where appropriate. The cost rate applied to customer deposits balances is based upon market segment-specific interest rates, as determined by the Commission. The balances for accumulated deferred taxes and investment tax credits are included in the regulatory capital structure at cost rates of zero and the overall cost of capital stated on a traditional basis, respectively.

The rate of return for common equity is determined by applying four capital cost assessment methodologies including Discounted Cash Flow, Capital Asset Pricing Model, Risk Premia, and an assessment of Realized Historical Returns. The fourth approach constitutes a benchmark by which investors gauge the future earnings prospects of financial assets and, along with other information, form expectations of future returns. By assumption and empirical assessment, efficient markets value (price) financial assets accordingly. These four methods are well founded by modern finance theory and are often used to determine the cost rate for common equity capital. The Risk Premia methodology infers the underlying opportunity cost of capital on a basis of the relative risks of debt and equity capital.

Q. Can you please summarize your findings and recommendations?

A. Yes. Our studies give rise to an overall rate of return recommendation of 8.07%. The determination of the 8.07% rate of return is shown in Exhibit 1, which reveals the balance amounts for each financial component of the capital structure, the share that each component represents, the attending cost rate, and the overall rate of return. As mentioned above, the overall rate of return recommendation is based upon a 13-month 2008 regulatory capital structure that, consistent with utility regulatory policy in the State of Florida incorporates customer deposits, accumulated deferred income taxes, and investment tax credit balances.

The recommended 8.07% overall return level incorporates a common equity return of 11.50%. As mentioned, the opportunity cost of shareholders of Florida Public Utilities Company is assessed with four valuation methods. The results of studies based on the valuation methods are shown in Exhibit 2, along with the equity return recommendation.

This recommendation, if adopted by the Florida Public Service Commission, will enable Florida Public Utilities Company to continue to provide highly reliable electricity service to its customers at favorable prices. At the same time, the recommendation provides an adequate level of compensation to the shareholders of Florida Public Utilities Company on the capital that they have committed to the Company. Satisfactory returns to equity also enable the Company to continue to attract long- and short-term debt at favorable terms and interest rates that, in both the near-term future and the long-run, are in the best interests of retail electricity consumers.

Fair and adequate allowed returns to capital are vital, and we cannot over-emphasize to the Commission the importance of setting the overall rate of return at a sufficient level, particularly in the current environment of considerable levels of risk and uncertainty. The determination of an adequate return level by the Florida Public Service Commission signals to the investment community including mutual funds, long-term private investors, speculators, mortgage bankers, and commercial banks that the business and regulatory environment in which Florida Public Utilities Company operates has continuity and stability over the long term. Importantly, it also signals that the Commission is supportive of the Company and the job that we do on an ongoing basis for retail consumers.

Q. Electricity is intermingled with and highly dependent upon energy markets, particularly markets for primary fuels. Can you please provide a profile of contemporary electricity markets and the implications for electricity distributors and the cost of equity capital?

A. Infrastructure industries, including the electricity services industry in particular, are undergoing significant restructuring with no immediate end in sight. This restructuring assumes a number of dimensions including service unbundling in both retail and wholesale markets, competitive entry and new mechanisms to determine the prices for services. At the wholesale level, utilities face and are part of the expansion of wholesale services and contract mechanisms to hedge varying degrees of risks; divestiture of generation; and the appearance of wide-scale participation in wholesale electricity commodity markets by power traders and speculators who are deeply involved in commodity markets generally. Wholesale markets are being organized under the auspices of regional transmission organizations referred to as RTOs. RTOs serve as the agent for markets as a whole, where regional markets are unbundled according to time (hourly markets), space (locational pricing of energy), and services including energy, reserves (including regulation, spin, non-spin, and supplemental categories), as well as financial transmission rights (FTRs) of various types. While wide-scale change has been in the works for years and is arguably most pronounced at the wholesale level, as precipitated by the Energy Act of 1992, significant change has been and is currently underway within retail markets as well. At the retail level, regulated utilities face a gamut of changes regarding new regulatory governance arrangements including pre-approval, decoupling, and various performance assessment mechanisms; auctions for provider of last resort ("POLR") services; renewable resource portfolio standards, and new rules and requirements regarding reliability requirements, aside from the new reliability (and implied cost) commitments imposed on service providers by the North American Electric Reliability Council ("NERC"), which has been recently designated by the Federal Energy Regulatory Commission ("FERC") as the national electric reliability organization ("ERO").

Driven to improve earnings performance and exploit growth opportunities, many integrated electric utilities have since the late-1980s pursued non-regulated business ventures including activities fairly far afield from electricity services such as real estate and insurance, as well as diversified energy services including distribution operations, nuclear generation, renewable resources, and power trading. In a number of cases, generation (and to a lesser extent transmission) assets have been sold off to independent generation companies or unregulated generation entities have been formed from the generation business units of the integrated utilities. Thus, deregulation has resulted in an increasingly broad range of business activities, business organizations and entity structures within the electricity services sector of the economy, obtained through competitive entry and consolidation of functionality across entities. The financial performance of entities within the electricity services industry including the expected returns to capital and financial risks, is much more closely linked to energy markets, generally, than was previously the case.

The net result is generally positive, as competitive entry arguably obtains reduced costs to the benefit of consumers, at least in the long run. Nonetheless, these changes in structure, much of which have been accompanied by and ushered in through regulatory changes, have also raised capital risks associated with electricity services, as perceived by investors. This backdrop of higher capital risks occurs at a time when electricity service providers, including Florida Public Utilities Company, face steadily expanding electricity service demands and an array of new requirements covering, among other things, capital renewal at a time of fast rising costs for electrical equipment.

Q. Your testimony mentions capital risks and capital renewal. Perhaps you can elaborate on the meaning of capital, and how it comes about.

A. Capital refers to economic resources of a durable nature that contribute to production of good and services, or may provide services directly. Capital resources of an economy are readily at hand; examples include manufacturing equipment, software, commercial buildings, residential dwellings, streets and highways, airports and, importantly, the accumulation of skills and knowledge of the workforce. Capital is accumulated savings over time, where savings refers to the proportion of the output of an economy that is not consumed as current goods and services. Essentially, savings is the share of output held back and invested in—i.e., put into—capital resources. The cumulative level of investment over time, covering decades, constitutes the capital stock of an economy and a society. It is useful to mention that capital can assume various investment forms aside from financial assets in private and public companies and other entities. The stock of capital includes real estate, durable household goods, education, public property and infrastructure such as libraries, museums, parks, roads, and transit systems. Individuals, firms, and government entities invest funds in capital resources if the expected flows of benefits realized by the investments in the future are equal to or greater than the value of current consumption given up or foregone.

Q. Please review the notions of cost of capital, opportunity cost of capital, and discuss how risk affects the opportunity cost of capital.

A. The cost of capital is the compensation required by investors for postponing consumption, for expected inflation, and for exposure to capital risks of various dimensions. *Cost of capital* refers to the underlying interest rate used to discount expected benefit flows of capital resources including returns to financial assets, and is sometimes referred to as the rate of discount, or simply the discount rate.

Financial assets include a multitude of debt vehicles, equity, and derivatives, and are tailored to participants of capital markets including household, small business, corporate, and government segments. Participants across these segments—*i.e.*, investors including lenders and holders of common and preferred stock— can supply capital while other participants (such as borrowers and common stock issuing companies) demand capital. Commercial banks, credit unions, finance companies, capital exchanges, and investment banks serve as intermediaries that provide the institutional means that facilitate the interaction and linkage of the supply and demand sides of financial markets. These functions essentially include lending, borrowing, and the issuance of equity vehicles. Banks and credit unions borrow (and store) financial assets that in turn are invested in the form of debt and to a lesser extent equity.

Household debt vehicles include, for example, personal loans covering appliances, household services, and credit card mechanisms through finance companies and banks, and real estate and so-called home equity loans. Business loans include short-term loans and lines of credit with banks, inventory financing through business wholesalers, and commercial paper of various terms. Corporate debt can be in the form of lines of credit with banks, and mortgage and debenture bonds, while government debt can be in the form of revenue bonds of cities, and short- and long-term debt of various terms.

Equity refers to common and preferred stock, where the investor assumes a share in the ownership of a corporate entity. In some cases, debt instruments can participate in equity returns and have rights of conversion to common stock.

Derivatives refers to options and forward contracts that are specifically designed for speculation and risk hedging, where the market worth of the derivative is determined by investor expectations in the underlying price of a financial asset or commodity.

Q. What factors contribute to the underlying cost of capital regarding financial assets?

A. The underlying cost of capital is determined by investors and, in the large, by individuals and entities (including government entities) that provide savings and thus the accumulation of capital within the economy. In the case of financial assets, expected benefits are in the form of future cash flows including interest payments, dividend payments, market appreciation, and return of principal. When investors supply funds to entities such as utilities and government entities and municipalities, not only are they postponing consumption—giving up the value of alternative expenditures in some other way, they are also exposing funds to the devaluation of ongoing inflation and various uncertainties and risk attending future cash flows. Investors are willing to incur these risk factors only if they are adequately compensated. While the market prices of other inputs including labor, materials, energy can be easily verifiable, the cost of capital—essentially, the price of capital—is not easily discerned and, all too often, requires estimation through the cautious application of analytical methods.

The cost of capital, however, remains positive absent inflation and risks, as savers require compensation for foregoing the right to use the funds saved for consumption of goods and services—essentially, the time value of money.

The cost of capital is determined by the demand for capital, supply of savings, expectations of inflation, and perceptions of risks harbored by participants in capital markets. The demand for and supply of capital are determined by expectations of future levels of economic activity, while expected inflation is driven largely by monetary policy over the relevant timeframe. Perceptions of risk, in turn, cover many dimensions including uncertain government policy and the effects of natural phenomena such as weather. The cost of capital—the discount rate stated in nominal terms—increases with rising demand for capital, with expectations of higher rates of inflation, and with heightened perceptions of risk. Arguably, risk is the key contributing factor for the estimation of the cost of capital.

Q. Please elaborate on capital risks, and estimation of the cost of capital.

A. In addition to the global risks alluded to above (weather, government policy, etc.) dimensions of risk also cover idiosyncratic factors associated with specific capital resources, such as that of individual entities or companies. Accordingly, financial markets will re-price downward the bonds of a private company, should the *current* financial condition of the company suddenly decline. Essentially, the decrease in the company's current condition, reflected as reduced interest coverage—causes the expectation of the future condition of the company to also decline. Expectations of future financial conditions (possible states) of the specific company are idiosyncratic risks. Because cost of capital rises with increased risks, the price of the bonds decline. Bond prices and discount rates, in the form of the net interest rates or bond yields (and yield to maturity), move in opposite directions; bond yields increase as bond prices decline, and decrease as bond prices rise.

Resources migrate to the highest valued use and worth, given perceived risks, such that the returns to capital are equivalent to opportunity costs. The various forms of capital compete among themselves for savings and with other non-capital resource inputs and opportunities. Similarly, the vehicles of investment of individual entities, such as the specific bonds of a municipality or the common stock of a company, must compete for savings through a process of capital attraction. That is, if the outlook for earnings of a company rises, participants in capital markets—investors—allocate more capital to the company by bidding up the price of the stock thus increasing the company's market capitalization. Conversely, perceptions of heightened risks associated with the debt of a company or municipality precipitates a decline in the market value of the outstanding bonds, as capital migrates from the company/municipality to other resource opportunities. Thus, the prices of financial assets of entities including debt and equity securities are highly sensitive to perceptions of risk. Capital markets trade off risks and expected returns, given the overall menu of available choices, as alternative opportunities.

At an undefined point in time such that levels of supply and demand for capital and expectations of inflation are roughly equivalent (as a matter of consensus), the cost of capital is a matter of risk. Essentially, then, the cost of a specific source of capital is basically determined by the underlying riskiness of that investment in view of alternative opportunities that, together, represent the investors' current opportunity set. Hence, the cost of capital associated with specific investment opportunities, is differentiated by risks alone, as the other factors that impact the cost of capital—*i.e.*, supply-demand balance, inflation expectations—are common to all investments, and capital more generally. Competitive capital markets, through the process of assessing, buying, and selling, ensure that the expected payoff in the form of market rate of return is approximately equal to that of other investments of equivalent risk. In short, debt and equity investment vehicles of comparable risk are priced the same. If not, investors as participants in capital markets will bid up securities with comparatively low risks and bid down others with comparatively high risks. If investor perceptions of capital risks attending a utility increase—or the expectations for returns decline—markets bid down the securities of the utility. This implies that a utility will be unable to attract capital on equivalent terms, a result that is manifested in either of two ways: the quantity of capital acquired, in the form of new securities offerings, is reduced for a given level of return (stated in dollars), or a higher prospective rate of return attends the new offerings—it costs more to obtain an equivalent quantity of capital.

As mentioned above, investor rate of return is the discount rate that causes the present value of the expected cash flows, as receipts realized by investors, to equal the market value of the financial asset. From the utility side, the cost of funds raised by the utility through the sale of securities is equal to the discounted present value of the cash outflows to be paid by the utility, as expected by investors. But since the (positive) cash flows stream to the investor is identical to the cash outflows of the utility, the two discount rates must be identical, abstracting from the effects of flotation costs, which causes the costs to the issuer to exceed the return required by investors to the extent that flotation costs decrease the net amount of funds actually available to the issue. In other words, the cost of capital to the utility is synonymous with the investors' expected rate of return. Hence, the cost of capital is the discounted expected cash flows necessary for the security to "pay the price"—*i.e.*, in order to satisfy investors' required rate of return.

When capital markets are sufficiently competitive, they ensure that the market value and worth of financial vehicles of the outstanding debt and equity—as held by the investment community, which can include households, financial institutions, government entities, and non-financial companies, is set (*i.e.*, priced) at a level such that the returns to capital approximate the cost of capital. Because investors are averse to risks, competitive financial markets price financial assets inversely according to perceptions of risks, all other factors held constant.

Q. Why is this construct relevant and how does it relate to Florida Public Utilities Company and its capital needs?

A. As discussed, capital resources are the result of cumulative investment, and are obtained or funded directly or indirectly from savings of households and firms over time. Savings is the share of income of the economy as a whole that is not expended as consumption within a current period, and is typically measured as dollars or percentage shares in either quarterly or annual periods. This means that the capital resources employed by Florida Public Utilities Company including power delivery systems such as transformers and lines, meters, trucks and vehicles, computer systems, software, office facilities and buildings, inventory and stores, and land are costly, where cost is reflected as the annual carrying charges on capital, measured in the form of the net utility rate base.

Whereas the cost of skilled labor, materials and supplies, purchases of generation and transmission services, or other inputs used in the production process of utilities are expressed in money terms—*e.g.*, purchased power stated as dollars per megawatt hour—the cost of capital is expressed as an interest rate, typically shown as an annual percentage of the principal amount committed by investors. The cost of capital—or perhaps more accurately, the *cost rate of capital*—to the firm can be referred to as the *required rate of return* (%) on the capital resources committed by investors. In the case of public utilities, invested capital is referred to as the rate base, valued at either original cost or fair market value. For the determination of setting retail prices in the U.S., the regulatory convention is to value the capital of public utilities at original cost.

To facilitate the commitment of capital (investment) by savers and their agents to the firm, the firm offers property rights, including bonds or promissory notes to debt holders and shares of stock to equity investors. These property rights define the commercial terms and conditions under which savers and their agents, as investors, commit capital. Property rights are capital (financial) assets, and are generally tradable. Financial assets are claims on the income of the firm as compensation for the commitment of capital, and are the financial obligations of the firm. Shares of stock constitute ownership in the firm.

In the case of long-term debt—*i.e.*, mortgage bonds, debentures, and long-term notes—the interest on the principal (face) amount of a bond (debt) or the coupon rate on the share of preferred stock defines the level of compensation. Often, the interest rate is a predefined annual rate that remains fixed over the term of the debt. However, long-term debt instruments can have a number of other provisions that, in essence, provide for more complete contracting by managing risks through risk sharing between the debt holders and the borrower (the firm). These provisions can include 1) adjustments to the rate of interest to reflect contemporary market conditions *and* rates of inflation, 2) participation in earnings of the firm, 3) conversion rights, and 4) voting rights in the management of the firm.

In the case of short-term promissory notes, agreements with commercial banks define the mechanism by which interest, stated in dollars, is determined. Often, the commercial terms of promissory notes define interest to be paid monthly on the outstanding daily balance (principal) outstanding. The rate of interest applied to the outstanding balance is typically tied (indexed) to the interest rate on obligations of some widely known financial market—say, the London Interbank Offer Rate (LIBOR) or Fed Funds—which also varies daily or monthly.

Common stock property rights are somewhat different from other financial obligations because, as owners of the firm, the returns to shareholders are residual amounts following the compensation of other resources employed by the firm including debt obligations. Common equity is essentially compensated last, and bears the burden of much of the business, regulatory, and financial risks of the firm. For this reason, common equity is, in virtually all cases, more costly than other forms of financial instruments.

As with other markets, capital markets have primary and secondary dimensions. Primary markets are the institutions and processes that facilitate the initial sale of the financial obligations of the firm to initial investors, whereas secondary markets are structured market processes that provide the means by which investors can purchase and sell existing rights, including shares of stock and debt obligations. Financial instruments can assume many forms, and debt securities (bonds) and equity shares are actively traded in financial markets, which are generally considered to be highly liquid and competitive. However, to the degree that financial obligations 1) carry specialized and non-common commercial terms, and 2) secondary—and to a lesser extent, primary—markets are less liquid, holders of such obligations assume higher risks, other factors held constant. This is the case where the pool of buyers and sellers is limited and the volume of transactions is comparatively small. Relatively low levels of liquidity imply higher transaction costs and risks to investors, which translates directly into higher costs of capital to the firm.

Competition is a term that describes some markets, and markets are said to be competitive if certain conditions exist. Markets can be characterized as competitive if they involve: 1) a very large number of buyers and sellers, 2) information relevant to the determination of prices is readily available, complete and not costly, and 3) transactions costs are low. Because of the workably competitive nature of financial markets, arbitrage opportunities are more or less exhausted. This means that, for both primary and secondary markets, financial property rights trade at levels (prices) such that perceived risks and opportunities for prospective returns to capital are appropriately balanced and approximate those of other investment opportunities. Thus, above-normal returns, which implicitly include compensation for risks, cannot be seemingly realized by investors over prospective periods in systematic fashion.

Competition inherent to U.S. and worldwide financial markets ensures that the prices of common shares (share prices) and bonds are at a level that reflects the opportunity cost of capital. As an example, assume that the perceived risks attending the returns to common shareholders of firm A are equivalent to those of firm B and other firms. If the share prices of firm A suggest a market return of 10%, while the prices of firm B and other firms of comparable risks suggest (allow) market returns of 13%, the market price of firm A will fall to a level that provides a basis for market returns of just 13%, prospectively. A price that allowed for a 10% prospective market return is insufficient in the presence of opportunities for market return of 13% on alternate investments of comparable risk. Essentially, the 13% market rate of return on investment alternatives constitutes the opportunity cost of capital. Most remarkable is the expedience—

literally, in minutes—with which share prices adjust to levels that appropriately balance prospective returns to equilibrium levels *based upon perceptions of risks*. In short, equivalent and comparable risks translate directly into comparable rates of return, which is the cost of capital of common shareholders in—and thus of—the firm.

As mentioned early on, the cost of capital is a function of the demand for and supply of capital, investor expectations of inflation, and investor perceptions of risks. Because the conditions of demand and supply as well as expectations of inflation are more-or-less common to financial markets at any point in time, financial vehicles are differentiated by risks. Hence, the expected returns and prices of bonds and common shares (normalized for denomination and size) at any point in time are largely if not exclusively differentiated by perceptions of risk.

Q. **How is this general discussion of capital markets relevant to Florida Public Utilities Company?**

A. Because the cost of capital is positively related to risks, continuity of regulatory policy mitigates capital risks of Florida Public Utilities Company to the benefit of retail consumers by providing a sustained regulatory environment that facilitates a steady flow of revenue that closely adheres to the costs of electricity services.

Q. **Would you please review the capital structure, interest coverage requirements, and the implications for sufficient coverage?**

A. Interest coverage refers to the times that debt interest is covered by income, and is the most important measure of investment risk of corporate debt. Interest coverage is a major concern of Florida Public Utilities Company as it is the basis upon which the Company maintains its favorable credit standing with markets and continues to obtain long- and short-term debt at favorable rates of interest. Interest coverage under the recommended capital structure and rate of return for the Company's consolidated electricity services business unit is estimated to be 4.06, compared to 2.5 times using current rates Please reference Exhibit 12, Page 2

For purposes of comparison, we also show interest coverage over the historical timeframe on Exhibit 12, page 2. As can be seen, the coverage implied by the recommended rate of return is adequate though not at a robust level. Two conclusions are reached:

1) While the implied coverage level is acceptable, the Company must sustain a flow of earnings at consistent levels in order to maintain adequate coverage and also satisfy debt covenants.
2) Contingency events and business conditions that give rise to sudden and unexpected changes in revenue or cost flows can imply immediate shortfall in coverage. In short, the coverage level obtained from earnings at the recommended rate of return is only adequate in today's environment of higher capital risks.

The importance of coverage cannot be overstated. Indeed, in discussions with investment banks, commercial banks, and stock analysts regarding the financial condition and soundness of the Company, a salient point of concern continues to be coverage of debt. Lending entities, private investors, and investment banks continue to emphasize the importance of consistently-realized adequate interest coverage as the essential measure of the Company's capability to service long- and short-term corporate debt.

As can be seen, the recommended rate of return requirement, 8.07%, provides satisfactory interest coverage. And although the overall return recommendation provides adequate coverage, it is certainly not abundant. Hence, it is absolutely necessary that Florida Public Utilities Company realize adequate and sustained flows of income to ensure that the Company satisfies credit risk requirements. Coverage is our window of access to capital at favorable rates of interest and under reasonable terms, enables the Company to provide electricity services. Setting the overall rate of return at a satisfactory level of 8.07% is necessary and in the best interest of retail electricity consumers.

Q. What is the appropriate capital structure for determining retail prices in this docket?

A. Two fundamental issues are present. First, should the Commission utilize a consolidated capital structure for setting retail electricity prices and under what conditions should the Commission depart from a consolidated capital structure? Second, should an average or year-end capital structure be utilized?

Issue 1: Conditions to Justify Departures from the Consolidated Capital Structure. In the absence of large-scale subsidiary operations, the Florida Commission should generally utilize a consolidated capital structure where such approach provides a reasonable balance between debt and equity. Under such conditions, the Commission is assured that the service provider is, in the best interest of retail consumers, underwriting its assets dedicated to providing utility services at least cost.

This can be viewed as a principle that defines criteria useful to the Commission in regulatory decisions regarding the issue of the appropriate capital structure for the determination of retail prices. Specifically, and as a general rule, the Commission should only deviate from a consolidated capital structure when this condition—*i.e.*, an appropriate balance between debt and equity—is not satisfied. The corollary to this principle is that the Commission and its staff should never remove or add accounting-based line items from a consolidated capital structure that is appropriately balanced. Two facts of financial accounting underlie this corollary, as follows:

1) A firm cannot ever trace and identify, as a matter of dollar flows, specific sources of funds to specific uses of funds. The Treasury of a firm essentially constitutes a pool or inventory of current funds, cash, that continually experiences fund inflows and outflows. One cannot say that a specific source of funds is earmarked for a specific use. As an example, one cannot say that cash flow returns and operating income that arise from the Company's electricity operations are used solely to underwrite resources for the electricity business. Electricity-sourced cash flows are, in fact, used across the combined operations of the natural gas, electricity, and propane businesses of the Company—and similarly for the natural gas and propane operations.

2) The Company's balances of long-term debt, short-term debt, preferred stock, and common equity stated on a consolidated basis represent the accrual over years of the net flows of funds of the Company including external and internal sources. The balances for these financing vehicles can and should be used as the basis by which the Company underwrites any and all of its assets, stated on either a consolidated or an individual basis. This is simply a business, accounting, and financial fact.

There is no reasonable basis, thus, to exclude Flo-Gas balances from the Company's capital structure for purposes of setting retail electricity prices in the current docket. Indeed, exclusion of Flo-Gas balances may harm retail electricity consumers in various ways, aside from the inherent contradiction to the realities and facts of financial accounting identified above.

Second, exclusion of Flo-Gas balances from the capital structures used to set prices for the regulated operations, including electricity and natural gas, implicitly assigns common equity, which is comparatively high-cost, to the Company's unregulated propane operations, placing the propane operations at a competitive disadvantage with other propane companies. One can expect that other companies will leverage assets in a manner similar to that of the Company, in order to finance propane and competitive, non-regulated energy services. As a consequence, the Company needs to follow a similar policy. If the Company is required to assign only equity to non-regulated operations, it is implicitly forced to charge correspondingly higher prices in order to generate adequate returns.

Third, the consolidated capital structure of Florida Public Utilities Company stated on 13-month average basis for 2008 represents a sound balance of debt and equity financing that fully satisfies the financial needs of the Company, particularly in view of the comparatively small size of Florida Public Utilities. This is evidenced by the comparative sample of electric utilities used to determine the cost of capital. Specifically, equity participation within the Company's 2008 capital structure resides within one standard deviation of the average participation of the sample. Hence, the Company's financing policy and strategy conforms to a reasonableness standard, in addition to fully satisfying the financial prudence and flow of funds criteria outlined above.

Nonetheless, the recommended weighted average cost of capital presented within our testimony follows the Commission's prescription. Namely, the Flo-Gas balances are excluded from common shareholder equity for purposes of determining the overall rate of return to set retail electricity prices within the immediate docket.

Issue 2: Average or Year-End Capital Structure. This second issue implies two subsidiary questions: is the average or year-end capital structure the most representative on a forward-looking basis beyond 2008. As shown on Exhibit 1, page 1, the average capital structure for 2008 for Florida Public Utilities Company contains equity participation of 40% and 50%, respectively, under regulatory and traditional methods of stating the underlying invested capital. As a result of the issuance of common equity shares at mid-year 2008, the average balances approach inherently does not take account of the level of equity participation beyond 2008, the period over which the retail prices will be in effect.

The appropriate correction for this understatement of the overall cost of capital for the Company, which is inherent with the use of average capital balances in the face of the pending issuance of new shares, is to use a year-end capital structure. The result of such approach is shown on pages 2 and 3 of Exhibit 1, where the year-end based weighted average cost of capital is presented, shown with and without Flo-Gas balances. Specifically, year-end balances reflect equity participation of 42% and 54% for the regulatory and traditional capital structure. This higher equity participation level translates into weighted average cost of capital results of 8.13%, stated for regulatory purposes. In short, the average capital structure for 2008 leaves Florida Public Utilities Company short by 6 basis points, which implies an unrecognized revenue shortfall of about $40,000, stated on a going-forward basis.

Q. **Can you please review your recommendation for the cost rate of long-term debt?**

A. Yes. Florida Public Utilities Company has raised long-term debt from time to time based upon the need for capital and our Company's financial policy of maintaining a balanced capital structure. Because of our conservative management philosophy, we have consistently raised new debt issues at favorable rates of interest at the time of issue. Contributing to favorable interest rates are the conservative sinking fund provisions of the earlier higher-cost debt issues of the late-1980s – early-1990s.

The cost rate of 7.96% for long-term debt, shown in the column entitled "Annual Cost Based Rate" of Exhibit 3, reflects the weighted average cost of the five issues of long-term mortgage bonds of the Company, currently. These debt issues have face interest rates of 4.90% to 10.03%, and were issued by the Company over the period 1988 – 2001. The balances shown reflect the amounts that the Company expects to carry on its balance sheet on average over the year 2008 and beyond. The Company does not plan to issue long-term debt during the interim two years.

The 7.96% overall cost rate of long-term debt reflects issuance costs and losses on reacquired debt, which causes the effective cost rate to be somewhat greater than that of the weighted cost of the face interest rates alone. The 7.96% overall cost rate for long-term debt is calculated using the amortization schedule for debt expenses. This costing procedure follows the conventional accounting approach to determining the cost rate for long-term debt, and is consistent with the policy endorsed by the Florida Public Service Commission.

Q. Would you please review the cost rate of short-term debt and related issues?

A. Florida Public Utilities Company maintains, and expects to maintain over the foreseeable future, a short-term debt facility that makes available short-term debt at a cost rate determined by London Interbank Offer Rate (LIBOR). The short-term debt cost rate is equal to the 30-day LIBOR plus 90 basis points, plus other charges related to unused facility balances as well as fees charged for the facility itself. The Company currently has a $12 million line of credit with

Bank of America, which upon 30 days notice can be increased to a maximum of $20 million. Based on current cash flow projections we anticipate increasing the line to $15 million by November 2007. We anticipate lowering the line of credit to $12 million after the issuance of additional shares of common equity, which is scheduled for the middle of 2008.

The interest rate margin above LIBOR (90 basis points) for the Company's current short-term debt facility is somewhat above that of the Company's previous short-term debt facility, which reached the end of its contract in March 2003. The higher margin requirements, as imposed by financial lending institutions internationally, reflect higher perceived risks, both generally and within energy markets, than in previous years.

The expected effective short-term debt cost rate incurred by the Company for short-term debt, for use to determine prices in the current docket, is determined by first projecting the Federal Funds rates in the U.S. for the timeframe over which the retail electricity prices will apply. Then, given the historical relationship between LIBOR and the rate for U.S. Fed Funds, the LIBOR rate is estimated. Once determined, the short-term debt cost to Florida Public Utilities is obtained by recognition of the 90 basis points margin above LIBOR plus other charges covering the unused balances and the fee for the availability of the credit facility.

The key short-term interest rate is the Fed Funds rate. Historically, Fed Funds have traded 18 Basis Points below LIBOR over the 1990 – 2006 timeframe.

The interest rate on Fed Funds is determined by the monetary policy of the Board of Governors of the Federal Reserve Bank, and closely follows that of short-term U.S. Treasury Bills. Historically, Federal Funds "trade" at an interest rate slightly above that of 90-day T-Bills. At this point, the apparent consensus view is that monetary policy and thus the short-term interest rates will hold firm at or near current levels over the foreseeable future, which implies a fed funds rate of 5.25% currently and, in turn, a LIBOR interest rate of 5.43%. In turn, this result translates into a cost rate of 6.33% for the outstanding balances on short-term debt balances, once the margin above LIBOR is recognized. The fees associated with the unused credit line and direct charges when coupled to charges for the outstanding balances obtain an overall effective short-term debt interest rate of 6.81%, which is applied to the 13-month average balances of short-term debt.

It is useful to briefly describe the longer history, as it relates to the determination of short-term interest rates. Specifically, the Federal Reserve followed a policy of interest rate targeting for a number of years prior to late 1979, when money supply targeting was abruptly adopted. The result was high and volatile short-term interest rates, although money supply targeting arguably reduced substantially the high levels of inflation and inflation expectations of the early 1980s. From the mid-1980s forward, monetary policy has been more accommodative of economic conditions and needs, within the long-term objective of containing overall inflation at moderate levels. As observed during the 1990s, the Federal Reserve has employed an array of indicators and metrics to determine monetary policy, including reserve targeting. As a general rule, reserve targeting gives rise to greater variation in short-term interest rates, while interest rate targeting, which suggests greater variation in the supply of reserves, results in less variation. At this writing, short-term interest rates, with Fed Funds residing at 5.25%, are expected to hold steady to slightly declining over the foreseeable future, barring changes in the expected level of economic activity or current escalation of core inflation.

The use of the current 5.25% Fed Funds interest rate as the basis for the Company's effective short-term debt cost rate is in keeping with the Commission's decisions regarding the Company's rate change filings of 2003 and 2004. Also, and as mentioned above, it appears that this interest rate level is likely to hold over the foreseeable future.

Finally, we wish to discuss the methodology used to determine the effective interest rate for 2006. The interest rate charges on the Company's short-term debt facility are based on daily balances. If the daily balances closely approximate month-end balances, month-end balances provide a useful basis to determine the average short-term debt cost rate. Where the daily balances deviate significantly from the month end balances, however, this approach will not provide an accurate reflection of the Company's true cost of short-term debt. This was the case for the Company during 2006. Accordingly, the short-term debt cost rate for the historical year 2006 has been developed using the average daily balances which accurately reflect the true cost rate incurred by the Company on short-term debt during that year.

Q. Please review the cost rate of preferred stock.

A. Florida Public Utilities preferred stock consists of a single issue of 6000 shares that dates to December 28, 1945 at a coupon rate of 4.75%, as shown on Exhibit 5.

Q. You briefly discussed methods for the determination of the cost of common equity capital in the summary of your approach to rate of return. Can you elaborate on these methods?

A. Yes. We begin by reiterating three essential points. First, the cost of equity of the firm—and of investors in the firm—is a function of perceptions of risk, the demand for and supply of capital, and expectations of inflation. Second, the cost of common equity of the firm is equal to the opportunity cost of capital incurred by common shareholders of the firm contemporaneously, though the experience of long-term history guides the assessment of opportunity costs. Third, the cost of equity of the firm is equal to the expected market rate of return on alternative investments of comparable risks available to shareholders—*i.e.*, the opportunity cost of capital.

The determination of the opportunity cost rate for equity capital is challenging for two reasons. In the case of debt, both the market price and future expected cash flow returns to capital are observable by inspection. Thus, the net expected yield to maturity, which reflects the opportunity cost of capital to holders of debt, can be determined directly. This *is* the market rate of return, *ex ante*. For purposes of determining the overall utility rate of return, however, the cost rate of long-term debt is that which is set at the time of issuance in primary financial markets.

In contrast, expectations of investors about the prospective cash flows and market returns on common equity cannot be observed directly, and must be inferred with estimation procedures. Also, the allowed equity rate of return is typically set according to the current and expected cost of capital, though much of the equity investment was committed in many years past.

In the determination of cost rate for debt obligations, investors' perceptions of risks are implicit in the primary and secondary market prices of the debt obligations themselves, and need not be known or even estimated. In contrast, the determination of the cost of common equity involves the perceptions of future risks harbored by investors, as a matter of the consensus view. Perceptions of risk are also not observable directly, and thus must be inferred. In short, the cost of common equity can only be discerned through the proper and careful application of well-established methods that provide the cornerstone for modern finance theory. While the methods employed herein are well-established, the procedures to determine the cost of equity capital require estimation of key parameters.

As mentioned, the recommendation for the rate of return on equity for Florida Public Utilities Company is developed by applying four estimation methods. These procedures include variants of the constant growth Discounted Cash Flow model (DCF), and the Capital Asset Pricing Model (CAPM). These classical approaches are commonly recognized within modern finance theory and are readily utilized by the investment community. The results of these two formal models of the cost of capital are augmented by historical returns realized by utility and non-utility companies of comparable risks, and results inferred from the risk-premium methodology. These four methods are discussed below.

The constant growth Discounted Cash Flow (DCF) model was originally developed by Myron Gordon in 1957, and was advanced actively during the early 1960s. In its classical form, the derived DCF model defines the cost of capital as the sum of the adjusted dividend yield, and expectations of future growth in cash flows to investors including dividends and future appreciation in share prices. The classical (one-stage) DCF model is as follows:

$$k_{e,j} = D_{0,j}(1+E(g_j))/P_{0,j} + E(g_j)$$

with,

$k_{e,j}$ = cost of equity capital, asset j

$D_{0,j}$ = current dividends per common share, asset j

$E(g_j)$ = expected growth in future cash flow returns to investors in asset j

$P_{0,j}$ = current price per common share, asset j

The one-stage form of DCF model is an elegant and intuitively tractable model with two terms, a mathematical result derived from the constant growth present value model. A cursory review of historical returns of equities suggests substantial variation in growth in the internal returns to capital and market appreciation is both the typical and dominant pattern. It is plausible that the *expected path* of future returns harbored by investors may assume a pattern of non-constant growth. This means that, at least under some market conditions, the constant growth form of discounted cash flow may not represent investor expectations of growth with sufficient accuracy. Arguably, other forms of DCF may serve as better approximations of investor expectations.

A plausible means to better model expectations of varying growth might be with stochastic models, where the path of returns and growth is a function of time, with a random component. However, stochastic models introduce considerable complexity. As a first-order approximation to stochastic processes, multiple-step constant growth models known as multi-stage DCF can serve nicely. Essentially, multi-stage DCF is a variation of present value theory which postulates that future returns assume a pattern of several growth steps or stages. While any number of stages of constant growth is possible, two or three stages are typically applied. In stylized fashion, the Three-Stage DCF model is shown below:

$$P_{0,j} = (1+g_j)/(k_{e,j}-g_j)\{D_{0,j}(1 - F^5_j) + D_{5,j}(F^5_j - F^{10}_j) + D_{10,j}(F^{10}_j)$$

with,

$k_{e,j}$ = cost of equity capital, asset j

$D_{t,j}$ = current and future dividends per common share, asset j

$E(g_j)$ = expected growth in future cash flow returns to investors in asset j

$P_{0,j}$ = current price per common share, asset j

F_j = $(1+E(g_j))/(1+k_{e,j})$

Appendix I provides a step-by-step derivation of the classical and multi-stage discounted cash flow models shown above.

The Capital Asset Price Model (CAPM) was developed by William Sharpe (1961) and John Lintner (1964). CAPM was derived from mean-variation analysis and, in particular, portfolio selection developed by H. Markowitz (1952). The derived CAPM shows how the valuation of a financial asset (price) is based upon two components: risk-free returns and an *adjusted risk-based return.* Surrogates for risk-free returns can be observed directly in capital markets, and include market returns on short- and intermediate-term debt. As a general rule, the cost rates and market returns on government debt obligations serve as appropriate surrogates.

The adjusted risk-based return is based upon three factors: 1) the covariation of the returns to the asset and that of markets for risky assets, 2) the statistical variance of returns of the market for risky assets, and 3) the *difference* between expected overall returns on risky assets, and risk free returns. The third parameter is referred to as the excess return, and is equal to the difference between the overall returns to risky assets for the market as a whole, and the risk free return rate. The CAPM is shown below:

$$k_{e,j} = r_f + B_{jm}*(r_m - r_f) \qquad \text{with, } B_{jm} = \sigma_{jm}/\sigma_m^2$$

where,

$k_{e,j}$ = cost of capital for risky asset *j*, stated in percentage terms

r_f = risk-free rate of return

B_{jm} = ratio of the covariation between risky asset *j* and the market as a whole, σ_{jm}, and the variance of market returns, σ_m^2

r_m = rate of return on the market as a whole

Appendix II derives the Capital Asset Pricing Model, as shown above.

The efficient market hypothesis plays an essential role in the determination of the cost of capital. Specifically, the working assumption, which is largely though not completely borne out by empirical analysis, is that capital markets are fairly efficient. This means that the supply and demand for risky financial assets, as reflected in bid and asked prices to buy and sell shares, result in financial assets being traded at price levels where *rates of return above the cost of capital cannot be systematically realized.* Above-normal returns—returns above the cost of capital—are realized only randomly. Essentially, the opportunities to systematically realize returns above the underlying cost of capital are exhausted by the competitive market process.

Estimating the cost of capital, though not trivial, can be fairly straightforward, and both the DCF and CAPM approaches provide a useful framework. The risks to investors in various sectors of the energy services industry cannot ever be known directly; risks—and hence the implied cost of capital—can only be inferred. Specifically, the determination of useful estimates of the cost of common equity capital within either framework requires a discerning application of theory through careful analysis, such as that presented herein. In particular, the determination of the cost of equity capital faces two overarching challenges, as follows:

- both approaches are forward looking and thus the results are highly dependent upon useful estimates of investor expectations about future market performance.
- The underlying assumptions for DCF and CAPM include, among other things, an efficient market and rational behavior of investors such that

> all opportunities for above- and below-normal returns to capital are exhausted on an expected value basis. In short, capital markets value financial assets at the implied opportunity costs of capital, given investor perceptions of risk.

It is useful to mention that the notion of *risky assets* can apply to any real or financial asset wherein the prospective returns from holding the asset are uncertain. Risky assets include commodity contracts, financial property rights, financial derivatives, and real assets such as transmission facilities. Risk assessment and option theory, moreover, can be applied to the analysis of unbundled services, such as electricity transmission development plans. Within the context of this discussion, however, risky assets refers to financial obligations of firms—common stock—and asset values refers to prices of common stock as observed on major stock exchanges.

Measurement of historical returns and risk metrics are increasingly used as a basis to assess plausible returns in the future. As discussed, efficient markets suggest that *all* financial assets are priced at levels such that the *expected* future returns of individual assets are equivalent to the underlying opportunity cost. Thus, if historical returns guide expectations of future returns, historical returns provide a useful benchmark and, within reasonable bounds, reflect the opportunity cost of capital. In this respect, the Historical Returns methodology can be viewed as a market-based approach of Comparable Earnings, and thus fully satisfies the *Bluefield* and *Hope* criteria. The key to successfully applying this approach is to identify and measure historical returns in a manner that reasonably reflects expectations of investors about the future outlook.

Historically realized returns and future expected returns of financial assets are ordered according to risks. This ordering according to risks is a natural and inevitable result of competitive financial markets: because risk is costly, higher costs must be offset by higher returns. While it is not based upon an explicit model, the analysis of the risk premia among classes of risky assets provides a means to infer the underlying opportunity cost of capital. The underlying concept of the risk premium approach is that *differences* in perceptions of risks among financial assets such as equities and debt are revealed in differences between the historical market returns. The historical differences between equity and debt returns—*i.e.*, risk premia—can thus serve as a surrogate for the compensation for risk over future timeframes. Risk premia, when combined with the expected cost of short-term debt, prospectively, provides a useful benchmark to gauge the underlying cost of equity capital.

Application of the Risk Premium approach contains two potential pitfalls, as follows:

- the opportunity cost of common equity capital, stated in nominal terms, is sensitive to the demand for and supply of capital;
- risk premia among debt and equity instruments are also quite sensitive to expected inflation. Thus, Risk Premium analysis must account for expected inflation in the future. That is, the underlying rate of inflation and conditions of the historical period over which risk premia are

estimated must match that of the expected conditions of the relevant period over which the common equity recommendation is being applied, and over which retail electricity prices are being set.

Q. You discuss the importance of comparability and measures of risk as the basis to determine the cost of common equity. Please elaborate.

A. As defined by the "Bluefield" and "Hope" decisions of the U.S. Supreme Court, a public utility (to paraphrase), is entitled to a rate of return on shareholder capital committed for the convenience and necessity of the public equivalent to that realized by companies in other businesses of comparable risk. Thus, the immediate task at hand is comparability: to identify and select companies of comparable business, regulatory, and financial risks to that of Florida Public Utilities Company. Once selected, we estimate the cost of common equity for the sample(s) of comparable companies that, by definition, is the opportunity cost of capital and thus Florida Public Utilities Company. The key distinction regarding comparability is market size, as recent empirical evidence convincingly demonstrates that, predominantly because of information inefficiencies and uncertainty, the cost of capital rises with progressively smaller companies, all other factors held constant.

The starting point is the market portfolio; that is, we begin with virtually all common shares traded on U.S. equity markets. Specifically, we have drawn heavily—though not exclusively—from a set of data sources and information including the Value Line data banks which cover some 7,000 companies with equity shares listed on capital market exchanges in the U.S. With few exceptions, the shares of interest are traded on the New York Stock Exchange and the exchange operated by the National Association of Securities Dealers referred to as NASDAQ. For these equity listings, Value Line reports a wide range of financial data, business descriptions and classification, historical price experience, and various diagnostic statistics of interest.

From the market portfolio we proceed to develop two samples. One sample, referred to as the Mid-Sized Electric Utility sample, is limited to retail electricity service providers that have modest yet significant levels of market participation and, with the exception of size-related capital risks, are of comparable risk to that of Florida Public Utilities Company. The second sample is referred to as the Gas Utility sample, and is composed of retail natural gas service providers. Our studies demonstrate that, as a practical matter, the level of capital risks and thus the opportunity cost of capital for the two samples, electric utilities and natural gas utilities, is comparable. It is useful to mention that for purposes of determining the equity rate of return requirements, Christensen Associates Energy Consulting has often drawn a third sample referred to as *comparable risk non-utility companies*, as our methods tend to demonstrate that, particularly within contemporary capital markets with high levels of international capital flows, comparable risk is the predominant selection criterion; line of business appears to have only a modest level of relevance to cost of capital, once the comparable risk criteria are satisfied. Thus, samples can be drawn from a broad range of business fields, generally speaking.

The determination of the first sample, the mid-sized electric utilities, involves two steps. The first step is to conduct an initial screen according to the predefined selection criteria. As mentioned, these criteria are as follows:

- *Liquidity*: companies that are of modest size but yet have sufficient market presence and participation to ensure sufficient market activity and transaction volume;
- *Business Line*: companies whose primary business line is retail electricity services; and,
- *Reasonably consistent financial experience.*

This first screen produced the 17 electric utility companies shown on Exhibit 10, page 1, including Florida Public Utilities Company, from an initial list of over 30 mid-sized entities from across the electric utility industry. As can be seen, the market capitalization of these companies, measured by common shares outstanding and market prices during 2005 range from $77 million for Florida Public Utilities Company to slightly greater than $4.6 billion for SCANA (South Carolina Electric and Gas). The non-weighted average size of Sample 1, the electric utilities, is $1.6 billion, as shown. Also shown on page 1 of Exhibit 10 is operating revenues, assets, operating margins, and CAPM Betas. CAPM Betas, which are arguably the most significant measure of capital risk, are shown in the adjusted form for 2005 and for 2001-2004 on average. In particular, note that CAPM Betas have risen, suggesting significantly higher capital associated energy markets including electric service providers.

Some of these 17 electric companies have substantial involvement in non-electric retail business lines including natural gas. It is virtually impossible these days to assemble a sample of companies that are exclusively in the retail electric business—sometimes referred to as a *pure play.* This should not matter, at least on the surface, if the sample is determined on a basis of comparable risks. Indeed, endeavors to diversify risk over alternative business lines tends to reduce variation in earnings, variation in internal cash flow, and variation in market returns, thus reducing overall investment risk and the cost of capital.

The second selection step of determining the utility sample applies risk criteria. These criteria include ~~five~~ four dimensions, or metrics:

1. *Equity Participation in Total Capital*;
2. *Coefficient of Variation in Internal Cash Flow* per share over five and ten years;
3. *CAPM Beta* which, as discussed above, is the ratio of the covariation of the market returns of a specific stock of a company and the market as a whole, and the statistical variance of the returns of the market; and,
4. *Variation in Market Returns*, which is measured as the coefficient of variation of monthly market prices—essentially, an index of volatility in market value (market capitalization).

The mean-variation theory on which Capital Asset Pricing Model is based suggests that risk metrics other than CAPM Beta do not matter, for the determination of portfolios that efficiently trade-off risks and potential future return levels. However, empirical evidence suggests that a) internal financial metrics such as items 1-3 above are also utilized by investors to value equities, and b) CAPM theory (as with other capital market theories) does not necessarily explain historical market returns particularly well. Thus, it appears that to a substantial degree information other than CAPM Beta is also relevant to investors in the valuation of equities.

Nonetheless, the risk metrics for each of the 17 initial members of the Mid-Sized Electric Utility sample, as arrayed on Exhibit 10, page 2, are determined. Those electric utility companies with risk metrics that generally fall within one standard deviation of that of the average for the sample of electric utilities as first drawn or are reasonably close to the metrics for Florida Public Utilities Company are retained in sample one, the electric utility sample. It is these utility companies that, by this arguably objective approach, satisfy the criteria of comparable risk and thus that of Supreme Court guidelines regarding fair rate of return and contained within the Bluefield Waterworks and Hope decisions. The companies utilized for the determination of the cost of capital are denoted in the far right column of page 2, Exhibit 10.

Turning to sample 2, the natural gas utilities, the selection process proceeds in similar fashion using equivalent criteria to those employed to determine the electric utility sample (sample 1). That is, a sample is first drawn on a basis of market liquidity and business line. The selected natural gas utilities are shown on Exhibit 10, page 3, where market capitalization, CAPM Betas are presented along with revenues, assets, and operating margins. As observed, the selected natural gas companies range in size, measured by market capitalization, from $219 million to 2.8 billion in 2005. Page 4 of Exhibit 10 contains equity participation, CAPM Betas, variation in market returns, as well as the statistical variation in cash flows. As observed, these companies, though of comparatively modest scale, are all significantly larger than Florida Public Utilities Company.

It should be mentioned that, with respect to the selection of both samples, the study will take occasional exception to the stated selection criteria where historical experience contains anomalies of various types, and when good sense suggests the exclusion or inclusion of specific companies. As an example, the 10-year coefficient of variation in cash flow for some companies may reside slightly outside one standard deviation of the statistical distribution of the sample. Or, low equity participation may not appear to translate into particularly high variation in market variation or Beta; an example is Southwest Gas. Regarding the CAPM Betas, the values are shown in increments of 0.05, and Betas for several members of the sample are somewhat below one standard deviation and, for others, somewhat above.

Once determined, the two samples including the Mid-Sized Electric Utilities (Sample 1) and Gas Utilities (Sample 2) are then used as the basis to estimate the cost of equity capital to Florida Public Utilities Company within the immediate proceeding. The estimate of the cost of capital, and thus the recommended return on common equity, is reflected as an interest rate that, by objective criteria of comparable risks, is the opportunity cost of capital incurred by the common shareholders of Florida Public Utilities Company.

Market Liquidity is a necessary selection criterion, as stated above. The selection process resulted in generally smaller-sized electric and gas utilities that have sufficient liquidity. However, the selected utility companies of the two samples are substantially larger than Florida Public Utilities Company. Because the cost of equity capital appears to increase progressively with smaller size, other factors constant, the implication is that the cost of equity capital, as estimated for the two samples, may not fully capture the inherent capital risks incurred by investors of Florida Public Utilities Company. This is discussed later within the testimony, and the exhibits present levels of risk premia associated with small sized equities.

Q. The outlook for the U.S. economy plays heavily in the formation by investors of the future expectations of financial markets. Because future economic performance is used to estimate the cost of common equity, it is useful to elaborate on the inherent linkage between economic performance and the cost of equity.

A. As mentioned above, future returns to capital and thus estimation of cost of capital are inherently expectational in nature. The assessment of equity costs involves implicit and explicit estimates of investor expectations about inflation, interest rates, and future market performance. This is particularly important, as near-term interest rates and market experience and conditions do not necessarily reflect long-term expectations of and about capital markets as a whole. The basis of selection of historical timeframes is overall macroeconomic performance. That is, the analyses incorporate observed market returns from timeframes where the overall economic performance, measured in terms of growth in productivity and real output, are equivalent to the outlook today.

The relationships between factor inputs and the real output of goods and services of the economy are crucial to U.S. citizens, and to capital markets and investors. This is because resource productivity, to a large extent, determines the future level of real output of the economy as a whole. Productivity growth, when coupled with the growth in the aggregate pool of capital and labor resources, translates directly into real output, employment, savings, earnings, and market performance. Furthermore, real output is a significant element within overall economic and social well being.

The current outlook for macroeconomic growth calls for prospective long-term productivity change to range between 2.00 and 2.60% annually. This is a more-or-less consensus view held by well-known macroeconomists and economic forecasters, although expected productivity has declining recently from the exceptionally high levels beginning in the early to mid-1990s. Three years previous, long-term productivity appeared to be capable of upwards of 2.75% over the extended future. And while this range of productivity is fairly high by overall long-term historical standards, it is consistent with selected periods of the post-War period including the 1950's, 1960's, and 1990's. Specifically, productivity rose at annual rates of 2.4%, 3.0%, and 2.1% during the 1950s, much of the 1960s, and the latter 1990s, respectively. Of particular interest and crucial to the immediate analyses, productivity increased very sharply beginning about 1994, departing substantially from the low productivity growth of the previous two decades.

Productivity growth slowed significantly during 2000 and 2001, as overall economic activity attenuated amid the stress attributable to a number of factors and events of a transient nature that, in total, ultimately precipitated the modest recession of early 2001. Since then, the economy has resumed a recovery path and productivity growth appears to have accelerated to pre-recession levels. Indeed, overall productivity growth of 2003-2005 observed a return to high rates, which continues to contribute significantly to ongoing earnings performance and significant market returns realized by investors within equity markets internationally.

In short, the U.S. economy is well positioned to realize and sustain substantial, if not high, rates of growth in productivity and real output, along with full employment and modest inflation over the foreseeable long-term future. Investors generally share this consensus view and, accordingly, the analyses herein draws upon realized overall market rates of return and interest rates as representative surrogates for the period of time that the retail prices for Florida Public Utilities Company are likely to be in place. The average percentage market return over the historical timeframes mentioned above, as gauged by the S&P 500 index, was slightly above 13.0%, reaching back to the 1970s, and higher within recent years except for the years of major market corrections, 2000 and 2002.

Overall economic performance and long-term growth can, however, be attenuated by events of a transitory nature and various long-term processes that can contribute to capital risks such as the costs to maintain environmental quality, or world-wide cultural friction. An immediate example is the decline in credit market liquidity observed in recent weeks. Finally, it is important to mention the impact of government fiscal policy and global demand for capital on interest rates. As mentioned, the cost of capital is a function of the demand and supply of funds, and we expect U.S. and world demand for capital to remain at high levels, thus placing steady pressure on interest rates. As a result, interest rates are likely to remain at current levels, which approach long-term trends, although short-term interest rates in the short run may decline somewhat from current levels.

Q. What are the analysis results obtained from the application of the cost of common equity methodologies?

A. The task before us is to estimate the cost of capital over the relevant and foreseeable timeframe for which retail electricity rates are to be effective. This means that the analyses should, to the degree possible, recognize future events and market conditions that might be reasonably expected by investors.

As mentioned, the analyses include Discounted Cash Flow, Capital Asset Pricing Model, Risk Premium methods, and Historical Market Returns, with the first two approaches representing formal models of capital valuation. The Discounted Cash Flow analysis is applied to the sample of natural gas companies only. All analyses are shown as a range of plausible values, as the analysis of the cost of common equity is confronted with the problem of observability that inherently results in unknown levels of model estimation error.

The assessment of the opportunity cost of capital involves obtaining and processing a considerable amount of data, and using these data within structured analysis procedures that begins with selection, as discussed above. Data are obtained from several sources including Ibbotson Associates, MarketVector, UBS PaineWebber, Value Line Investment Survey, and Zacks Security Market Research.

The single stage *Discounted Cash Flow Analyses* for the Mid-Sized Electric Utilities (sample 1) and Gas Utilities (sample 2) are presented on pages 1 and 2 of Exhibit 7. As shown, the DCF results suggest that the underlying cost of common equity capital for the sample of electric utilities resides within the range of 9.0 – 9.9% with a corresponding weighted average of 9.6%. Similar results for the sample of gas utilities are 9.0 – 10.4%, with a weighted average of 9.5%. A key point is that these analyses are for a sample of companies which, as mentioned, are significantly larger than Florida Public Utilities Company and, absent further adjustment for size premia associated with very small capitalization companies such as the Company, will systematically understate the cost of common equity capital.

While nettlesome details are always present within capital market analyses, the classical DCF model consists of the two essential components of prospective dividend yield, and expected growth. For the sample of Mid-Sized Electric utilities, the analyses and the resulting estimates of the opportunity cost of capital reveal that the adjusted one year prospective yield lies within the range of 4.5% – 5.4%, while the corresponding estimates of expected growth of future cash flows are within the range of 3.3% – 4.7%. Analysis results are shown on a simple- and weighted-average basis, with the weights based upon the market capitalization of the sample utilities. The multi-stage DCF estimates of the cost of equity capital obtain similar results and are not shown.

The essential element for both single- and multi-stage DCF analysis is to appropriately assess investor expectations of growth of capitalization value and dividends. The analyses rely upon the historical experience of the sample companies to develop reasonable estimates of growth of internal cash and earnings. My studies generally rely on a combination of historical experience and analyst projections of cash flow and earnings growth, as implicitly contained within the valuation of investors, including larger institutions and individual investors. Timeframe is important and, for the immediate study, analyst views appear to be highly similar to those of historical experience. The study relies on long-term historical experience as the basis for expected growth in the future. The immediately study utilizes historical cash flow and earnings per share growth, which is measured in two ways for single-stage DCF. Specifically, historical growth experience is assessed over successive five-year periods, as well as by logarithmic trend-based analysis over ten years.

We should mention that while the immediate study utilizes historical growth experience, other studies by Christensen Associates Energy Consulting, depending on timeframe, have also drawn on and applied analyst expectations of future growth within the DCF formulation of the cost of capital. Historical growth and analyst expectations of growth are positively correlated and, not surprisingly, our studies suggests that, other factors held constant, differences among the dividend yields and other metrics for companies actively traded on equity markets are explained by historical growth analyst expectations of future growth. Generally speaking, analyst expectations are above those of historical experience and, were analyst expectations incorporated within the current analyses, it is likely that the DCF model would obtain higher estimates of the cost of common equity than those obtained via historical growth alone.

As mentioned above, the DCF analyses, as with CAPM and Risk Premium methods incorporate an adjustment for issuance costs of 6%, which translates into about 33 basis points. However, the cost of capital studies presented herein incorporate no allowance for market pressure or quarterly dividends. Empirical evidence suggests that market pressure is very small to non-existent, at least for larger capitalization companies. Had the analyses incorporated an adjustment for quarterly payment of dividends, the result would be—depending on perspective (frequency of payment or frequency of discounting)—to alter the estimated cost of capital by about 20 – 30 basis points.

As with Discounted Cash Flow, the *Capital Asset Pricing Model* is applied to both the Mid-Sized Electric Utility and the Gas Utility samples. The CAPM analyses are shown on Exhibit 6, pages 1 (sample 1) and 2 (sample 2). The application of CAPM requires estimates of the risk-free rate, investor expectations of overall market returns, and market Betas which account for and embody systematic risk with reference to equity markets as a whole. Incorporating estimates of market rates of return and short-term interest rates into the CAPM formulation along with the market Betas results in estimates of the cost of common equity for Florida Public Utilities Company.

Expected market returns for equity markets in the large are captured by the S&P500 Index, measured with the inclusion of dividend payments. The expected value of future returns of course is a key element to the application of the Capital Asset Pricing Model. Plausible measures of expected market returns used in CAPM can be gleaned from timeframes of similar economic performance to that of the period for which the cost of capital is estimated—mid-year 2006 and prior to the run-up in equity markets of the second half of that year. For this timeframe, the CAPM analysis utilizes the experience of U.S. equity markets for the period 1970 forward, which is equal to 13.0% through 2005. Realized market returns, for monthly and annual periods as well as for decades, vary greatly as shown within the table referred to as "Market Inputs: Dividend Yields and Overall Returns". Here, we observe significant differences in return levels experienced by investors across decades. This is also shown within the table entitled "Variation in Yields and Returns" where, as can be seen toward the right, the standard deviation in monthly returns varies greatly—by over 20% during the 1970s and since 1999—the years 2000 and 2002 in particular. This level of variation for equity market returns is not unusual, and demonstrates the order of magnitude of the greater risk assumed by investors in equities in comparison to the inherent risks within debt markets, which are much lower. In short, equity market returns of well above 10% are absolutely necessary in order to compensate investors for the level of risks that they inherently assume. Though drawn from a sufficiently long interval, this level of expected market return is not unusually high; indeed, it is significantly diminished from previous eras including the 1950s, the 1960s, and the 1994 – 1999 period in particular. Stated without reinvested dividends, these decade-long eras reveal overall equity market returns of close to 15%. These timeframes represent periods of overall productivity that approximates, but is arguably somewhat above, expectations of mid-year 2006, when the cost of capital was estimated within the immediate docket, or currently. Not surprising, productivity expectations are somewhat diminished from those of the 1950s, 1960s and the surge of the 1990s continuing into 2003 – 2004. Nonetheless, should expectations of future market returns be somewhat greater, the CAPM analyses understate the cost of capital to Florida Public Utilities Company; conversely, lower expectations imply that the cost of capital is somewhat overstated.

Market Betas for the companies of the two samples are drawn from the 2005-ending experience, as we observe a substantial increase in market Betas for the sample vis-à-vis the average Beta over the previous four years. Notably, the variation of CAPM Beta for the electric utilities of sample 1 is significantly higher than that for the gas utility sample, as demonstrated by the differences between the standard deviation of the sample (referred to "S.D.") for 2005 with respect to the average Beta for 2001 – 2004. Nevertheless, the CAPM Betas for 2005 for the two samples are closely comparable, overall; hence, the CAPM analyses produce similar cost of capital estimates. Specifically, CAPM analyses for the Mid-Sized Electric Utility sample suggest a cost of common equity to Florida Public Utilities Company of 9.6% – 13.3% with a weighted average midpoint of 11.3%, while the corresponding analyses for the Gas Utilities sample obtain 9.4% – 13.2% with a midpoint value also of 11.3%, shown with the inclusion of issuance costs.

As discussed earlier, the *Risk Premium* methodology infers the cost of common equity capital from the premia of realized equity returns with reference to rates of return on debt. The immediate studies rely upon historically observed risk premia for common stocks over that of intermediate term government debt for timeframes that reflect the current outlook for the U.S. economy as regards to advances of productivity and real output. This analysis suggests that the overall market returns prospectively are somewhat less (12.25%) on average across scenarios than the overall market return inputs used with the CAPM analysis.

Of particular interest, these timeframes experienced modest rates of inflation, which is important to the determination of risk premia over forward timeframes. Specifically, risk premia tend to decline as inflation rises. This is because inflation risk—*i.e.*, uncertainty regarding the future level of expected inflation—rises with higher inflation. Unlike equity returns which are somewhat hedged against inflation (higher nominal revenues, operating income, and net income), high inflation implies losses for debt holders. Hence, capital markets capitalize the uncertainty attending higher inflation in higher market costs of debt. Second, high inflation appears to be commensurate with lower returns to equity holders, a result of less favorable economic conditions. Together, risk premia tend to be significantly reduced during periods of relatively high inflation and less favorable economic and business conditions.

The manifestation of inflation risk and business conditions within risk premia between equity and debt is shown on Exhibit 8. The 1950s, 1960s, and 1990s reveal risk premia of 10.6 – 11.7%, with correspondingly inflation of 2.4%. This is in sharp contrast to the U.S. experience of the 1970s and 1980s, with risk premia of 3.0% – 4.3% and corresponding inflation of 5.7% over the period. The main point, for purposes of assessing capital costs prospectively, is that risk premia must be developed from historical timeframes where underlying inflation matches that of the current and prospective period for which rate of return is being determined—2008 forward. Thus, the analyses draw risk premia from the 1950s, 1960s and, where corresponding rates of change in overall prices were experienced. And as discussed above, these historical timeframes match the current outlook fairly well from the perspective of productivity and market returns.

The essential elements of the risk premium analysis includes 1) the risk-free holding period return, 2) the risk premia between equity and debt, and 3) cost rate adjustments for industry and size differences with respect to U.S. equity markets overall. Specifically, the approach adds risk premia to the risk-free holding period return. Consistent with the CAPM analyses, the risk premium analyses use the cost rate for 1-year treasury securities, as expected over the prospective timeframe, as the baseline cost rate. Essentially, the cost rate for 1-year Treasury securities is the basis for the risk-free holding period return.

Debt cost rates are differentiated by term. Thus, the analyses incorporate an upward adjustment for the historical spread between 1-year and 4-year treasuries, as the historical risk premia are based upon realized market returns between equities and intermediate term government debt. Together, the cost rate 1-year Treasuries, the spread between 1- and 4-year Treasury securities, and the historical debt-equity risk premia provide an estimate of the cost of common equity for equity markets as a whole. As shown in the table entitled "Equity Market Return" of pages 1 and 2 of Exhibit 8, the analysis obtains a cost of equity for equity markets of 11.5 – 13.0%, which confirms the historical analysis utilized in the CAPM analyses discussed above.

Further adjustments are necessary in order to fairly assess the cost of equity capital for investors in Florida Public Utilities Company, including 1) a differential for lower market risks of utilities generally, referred to as "diversifiable risks" and 2) the small size premia (small firm effect) referred to as "small cap equities." (Adjustments are shown for small and very small-sized companies.) The effects of these adjustments are shown in the section entitled "Cost Rate Adjustments" of Exhibit 10, pages 1 and 2. The CAPM analysis reviewed earlier is the basis to determine how diversifiable risks associated with samples 1 and 2, including the Mid-Sized Electric Utilities and Gas Utilities respectively, are below those of the composite market (CAPM Betas of 0.75).

As shown, this adjustment lowers the common equity cost rate by -2.2% and -2.5% respectively, for the electric and gas utility samples.

The differential for the small size premia recognizes that the cost of equity is higher for small firms, other factors held constant. Empirically, the Small Firm Effect is the difference between realized market returns and the cost of equity capital, as estimated by CAPM over many years. As shown on page 2 of Exhibit 2, the small size premia can be well over four percentage points for very small-sized companies such as Florida Public Utilities Company. The Risk Premium analysis takes a conservative approach and uses the Low Capitalization Risk Premium, with a plausible range 1.5 – 2.8%. Incorporating these two adjustments into the analysis across the two samples suggests that the cost of equity capital lies within the range of 12.0 – 12.2%. Recognition of issuance expenses associated with incremental shares of common equity provides a Risk Premium cost of capital range of 12.3 – 12.5% for the two samples, with corresponding ranges.

The fourth analysis approach relies upon *Historical Returns* to determine estimates of expectations of future returns harbored by investors. The estimates are drawn from the historical market returns over the late 1996 – 2005 timeframe. This timeframe includes years of exceptionally low and exceptionally high rates of return that, overall, are fairly well balanced. The historical realized returns for the Mid-Sized Electric Utilities are presented on pages 1-3 of Exhibit 9, while realized returns for the Gas Utilities are shown on pages 4-6. For each of the two samples—Mid-Sized Electric Utilities and Gas

Utilities—historical returns are shown in three ways including "Average Returns Per Annum" (1996-2001 – 1996-2005); "Five-Year Returns" for consecutive 5-year periods (1996-2001 – 2000-2005); and "Cumulative Returns" (1996-2001 – 1996-2005). As shown, the results, which are determined on a simple- and weighted-average basis, suggest that investors can expect to realize future rates of return of between 10.1 – 12.5%. Realized historical returns realized by investors conform to the cost of capital estimates obtained by the formal cost of capital models, Discounted Cash Flow, CAPM, and Risk Premium methods.

Q. What conclusions are reached by your analysis and what is your rate of return recommendation?

A. The analysis of the opportunity cost of capital incurred by common shareholders of Florida Public Utilities Company is summarized in Exhibit 2. Exhibit 2 compiles the results of the four analysis methods including the DCF, CAPM, Risk Premium, and Historical Returns approaches. As mentioned earlier, the DCF, CAPM and Historical Returns are estimated for mid-sized companies that, while not large, have much larger market capitalization than Florida Public Utilities Company. The clear implication is that estimates of the cost of equity capital for Florida Public Utilities Company based on these three methods are conservative. As shown on page 2 of Exhibit 2, small size premia for Florida Public Utilities Company are about 2.00 percentage points or somewhat higher.

Mid-point values are shown in this summary, though ranges of values are presented within the exhibits presenting the detailed results for each approach.

The ranges for the cost of equity estimates are based on statistics drawn from the analyses themselves, and could be presented as either larger (wider) or smaller (narrower) ranges of plausible values. The analyses suggest that, for common shareholders of Florida Public Utilities Company to be adequately compensated on the capital committed to public service, and to fully satisfy the statutory requirements defined by the U.S. Supreme Court, the rate of return on common equity must be set at a level equal to 11.5% or higher.

Q. Does this conclude your testimony?

A. It does.

BY MR. HORTON:

Q Mr. Camfield, did you also prepare and prefile supplemental testimony, I believe it was two or three pages?

A I did.

Q And would you have any changes to make to that supplemental testimony?

A No changes.

MR. HORTON: Mr. Chairman, I would ask that Mr. Camfield's supplemental testimony be inserted into the record as though read.

CHAIRMAN CARTER: The supplemental prefiled testimony will be entered into the record as though read.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 070304-EI

SUPPLEMENTAL TESTIMONY
OF
ROBERT J. CAMFIELD

ON BEHALF OF

FLORIDA PUBLIC UTILITIES COMPANY

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Robert J. Camfield, and my business address is 4610 University Avenue, Madison, Wisconsin 53705.

Q. HAVE YOU PREPARED AND PREFILED DIRECT TESTIMONY IN THIS DOCKET?

A. Yes, that is correct.

Q. WHAT IS THE PURPOSE OF THIS SUPPLEMENTAL TESTIMONY?

A. This testimony covers an analysis step that was intended to be incorporated within the analysis and exhibits that accompanied the original testimony. Specifically, the logarithmic trend basis, used to assess historical growth for discounted cash flow analysis, was inadvertently missing. Accordingly, this supplemental testimony is necessary in order to complete the analysis, as stated.

Q. WITH RESPECT TO THE LOGARITHMIC TREND BASED ANALYSIS, YOU ARE CLARIFYING THAT YOU HAD NOT

COMPLETED THAT ANALYSIS WHEN YOUR PREFILED TESTIMONY WAS FILED?

A. Yes, that is correct.

Q. BUT YOU HAVE NOW COMPLETED THAT ANALYSIS?

A. Yes, that is correct.

Q. DOES YOUR ASSESSMENT USING THE LOGARITHMIC TREND-BASED ANALYSIS RESULT IN ANY CHANGES TO YOUR RECOMMENDATION?

A. No, the recommendation does not change. More specifically, the incorporation of the log trend growth estimates within the discounted cash flow ("DCF") analysis decreases the estimate of growth for the sample of comparable risk electric companies from 4.19% to 4.04%, which causes the DCF estimate of the cost of capital to decline from 9.63% to 9.48%. for the comparable risk sample of gas utilities, the inclusion of log trend growth within the DCF cost of equity capital increases estimates of growth from 5.19% to 5.65%, with corresponding changes on the estimates of the equity cost rate—from 9.46% to 9.93%. On balance, the discounted cash flow estimates of the cost of equity rise somewhat. When viewed in the context of the other estimation methods for cost of capital, including capital asset pricing model, historical realized returns, and risk premium, the rate of return on common equity is left unchanged at 11.5%.

Q. DOES THIS CONCLUDE YOUR SUPPLEMENTAL TESTIMONY?

A. Yes, it does.

BY MR. HORTON:

Q Mr. Camfield, did you cause to be prepared, you and Ms. Cox cause to be prepared and attached to your testimony exhibits which have been identified as Exhibits 8 through 23 on the Comprehensive Exhibit List?

A That's correct.

Q And with the exception of the change that you previously identified, do you have any additions or corrections to make to the exhibits?

A No changes.

Q Thank you, sir.

Mr. Camfield, do you have a summary of your testimony to present?

A I do.

Let me say, first of all, Mr. Chairman and Commissioners, Commission staff, and parties to the record that I am pleased to have the chance to appear before you here representing Florida Public Utilities Company on the topics that I mentioned.

As far as the cost of capital is concerned, it's a major element and a major component of all rate case proceedings in the determination, of course, of the ultimate retail prices that retail consumers pay for electric power. And so it is thus very important that the percentage point known as the overall rate of return gets applied to the net invested capital of the company as determined by the governing authority, in this case the Florida Commission. And so it's a pretty important number.

And no doubt the Florida Commission and other regulatory agencies have, I think, fairly well-founded guidance and principles upon which to determine the overall rate of return as well as the return on common equity. These principles are sometimes known as simply the fair rate of return principles, including returns equivalent to investments of comparable risk, maintaining the financial integrity of the utility on the investment that it commits to the convenience and necessity of the public, and then, thirdly, importantly, that a company can raise capital on fair terms when it needs to add to its capital to provide on-going service to retail consumers.

That is only part of the story, of course, because those principles, however well-founded they might be, don't give us a number. We need a specific number in the form of a percentage rate known as the overall rate of return, and for that we must provide some analysis, conduct some analysis, sometimes known as a cost of capital study, and that is what I have done along with my colleague Doreen Cox. And our recommended rate of return is for an 8.07 rate of return. It is based upon a 13-month average capital structure as expected by Florida Public Utilities Company for this year, 2008. It includes long-term debt, short-term debt, preferred stock, common equity, customer deposits, deferred taxes, investment tax credits.

And let me just read off for the record these cost rates. Namely for long-term debt, we have a capitalization share, this is a regulatory capital structure, as we refer to it, of 34 percent with a cost rate of 7.96 percent; short-term debt of 4.43 percent, with a cost rate of 6.81 percent. I will go back to that in a moment. Preferred stock of less than 1 percent, only a small share, with a cost rate of 4.75 percent. Common equity balance as stated on a regulatory capital structure basis is a tad less than 40 percent with a rate of return on equity as we request and my studies suggest of 11.5 percent.

Then for customer deposits we have 6.85 percent. To give you a reference, this might help, it's Exhibit DC-RC-1, Page 1 of 3. And for deferred taxes, because that's a result of tax normalization, they are included in the capital structure at zero cost rate, 14 percent is their share in total capital committed by the company.

ITC has two components, of course, one known as the zero cost component and the other known as the ITC at overall cost. And as I alluded to, my colleague, Ms. Cox, had prepared this exhibit, of a very small amount, less than 1 percentage point, at a 9.67 percentage point. So if you take the capitalization rates times the cost rates you can simply add up the sum product there of an overall cost rate of 8.07 percent.

Now I want to go back to the short-term debt cost rate, because that 6.81 percent value there shown currently is not the company's current proposal in view of the sharp decline that we see in current or contemporary short-term debt cost these days. And our current proposal is to use a value of 4.62 percent -- excuse me, I have that wrong, it is 5.62 percent. And that's a result of our revised analysis.

Mr. Chairman.

CHAIRMAN CARTER: Are you about close to wrapping up your summary? Because I've given you a couple of extra minutes there. I don't know -- Mr. Horton, did you remind the witnesses that there was a five-minute summary --

MR. HORTON: Yes, sir, I did. I would remind him again.

CHAIRMAN CARTER: Thank you.

THE WITNESS: My apologies for taking your time, unnecessarily, perhaps.

Moving on to the common equity rate of return number, the 11.5 percent, I have conducted a study that involves two samples of electric utilities and gas utilities, and these companies are determined on the basis of a selection process that I use and have used in previous analyses. I apply four cost of capital methods to estimate costs of capital for these companies as sample proxy for FPU. And these methods include a capital asset pricing model, discounted cash flow, risk premium methodology, and, then finally, historical market returns. And these four methods provide a range of values that are from less than 10 percent, 9.63 specifically, to a high of 12.2 percent, and those average values overall lead me to the recommendation of 11.5 percentage points.

Thank you, sir.

MR. HORTON: Mr. Chairman, I neglected to ask one question.

BY MR. HORTON:

Q Mr. Camfield, were you also responsible for preparing some of the MFRs which were submitted in support of this case?

A I contributed to some of the MFRs, that's correct.

Q Do you know of any changes that need to be made to those MFRs you prepared?

A No changes at this time.

MR. HORTON: Thank you. And with that, Mr. Chairman, he is available for cross.

CHAIRMAN CARTER: Ms. Christensen, you're recognized.

MS. CHRISTENSEN: Thank you.

CROSS EXAMINATION

BY MS. CHRISTENSEN:

Q Mr. Camfield, referring to Pages 33 and 34 of your direct testimony, specifically on Page 33?

A Yes.

Q On Page 33 you state that the federal fund rate was 5.25 percent, and you indicated that the LIBOR rate was 5.43 percent, which translated to a short-term debit cost rate of 6.33 percent. Is that correct?

A I believe it says translates into a cost rate of 6.33 percent. Yes, I concur.

Q Okay. And, in addition, you also stated at this point in time the apparent consensus view is that the monetary policy and thus the short-term interest rates will hold firm at or near current levels over the foreseeable future, correct? In your testimony that's what you had originally testified to?

A That's correct.

Q Now, you agree, and I think from your summary you agree here today that the short-term interest rates have declined significantly since you made that statement and filed your prefiled testimony, is that correct?

A That's correct.

Q And it is also correct that the Federal Reserve has, indeed, reduced the federal fund rate?

A They have.

Q And would you agree that the current federal fund rate as of this week is 3 percent?

A The fed funds rate currently is 3 percent.

Q And according to your short-term debit cost rate methodology, that would imply a LIBOR rate of 3.18 percent, correct?

A That's correct.

Q And applying further the methodology you used in your prefiled testimony, you would result in a short-term debit cost rate of 4.08 percent, correct?

A May I hear the question again, please?

Q Correct that. Short-term debt cost rate of 4.08 percent?

A I need to look at the analysis that I conducted and provided in response to an interrogatory request on this issue.

Q Okay. Well, let me ask you this.

A It would just take a moment.

Q Sure; certainly.

MR. HORTON: Could we have just a moment to find the response? (Pause.)

THE WITNESS: Thank you for your patience. I am ready to proceed.

BY MS. CHRISTENSEN:

Q Would you like me to repeat the question?

A Please.

Q Okay. Applying the methodology that you used in your direct prefiled testimony utilizing today's current federal fund rate of 3 percent with an implied LIBOR rate of 3.18 percent would result in a short-term debt debit cost rate of 4.08 percent?

A I would need to specifically make the calculation to confirm that.

Q Subject to check, would you agree that that sounds close to what you would expect the result to be?

A If the LIBOR is at 3.18, the company's short-term debt facility provides for 90 basis points above the 3.18 percent, which I think takes us to 4.08 percent. And I believe that is what you are suggesting.

Q That is correct.

A Yes. Now, there are some other fees and so forth associated with a total facility cost that need to be taken into account.

Q Okay. But you would expect it to be somewhere around 4.08 percent, give or take?

A Somewhat above 4.08, that is correct.

Q Okay. Now, referring to your Exhibit DC-RC-2. Let me give you the opportunity to get there, and myself, as well.

Referring to DC-RC-2?

A Yes.

Q And it identifies the different methodologies that you used to reach your recommended common equity rate of return?

A Yes.

Q The discount cash flow method was one of the methods that you used in determining the recommended ROE, is that correct?

A It is.

Q And according to the results of your DCF model, which is shown on this exhibit, the ROE for the electric proxy groups that you used is 9.63 percent, is that correct?

A That is correct.

Q And you utilized a single-stage model to determine that result?

A That is correct.

Q Okay. And for the gas proxy group that you utilized using the single-stage DCF model, your results were 9.46 percent, correct?

A No, I think in the revised exhibit it is higher than that. I think it is 9.96.

Q And that is referring to the supplemental response?

A That is correct.

Q For the gas company only?

A For the gas company only.

Q Okay. Now looking at -- but the revised model was based on -- I think you did, what, a three-stage model for the DCF results in the revised model, or was it still a single stage?

A It was still a single stage. But I think the corrected values for the DCF, this would be the revised values, are 9.48 percent and 9.96 percent, including the issuance cost adjustment of 33 basis points.

Q Okay. So, 9.48 percent then for the electric grouping?

A Yes.

Q Okay. Now, looking at this exhibit, it appears that the DCF model is weighted as just 1/6th of the results that you utilized?

A Well, the range of numbers are provided across the samples and methods as applied to those samples, and I apply equal or give equal weight to each of the methods. Equal weight to each of the four methods.

Q To each of the four methods or did you give equal weighs to -- it looks as though you have six sets of results here. Did you weight those six sets of results equally?

A Well, there are more numbers shown. For example, results for say historical returns than for the other returns. But, I have no analytical basis to give any additional weight to any of the methodologies, so implicitly each methodology gets equal weight.

Q Right. So what are you saying it is one out of four or did you weight it one out of six?

A One out of four.

Q Okay. Now, you used the CAPM risk premium and realized market return results which relied solely on the use of historical stocks and bonds data, is that correct?

A That is correct.

Q And you used analyst EPS or EPS growth rate forecasts in your DCF modeling, is that correct?

A I did not. It is all historically based. Now, in previous testimony I have incorporated analyst expectations and projections of earnings per share in other quantities associated with the cost of capital, but in this case I did not, and that is stated in the testimony.

Q Okay. So you did not include any analyst expectations of growth in your testimony?

A Not in this case, no, in view of where we are within the business cycle.

Q Okay. Well, let's refer to your CAPM approach. Now, you arrived at an equity risk premium in your two CAPM applications using historical stock and bond returns only, is that correct?

A Well, the CAPM pricing model application involves a risk premia between overall market returns for equity markets as a whole and a risk free rate. There is some uncertainty, certainly, regarding experts about which risk free rate proxy ought to be used. In this case I used for the CAPM an intermediate term risk free rate. It is ten-year treasury yields. It builds.

Q Okay. Mr. Camfield, in your CAPM model you used a

equity risk premium of 8.27 percent, is that correct?
A That is correct.
Q And that presumes an expected stock market return of 13 percent, is that correct?
A Yes. And that is observed historically over the period 1970 through 2003.
Q Mr. Camfield, if you know, does FPU use an expected stock market return of 13 percent as an expected stock market return for its pension assets?
A May I hear the question again?
Q If you know, does FPU when it is analyzing its pension asset returns, utilize an expected market return of 13 percent?
A I don't know.
Q Okay. Now, unlike your approach to arrive at the DCF growth rate, am I correct in assuming that you only used historical data to estimate an expected equity risk premium for the CAPM approach?
A That is correct.
Q And I think you stated earlier that you did not use forecasts of stock returns in your approach?
A I did not.
Q Okay. Are you familiar with Doctor Woolridge's testimony?
A Yes.

Q Okay. In developing an equity risk premium for his CAPM, Doctor Woolridge used forecasts of stock returns, is that correct?

A It is my understanding that Professor Woolridge utilizes a combination of historical and forecast market returns.

Q Okay. Mr. Camfield, you are aware, are you not, that there is a quarterly survey of CFOs published by Duke University in CFO Magazine, are you aware of that?

A Yes.

Q And are you aware that in December of 2007, the CFO survey used by Doctor Woolridge, the expected equity risk premium of the CFOs was 4.24 percent?

A Yes.

Q And would you agree, subject to check, that about 500 CFOs participate in that survey?

A I frankly don't know the scope of the survey. I know that it has a fairly large base.

Q Okay. Now, let me return you back to Page 54 of your testimony, and on Lines 14 and 15, you state, "My studies generally rely on a combination of historical experience and analyst projections of cash flow and earnings growth as implicitly contained within the evaluation of investors, including large institutions and individual investors," is that correct?

A It sounds like you have read it right, and it sounds like I would have written it, I just can't seem to find it here. Could you give me --

Q Page 54 of your testimony, Lines 14 through 17.

A Yes, I have it. Uh-huh.

Q Is that a correct summary of your testimony?

A Yes.

Q And is it your testimony today that you did not do that in this case?

A I didn't. I did not rely upon the combination in the context of DCF.

Q Okay.

A Analysts should we say. Just to complete the thought, analyst projections of earnings and dividends per share and so forth as they would be combined with history.

MS. CHRISTENSEN: Okay. I have no further questions of Mr. Camfield on his direct testimony. Thank you.

CHAIRMAN CARTER: I assume by that then he will still be with us for Part II, is that right?

MS. CHRISTENSEN: Yes. Since we are taking up direct and rebuttal at two different times, I have broken my questions out into two different lines. Thank you.

CHAIRMAN CARTER: Commissioners? No questions.

Ms. Brown, you are recognized.

MS. BROWN: Staff has no questions.

CHAIRMAN CARTER: Mr. Horton.

MR. HORTON: I have no redirect. Thank you.

CHAIRMAN CARTER: Let's deal with the exhibits.

MR. HORTON: I would move Exhibits 8 through 23.

CHAIRMAN CARTER: Any objections?

MS. CHRISTENSEN: No objections.

CHAIRMAN CARTER: Hearing none, show it done, Exhibits 8 through 23. Okay.

(Exhibits 8 through 23 admitted into evidence.)

MR. HORTON: And Mr. Camfield may be temporarily excused.

CHAIRMAN CARTER: Temporarily excused.

MR. HORTON: Thank you, sir. And I believe I would call Mr. Cutshaw and Mr. Myers.

CHAIRMAN CARTER: Okay. So this is another panel?

MR. HORTON: Yes, sir, it is.

CHAIRMAN CARTER: All right. This panel will actually be two people, right?

MR. HORTON: I'm sorry?

CHAIRMAN CARTER: This panel will actually be two people, right?

MR. HORTON: Yes, sir.

CHAIRMAN CARTER: Good.

MR. HORTON: I don't know if they like to be two people, but, yes.

CHAIRMAN CARTER: Okay. Cutshaw and Myers.

Before go further, Commissioners, if we have any questions that we wanted to ask Mr. Cutshaw before he is back before us, at any time if you would like to do that, that is fitting and proper.

Mr. Horton, you are recognized.

P. MARK CUTSHAW

DON MYERS

were called as witnesses on behalf of Florida Public Utilities Company, and having been duly sworn, testified as follows:

DIRECT EXAMINATION

BY MR. HORTON:

Q Mr. Myers, would you state your name and address for the record?

A (By Witness Myers) My name is Don Myers, 2825 Pennsylvania Avenue, Marianna, Florida.

Q And what is your position with Florida Public Utilities?

A I am the general manager of Northwest Florida.

Q Mr. Myers, as part of this panel, did you prepare and prefile in this docket direct testimony consisting of 21 pages?

A Yes, I did.

Q And do you have any additions or corrections to make to your portion of this testimony at this time?

A No, I don't.

Q And with that if I were to ask you the questions contained in your testimony, would your answers be the same today?

A Yes, they would.

Q Mr. Myers, were you are also responsible for preparing exhibits which have been marked as Exhibit 24?

A Yes.

Q Any change or correction to that part of the exhibit to your knowledge?

A No, no changes.

Q Were you also responsible for preparation of a portion of the MFRs that were presented and filed in this case?

A Yes, I was.

Q And those have been identified as part of Composite Exhibit 4, I believe, is that correct?

A That is correct.

Q Mr. Cutshaw, would you state your name and address for the record, please, sir?

A (By Witness Cutshaw) My name is Mark Cutshaw, 911 South 8th Street, Fernandina Beach, Florida.

Q And what is your position with Florida Public Utilities Company?

A I am the general manager for our Northeast Florida Division.

Q And as part of this panel, were you responsible for preparing and prefiling direct testimony consisting of 21 pages?

A Yes, I was.

Q And do you have any additions or corrections to make to your portion of the testimony at this time?

A Not at this time.

Q Portions of your testimony -- for each of you, portions of your testimony have been stipulated, have they not?

A That is correct.

Q Okay. If I were to ask you the questions contained in your direct testimony, would your answers be the same?

A Yes, they would.

MR. HORTON: Mr. Chairman, at this time I would ask that their prefiled direct testimony be inserted into the record as though read.

CHAIRMAN CARTER: The prefiled testimony will be inserted into the record as though read.

MR. HORTON: Thank you.

DIRECT TESTIMONY
OF
P. MARK CUTSHAW
AND
DON MYERS

IN

FLORIDA PUBLIC UTITITIES COMPANY
DOCKET NO. 70304-EI

IN RE: PETITION OF
FLORIDA PUBLIC UTILITIES COMPANY
FOR AN ELECTRIC RATE INCREASE

Q. Please state your name, affiliation, business address and summarize your professional experience and academic background.

A. Witness Cutshaw: My name is P. Mark Cutshaw. I am the General Manager, Northeast Florida for Florida Public Utilities Company (FPU). My business office address is 911 South 8th Street, Fernandina Beach, Florida 32034. I joined FPUC in May 1991 as Division Manager in the Marianna (Northwest Florida) Division. In January 2006, I moved into my current position of General Manager in our Northeast Florida Division. I graduated from Auburn University in 1982 with a B.S. in Electrical Engineering and began my career with Mississippi Power Company in June 1982. While at Mississippi Power Company I held positions of increasing responsibility that involved budgeting, operations and maintenance activities at different company locations. My work experience at FPUC includes all aspects of budgeting, customer service, operations and maintenance in both the Northeast and Northwest Florida Divisions. In 1993, I participated in the Cost of Service study for the Marianna Division Rate Case Filing and testified during the proceeding. I also participated in the 2003 rate case filing that consolidated the rates for both divisions. I have also been involved with other filings, audits and data requests before the FPSC.

Witness Myers: My name is Don Myers. I am General Manager, Northwest Florida for Florida Public Utilities Company (FPU). My business office is 2825

Pennsylvania Avenue, Marianna, Florida 32447. I joined FPUC in May 1989 as Engineer in the NW Fla. Division. In Dec. 1990, I was promoted to Operations Manager. In October 2006, I was promoted to General Manager, Northwest Florida. My work experience at FPUC includes designing lines to provide customer service, administrative support for the Line Department, operations and outage management and maintenance in the Northwest Florida Division. I have been involved with other filings, audits, and data requests for the FPSC. I graduated from the University of Vermont in 1974 with a B. S. in Electrical Engineering. From June 1974 to September 1976, I worked for GTE Sylvania and in 1979 joined Gulf Power Company as Engineer and later as Substation Engineer. While at GPC, I was involved in Distribution line design and substation equipment testing, operation, and maintenance.

Q. Are you also familiar with the operations and management of the Northeast and Northwest Florida divisions?

A. Yes. As General Managers of both divisions, we are familiar with all aspects of the operations and management. Since the consolidation of the rates during the 2003 proceeding it has become even more critical to share information and attempt to use similar management techniques as much as practical. However, there are some necessary differences based upon the coastal and inland locations of the service areas that have some impact on the operations.

Q. What is the purpose of your testimony in this proceeding?

A. I will cover a number of issues with regard to the FPU application for a general rate increase. First, I will describe the determination of the projected revenue requirement for 2008, the projected revenues for that year and what we expect to be a revenue deficiency if rates remain at their current levels. I will also describe, from an operations perspective, why this increase in rates is necessary at this time. In addition, I am available to answer detailed questions regarding the projected capital and operating cost items as they relate specifically to the division operations. Second, I will describe the derivation of the storm reserve that we are including in the revenue requirement. Third will be a presentation of the interclass revenue allocation proposed for recovery of the 2008 revenue requirement with a description of the cost-of-service study that was conducted to determine these allocations. Fourth, I will describe the changes that will take place regarding the design of rates, i.e. the change in component prices for each class of service and will present the bill impacts that will result from these classes of service.

Derivation of the Projected Revenue Requirement

Q. What is the revenue requirement increase requested by FPU in this proceeding and how is this determined.

A. FPU is requesting a $5,249,895 increase in base and other service rates using a 2008 forecasted test year. The total base and other service revenue requirement for the test year 2008 is $18,979,176 which includes an overall rate of return of 8.07% as shown in Schedule D-1 and described in the written prepared testimony of Doreen Cox and Robert J. Camfield. Base revenues in 2008 using current rates are projected to be $13,027,278. This represents a 39.90% increase in base revenues and a 40.30% increase in overall revenues. Witnesses Martin, Khojasteh and Mesite describe derivation of these numbers in the Accounting Panel testimony submitted as part of this filing.

Q. What are the primary reasons for the projected revenue deficiency?

A. The last increase of FPU base rates became effective in April, 2004 based on the results of Docket No. 030438-EI. During this proceeding the base rates of both divisions were consolidated. Prior to that increase the Northwest Florida division had an increase of base rates on February 10, 1994 in accordance with Order No. PSC-94-0170-FOF-EI and the Northeast Florida Division had an increase of base rates on November 27, 1989 in accordance with Order No. 22224. Factors that have led to the projected revenue deficiency are outlined in the testimony of Cheryl Martin, many of which are outside the scope of control of FPU. Also outlined in her testimony are actions that have occurred to reduce the impact of the projected revenue deficiency. During this time there have been factors such as the inflationary effect on all utility plant replacements, replacement of large capital related plant items, storm hardening initiatives, reliability improvement work, increase in the storm reserve requirements and the decrease in usage by customer resulting from higher rates.

Q. Briefly describe what large capital related plant items that have been or will be replaced?

Since the last rate proceeding, two 20 MVA substation transformers in our Northeast Florida Division failed while in service. One transformer was replaced in 2005 and the second is to be replaced near the end of 2007. Both transformers were installed in 1982 and 1986 and were approximately 73% depreciated. Due to the tremendous load growth in that area, replacement transformers rated at 40 MVA were necessary to provide continued redundancy necessary to ensure reliable electric service. The estimated value of these replacements is estimated at nearly 1.5 million. These transformer replacements along with replacement of nearly depreciated plant, system improvements for reliability and expansion due to customer growth has increased total Electric Net Utility Plant from $34,900,000 for historic year-end 2002 during the last rate proceeding to what is projected to be $44,800,000 as of December 2008. Also included in this filing is a plan to begin replacing all wood transmission poles with concrete poles on our 69 KV transmission system in accordance with the storm hardening requirements for transmission lines. This plan will result in the replacement of all wood structures over a 20 year period with total cost over the period being approximately $7,092,000. In order to accomplish this work, a cost amortization and work schedule has been included in this filing.

Q. Could you briefly describe what storm hardening initiatives are involved and the impact on your operations?

On September 20, 2006, FPU filed a petition for the approval of cost recovery surcharge to recover cost associated with mandatory storm preparedness initiatives and was docketed under Docket No. 060638-EI. This docket remains unresolved at this date. On July 3, 2007, FPU filed its storm hardening plans as required by PSC rules in Docket 070300-EI and that petition and plan have been consolidated with this proceeding. In the initial docket, FPU identified approximately $700,000 in costs associated with implementation of these initiatives. With the plan filed in response to the Commission rules we have identified similar costs and those have been incorporated in the request for rate relief. The majority of the additional costs for the storm hardening plans as we go forward involve the additional costs associated with Commission requirements for increased vegetation management, wood pole inspections, joint use attachment inspections, transmission line inspections and the depreciation associated with the GIS that has been installed in the Northeast Florida Division.

Q. Could you briefly describe what work is being conducted to improve the overall reliability in your operations?

FPU has continued to focus on reliability issues that resulted from vegetation, lighting, animal contacts and other operation problems. Efforts are also underway to begin complying with the storm initiatives, pole inspections and use of the NESC extreme wind loading requirements. However, FPU has encountered increased plant replacement costs and expense related costs that have resulted in a negative impact to the rate of return for recent years. FPU will also continue to improve system design, mapping, facilities management applications and SCADA systems to assist in improving and measuring system reliability.

Q. Could you briefly describe the quality of service that you provide customers in your service areas?

A. For many years, both divisions have provided reliable and low cost service to the customers within our service territory and have very few customer complaints. FPU has consistently provided some of the lowest electrical rates in Florida. Although exact measurement of service reliability using the current reliability factors has only been used in the last few years, results compare very well to other utilities. All this has been achieved with very few FPSC customer complaints.

Q. Do you have any way in which you measure the quality of service that you offer?

A. We measure our service based on cost, reliability and customer service. As mentioned above, we consistently rank very favorably to other utilities in all areas. This rate proceeding will have a direct effect on both cost and reliability factors. Although cost will increase, FPU will still provide fair electric rates to customers while allowing for continued focus on increasing reliability above current levels. We will also increase our ability to measure these factors more accurately to ensure the reliability data provided is accurate and documented. Indirectly customer service will be improved based on improvement in reliability.

Q. What methods have been used to inform customers of increases in their electric costs?

A. Prior to 2005, rates paid by FPU customers were well below the average rates of other utilities while reliability was good. Based on these factors the necessity of a high level of communications was not necessary. However, the favorable purchased power contracts were nearing the expiration date and the expectation was that significant increases would occur. This required an increased level of communications with customers beginning during 2005 in order to inform them of the increases in cost that should be anticipated. Communications included information in the form of print media, direct letters and bill stuffers. These communications continued into 2006 and 2007 with emphasis on the impact of the fuel increases. The communications will continue into 2007 and 2008 with additional information concerning the annual fuel increases and the base rate increases that are being considered. Customer communications will continue into the future to ensure all customers are informed on electrical costs so that the necessary conservation measures can be implemented to avoid higher prices.

Q. How were projections made for the 2008 test year?

A. Usage, expenses, billing determinants, and revenues were forecasted for 2007 and 2008 using projection factors based on a weather-normalized trend analysis performed by CA Energy Consulting, LLC which is a wholly owned subsidiary of Laurits R. Christensen Associates, Inc. (Christensen Associates) the Company's rate consultant. A discussion of the process used and the resulting projection factors is provided in Schedules F9 – F11. In order to arrive at the company-level growth factors, they developed class-level forecasts of usage per customer and total customers, and then aggregated them up to operating division and total company levels. Sixteen separate analyses were performed to derive these factors. There were separate analyses performed for usage per customer and the number of customers by division by rate class, excluding GSLD-1 and lighting classes. (Therefore, two divisions and four customer classes were modeled, which is 2 x 2 x 4 = 16 separate analyses.) CA Energy Consulting used these values to calculate total usage for each customer class, which is simply the product of usage per customer and the total number of customers. Lighting sales and revenues were projected to increase at the rate of customer growth, and GSLD-1 billing determinants were assumed to remain at 2006 levels. The total usage values are then added across customer classes and then pooled across operating divisions.

Q. Were the recent increases in fuel costs for FPU customers considered in the usage projections?

A. Yes. Customers in the Northeast Florida Division experienced a 35% - 50% increase in their total bill at the beginning of 2007 due to a new purchased power contract with additional increases expected at the beginning of 2008. At the beginning of 2008 the customers in the Northwest Florida will experience similar increases compared to 2006 and other historic levels. Based on the well below average prices seen by FPU customers for many years, these increases will force customers to focus on conservation of electricity as they have never done before.

Based on this, a decrease in overall usage has been anticipated in the usage amounts.

Q What method did you use to adjust projected the billing determinants for the effect of increasing electricity prices?

A. First, the annual percentage bill increase was estimated for 2007 and 2008 for each customer class and division. The quantities used in these calculations were equal to the average kWh (and kW, if applicable) of the customer class. The rates used in creating the estimated bill changes were based on our preliminary estimates of fuel and base price increases for 2007 and 2008. For the Northwest Division, 2008 bill impacts (relative to 2006 bills) ranged from 34.5 percent to 50.0 percent. For the Northeast Division, 2007 bill impacts (relative to 2006) ranged from 15.1 percent to 22.0 percent; and 2008 bill impacts (relative to 2006) ranged from 44.7 percent to 61.9 percent.

Second, we assumed a price elasticity value of -0.20 for each customer class. This value is based on a survey of customer price response studies conducted by Dr. Steven Braithwait for EPRI.[1] Table 2-1 of this study is attached as Exhibit 1. We selected -0.20 as a price elasticity based on the results that appear in the short-run, medium column. Note that this selection is somewhat conservative, as we have failed to include the fact that commercial customers are estimated to have a slightly higher (in absolute value) short-run elasticity (-0.30) and we have not considered long-run price response effects (which result in significantly higher elasticity estimates that can exceed -1.0). The third and final step in deriving the load reduction projections is to multiply the assumed price elasticity value of -0.20 by the estimated bill increase for each rate class and division combination. This method results in load reduction estimates that range from 3 percent to 12.4 percent, depending upon the rate class and year in question.

[1] "Customer Response to Electricity Prices: Information to Support Wholesale Price Forecasting and Market Analysis," EPRI, Palo Alto, CA: 2001.

Q Were the same projected billing determinants for 2008 used throughout your revenue and rate determinations?

A. Yes. The billing determinants for 2008 as shown in Schedules E-18a, b, and c were used for all such determinations under present and proposed rates as well as the proposed rate design. These same billing determinants are the bases used for the cost of service study used to arrive at our proposed interclass revenue allocation.

Q. How were the projected billing determinants used in deriving projected revenues for the 2008 test year?

A. First, revenue verification was performed for the 2006 historical year using actual billing determinants and existing rates to demonstrate that base rate revenue matched our accounting records. Then projected billing determinants were applied to the existing tariffs to derive a base rate revenue projection for the 2008 test year. We added projected revenues from service charges, pole rentals and other miscellaneous sources of revenue to derive an estimate of the total operating revenues for the 2008 test year.

Q. Do the revenues you have computed from the sale of electricity include any revenues for the recovery of purchase power (fuel) and energy conservation expenses (ECCR)?

A. No. The revenues from those two sources are not considered base rate revenue and are excluded from revenue computations in accordance with the Commission's minimum filing requirements. The conservation revenues are determined on a consolidated basis for both the Northeast and Northwest Divisions. However, due to the differences in wholesale power providers in the two divisions, the purchased power adjustments have not yet been consolidated.

Q. How are the test year 2008 operating revenues used in this filing?

A. The projected revenues are a key input used by Ms. Martin in determining the total revenue increase needed for 2008. The projected revenues, by service class, are also a key input in the cost of service study used to determine the proposed interclass revenue allocation – the proposed increase in revenues by class of service.

Q. Do the projected billing determinants accurately reflect the realistic revenues and costs?

A. Yes. The projected billing determinants are reflective of the anticipated usage levels given the significant cost increases that will be included in customer bills. Customers will implement conservation measures in order to reduce overall cost resulting from the continued increase in fuel cost along with the base rate increases.

Derivation of the Required Storm Reserve

Q. Mr. Cutshaw, you are requesting an increase in the annual property damage accrual from the present level of $121,620 to $203,880. What is the basis of the $121,620 annual accrual?

A. The present level of $121,620 was established in the last rate case and has not been increased for many years. The Fernandina Beach annual accrual of $21,620 was authorized in Docket No. 881056-EI (1989) and the Marianna annual accrual of $100,000 was authorized in Docket No. 930400-EI (1994). An increase of these amounts was not approved in our 2003 rate proceeding Docket 074304-EI.

Q. Why is it necessary to increase the annual accrual at this time?

A. The need for additional reserves is apparent when we look at the substantial growth in transmission and distribution facilities since the last FPU rate cases. The State of Florida has been impacted by several storm events that resulted in significant damage to utility infrastructure in the state. The devastation caused the entire state to look seriously at methods of minimizing the impact of these storms in order to reduce overall statewide economic impact. Storm hardening initiatives, increased pole inspections and an emphasis on placing electric infrastructure underground were implemented in order to address this situation. However, it will be several years before the implementation of these measures will have a significant impact on reducing the overall damage. Considering the small service territory and locations, the impact on the two divisions could be extensive.

Q. When will the improvements from the storm hardening initiatives, increased pole inspections and emphasis on underground decrease storm reserves?

A. The storm hardening initiatives, increased pole inspections and emphasis on undergrounding will provide future improvements related to the ability to withstand hurricanes. The initiatives will take from three to eight years to complete and the transmission system hardening as proposed with cover twenty years. Due to the length of time necessary to implement all the improvements and the uncertainty of when a hurricane may impact one of the service territories, the storm reserve should be increased.

Q. What was the impact of hurricanes on FPUC during the 2004 and 2005 storm seasons?

A. During the 2004 and 2005 hurricane seasons, FPU was impacted by seven (7) different hurricanes. Of these hurricanes only three (3) had significant impact on the operations. During September 2004 Hurricane Frances (Northeast and Northwest Florida Divisions) and Hurricane Ivan (Northwest Florida Division) caused considerable damage and outages. The total impact during 2004 to the storm reserve was $805,700 that was necessary to address the damage resulting from these two hurricanes. During 2005, only Hurricane Dennis (Northwest Florida Division) had a major impact on the operations. However, this had no impact to the storm reserve.

Q. How is the Northeast Florida Division (Amelia Island) system affected by storms?

A. Our Northeast Florida Division (Amelia Island) is located on the east coast of Florida at the Florida/Georgia border. Amelia Island consists of approximately thirty five (35) square miles and has an extremely low elevation. Significant storm damage has not occurred on Amelia Island since the 1960's. However, based on the coastal location, should a major hurricane impact the area with winds and an associated storm surge, damage to the area would be extensive and would be comparable damage experienced by other similar areas within the state during the 2004 and 2005 storm seasons.

Q. How is the Northwest Florida Division (Jackson, Calhoun and Liberty Counties) system affected by storms?

A. Our Northwest Florida Division consists of service territories in three counties, all of which are located 40 – 60 miles inland but still within range of wind and tornadoes associated with major hurricanes. Experience during 2004 from Hurricanes Frances and Ivan indicated that the hurricane force winds and the associated tornadoes are possible in this division. Damage from these forces resulted in significant damage and extended customer outages.

Q. How was the determination made regarding the appropriate level of the storm reserve?

A. The current investment in transmission and distribution plant is $66,776,000. Using current accruals, the storm reserve will be funded at $1,707,737 by December 2007. Based upon an estimate that a major storm could realistically result in damage totaling 5% of the transmission and distribution plant investment, a total of $3,338,800 is required.

Q. What does the $3,338,800 represent?

A. This would represent the cost of the worst-case storm striking in our service area that would be charged against the reserve. This should be the amount necessary in the reserve to minimize the impact on rates.

Q. What effect will this reserve amount have on the annual property damage accrual?

A. Presently we are authorized to increase the consolidated electric damage reserve to $2,900,000 (see Docket No. 001146-EI Marianna and Docket No. 001147-EI Fernandina Beach). Our reserve balance is projected to be $1,707,737 as of December 2007. To arrive at a projected reserve balance of $3,338,800 over the next 8 years would require an annual accrual of $203,880. This would increase the monthly accrual from $10,135 to $16,990.

Q. Are there any other accruals made to the storm reserve on an annual basis?

A. Yes. We have the approved annual accrual of 121,620. In previous years any over earnings from the electric operations or unused economic development contributions were accrued to the storm reserve. Since the last rate the only accruals made to the storm reserve were related to the unused economic development contributions. The accruals during 2004 and 2006 were $21,509 and $16,759 respectively.

Q. Mr. Cutshaw, what property insurance does the consolidated electric division presently carry?

A. We have property insurance on all buildings, yards and contents, vehicles and substations. The annual premiums run approximately $36,000 with a $100,000 deductible per incident. As of December 31, 2006 we had approximately $66.8 million in installed cost of transmission and distribution facilities that were uninsured.

Q. Have you received insurance quotes on your uninsured transmission and distribution facilities?

A. No we have not. Based upon previous quotations from insurance providers, this option has not proven to be feasible and would more prohibitive based on the recent storm history in Florida. During our 2003 rate proceeding, information was provided that indicated coverage with a \$10 million limit with \$1.5 million deductible would have an annual cost of \$1,200,000.

Q. Is it your opinion that with these premium quotes, a self-insurance approach is the route to follow?

A. Yes. At this time it would obviously be cost beneficial to self-insure the distribution and transmission systems. We would also need some assurance from the Commission that any prudent storm damage expense incurred could be recovered through some type of appropriate regulatory action should we be struck by a severe hurricane. The purpose of this regulatory action would be to recover expenses incurred over and above the balance in reserve, replenish the reserve and also enable the company to obtain bank financing to make the necessary repairs.

Interclass Revenue Allocation

Q. What increase in rates are you requesting for each of the classes of customers served by FPU?

A. The total base rate revenue recovered from each of the customer classes (on a consolidated basis) will increase by the following percentages:

Class	Base Rate Increase %
Residential	42.0%
General Service	50.0%
General Service Demand	40.0%

General Service Large Demand	50.0%
General Service Large Demand 1	0.00%
Outdoor Lighting	20.0%
Street Lighting	43.0%

Q. How did FPU determine the increases in revenues by class?

A. Our fundamental ratemaking objective is to apportion revenue recovery responsibility and design rates to reflect, to the maximum extent practicable, the cost of serving each customer and customer class. In order to determine the cost responsibility we used the results of a fully-allocated embedded cost of service study conducted on the consolidated divisions served by FPU as provided in Schedule E1. A comparison of the rates of return by class for present rates is provided in Schedule E3 along with the percentage increase in base rates required for each class to recover the target rate of return. It is a Commission policy that the percentage rate increase for each class must be no more than 1.5 times the system average increase and that no rate receive a decrease in rates. Based on the results of the Cost of Service study, the RS, GS, GSD, GSLD, GSLD1, Outdoor Lighting and Street Lighting rates were determined to match parity percentages, as much as practical, that were determined during the last rate proceeding with an attempt to recover the target return without exceeding this constraint.

Q. Please describe the fully-allocated cost of service study that was used to determine this interclass revenue allocation.

A. The method used to allocate our costs closely follows the long-held ratemaking principles and practices of cost apportionment as specified in the "Electric Utility Cost Allocation Manual" developed by the National Association of Regulatory Utility Commissioners (NARUC) in January 1992. Once the relevant data on rate base and net operating income are compiled, as the Company has done in Schedules A-D, these costs are apportioned to customer classes through a three step process called functionalization, classification, and allocation. I will describe each of these steps.

Functionalization: The costs are identified by the function they perform or, another way of looking at it, the service provided. FPU provides three services: transmission, distribution, and customer services. Since FPU purchases all of its power from a third party and delivers it to the customer, there is no production service provided by the Company.

Classification: The costs identified for each function are classified based on the manner in which costs vary, i.e. costs will change by changes in this component of utility service provided. The three (standard) cost classifications used by FPU are demand related (costs vary by kW load); energy related (costs vary by kWh used); and, customer related (costs that are directly related to the number of customers using the service). Transmission services are treated predominantly as a demand-related cost. Distribution services are separated into demand, energy and customer related. And, customer services are either demand related or customer related.

Allocation: Once the costs are functionalized and classified, they must be allocated to the different customer classes. This is done using allocation factors for each of the cost classification categories. The allocation factors used in the FPU study are listed and described in Schedule E-13. As a summary, transmission costs are allocated according to the coincident peak plus 1/13th demand factor (a weighted combination of contribution to the system peak and the average hourly demand of the class). Distribution demand costs are allocated according to each class' non-coincident peak demands. Customer costs are allocated by the number of customers and by a weighting of the specific customer-related cost, e.g. meter expense.

Q. Please describe the load data used derive the class coincident and non-coincident demands used in the cost of service study.

A. Florida Public Utilities Company is too small to have its own load research program; therefore, we rely on the load research data collected by Gulf Power Company (Gulf Power). Gulf Power Company provided data for 2003 and 2006 which were translated to billing determinants and load-based cost of service allocators for the 2008 test year.

Q. Please describe any special studies performed and how they relate to the allocation methods you described above.

A. In order to allocate certain cost, a study was performed on distribution plant as it related to poles, conductors/conduit/devices, meters, outdoor lights and street lights. The poles and conductors/conduit/devices were evaluated to determine the appropriate contribution to either the primary or secondary distribution systems. Meters were evaluated to determine the appropriate contribution to each rate class. Customer Lights and Street Lights were evaluated to determine the appropriate contribution to the each class. These factors were then used as a basis for allocating cost.

Q. Please describe the results of your cost of service study.

A. The cost of service study was completed in order to achieve parity similar to the last rate proceeding for all rate classes. The initial results were analyzed to ensure that no rate class received an increase greater than a 1.5 times the system average and no rate class received a decrease. Adjustments were made to ensure compliance with these requirements and any difference in the revenue requirement was then allocated back to the other rate classes with each rate adjusted accordingly to provide for the target revenue return. Final percentage increases were shown above.

Rate Design

Q. After you determined the interclass revenue allocation, how did you design rates to achieve the revenue requirement?

A. The results of the cost of service study shown in Schedule E-1 include unitized costs for customer, demand and energy charges within each specified class of service. We use these unitized costs to adjust the pricing components within each class to the maximum degree possible.

Q. Please describe the rate design changes for the Residential Class.

A. The current Residential rate consists of $10.00 per month customer charge with a 1.373¢ per kWh energy charge. To this we applied the percentage increase for the Residential class to derive the proposed rates of $14.00 per month and 1.967¢ per kWh.

Q. Please describe the rate design changes for the General Service Non-Demand Class.

A. The current General Service rate consists of $14.00 per month customer charge with a 1.473¢ per kWh energy charge. To this we applied the percentage increase for the General Service class to derive the proposed rates of $21.00 per month and 2.206¢ per kWh.

Q. Please describe the rate design changes for the General Service Demand Class.

A. The current General Service Demand rate consists of $44.00 per month customer charge with a 0.232¢ per kWh energy charge and $2.48 demand charge. To this we applied the percentage increase for the General Service Demand class to derive the proposed rates of $62.00 per month and 0.323¢ per kWh and $3.47 per kW.

Q. Please describe the rate design changes for the General Service Large Demand Class.

A. The current General Service Large Demand consists of $75.00 per month customer charge with a 0.086¢ per kWh energy charge and $2.89 demand charge. To this we applied the percentage increase for the General Service Large Demand class to derive the proposed rates of $113.00 per month and 0.113¢ per kWh and $4.34 per kW.

Q. Please describe the rate design changes for the General Service Demand - Large 1 Class.

A. The current General Service Large Demand 1 rate consists of $600.00 per month customer charge with a 0.000¢ per kWh energy charge, $1.12 per KW demand charge and $0.24 per KVAR reactive demand charge. To this we applied the percentage increase for the General Service Large Demand 1 class to derive the proposed rates of $600.00 per month and 0.000¢ per kWh, $1.12 per kW demand and $0.24 per KVAR reactive demand. The rates in this class were not changed based on the cost of service study results.

Q. Please describe the rate design changes for the Outdoor Lighting Classes.

A. The current Outdoor Lighting base rates were increased by 20% for all lights and poles. The cost of study results were combined for all Outdoor Lighting types in order to determine the overall increase which was applied to each fixture and pole.

Q. Please describe the rate design changes for the Street Lighting Classes.

A. The current Street Lighting base rates increased by 43% for all lights and poles. The cost of study results were combined for all Street Lighting types in order to determine the overall increase which was applied to each fixture and pole.

Q. Are you proposing any changes to the Transformer Ownership Discount and Standby Service Rates?

The Transformer Ownership Discount is currently set at $0.55 KW demand for customers who own their distributions facilities. Using the billing determinants, we derived a rate of \$0.26 KW demand for GSD and \$0.34 KW demand for GSLD. However, we propose to leave the discount at the current rate of \$0.55 KW demand for both GSD and GSLD. There are currently no customers on the Standby Service Rate and that rate is currently set based on demand requirements. The current rates for customers with less than 500 KW are a \$25.00 customer charge and \$1.89 KW demand charge. The current rates for customers with more than 500 KW are a \$25.00 customer charge and \$0.50 KW demand charge. Using the billing determines the proposed charges for customer with less than 500 KW are a \$25.00 customer charge and \$1.76 KW demand charge and for customers with more than 500 KW a \$25.00 customer charge and \$0.43 KW demand charge.

Q. Are you proposing changes to the service charges in this filing?

A. Yes. The proposed service charges are provided in Schedule E-10. Each service charge was evaluated in order to determine the appropriate cost and revenue requirement for each. Labor cost, transportation cost and overheads were applied to the typical task associated with each service charge. Based on typical costs, service charge amounts were determined for six different tasks.

A service charge for the initial establishment of service was set at \$53.00 as compared to the existing amount of \$44.00. A service charge for making changes to or reestablishing an existing service was set at \$23.00 as compared to the existing amount of \$19.00. A service charge to temporarily disconnect and then reconnect a service due to customer request was set at \$33.00 as compared to the existing amount of \$27.00. A service charge to reconnect a service after a rule violation was set at \$44.00 during normal business hours and \$95.00 after normal business hours as compared to the existing amount of \$37.00 during normal business hours and \$60.00 after normal business hours. A service charge used for connecting a temporary service was set at \$52.00 as compared to the existing amount of \$44.00. A service charge for collection of delinquent accounts in the field was set at \$14.00 as compared to the existing amount of \$11.50.

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

A. Yes it does.

Exhibit 1

Table 2-1: Own-Price Elasticities of Demand for Electricity – Synthesis of Values Reported in the Literature

Private	Short-Run			Long-Run		
	Low	Med	High	Low	Med	High
Residential	-0.05	-0.20	-0.40	-0.30	-0.60	-1.20
Commercial	-0.20	-0.30	-0.70	-0.80	-1.10	-1.30
Industrial	-0.10	-0.20	-0.30	-0.90	-1.20	-1.40

BY MR. HORTON:

Q Mr. Cutshaw, were you also responsible for preparation of what has been identified as Hearing Exhibit 24?

A That is correct.

Q Any change to make to that exhibit?

A No change.

Q And you were also responsible for preparing MFRs as has been identified in Composite Exhibit 4?

A That is correct.

Q Any changes to your knowledge to those MFRs?

A No change.

Q Mr. Cutshaw, do you have a summary of your testimony at this time?

A Yes, I do.

In our direct testimony we address several different areas and issues. We were responsible for the development and the allocation of rates associated with the requested increase plant additions, storm hardening, and storm reserve issues. The overall expenses were determined using 2006 as the historic test year projected forward to 2008, which is the projected test year in this request.

A portion of the additional expense was due to normal inflationary impact on utility plant that has occurred since our last rate proceeding in 2004. Additional increases occurred due to the replacement of two large substation transformers that failed while in service, and the replacement of a distribution substation that had reached the end of its useful life. The total net utility plant has increased approximately 28 percent since the last rate proceeding.

Another portion of the increase is due to the compliance of the storm hardening initiatives, the pole inspection program, and storm hardening projects. During the development of these issues, FPU expressed to staff the willingness to comply with each requirement while also communicating concerns regarding the revenues would be needed to support the additional expense associated with these items. We included the costs associated with these initiatives and remain open to revision of the initiatives to help reduce costs.

The most significant part of these expenses is related to the increased level of the vegetation management program, pole inspection program, transmission line pole inspections, and the transmission pole replacement program. Modifications have since been made to the vegetation management program and transmission pole replacement program that have been acceptable by all parties.

Another major area discussed is the interclass revenue allocation proposed for recovery for the 2008 revenue requirement with a description of the cost of service study that was conducted to determine these allocations. The cost of service study followed the long held ratemaking principles and practices of cost apportionment as specified in the Electric Utility Cost Allocation Manual.

The cost of service study was used as a basis to determine the appropriate rate per class in order to achieve parity similar to those from the last rate proceeding. Overall billing determinants for usage and revenues were forecasted using projection factors based on a weather normalized trend analysis. All rate classes were analyzed based on usage per customer, customer growth, and overall energy costs in order to develop the 2008 usage and revenue requirements.

Mr. Myers will cover the other aspects within his summary.

That concludes my summary.

Q Mr. Myers?

A (By Witness Myers) Yes. The first major area of my testimony involves vegetation management as filed in the MFRs. This item has been stipulated. The second major area of my testimony includes the derivation of storm reserve that we are including in the revenue requirement.

The company included an increase in the annual property damage accrual from $121,620 to $203,880 per year. The increase in accrual would allow the company to have a storm reserve of $3,338,800 in eight years, which will approximate 5 percent of the total plant investment.

The December 2007 storm reserve estimate included in my previous testimony is $1,707,337. The increase in the storm reserve will minimize the impact of storm surcharges that would be necessary to address the damage in the event of a major storm.

The last major item to be discussed is the change that will take place regarding the design of rates which will include the change in component prices for each class of service and the bill impacts that will result from these classes of service. The initial results indicated base rates increasing from 30 to 40 percent for these class rates. These rate classes will experience a total bill impact to customers from 5 to 12 percent upon increases in revenues. The company is also proposing changes in the service charges associated with the tariff and has provided justification for these changes.

That concludes my summary.

MR. HORTON: Mr. Chairman, the panel is available for cross.

CHAIRMAN CARTER: You're recognized.

CROSS EXAMINATION

BY MS. CHRISTENSEN:

Q Good afternoon, Mr. Cutshaw and Mr. Myers. I have questions -- I think I have directed most of my questions to Mr. Cutshaw, but, Mr. Myers, if you are the more appropriate witness, please feel free to address them.

I would like to refer you to Page 10 of your direct panel testimony.

A (By Mr. Cutshaw) Okay.

Q In that question, it was addressed to Mr. Cutshaw, you talk about your current accrual. Would it be correct that your current accrual for storm reserve is $121,620?

A That is correct.

Q And isn't it correct that your current storm reserve accrual has been more than sufficient for your company based on historical levels of storms that have impacted your electric divisions?

A Based on historical experience, that is correct.

Q Okay. If you know, when was the last time that the company incurred storm damage and what amount was charged to the storm reserve?

A I don't know that I have the exact information, but I know in 2004 and 2005 there were some impacts to the storm reserve based on the hurricanes during those years, but the amounts were not significant compared to the storm reserve.

Q Okay. So you would agree that the storm reserve at that time were sufficient to cover those impacts?

A For those particular hurricanes they were sufficient.

Q Okay. Would it be correct that the charges made to the storm reserves that were recorded prior to the implementation of the new requirements of Rule 25-6 and Rule 25-6.0143(1), Florida Administrative Code, that your charges for 2004 were made prior to that rule implementation which went into effect June 11th, 2007?

A I would say that would be correct, then.

Q Okay. And it would be also correct to say that the rule provided that only incremental costs could be recovered through storm reserves, not the total cost incurred?

A I would have to go back and look at all the charges, but I know in some cases the only charges to the storm reserve in 2005 were the incremental costs.

Q Okay. And prior to that there was no requirement that just incremental costs be charged to the storm reserve that you are aware of?

A I'm not aware of any.

Q Okay. So it is possible that any charges made to the storm reserve prior to the 2004 storm season could have been less if you were applying incremental only charges to the storm reserve, correct?

A That is possible, but I would have to verify that.

Q Okay. Now, starting on Page 10, Line 30 of your direct testimony, you state that the storm hardening initiatives were implemented in order to reduce storm damage that was incurred?

A That is correct.

Q Okay. Now, isn't it correct that your filing increased -- would it be correct to say that in your filing for increased costs to customers in the rate case for storm hardening, you have not reflected the impact of any savings that the hardening measures would create?

A In this rate proceeding, based on some uncertainty into exactly what storm hardening initiatives would be included, and the fact that even though you are doing the storm hardening initiatives today, it may be a period of time before those actually have an impact on reducing costs. So, no, we did not include any reductions in cost based on these.

Q Okay. Would you agree that if a storm were to impact either or both of the electric divisions that the allowable storm -- and if the storm damage were to exceed the storm reserves, that the company has several options available to it to recover those incremental costs?

A Yes, we do.

Q And it would be also correct that several of the larger electric utilities in Florida have incurred significant storm damage in excess of their storm reserves in the 2004/2005 storm seasons?

A That is correct.

Q And would you agree that these companies were able to implement storm surcharges to recover the storm losses that were in excess of their storm reserves?

A Yes, they did.

Q Now, isn't it correct that your storm analysis essentially costs of only your calculations of 5 percent of the company's current investment in transmission and distribution plant costs without any other additional costs being included?

A That is correct.

Q And would you agree that this 5 percent equates to $3.3 million?

A I would have to look at the calculation, but that seems correct.

Q Okay, subject to check. Other than your estimate of the cost to repair 5 percent of the damage to your transmission and distribution plant, would it be correct to say you have prepared no other formal studies or documents that reflect the projected risk and levels of storm damage the company might be faced with from future storms?

A That is correct.

Q Looking at Page 12 of your direct testimony, starting at Line 27, you state that the 3.3 million reserve target is based on a worst-case scenario, is that correct?

A Correct.

Q Did you perform any analysis of what the least case or the medium case scenario would cost?

A No, we did not.

Q Now, would it be correct that with the current

$121,620 accrual, that if you received no hurricane damage over the next eight years, that the storm reserve will be increased almost by a million dollars, excluding interest rate?

A That seems correct.

Q And that if you add the $972,960 to the current reserve balance of 1.7 million, that would equate to approximately $2.7 million in the reserve in eight years, would that be correct?

A It seems to be correct.

Q Okay. And using the current investment of $66.8 million in T&D plant and the 2.7 million theoretical reserve would equate to over 4 percent of your T&D plant, is that correct?

A That is correct.

MS. CHRISTENSEN: I have no further questions for Mr. Cutshaw and Mr. Myers on their direct panel testimony.

CHAIRMAN CARTER: Okay. Let's do this.

Commissioners, do you have any questions for this panel at this time? Staff.

MS. BROWN: We have no questions.

CHAIRMAN CARTER: Mr. Horton.

MR. HORTON: I have no redirect.

CHAIRMAN CARTER: Okay. Let's deal with the exhibit.

MR. HORTON: I would move Exhibit 24.

CHAIRMAN CARTER: Any objections? Hearing none, show it done.

(Exhibit 24 admitted into the record.)

MR. HORTON: And I would also move Composite Exhibit 4, which is the MFR.

CHAIRMAN CARTER: Hang on one second. Number 4?

MR. HORTON: Yes, sir. And, Mr. Chairman, I notice that Exhibit 25 appears to be the same as Exhibit 4.

CHAIRMAN CARTER: Hang on one second. Let me get to where you are.

Staff, I think we talked about this as the combination of all of -- is that what we said that was?

MS. BROWN: I think it is a duplicate of what is identified in Exhibit 4, so we can cross it out. I guess we would leave the same numbering, but just cross out that exhibit.

CHAIRMAN CARTER: Okay. So we cross out 4 and substitute it for 25, is that our plan?

MS. BROWN: We could do that.

CHAIRMAN CARTER: Mr. Horton?

MR. HORTON: Either way. They are both the same.

CHAIRMAN CARTER: Ms. Christensen?

MS. CHRISTENSEN: Mr. Chairman.

CHAIRMAN CARTER: Oh. If that's the case, let's throw them both out. Let's keep 4, then, and we will just put a circle around -- we will draw a smiley face around 25.

MR. HORTON: And may the panel be temporarily excused?

CHAIRMAN CARTER: The panel can be temporarily dismissed. You are on recess.

(Exhibit 4 admitted into the record.)

CHAIRMAN CARTER: Your next witness.

MR. HORTON: That concludes the direct presentation of Florida Public Utilities, Mr. Chairman.

CHAIRMAN CARTER: One second.

Ms. Christensen, you're recognized. Call your first witness.

MS. CHRISTENSEN: Office of Public Counsel would like to call Mr. Hugh Larkin to the stand.

CHAIRMAN CARTER: I think Mr. Larkin has already been sworn.

THE WITNESS: I have, Mr. Chairman.

CHAIRMAN CARTER: Excellent.

HUGH LARKIN

was called as a witness on behalf of Office of Public Counsel, and having been duly sworn, testified as follows:

DIRECT EXAMINATION

BY MS. CHRISTENSEN:

Q Good afternoon, Mr. Larkin. Can you please state your name and your business address for the record?

A Yes. My name is Hugh Larkin, Jr. My business address is 15728 Farmington Road, Livonia, Michigan 48154.

Q Now, did you cause to be filed in this case prefiled direct testimony?

A Yes, I have.

Q And do you have any corrections to your prefiled direct testimony?

A There is one typographical error on Page 39, Line 15. The word "or" should be "for". It is at the beginning of the line. Instead of O-R it should be F-O-R.

Q Okay. With that minor correction, if I were to ask you these same questions today, would your answers be the same?

A Yes, they would.

MS. CHRISTENSEN: Okay. I would ask that Mr. Larkin's prefiled testimony be entered into the record as though read.

CHAIRMAN CARTER: The prefiled testimony will be entered into the record as though read.

DIRECT TESTIMONY OF HUGH LARKIN, JR.
ON BEHALF OF THE CITIZENS OF FLORIDA
BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION
FLORIDA PUBLIC UTILITIES COMPANY
DOCKETS NOS. 070304-EI and 070300-EI

I. INTRODUCTION

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

A. My name is Hugh Larkin, Jr. I am a Certified Public Accountant licensed in the States of Michigan and Florida and the senior partner of the firm of Larkin & Associates, PLLC, Certified Public Accountants, with offices at 15728 Farmington Road, Livonia, Michigan 48154.

Q. PLEASE DESCRIBE THE FIRM LARKIN & ASSOCIATES, PLLC.

A. Larkin & Associates, PLLC, is a Certified Public Accounting and Regulatory Consulting Firm. The firm performs independent regulatory consulting primarily for public service/utility commission staffs and consumer interest groups (public counsels, public advocates, consumer counsels, attorneys general, etc.). Larkin & Associates, PLLC, has extensive experience in the utility regulatory field as expert witnesses in over 600 regulatory proceedings including numerous electric, water and sewer, gas and telephone utilities.

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

A. Yes. Over the last 31 years, I have testified before the Florida Public Service Commission in numerous rate cases involving electric utilities.

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

A. Yes. I have attached Appendix I, which is a summary of my regulatory experience and qualifications.

Q. BY WHOM WERE YOU RETAINED, AND WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. Larkin & Associates, PLLC, was retained by the Florida Office of Public Counsel ("OPC") to review the rate increase requested by Florida Public Utilities Company ("Company" or "FPU") for its consolidated electric division. Accordingly, I am appearing on behalf of the Citizens of Florida ("Citizens").

Q. WHAT AREAS WILL YOU BE ADDRESSING IN YOUR TESTIMONY?

A. I will be addressing various rate base and revenue requirement issues. Patricia W. Merchant, with the Florida Office of Public Counsel, will also be addressing rate base and revenue requirement issues, and J. Randall Woolridge will be filing testimony on behalf of the Citizens in the area of cost of capital/rate of return.

Q. WHAT IS THE PURPOSE OF THE ADJUSTMENTS THAT YOU AND OTHER OPC WITNESSES ARE RECOMMENDING?

A. Myself and OPC witnesses Merchant and Woolridge have examined the Company's rate filing. We have found significant overstatements in the areas we are addressing. If these overstatements are not corrected, ratepayers will pay rates in excess of what is necessary for safe and reliable service.

Q. WHO WILL BE SPONSORING THE OPC'S OVERALL REVENUE REQUIREMENT RECOMMENDATION REGARDING FPU?

A. I will be sponsoring the exhibits which incorporate my recommendations and those of Ms. Merchant and Dr. Woolridge. Therefore, I am sponsoring OPC's recommendation regarding revenue requirement.

Q. WHAT IS OPC'S OVERALL RECOMMENDATION REGARDING REVENUE REQUIREMENT?

A. Exhibit ___(HL-1) Schedule A-1 shows the revenue requirement increase that the OPC is recommending. That amount is $1,898,502 and is the result of the combined recommendations of myself, Ms. Merchant and Dr. Woolridge. Our recommended rate base and operating income are shown on Schedule B-1 and C-1, respectively. On Schedule D-1 I have shown Dr. Woolridge's recommended cost rates associated with the capital structure reconciled with our recommended rate base.

II. WORKING CAPITAL

Q. ARE YOU PROPOSING ADJUSTMENTS TO THE COMPANY'S WORKING CAPITAL REQUEST?

A. Yes, I am.

Q. WOULD YOU PLEASE DISCUSS FLORIDA PUBLIC UTILITIES COMPANY'S WORKING CAPITAL REQUEST AND THE ADJUSTMENTS YOU ARE RECOMMENDING?

A. Yes. On Schedule B-17, page 1 of 1, FPU shows its working capital request for the projected year 2007 and the projected test year 2008. The amount of working capital included in rate base upon which the Company's revenue requirement is calculated is the projected 2008 working capital amount. For the most part, this request is based upon the 2006 actual balance sheet amounts, escalated by a factor of inflation times customer growth. FPU's calculation of working capital is overstated in a number of areas.

Q. WOULD YOU PLEASE DISCUSS YOUR ADJUSTMENTS TO WORKING CAPITAL AND WHY SUCH ADJUSTMENTS ARE APPROPRIATE?

A. Yes, I will. Each of my recommended adjustments to the Company's working capital request are presented on Exhibit__(HL-1), Schedule B-2, attached to this testimony. Column (a) on this schedule is FPU's working capital request. Column (b) is my recommended adjustments, which are explained in the following paragraphs. Column (c) is the final amount I am recommending be included in working capital.

Q. WOULD YOU PLEASE DISCUSS EACH ADJUSTMENT YOU ARE RECOMMENDING?

A. Yes, I will. The first adjustment I am recommending is to Other Property and Investments.

<u>Other Property and Investments</u>

Q. WHAT IS THE ADJUSTMENT YOU HAVE MADE?

A. FPU has included an amount of $3,100 in working capital, which is shown in FPU's Balance Sheet under the heading "Other Property and Investments." The total amount is included in an account entitled "Other Special Funds." The $3,100 is an allocation of 31% of a total of $10,000. "Other Properties and Investments" are non-regulated assets and, in general, are not included as investments upon which ratepayers should provide a rate of return. FPU has failed to show that the other special funds investment is related to utility operations and is a required investment for utility services. As such, it should be eliminated from working capital requirements.

Cash

Q. WHAT RECOMMENDATION ARE YOU MAKING REGARDING THE CASH BALANCE FPU HAS REQUESTED?

A. FPU maintains unusually large balances of cash in its bank account. FPU, in the year 2006, allocated $247,509 of approximately $850,000 in average cash balances to the electric operations. In 2007, the total Company average cash balances were approximately $678,000, of which $210,108 was allocated to the electric operations. In the test year 2008, the total Company average cash balance was $227,993, of which $70,678 was allocated to electric operations for working capital requirements. The Commission, in the past, has reduced FPU's request for cash balances in its working capital requirements to a level which is more reasonable given the fact that working capital is designed only to provide the return on those funds necessary for the day-to-day operations of the utility. Since FPU has not shown that the substantial balances it is requesting are necessary for the day-to-day operations of its electric divisions I have adjusted the working cash requirement to $10,000. This reduces working capital by $60,678, which is shown in Column (b) of Exhibit __(HL-1), Schedule B-2.

<u>Special Deposits - Electric</u>

Q. WHAT ADJUSTMENT ARE YOU RECOMMENDING TO ACCOUNT 1340 - SPECIAL DEPOSITS - ELECTRIC?

A. I have eliminated these funds from the working capital requirement. According to his deposition, Mark Cutshaw stated that:

> "... the Company must submit a deposit that equals basically one month's transmission service prior to starting the negotiations on the contract, ..."
>
> ...
>
> "... so at some point, we will get some or all of the deposit back."[1]

Further on the in deposition, Mr. Cutshaw states "they do pay interest", i.e., that interest is paid on the deposits.[2] It is not appropriate for the Company to earn a rate of return on these deposits through working capital when they will either be returned or the Company will be paid interest on the deposit. I have removed the total amount of these deposits of $317,836 on Schedule B-2.

<u>Customer Accounts Receivable</u>

Q. HOW DID THE COMPANY DETERMINE CUSTOMER ACCOUNTS RECEIVABLE

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1 Cutshaw/Myers panel Deposition at p. 61, lines 1-3.

INCLUDED IN WORKING CAPITAL FOR THE PROJECTED TEST YEAR ENDING DECEMBER 31, 2008?

A. It appears that the Company started with the year 2006 and utilized the actual December 31, 2006 accounts receivable balance as the first month in its calculation of the 13-month average for 2007 on Schedule B-3 (line 18), page 1 of 6. It then escalated that amount by approximately 24% and used that balance for each of the twelve subsequent months in the year 2007. The December 31, 2007 projected balance then appears to be escalated by approximately 18.5% in January 2008 and that balance was used for the remainder of the year 2008. The result is that the 13-month average accounts receivable balance for the year 2008 has been escalated from the 13-month average of 2006 by approximately 46.4%. The Company's explanation of the growth between 2007 and 2008, as explained on Schedule B-5 (p. 27, line 14), states "Increase in base rates and fuel costs." In other words, the Company has projected the maximum increase in base rates in addition to whatever fuel rate it had assumed to arrive at the projected 2008 accounts receivable balance.

Q. DO YOU AGREE WITH THE COMPANY'S APPROACH TO DETERMINING THE PROJECTED TEST YEAR ACCOUNTS RECEIVABLE BALANCE TO BE INCLUDED IN WORKING CAPITAL?

A. No, I do not. First of all, the Company has included in the accounts receivable balance

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2 Cutshaw/Myers panel Deposition at p. 61, lines 8-9.

receivables which are not related to the delivery of electric service. These include Account 1420.21 Customer Accounts Receivable Billed, Account 1420.22 Accounts Receivable - Jobbing, Account 1430.1 Accounts Receivable Employees, and Account 1430.2 Accounts Receivable - Miscellaneous. In Exhibit___(HL-1), Schedule B-3 I have shown the amount of receivables included in the Company's 2006 13-month average related to these receivables. These receivables were escalated to the 2008 rate year in the same manner I have previously discussed.

The Company has included for both divisions $206,380 of receivables which relate to jobbing, third-party damages owed to the Company, and other activities, including employee receivables, which are unrelated to the provision of electric service. These are below the line revenues and expenses and should be removed from rate base. Ratepayers should not be required to pay a rate of return on receivable balances associated with non-regulated activities like jobbing or third-party damages. The 13-month average of receivables in the year 2008 of $5,042,458 should be reduced by $206,380, escalated by approximately 46.4% to account for the difference between the 2006 13-month average of accounts receivables and the 2008 13-month average of accounts receivables. The total escalated amount is $302,140 ($206,380 x 1.464 = $302,140).

Q. AFTER REMOVING THE UNREGULATED RECEIVABLES, DO YOU FEEL THAT THE METHODOLOGY USED BY FPU TO PROJECT THE ACCOUNTS RECEIVABLE

BALANCE IS A REASONABLE BASIS FOR PROJECTING FUTURE ACCOUNTS RECEIVABLE BALANCES?

A. No, I do not. The Company has projected Customer Accounts Receivable for the year 2008 by escalating the 2006 balance by approximately 46.4%. This is not the methodology which the Company used to project sales growth. The accounts receivable balance is related to revenues. Historically, the Company's Utility Accounts Receivable has declined in total over the past several years. Exhibit___(HL-1), Schedule B-4 shows the annual average Utility Accounts Receivables from 1998 through the 12-months ended August 2007.

As can be seen from this schedule, the 13-month average accounts receivable has remained relatively constant through 2006, declining from $3,528,591 in 1998 to $3,407,042 for the 12-months ended August 2007. There is no relationship between the Company's projection method and the actual relationship between sales and accounts receivable. Since the level of accounts receivable as a percentage of revenues has declined over time, the use of the most recent historical test year relationship is a more reasonable way to project the accounts receivable balance in 2008. The 12-months ended August 2007 percentage of accounts receivable to revenue was 6.42%. Applying that percentage to the Company's projected revenue for 2008 of $62,488,964 (Schedule C-5, 2008) results in a projected accounts receivable 13-month average balance of $4,011,791. This is an increase from the 2006 balance of $3,237,585 (which excluded other receivables of $206,380) of $774,206. Exhibit ___(HL-1), Schedule B-2, line 6, shows the Company's projected balance to be

$5,042,458 including other accounts receivable estimated at $302,140. Excluding the other accounts receivable, the Company's balance would be $4,740,318. Reducing this balance to my projection would reduce the Company's balance by $728,527. The total reduction in accounts receivable projection would be $1,030,667 ($302,140 other accounts receivable and over projection $728,527 = 1,030,667).

Accumulated Provision for Uncollectibles

Q. HOW SHOULD THE ACCUMULATED PROVISION FOR UNCOLLECTIBLES BE CALCULATED?

A. The historical relationship between Accounts Receivable and the Accumulated Provision for Uncollectibles is shown on Schedule B-5. The accumulated provision for uncollectibles is related to the number of accounts in customer accounts receivable that maybe uncollectible. The historical relationship between customer accounts receivable and the provision for uncollectibles is an indication of what percentage of receivables may become uncollectible. The relationship of uncollectible to receivable had increased until 2001. The relationship declined in 2002 and through 2003. It increased in 2004 and 2005, and declined in 2006. The balances are presented in Exhibit___(HL-1), Schedule B-5.

I have used the average percentage of uncollectibles to accounts receivable for the years 2006 and 13-months ended September 2007 to estimate the provision of the year 2008. The average of those two years is 1.12%. Applying that percentage to customer accounts receivable for 2008 results in an accumulated provision for uncollectibles of $44,731 ($4,011,791 x 1.12% = $44,731). I have adjusted the balance of the accumulated provision for uncollectibles in Account 1440, line 7, Exhibit__(HL-1), Schedule B-2 to $44,462. This is an increase to the amount included by FPU of $7,986.

Prepaid Insurance

Q. DO YOU AGREE WITH THE COMPANY'S ALLOCATION OF PREPAID INSURANCE TO THE ELECTRIC OPERATIONS OF FPU?

A. No, I do not. The Company allocated prepaid insurance based on adjusted gross profit. The electric division of FPU was allocated 31% of prepaid insurance. The prepaid insurance is primarily for premiums associated with liability policies, directors and officers liability insurance and workmans compensation. Allocating these costs based on the electric operations proportion of total adjusted gross profit is not appropriate. These insurance costs are more related to labor costs, i.e., liability insurance and Workmen Compensation. A more appropriate allocation factor would be the electric operations proportion of total payroll. The electric operations payroll is approximately 25% of total Company payroll. Allocating the 2008 test year prepaid insurance of $629,658 by 25% results in electric operations prepaid insurance for Working Capital purposes of $157,415. This results in a reduction of prepaid insurance allocated to Working Capital of $37,779.

Unbilled Revenue

Q. DOES IT APPEAR THAT FPU HAS FOLLOWED THE SAME METHODOLOGY TO PROJECT UNBILLED REVENUE?

A. No, it does not. In response to OPC's First Set of Interrogatories, Interrogatory No. 9, FPU stated that it increased the historical 13-month average of unbilled revenue by 3.4% to project the year ended 2007 and by 3.5% to project the 13-month average for 2008. However, while it appears that the Company increased unbilled revenue by 3.4% for the year 2007, for the year 2008, the Company increased the 13-month average by approximately 23.5%. This appears to be a calculation error. Therefore, I have adjusted the 13-month average to reflect the 3.5% increase which the Company stated it escalated unbilled revenue by for the 13-month average for 2008. This reduces the Company's unbilled revenue in the working capital calculation by $88,808.

Regulatory Asset - Retirement Plan

Q. THE COMPANY HAS USED A DIFFERENT ALLOCATION FACTOR FOR PENSION ASSETS AND PENSION LIABILITIES. ARE THERE CONCERNS WITH THE USE OF DIFFERENT ALLOCATION PERCENTAGES?

A. Yes. There are two concerns. First, the Company allocated 34% of pension assets to electric and only 25% of pension liability to electric. This results in a working capital increase as a result of the different allocations. It is my understanding that FAS 158 requires recording of pension assets and pension liabilities in equal amounts. The Company claims that the non-regulated operations of the Company are treated differently and that the pension asset only represents the regulated portion of the Company. (Martin/Khojasteh/Mesite panel deposition, at pages 49 to 50.) There is no evidence to show that the use of a 34% allocation for pension assets is more appropriate and/or representative of the regulated payroll for electric operations. The Company should be required to provide supporting documentation and calculations for their use of a higher allocation percentage for the regulatory asset. Since that has not been provided, an adjustment to reduce working capital by $119,159 should be made based on a 25% allocation factor.

Q. WHAT IS YOUR SECOND CONCERN REGARDING THE PENSION ASSET ACCRUAL?

A. Under FAS 158 the additional obligation being accrued is to be charged to Other Comprehensive Income (OCI). The exception to that is under FASB 71, which states that a regulated utility can set up a deferred regulatory asset if the regulatory authority provided authority to defer the cost under the presumption that the costs will be recovered from ratepayers. The Company set up the regulatory asset in 2006 prior to receiving approval from the Commission. Instead, the asset was established and approval is being requested (after the fact) in this rate case. (Martin/Khojasteh/Mesite panel deposition, at page 51).

This practice is not consistent with the requirements of FASB 71.

Temporary Services

Q. WHAT ADJUSTMENT ARE YOU PROPOSING TO MAKE REGARDING TEMPORARY SERVICES?

A. The Company has included in working capital an amount which it terms "Temporary Services." The corresponding FERC Uniform System of Accounts (USOA) Account No. 185 is "Temporary Facilities." The definition of temporary facilities in the USOA is as follows:

> **185 Temporary facilities (Major only).**
> This account shall include amounts shown by work orders for plant installed for temporary use in utility service for periods of less than one year. Such work orders shall be charged with the cost of temporary facilities and credited with payments received from customers and net salvage realized on removal of the temporary facilities. Any net credit or debit resulting shall be cleared to account 451, Miscellaneous Service Revenues.

Q. WHAT DOES IT INDICATE WHEN THE TEMPORARY FACILITIES OR TEMPORARY SERVICES BALANCE IS A DEBIT AS OPPOSED TO A CREDIT?

A. This indicates that the Company is not collecting a sufficient amount of money for temporary facilities or services to offset all the costs of providing that service. FPU has indicated in response to OPC's Interrogatory Number 11, the following,

> "The installation and removal costs of temporary services are charged to Account 1850.1. As customers are billed for the temporary services, revenues are charged against 1850.1. Additionally, at December of each year, the previous year's December 31 balance in the account is written-off to miscellaneous service revenue, Account 4000.451."

In every month that I have been able to examine, including the December 31, 2006, balance, the temporary service account had a debit balance. That means that the expenses incurred in providing temporary services exceeded the revenue received from such services. When the debit balance is written-off at the end of the year, December 31, ratepayers will subsidize this service and, in affect, be required to provide a return on services provided at below cost. I am removing the temporary service debit balance from rate base and am also increasing miscellaneous service revenue by the amount written off since ratepayers would be subsidizing this service if this adjustment is not made. I have reduced the working capital requirement for temporary services by $16,961. I have also increased miscellaneous service revenue by $27,150, the debit balance shown in temporary services at December 31, 2007 from Schedule B-3 (2007), page 1 of 6.

<u>Deferred Debits - Rate Case Expense</u>

Q. HOW HAS FPU CALCULATED THE DEFERRED DEBIT ASSOCIATED WITH RATE CASE EXPENSE?

A. The Company has calculated a 13-month average balance assuming that it would incur $622,000 in rate case expense associated with the current docket from the period June 2007 through March 2008. To this balance, it added the unrecovered rate case expense from the prior case of $106,000 at January 1, 2008. FPU then calculated a monthly amortization and calculated the 13-month average balance arriving at a total of $608,236.

Q. WAS THE COMPANY ALLOWED A 13-MONTH AVERAGE BALANCE OF DEFERRED RATE CASE EXPENSE IN THE SETTLEMENT ORDER RELATED TO THE LAST CASE?

A. No, it was not. In PSC-04-0369-AS-EI issued April 6, 2004, FPU was allowed one-half of the total rate case expense as a working capital allowance.

Q. WHY IS IT APPROPRIATE TO ALLOW ONLY HALF OF THE TOTAL RATE CASE EXPENSE AS A WORKING CAPITAL ALLOWANCE?

A. Because the Company will collect the rate case expense amortized monthly over the period of amortization, which is four years, the one-half amount is appropriate. If one were to allow the test year 13-month average balance, the Company would collect a return on the deferred rate case expense for every year subsequent to the test year as if that balance was never repaid. The Commission's approach, which I think is appropriate, is to allow only one-half of the deferred rate case expense as a working capital allowance; thus, the Company will receive a rate of return on half of the rate case expense over the life of the amortization instead of a return on a 13-month average which would over compensate the Company.

Q. MR. MESITE STATES THAT REFLECTING ONE HALF OF THE DEFERRED RATE CASE EXPENSE UNFAIRLY PENALIZES THE COMPANY, IS THAT CORRECT?

A. No, it is not. If the Commission were to reflect 100% of the 2008 deferred rate case expense in working capital, the Company would earn a return on that balance for the entire four-year amortization period. Ratepayers will be paying down the balance each month. On average one-half the balance would be outstanding. The Commission's policy is not a penalty, but fair treatment of both parties.

Q. HOW HAVE YOU CALCULATED THE TOTAL BALANCE OF RATE CASE EXPENSE WHICH WOULD ALLOW ONE-HALF AS A WORKING CAPITAL ALLOWANCE?

A. The Company has requested $622,000 of rate case expense in the current docket. I have removed $100,000 of that expense, which I will explain subsequently when I discuss rate case expense in my testimony. That leaves $522,000 of the Company's request which should be subsequently trued-up to actual. To that amount, I have added the unamortized balance of the prior rate case as of the estimated date that rates in this case will go into effect, which I assume will be in April 2008. The unamortized cost associated with the prior case would be approximately $84,800. Adding the $84,800 to the rate case expense recommended by me of $522,000, I arrive at a total rate case expense balance before rates go into effect of $606,800.

Following the Commission policy of allowing one-half of that as a working capital allowance, I arrive at the working capital allowance of $303,400. This reduces the Company's requested 13-month average balance of rate case expense of $608,236 by $304,836 leaving a balance of $303,400.

<u>Regulatory Treatment of Over and Under Recovery of Fuel and Conservation Costs</u>

Q. HAS FPU REQUESTED CHANGING THE COMMISSION'S LONG STANDING PRACTICE OF EXCLUDING UNDER-RECOVERIES OF FUEL COSTS AND CONSERVATION EXPENSE FROM WORKING CAPITAL REQUIREMENTS WHILE INCLUDING OVER-RECOVERIES OF FUEL COSTS AND CONSERVATION EXPENSE IN WORKING CAPITAL?

A. Yes, it has.

Q. WHAT IS FPU'S REASONING FOR REQUESTING A CHANGE IN THE COMMISSION POLICY RELATED TO OVER AND UNDER-RECOVERIES OF FUEL AND CONSERVATION COSTS?

A. The Company's reasoning is stated by Mr. Mesite on page 11 of the Company's testimony. Mr. Mesite's reasoning is as follows:

> We have included the net over and under recovery of fuel and conservation costs in working capital. Previously, only the over recoveries have been included. This is an unfair burden on the

company and penalizes the Company. The fuel is reviewed as well as the over and under recoveries in a special fuel hearing each year. Only those prudently incurred fuel expenses and appropriate fuel rates are approved. It is unfair to penalize the Company for items outside of their control if an over recovery results from these approved fuel rates. Factors such as sales levels, purchased fuel levels, and fuel costs different from expectations can all contribute to an over recovery; but are not in the direct control of the Company. These same circumstances may apply to conservation whereby the timing of revenues and expenses may deviate from projections. Therefore, the Company should not be penalized by only including over recoveries and not under recoveries in working capital. Although the projected test year includes an under recovery for fuel, this should be allowed in working capital so as to not unfairly penalize the Company.

Q. IS MR. MESITE'S REASONING FOR REQUESTING THE CHANGE IN COMMISSION POLICY CORRECT?

A. No, it is not. The Commission's policy is a well reasoned policy implemented in the 1980s to properly reflect how and who should pay the carrying cost on over and under recoveries of fuel and conservation costs.

The reasoning behind the Commission policy is as follows: first, the revenues and expenses related to fuel and conservation are eliminated from the operating income statement in the base rate case filing because these revenues and expenses are recovered by the Company through a separate mechanism included on customers' bills. These costs are not recovered through base rates and, therefore, they should be eliminated from the income statement so that the costs and revenues associated with fuel and conservation costs are not included and recovered in base rates. The elimination of the income and expense related to these separate recovery mechanisms are appropriate because they are not, and should not, be included in base rates.

However, the over and under recoveries of these costs have to be treated differently in the working capital requirement so that the proper parties, that is, i.e., the ratepayer or the stockholder, receives or pays the proper return on the over or under recovery.

Q. WHY HAS THE COMMISSION HISTORICALLY ELIMINATED UNDER RECOVERIES FROM THE WORKING CAPITAL REQUIREMENT?

A. Under recoveries of fuel and conservation costs are assets to the Company. That is, they are receivables from ratepayers for costs incurred not currently recovered through the adjustment clauses. If these balances are included in working capital, then the Company would receive a rate of return on these assets through the working capital inclusion in rate base and the earning of a rate of return on rate base. The Company receives its rate of return on these assets through the fuel adjustment clause mechanism and the conservation adjustment clause mechanism. Those mechanisms add interest for any under-recovery to the cost which is subsequently billed through those mechanisms to ratepayers. So that if the receivable is included in working capital when base rates are established, then ratepayers would pay a double return on these under recoveries. They would pay once through the working capital requirement and a second time through the cost recovery mechanism as authorized by the Commission. The Commission policy of excluding under-recoveries from working capital is appropriate and allows the Company to only recover a return once through the cost recovery mechanism on these under-recoveries.

Q. MR. MESITE INDICATES THAT IF YOU EXCLUDE THE UNDER-RECOVERIES THEN YOU OUGHT TO ALSO EXCLUDE THE OVER-RECOVERIES WHEN CALCULATING WORKING CAPITAL. IS HIS THEORY CORRECT?

A. No, it is not. First of all, an over-recovery is a liability on the Company's balance sheet. In other words, the Company has collected more in fuel costs and conservation costs through its cost recovery mechanism than it actually incurred in expense on the income statement. Therefore, ratepayers have an amount due back from the Company for this over-recovery. The Company has the use of these funds during the period of time that the over collection has occurred and the period when they are returned to ratepayers. An interest calculation is made on these over recoveries and added to the amount returned to ratepayers through the cost recovery mechanism. However, if that liability is not included in working capital as a reduction of working capital, then the ratepayer is, in effect, paying his own interest to himself, because the working capital would be higher by the amount of funds that the Company actually has in its possession for use for working capital purposes. It is the intention of the mechanism that the stockholders pay the interest to ratepayers and that ratepayers not pay the interest to themselves. The inclusion of the over-recovery in the working capital calculation assures that stockholders pay the interest, and that interest is charged below the line and not recovered from ratepayers. This has been the historical treatment that the Commission has made regarding these two items and why they have historically excluded under-recoveries and included over-recoveries in the working capital requirement. There is no need to change this long-established Commission policy. No facts or circumstances have changed that warrant a re-evaluation. Therefore, I am removing the $1,143,377 related to under-recoveries.

Storm Reserve

Q. THE COMPANY IS ASKING FOR AN INCREASE IN THE ACCRUAL FOR STORM DAMAGE FROM THE CURRENT LEVEL OF $121,620 ANNUALLY TO $203,880 ANNUALLY. DO YOU THINK AN INCREASE IS JUSTIFIED?

A. No. The Company's increase is a 67.6% increase in the accrual for storm reserve. Company witness Cutshaw justifies this increase by stating that the storm reserve should be 5% of the Company's transmission and distribution system, or $3,338,800. He then deducts the reserve at the date the calculation was made and arrives at an unfunded reserve of $1,631,063. He then divides that by eight years to arrive at an annual accrual of $203,883.

Q. IN ITS LAST RATE FILING, DID THE COMPANY USE ESSENTIALLY THE SAME

ARGUMENT TO JUSTIFY AN INCREASE IN THE ACCRUED STORM DAMAGE RESERVE?

A. Yes, it did. Mr. Cutshaw, in that case, also picked a hypothetical total reserve number and then calculated an increase in reserve accrual to reach that amount of project reserves.

Q. DID MR. CUTSHAW PROVIDE ANY OTHER JUSTIFICATION FOR INCREASING THE RESERVE?

A. Yes. Mr. Cutshaw referred to the number of storms that hit Florida in the years 2004 and 2005 as additional justification for increasing the storm reserve.

Q. DOES THAT DATA INDICATE THAT THE STORM RESERVE WAS INADEQUATE TO HANDLE THE LARGE NUMBER OF STORMS WHICH HIT FLORIDA IN THE YEAR 2005 AND 2006?

A. No, it did not. In fact, it indicated that the Company's storm reserve was well above the requirements for the storm costs which were charged against the reserve in the years 2004 and 2005.

Q. HOW MUCH STORM DAMAGE COST HAS THE COMPANY ACTUALLY INCURRED AND CHARGED TO THE STORM RESERVE OVER THE LAST 19 YEARS?

A. In the following referenced schedule, I have shown the actual charges to the storm reserve from the years 1989 through 2007, a 19 year period. There were no charges from 1989 through 1993. Storm costs were only incurred in the years indicated in Exhibit___(HL-1), Schedule B-6.

As can be seen, in the last 19 years (1989 to 2007) there are only three years in which FPU incurred storm damage costs which exceeded $100,000. In the year in which the most storm damage was incurred, the year 2004, there were actually four storms that effected FPU. Two of those storms, Francis and Ivan, affected both the northeast and northwest division, although the dollar amounts were minor in the division farthest away from where the storm struck. FPU's storm reserve balance, at the end of 2005, was $1,506,887 after all 2004 and 2005 storm costs. Clearly, this balance was substantial compared to the highest dollar amount of storm costs incurred in the year 2004 of $810,502. There is no indication that the storm reserve was not sufficient to cover any cost which the Company incurred. To set a theoretical balance and then raise rates to allow that theoretical balance to be recovered from ratepayers when the last 19 years indicates that the maximum amount of storm damage incurred by the Company in any one year was only approximately 37% of the total reserve at the end of the prior year (2003) ($810,502 / $2,200,651 = 36.8%) is not reasonable. Clearly, there is no justification to increase the storm reserve accrual when it is apparent that there is sufficient dollars there to cover whatever storm damage has occurred on a historical basis.

Q. IS IT REASONABLE TO SET STORM DAMAGE ACCRUALS BASED ON A HYPOTHETICAL SCENARIO?

A. In my opinion, it is not. Mr. Cutshaw's assumption that 5% of all transmission and distribution plant should be set aside as a reserve has no historical basis based on the Company's storm damage experience, at least over the last 19 years.

Q. WHAT ADJUSTMENTS HAVE YOU MADE TO THE COMPANY'S FILING TO REDUCE THE STORM ACCRUAL TO THAT PREVIOUSLY APPROVED BY THE COMMISSION?

A. First, the reserve accrual charged to operating expense should be reduced from $203,880 to $121,620, a reduction of $82,260. The storm reserve is used as a reduction of working capital because FPU's storm reserve is not a funded reserve, and therefore, ratepayers must receive a reduction in capital cost on which they pay a return for the funds provided to the Company. The Company has reflected the higher accrual in this reserve.

The 13-month average calculation of storm damage reserve balance is increased by $8,871. This is an increase because the Company has miscalculated the 13-month average. First, the Company has reflected a $50,000 reduction in the storm reserve in September 2007, which does not appear to be a storm related adjustment. There appears to be no storm damage in the year 2007, according to the Company's response to OPC Interrogatory No. 80, Exhibit 80. Additionally, the Company started the calculation with the wrong balance at December 31, 2007. After correcting for these two errors, the 13-month average balance increases. The balance increases because the two errors are larger than the decrease in the accrual. I have increased the storm reserve balance on Schedule B-2 by $8,871.

Interest Accrued - Customer Deposits

Q. HAVE YOU ADJUSTED THE WORKING CAPITAL ALLOWANCE FOR INTEREST ACCRUED - CUSTOMER DEPOSITS?

A. Yes, I have. Comparing what the Company has used for the 13-month average ended December 31, 2008 to the actual 13-month average of Interest Accrued - Customer Deposit at September 30, 2007, it is apparent that the Company's projection methodology results in too low of a interest accrued balance. The 13-month average at September 30, 2007 was $71,025. This is an increase of 8.6% over the 13-month average for the period 13-months ended December 31, 2006. I have escalated the actual 13-month balance for the period ended September 30, 2007 by an additional 8.6% to arrive at the December 31, 2008 balance of $77,133. This is an increase in this accrual of $10,178 over the Company's balance, which I reflect on Schedule B-2, line 35.

Q. WHAT IS YOUR TOTAL RECOMMENDED ADJUSTMENT TO WORKING CAPITAL?

A. As shown on Schedule B-2, line 57, Working Capital should be reduced by $3,150,236 to ($4,460,890).

III. OTHER OPERATING REVENUES

Forfeited Discounts

Q. FPU HAS PROJECTED THAT FORFEITED DISCOUNTS WILL DECREASE FROM THE TEST YEAR ENDED DECEMBER 31, 2006 TO THE TEST YEAR ENDING DECEMBER 31, 2008. DO YOU AGREE WITH THAT PROJECTION?

A. No, I do not. Although the account is labeled "Forfeited Discounts" in the Company's rate case filing, the Company's tariffs and actual accounting system correctly labeled this as a late payment charge. The Company, in this filing, is proposing to actually shorten up the period time that ratepayers have to pay their bills. The revised tariff sheets indicate that the Company wants to change the 20-day grace period from the date of the mailing or other delivery thereof, to the date the bill is generated. This would have the effect of shortening the period of time that ratepayers would have to pay their bill. In addition to this fact, which would increase the amount of service charges, the amount of the ratepayer's bills will also increase. With the implementation of the new purchase power contracts and transmission delivery agreements, rates have increased significantly. Therefore, it is very unlikely that late charge payments will decrease, but in fact, will increase both because of the shortened time period to pay the bill and the larger bills. The Company's tariff sheet states that "The balance of all past due charges for services rendered are subject to a late payment charge of 1.5% or $5.00, which ever is the greater, except the accounts of Federal, State, and local government entities, agencies, and instrumentalities." These entities would be subject to a late payment charge as allowed by law.

The actual late payment charges for the year 2006 were $354,696. I have escalated that amount by 5% for each of the years 2007 and 2008 to arrive at a late payment fee of $391,052. This is an increase over the Company's projected 2008 late payment fees of $342,133 of $48,919. There are at least three factors which will cause the Company's late payment fees to increase. The first is the decrease of the time period for the payment of the bill. The second is the growth in the Company's bill as a result of higher fuel costs and delivery costs of energy. The third is customer growth. I am recommending that late fees be increased by $48,919.

IV. OPERATING AND MAINTENANCE EXPENSE

Rate Case Expense

Q. DO YOU AGREE WITH FPU'S ESTIMATED TOTAL RATE CASE EXPENSE FOR DOCKET NO. 070304-EI?

A. No, I do not. The Company has included costs which should not be recovered from ratepayers as rate case expense.

Q. WOULD YOU PLEASE ENUMERATE THOSE ESTIMATED EXPENSES AND WHY

THEY SHOULD NOT BE INCLUDED IN RATES?

A. The Company has entered into a fixed fee contract with Christensen Associates for $165,000 for rate case preparation. The Company has included an additional $45,000 over and above the fixed fee contract, which it has labeled either "Other Costs" or "Estimate from consultant $165,000 plus estimate for extraordinary cost after filing." The Company should not be allowed to include costs which are over and above the fixed fee contract. The filing was completed and the Company has made that filing. If Christensen Associates goes over the amount agreed upon, then the Company should be responsible for that amount since the rate case analysis was completed and filed on a timely basis.

Q. WHAT OTHER COSTS DO YOU THINK SHOULD BE EXCLUDED FROM RATE CASE EXPENSE?

A. The Company has included $30,000 of costs which it has labeled "extra work by internal auditors due to rate case and tax consultant due to work constraints of rate case." Only those costs which are directly related to the preparation, filing and testimony before the Commission are legitimate rate case expenses. To argue that there are some extraordinary costs incurred by the Company as a result of the filing and that ratepayers are responsible for that cost is egregious. The filing itself was prepared by outside consultants. To argue that the Company's personnel were too busy preparing the rate case that they could not do other work does not justify including costs as rate case expense. I am recommending that the

$30,000 of supposed rate case expense be eliminated from consideration as rate case expense.

Q. WHAT OTHER COSTS DO YOU THINK SHOULD BE ELIMINATED FROM RATE CASE EXPENSE?

A. The Company has included $25,000, which it has labeled "Salaried Overtime Pay for Extraordinary Work Load." First, it makes no sense to have salaried employees if, when they are required to fulfill the obligation of their jobs, they are paid overtime. The preparation and filing of rate cases are normal costs incurred by utilities in the normal course of business. When salaried employees are employed, they are employed with the understanding that their work will be determined by the requirements of the job. They would not be limited to 40 hour work week and that time spent would be based on the requirements of the job. Additionally, the bulk of this filing was prepared by outside consultants. The Company's documentation shows that it has budgeted close to $200,000 in consulting fees from Christensen Associations ($165,000) and Darryl Troy ($30,000). Substantially all of the work load of preparing schedules and analysis was borne by these outside consultants. To now ask ratepayers to pay overtime pay for salaried workers is not justified. I am recommending that the $45,000 of additional costs for Christensen Associates, the $30,000 for internal audit work, and $25,000 for overtime pay be eliminated from consideration as rate case expense. Of course, after the completion of the rate case, the Company should file complete documentation of every cost related to the rate case and an adjustment should be made to true-up estimated costs to actual.

Q. WHAT IS THE ADJUSTMENT TO THE COMPANY'S AMORTIZATION OF RATE CASE EXPENSE THAT YOU ARE RECOMMENDING?

A. I have assumed that the rates associated with Docket No. 070304-EI will go into effect April 1, 2008. The Company will have remaining from the prior rate case approximately $84,811 of rate case expense. I am recommending the removal of $100,000 of costs from the Company's current projection of rate case expense of $622,000. This leaves $522,000 plus the remainder from the prior rate case of $84,811 for a total of $606,811. Amortized over a four-year period, this would be approximately $152,000 in amortization expense. This is $30,000 less than the Company's proposed amortization. I am recommending that the amortization of rate case expense be $152,000 over a four-year period, which reduces the Company's amortization by $30,000.

<u>Other Informational Advertising</u>

Q. FPU HAS INCLUDED IN THE TEST YEAR 2008 $159,543 OF WHAT IS TERMED "OTHER INFORMATIONAL ADVERTISING". WOULD YOU PLEASE DISCUSS THIS CATEGORY OF EXPENSE AND WHETHER THE COMMISSION SHOULD APPROVE EXPENSES OF THIS TYPE?

A. First, let me state the historical experience of FPU in making expenditures for other informational advertising. The Company's expenditures were $1,037, $783 and $261, in 2003, 2004 and 2005, respectively. In the test year 2006, FPU incurred expenses of $121,226. As of year-to-date September 30, 2007. it has incurred $100,476. In actuality, these expenses were incurred through August, as there were no expenditures in the month of September. When asked to explain the Company's requested increase in the test year ended December 31, 2008, the Company stated in its response to Citizens Interrogatory No. 46:

> Beginning in 2006 with the expiration of purchase power contracts and the resulting dramatic increase in fuel costs, the Company saw the need to increase communications to customers to keep customers informed and provide information on methods that could be used to control those costs. This information is also required to be provided in accordance with FPSC rules when customer cost is affected significantly.

FPU was also asked to provide in Citizens Interrogatory No. 102:

> . . . a breakdown all communication expense for each year 2006, 2007 and projected 2008 and include description and amount of each type (by media type) and a statement as to the necessity of each type to be incurred annually. For each type of media, provide the type of communication, the cost of production or printing, how many copies will be produced, the number of times any advertisements will run, how many bill inserts will be used, etc.

The Company stated that the information was not available as requested, but provided an exhibit numbered 102.1 with its response to Interrogatory No. 102. This exhibit listed, among other things, the vendor name, invoice number, invoice date and invoice amount with an explanation of purpose for the expenditure. In almost every instance, the expenditure was

"Advertising of company name and website at an event where a large number of customers attend," or "Advertising and public relations work related to fuel increase."

FPU's responses indicate that it intends to continue with the same type of advertising, providing the same information. Clearly, ratepayers are already aware of the significant fuel increase that occurred in 2006 and continued in 2007. To provide dollars of advertising to state the same message over and over again is not appropriate or reasonable. Ratepayers already know that there has been a significant increase in fuel and the related transmission costs. FPU has not justified continuing this level of expense, let alone increasing the test year 2006 actual expenditures of $121,227 to $159,243. An increase of $38,316.

Unless FPU has a detailed customer information plan that it can present to the Commission which justifies continuing any information program about increased fuel costs, I am recommending that the expense in this account be limited to an average of the actual expenditures over the last five years. That average, including the year 2007 year-to-date, would amount to $44,757. This would reduce the requested 2008 test year other informational advertising expense of $159,543 by $114,786.

<u>Tree Replacement</u>

Q. FPU HAS REQUESTED IN BOTH DIVISIONS A TOTAL OF $31,050 FOR REPLACING CUSTOMER TREES WITH LOW GROWING TREES. WHAT IS YOUR OPINION REGARDING THIS REQUEST?

A. I do not believe the Commission should authorize the Company to spend $31,050 on an annual basis to dig out and replace trees on private property with trees funded by ratepayers. Customers are responsible for planting and keeping trees away from power lines. Additionally, the Company has a program for tree trimming and line clearance, which supposedly keeps trees away from power lines. I do not believe it is ratepayers responsibility to fund the replacement of trees by FPU. I am, therefore, removing the $31,050 of expense requested by FPU.

<u>Inspection and Testing of Substation Equipment</u>

Q. WHAT HAS FPU REQUESTED IN TERMS OF INCREASE IN EXPENSE FOR INSPECTION AND TESTING?

A. FPU incurs two types of inspection and testing expense. The first, which is accounted for in Account 562 - Station Expense, relates to substations which handle transmission line voltage. FPU is asking for an increase in the level of expense for inspection and testing of transmission substations of 154% from a test year amount of $17,124 to a projected test year amount of $43,478.

The other type of inspection and testing which FPU incurs relates to substations in the distribution system. FPU is asking for a 112% increase in this level of expense from the test year December 31, 2006 amount of $47,082 to the projected test year amount for 2008 of

$99,878. FPU, in its response to Interrogatory No. 50, states:

> . . . based upon past equipment performance, the inspection and type of testing of substation equipment <u>may not</u> be adequate and needs to be increased to decrease outages and extend the life of the equipment. (Emphasis added)

Q. HAS FPU PROVIDED A SPECIFIC PLAN WITH DOCUMENTATION OF WHAT IS NECESSARY AND WHY ITS PRIOR PROGRAM NEEDS TO BE INCREASED BY SUCH A DRASTIC AMOUNT?

A. No. FPU provided a one page document, which I have included as Exhibit__(HL-2) which shows the extent of the detail behind FPU's requested increase in station expense.

In addition, FPU has copied pages from a document prepared by InterNational Electric Testing Association, Inc. dated in 2005. This obviously is a generic document and does not pertain specifically to the needs of FPU and what FPU would implement as necessary components of its own inspection and testing program. Unless FPU has a specific program which deals with each individual substation and what is necessary for that particular substation over and above its current inspection and testing program, then generic increases in these categories of expenses which FPU has requested should be disallowed. I have taken the test year December 31, 2006 station expense in Account 562 for is inspection and testing of transmission substations in the amount of $17,124 and escalated that by the compound inflation for 2007 and 2008 to arrive at a test year 2008 amount of $18,323. I have reduced

FPU's projected test year amount by $25,155 ($43,478-18,323). For Account 582 - Station Expense, for the inspection and testing of distribution substations, I have also taken the test year December 31, 2006 amount of $47,082 and escalated it by the compound inflation rate to arrive at the 2008 level of expense of $50,378. This results in a reduction to Account 582 - Station Expense Inspection and Testing of $49,600 ($99,878 - $50,378). FPU has not provided substantiation for these projected increases and they should, therefore, be disallowed.

Economic Development Expense

Q. WHAT AMOUNT HAS FPU INCLUDED FOR ECONOMIC DEVELOPMENT COSTS?

A. FPU is requesting recovery of $15,701 for Economic Development Costs. In its last rate case, FPU was allowed $22,641 Economic Development Costs per calendar year. In any calendar year where the Company spent less than that amount, 95% of the difference between $22,641 and the amount spent was to be credited to its storm damage reserve. FPU refers to Florida Rule 25-6.0426, Recovery of Economic Development Expenses in its response to Interrogatory 52. Florida Rule 25-6.0426 (4) states that:

> At the time of each utility's next rate case and for subsequent rate proceedings enumerated in subsection (6) the Commission will determine the level of sharing of prudent economic development costs and the future treatment of these expenses for surveillance purposes.

Q. DO YOU AGREE WITH THE COMPANY'S PROJECTION FOR THIS EXPENSE?

A. No. FPU is clearly not spending the funds it previously projected to maximize growth within the community. FPU has spent $5,000 in each of the years 2003 through year-to-date 2007, with the exception of 2004, in which it did not spend any money for Economic Development. Thus, FPU should not be allowed to recover more than what it has historically been spending.

Q. WHAT AMOUNT ARE YOU RECOMMENDING FOR ECONOMIC DEVELOPMENT COSTS?

A. I am recommending the Company be allowed to recover $5,000 for Economic Development Expense, which equates to what FPU has spent in each year except 2004.

Q. WHAT ADJUSTMENT IS NEEDED FOR THIS EXPENSE?

A. A reduction of $10,701 should be made to the Company's proposed 2008 test year amount.

<u>Postage Expense</u>

Q. PLEASE EXPLAIN YOUR ADJUSTMENT TO POSTAGE EXPENSE.

A. The Company has projected an increase of $20,100, with $6,030 allocated to the electric division. In the Martin/Khojasteh/Mesite panel deposition at page 38, of the accounting panel, the Company asserted that the increase was based on assumptions of increases in future years based on historical increases, rather than other factors such as increased mailings. The Company also acknowledged it has not received any notification from the post office as to potential future postage increases. Therefore, I am recommending a reduction to Customer Information Expense of $6,030 related to the hypothetical postage increase.

Supervisory Training Expense

Q. WHAT AMOUNT HAS FPU INCLUDED IN THE TEST YEAR FOR SUPERVISORY TRAINING EXPENSE?

A. FPU has projected $21,100, with $5,486 allocated to its electric operations.

Q. HAS THE COMPANY PROVIDED ADEQUATE SUPPORT FOR THIS INCREASE?

A. No. The Company asserted that it has provided supervisory training since 2002, with the exception of 2006 because it did not have time or ability to do so. It trended the 2006 expense to account for the absence of training in that year. FPU's response to Citizens Interrogatory No. 76 states that actual expenditures relating to supervisory training expense for 2007 through September were are $7,350. As the Company has not reached the level of supervisory training it projected for 2007, test year expense should be reduced.

Q. WHAT ADJUSTMENT IS NEEDED TO FOR THIS EXPENSE?

A. Annualizing the current year-to-date expenses amounts to $9,800 ($7,350/9 x 12), with $2,548, or 26% allocated to electric operations. Therefore, Supervisory Training Expense should be reduced by $2,938.

Travel for Compliance Accountant

Q. OPC WITNESS MERCHANT HAS REMOVED THE COMPANY'S REQUEST FOR A NEW POSITION FOR A COMPLIANCE ACCOUNTANT. SHOULD THE TRAVEL ASSOCIATED WITH THAT POSITION ALSO BE REMOVED?

A. Yes. If a new employee has not been hired and Ms. Merchant has determined that one is not necessary, it would not be appropriate to increase travel expenses for a position which will not be filled. I am, therefore, removing $5,200 from Account 921.5.

BDO Seidman Increase

Q. THE COMPANY IS REQUESTING AN INCREASE FOR ITS AUDITORS OF $292,500 IN THE TEST YEAR 2008. DOES THE CALCULATION AND UNDERLYING SUPPORT APPEAR CORRECT?

A. The Company's calculation of the adjustment itself is flawed in several ways. First, it appears that the Company did not reflect the actual audit fees for the year 2006 when it attempted to calculate the increase for 2008. For the test year ended December 31, 2006, the expense on a total Company basis in Account 923.3 for Outside Audit and Accounting was

$447,874. This included amounts paid both to the external auditor BDO Seidman and fees paid to another CPA firm Crowe, Chaizek for internal audit work. Second, the Company did not analyze the year 2006 to determine what fees would be ongoing for Crowe, Chaizek and did not use the proper expense level for its external audit by BDO Seidman. It, therefore, derived an increase in audit fees which is materially overstated.

Q. CAN YOU EXPLAIN FURTHER HOW THIS ERROR WAS MADE?

A. The Company did not originally submit workpapers to OPC's repeated discovery requests. The Company, however, did eventually provide workpapers for this adjustment as a result of a deposition late-filed request. One of the workpapers shows how the Company arrived at the December 31, 2006 audit fees. An examination of this workpaper shows that the Company added two amounts that are labeled "estimated liability (excluding payments) to arrive at an audit fee of $125,000. Thus, the Company has excluded any payments it made during in 2006 for the 2006 audit. This exclusion understated the 2006 audit fees by at least $145,000.

Q. HOW DID FPU CALCULATE THE INCREASED AUDIT FEES FOR 2008?

A. The Company sent an email to its auditor with an estimate of the 2008 audit fees and quarterly review, which totaled $680,000. The auditor replied that the Company's estimate was overstated and that the audit fees including fees for an internal control and financial reporting audit would be $417,500. The auditors email also stated that the internal control and financial report audit for 2008 was needed regardless of whether the Company became accelerated or not. So it appears that the audit fee estimated by the auditor has some options. That is, whether the Company becomes an accelerated filer or not.

The Company took the $417,500 estimated by its auditor, BDO Seidman, and subtracted the understated 2006 audit fees of $125,000 to arrive an increase of $292,500. Of this amount, it allocated 31% to the electric division, or $90,675.

Q. WHAT IS YOUR RECOMMENDATION REGARDING THIS ADJUSTMENT?

A. It is clear that the adjustment is miscalculated. It is also clear that the Company has some options regarding becoming an accelerated filer, if one is to accept what the email states. Additionally, if the internal control and financial reporting audit is conducted by the outside auditor, BDO Seidman, one must question whether the substantial fees paid to Crowe, Chaizek in 2006 of approximately $144,000 would be an ongoing expense to the Company. None of these questions have been answered by the Company in its analysis or in its testimony. I am, therefore, removing the entire adjustment of $90,675 from audit fees until the Company presents a full analysis of the 2006 audit fees of $447,874 and a document explaining what actually would be required in the year 2008.

Uncollectible Accounts

Q. FPU HAS REQUESTED UNCOLLECTIBLE ACCOUNTS EXPENSE OF $216,664. DO YOU AGREE WITH THAT EXPENSE LEVEL?

A. No. On Schedule C-11 of the Company's filing, FPU calculates a bad debt write-off based on projected 2008 revenues exclusive of the impact of the requested increase in rates of $144,563. However, in its filing on Schedule C-7 (2008), p. 1 of 3, in Account 904, Uncollectible Accounts, the Company has requested $216,664. When asked to explain why there is a difference between what it calculated on Schedule C-11 and reflected on Schedule C-7, the Company gave the following answer in Interrogatory No. 115:

> The $144,563 projection of bad debt write-off differs from the $216,664 bad debt expense due to the timing delay between the accrual of the bad debt provision (when the expense is incurred) and the actual write-off of the uncollectible account. We are however expecting a large increase in bad debts due to both our base rate increase and the larger part, the fuel increases.

This explanation makes no sense. Bad debt expense is a result of accruing a potential write-off to expense and then writing off the bad debts against the provision for bad debts when the bad debt actually occurs. It is my opinion that the Company made an error in its calculation and does not want to own up to it. So at a minimum, the expense should be reduced for this clear error.

Q. DO YOU AGREE WITH THE COMPANY'S CALCULATION OF THE 2008 EXPENSE OF $144,563?

A. No, I do not. The Company has not shown that its bad debt write-off percentage of 0.2340% in the year 2008 has any validity or is related in any way to actual experience. It appears to be a percentage that the Company created without a proper analysis of historical write-offs net of recoveries as a percentage of total revenues. On Exhibit ___(HL-1), Schedule C-4, I have shown the Company's calculation from Schedule C-11 for the years 2002 through 2005. I have added the information for the year 2006 and recoveries for each of the years 2002 through 2006. The net write-offs are shown in Column (E). I totaled the net write-offs and divided it by the revenues for the five years to arrive at an average write-off percentage for the last five years of 0.11552%. I have applied this factor to the Company's projected revenues in the year 2008 absent the rate increase of $61,786,961 to arrive at the 2008 bad debt expense of $71,179. This is significantly less than what the Company has in its filing of $216,664. I am recommending an adjustment to the Company's uncollectible accounts expense in Account 905 of $145,485.

Q. IS THERE ANY OTHER ADJUSTMENT THAT SHOULD BE MADE TO REFLECT THE APPROPRIATE UNCOLLECTIBLE FACTOR?

A. Yes, the revenue conversion factor includes a 0.20% uncollectible factor. This should be adjusted to the historical average of 0.1152%. I have done that in calculating the revenue deficiency of the Company.

Revisions to Projection Factors

Q. HOW DID FPU PROJECT THE HISTORIC TEST YEAR OPERATION AND MAINTENANCE EXPENSES?

A. Various projection factors were used. Thirteen accounts were escalated using a payroll projection factor of 5.5% per year, or 11.3% to go from 2006 to 2008 projected. For twelve expense accounts, the Company used an inflation factor based on CPI, which resulted in a factor of 4.6% to go from 2006 to 2008 projected. For thirty-three expense accounts, the Company applied a factor consisting of inflation times customer growth, resulting in a projection rate of 7.0% to go from 2006 to projected 2008. For twenty accounts, FPU applied a factor of 14.1% to go from 2006 to projected 2008 consisting of payroll times customer growth.

Q. FOR EXPENSE ACCOUNTS IN WHICH BOTH PAYROLL AND NON-PAYROLL

COSTS WOULD BE RECORDED, DID THE COMPANY SEPARATE OUT THE PAYROLL AND NON-PAYROLL COSTS PRIOR TO TRENDING?

A. No, it did not. In some other recent Florida regulatory proceedings in which I've participated, the utility separated the accounts between payroll and non-payroll and would apply separate factors. For example, a payroll trend factor would be applied to the payroll related costs in the account while a non-payroll related trend factor would be applied to the non-payroll costs. FPU's application of a payroll factor or combination payroll and customer growth factor to the full balances in certain accounts would result in a higher trending to that account as the payroll factor is considerably higher than the inflation factors used in this case. For example, the Company applied the payroll trend factor to the entire balance of Account 903 - Customer Records and Collection Expense. While this account may include some payroll costs, it is also likely that it contains non-payroll related costs.

Q. DID YOU REVISE THE COMPANY'S ESCALATION ADJUSTMENTS TO SEPARATE THE PAYROLL FROM NON-PAYROLL COSTS IN THE VARIOUS EXPENSE ACCOUNTS.

A. No, I did not. I did not have the information necessary to separate the various expense accounts between payroll and non-payroll costs in order to apply separate trend factors. Thus, for the accounts in which the Company applied a payroll trend factor or payroll times customer growth factor to the entire account balance, the projected 2008 amount would be overstated.

Q. IS THE COMPANY'S USE OF COMBINED TREND RATES APPROPRIATE?

A. No, not in this case. The use of the combined payroll and customer growth trend rate for projecting 2008 costs is not appropriate. The Company applied this combined factor to twenty separate expense accounts, including its FICA expense account (Account 4080.7). The rationale for using a combined rate is that as the number of customers increase, a need for additional employees arises. However, increased productivity and cost savings measures, including the implementation of new technologies and better computer systems, would alleviate the need for additional employees. In addition, the Company is making several specific adjustments in addition to its trending adjustments for new employees it is projecting to add between 2006 and the projected 2008 test year. It is not appropriate to apply a trending rate to factor in employee increases associated with customer growth and also make specific adjustments to add projected additional employees. To do so would result in a double-counting of costs associated with hiring new employees. For the accounts in which the combined payroll and customer growth factor was applied, I recommend that the payroll only factor of 11.3% be used. The adjustment needed to reflect the lowering of the 14.1% factor used by the Company to the 11.3% payroll only factor is calculated on Schedule C-3, page 2 of 3, reducing 2008 expenses by $36,691.

As previously mentioned, the application of the payroll factor to the full 2006 amounts in these accounts likely also results in an overstatement of projected 2008 costs as several of these accounts would include both payroll and non-payroll costs. Consequently, an even larger adjustment to the trending in these accounts may be appropriate.

Q. IS THE USE OF THE COMBINED INFLATION AND CUSTOMER GROWTH TREND RATE APPROPRIATE?

A. I also disagree with the Company's use of the combined inflation and customer growth trend rates. As mentioned above, the Company applied this combined rate of 7.0% to go from 2006 to 2008 projected amounts to thirty-three separate expense accounts. In its filing, the Company did not provide sufficient evidence to justify the application of the combined rate. Customer growth would have little to no impact on many of the accounts to which the Company applied the combined factor. For example, the combined factor was applied to all of the advertising expense accounts, industry association dues and economic development costs. The Company also applied this combined factor to Account 593.1 - Maintenance of Poles/Towers in addition to making a specific adjustment for the amount of line crews projected to be added. This would result in a double-counting of cost increases associated partially with customer growth. The Company has not demonstrated that productivity increases and cost savings resulting from improved technologies would not offset the increase associated with customer growth. In fact, in many cases in which I have participated over the last few years, the number of utility employees has been declining, with the ratio of utility employees to customers declining. In other words, the utilities have been reducing the number of employees despite customer growth.

For the accounts in which the combined inflation and customer growth factor was applied, I recommend that the inflation only factor of 4.6% to go from 2006 to projected 2008 be applied. The adjustment needed to reflect the lowering of the 7.0% factor used by the Company to the 4.6% inflation only factor is calculated on Schedule C-3, page 1 of 3, reducing 2008 expenses by $65,491.

Q. IS THERE ANY ADDITIONAL INFORMATION THE COMMISSION SHOULD CONSIDER WHEN EVALUATING THE COMPANY'S PROPOSED ESCALATION/TREND FACTORS?

A. Yes. Page 3 of Schedule C-3 provides a comparison, by account, of the Company's projected 2007 operation and maintenance expenses contained in the filing to the annualized 2007 actual costs recorded to date. In response to a Citizens' request for Production of Documents (11), the Company provided its trial balance for 2007 through September. On page 3 of Schedule C-3, I annualized the through September amounts. As shown on the schedule, the 2007 annualized actual expense amounts are considerably less than the projected 2007 amounts contained in the filing. On pages 1 and 2 of Schedule C-3, for each account in which I revised the Company's proposed projection/trend factor, I provide the amount by which the 2007 projected amount exceeded the annualized 2007 actual costs.

Q. WHAT IS THE OVERALL IMPACT OF YOUR REVISIONS TO THE COMBINED TREND RATES TO REFLECT PAYROLL ONLY OR INFLATION ONLY RATES?

A. As shown on page 1 of Schedule C-3, projected 2008 operation and maintenance expense should be reduced by $102,182 and taxes other than income should be reduced by $5,802.

Staff Audit Findings

Q. WHAT STAFF AUDIT FINDINGS DO YOU AGREE WITH AND ARE REFLECTING IN YOUR SUMMARY SCHEDULES ON EXHIBIT__(HL-1) SCHEDULE C-2?

A. The OPC agrees that many of Staff's audit findings are appropriate and should be reflected in the revenue requirement calculations. I agree that the following Staff Audit adjustments to operation and maintenance expenses should be reflected:

a. Audit Finding 5- Legal and Mailing. FPU included in account 928, regulatory commission expense, costs paid to Messer, Caparello and Self for costs related to obtaining the new fuel contracts for expanding the territory. The fuel contracts will not be renewed for another ten years, therefore, these costs are not recurring. FPU also included in Account 923.1, Outside Services, postage and printing costs for a letter pertaining to increased electric costs. These Staff adjustments reduce projected

2008 expenses in Account 928 and 923.1 by $35,808 and $6,911, respectively.

b. Audit Finding 6- Miscellaneous Sales Expense-Customer Survey. In 2006 the utility conducted a customer survey and allocated the costs equally between Marianna and Fernandina. The utility plans to conduct surveys in the future, but they will not be as extensive and costly as the one in 2006. Therefore, this also may be a non-recurring expense and $27,397 should be removed from the test year.

c. Audit Finding 7- Economic Development. Account 920.23 includes membership dues to Opportunity Florida. The utility joined this organization for networking and opportunities with other industries. These costs should not be charged to ratepayers; thus, projected 2008 expense should be reduced by $5,351.

d. Audit Finding 8- Maintenance of General Plant. FPU constructed a wall in its Marianna office in March 2006. This should be capitalized in account 114.1010.39, Structures and Improvements, and depreciated, rather than expensed. Therefore, 2008 Account 935, should be reduced by $2,375 and Plant should be increased in 2006 by the average of $1,707. Average accumulated depreciation should be increased by $16 and depreciation expense should be increased by $37.

e. Audit Finding 9- Other Distribution Expense. Account 588.2, included airline expenses for a safety contractor's wife. This account should be reduced by $773 a it should not be charged to ratepayers.

f. Audit Finding 10- Maintenance of Transformers. FPU removed a pad and set a new transformer at the Ritz Carlton Hotel in August of 2006. This should be capitalized in account 11.1010.368, and depreciated, rather than expensed. Therefore, 2008 Account 595.3, should be reduced by $2,738 and Plant should be increased in 2006 by the average of $923. Average accumulated depreciation should be increased by $10 and depreciation expense should be increased by $42.

g. Audit Finding 11- Moving Expenses. FPU paid moving expenses of a deposit on a rental house and two months rent for the new Division Manager. These costs may not be recurring, and $3,835 should be should be removed from the test year.

h. Audit Finding 16- Clearing Accounts. FPU allocated several expenses to its clearing accounts via a payroll entry rather than the regular allocation process. The General Liability, Pension, Medical and 401K clearing accounts should be reduced by $52,628, $88,510, $120,339, and $975, respectively.

On Schedule C-2, I provide a summary of each of the above adjustments, by account. The overall adjustment on this schedule is flowed-through to the summary of adjustments to net operating income on Schedule C-1, page 2.

V. STORM HARDENING EXPENSES

Collaborative Research

Q. IN ITS ORIGINAL FILING, FPU HAS REQUESTED $25,750 FOR TRAVEL AND PURC COSTS IN THE UTILITY COLLABORATIVE RESEARCH PROJECTS. IS THE COMPANY STILL REQUESTING THAT LEVEL OF COSTS?

A. No. In a data response the Company initially revised the cost down to, $5,170 and at deposition, further reduced it to $832. I have adjusted the Company's filing from $25,750 to $832, an adjustment of $24,918.

Post-Storm Data Collection and Review

Q. WOULD YOU PLEASE EXPLAIN WHAT THE COMPANY IS REQUESTING IN THE AREA OF POST-STORM DATA COLLECTION AND REVIEW?

A. The Company has requested that expenses be increased by $27,000 on an annual basis. In response to OPC's Interrogatory No. 59, the Company stated:

> The Company needs to develop a post-storm data collection and forensic review for damage associated with hurricanes in accordance with the storm hardening initiatives which will improve future reliability during these situations.

The Company further states that the $27,000 includes $17,000 of a development of the overall program methodology and that the additional $10,000 is an annualized estimate amount for four days of contractor work per year to perform this work. The Company assumes that on average some type of hurricane will hit one of the two divisions "... almost two times per year." (See, Interrogatory No. 59)

From the Company's explanation, it appears that this work will only take place after a hurricane. The development of the overall program methodology is a one-time cost. The logical conclusion of the Company's explanation is that the entire cost is directly related to storm costs. As such, should be charged to the storm reserve when and if the Company incurs such costs. I have, therefore, removed the entire $27,000 since it will not be an annual recurring expense and it should be charged against storm reserve.

VI. TAXES

Interest Synchronization Adjustment

Q. HAVE YOU CALCULATED AN INTEREST SYNCHRONIZATION ADJUSTMENT?

A. Yes, I have. The OPC's recommended adjustments to rate base and the capital structure impact the amount of interest deduction for tax purposes. OPC's recommended adjustment to income taxes for interest synchronization is shown on Schedule C-5.

Income Taxes

Q. HAVE YOU CALCULATED THE IMPACT OF THE OPC'S RECOMMENDED ADJUSTMENTS TO OPERATING INCOME ON INCOME TAXES?

A. Yes. The impact of the OPC's recommended adjustments to operating income on income tax expense is shown on Schedule C-6. The calculation uses the composite state and federal income tax rate of $37.63%.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

BY MS. CHRISTENSEN:

Q Mr. Larkin, with your prefiled testimony, do you have Exhibits Appendix 1, HL-1, and HL-2 attached to your prefiled testimony?

A I do.

Q And do you have any corrections to those exhibits?

A No.

Q At this time I would ask Mr. Larkin to summarize his testimony, please.

CHAIRMAN CARTER: Absolutely.

A Good afternoon, Commissioners. My testimony primarily deals with two parts of the company's filing. The first part is the working capital calculation which is essentially investments that the company has to make in order to provide service prior to collecting those revenues from ratepayers.

The company has a negative working capital. That means that ratepayers and those that provide services to the company provide those rates and services in an amount that is greater than the company's investment in things like accounts receivable and cash and other requirements.

I analyzed the company's customer accounts receivable and found that in my opinion they are overstated. They include things that ratepayers should not have to pay a rate of return on, such as jobbing costs, third-party damages to the company's system, and receivables from employees, although the receivables from the employees are relatively small.

I have also taken out of working capital -- well, I think this issue might have been settled, but one of the issues that was raised by one of the company's witnesses was the regulatory treatment of over and underrecovery of fuel and conservation costs. As you know, these costs are recovered through separate surcharges on the ratepayers' bills. They are not included in base rates.

When the company underrecovers its investment in fuel costs that asset is recovered from the ratepayer as a surcharge on its fuel bill. Not as part of base rates, but in the fuel bill. And to that underrecovery is added an interest charge. Now, the company says we have added that overrecovery into the working capital, too. That means that they are asking for two recoveries; one through the working capital and another interest recovery through the fuel adjustment clause. And they say, well, that is fair because we ought to either include the underrecoveries and the overrecoveries so that they are treated the same.

But this Commission since the 1980s has found that that is inappropriate. That the overrecoveries have to be included in working capital because to do so would require the ratepayer to pay his own rate of return, and the underrecoveries have to be excluded. I have made adjustments for forfeited discounts, I have made adjustments to the tree replacement program, I have made adjustments to the storm damage request, and adjustments to other items in the company's operating expenses that I feel are inappropriate or overstated.

That concludes my summary.

MS. CHRISTENSEN: Mr. Larkin is tendered for cross examination.

CHAIRMAN CARTER: Thank you.

Mr. Horton.

MR. HORTON: I do. Could I have about 30 seconds here?

CHAIRMAN CARTER: Take your time. I'm sorry, Mr. Hatch, and Ms. Keating, I hope that --

MR. HATCH: No problem. If I needed anything I would have jumped up and screamed.

MR. KONUCH: Same here.

CHAIRMAN CARTER: Good. Thank you.

CROSS EXAMINATION

BY MR. HORTON:

Q Mr. Larkin, it is good to see you again.

A Nice to see you.

Q You identified in your -- you mentioned three items in your summary that you said would not be appropriate for inclusion in working capital. Are those the only three that you are suggesting are not appropriate for inclusion in working capital?

A I didn't catch all of it. What is not appropriate?

Q Well, you identified three accounts, I believe it was, in your summary that you said were not appropriate for inclusion in the working capital. Those are the only three?

A In accounts receivable.

Q In accounts receivable.

A Yes.

Q Those are the only three?

A Yes. Well, things that aren't related to utility service should not be included.

Q Okay.

A And I identified three that I could identify.

Q Okay. In your testimony you address cash for the amount included in working capital, and I believe in your testimony your recommendation is that $10,000 be included in the working capital for the cash requirement for the company, is that correct?

A That is correct.

Q What is the basis for your $10,000?

A It is a token amount, a balance that the company might have to keep in its bank account. But there has been no showing on the part of the company that they need substantial cash balances. That the ratepayer is providing substantial credits, funds ahead of time that will fund all of the working capital requirements that the company has.

Q Have you done any type of analysis of the cash needs for the company?

A Well, we asked the company for their cash needs. We were never provided with any study, any analysis, anything that showed why they keep these substantial balances. They make verbal statements, they make arguments, they make no study, no analysis that shows why they are keeping those large dollar amounts in the bank.

Q But you agree that the company does have a need for a cash balance?

A It has a need for some limited amount of cash.

Q And what is the purpose for having cash on hand, to pay bills?

A Well, to pay bills, but when the ratepayer is providing substantial upfront cash and the company's vendors are giving terms, there is a need for just a small amount of cash so that the bank account has some minimal amount in it.

Q Would you know the total amount of bills that the electric division would have to pay each month?

A Do I know?

Q Uh-huh.

A Not exactly, no.

Q Have you been provided that?

A No.

Q Did you monitor the deposition of the Martin panel deposition in December?

A I have read the deposition, yes.

Q You have read the deposition?

A Yes.

Q And you recall that Ms. Martin testified that the company carries a balance of cash appropriate to meet the immediate needs of the company?

A Carries a balance of cash for what?

Q To meet the immediate needs of the company.

A Yes. And I have already acknowledged that the company has made arguments, but it provided no documentation of why those amounts are so substantial.

Q Do you recall the amount of cash that was allowed in the last rate case for the company in working capital?

A It was a settled amount, but the time before that it was approximately $10,000. My recollection was an amount of about $10,000 in the case before the last settlement.

Q Do you recall what your recommendation was in the last case for this company?

A My recommendation?

Q Yes, sir.

A I don't recall offhand.

Q That would probably be reflected in the position of Public Counsel in that case, would it not?

A It would.

Q Now, if you use a balance sheet approach to calculate working capital, which this Commission does, do they not?

A If you used the balance sheet approach to working capital --

Q Right, and that is the approach this Commission uses, is it not?

A That is what is used, yes, but then you make adjustments to the working capital based on what is necessary.

Q Okay. And if you reduce the cash account, what is the corresponding adjustment that would need to be made in that?

A What is the --

Q If you reduce the cash account --

A Yes.

Q -- isn't there a corresponding adjustment that would be needed to maintain the balance?

A No. In ratemaking we make one-sided adjustments. You reduce things so that they meet the regulatory principles that you are trying to apply. We don't make a reduction to the assets and then make a reduction to the capital structure, or we don't make a reduction to the cash and then make a reduction to the liability. We make one-sided entries and that has always been the case in ratemaking.

Q But the company would still have to make an adjustment in their books, would they not?

A They would have to make an adjustment in their books?

Q Yes, sir.

A They would transfer the cash from cash in checking to cash in investment.

Q Okay. With respect to the accounts receivable, and I believe that is what you were -- that is Page 8 of your testimony, and I believe you have some exhibits with respect to receivables, is that correct?

A Page 8. Yes, I think that is right. I'm there.

Q Okay. Well, that was just a general reference, but you do address the accounts receivable. Have you reviewed the Late-filed Exhibit 16 to the panel deposition in December?

A I don't believe so.

Q In your exhibit to your Schedule B-3, Page 1 of 1, and, I'm sorry, I don't know what that --

A Yes.

Q All right. You show four accounts there that you say are included in the receivables account, correct?

A Yes.

Q All right. Are you aware that Late-filed Exhibit 16 from the deposition indicates that jobbing is not included in accounts receivable as they calculate it?

A I reconciled the company's trial balance to the 2006 year, and that is how I arrived at these numbers. I went to

2006, and I took the 13 month average and I added them up, and I saw that you excluded this time merchandising, but these four accounts were included.

Q What would be in the other accounts receivable employees? Do you know some examples of some things that would be included in that account?

A I think there are things like due from retired employees their portion of medical benefits. There could be shoes purchased through the company, safety equipment purchased through the company.

Q And wouldn't that be repayment to the company of costs that the company had incurred, or the employees's share of their costs for the insurance and other items, would it not?

A I'm not hearing your question.

Q I'm sorry. That account would include payments from retirees or employments representing or reflecting their share of insurance or other costs paid by the company, correct?

A That is correct, but it is minor compared to the other items.

Q On Schedule B-4, which is the next page, you reflect a ten-year average of the accounts receivables, is that correct?

A I show ten years of data, and the relationship of the 13-month average of receivables to the revenues for each year, but they are not averaged down. I mean, the numbers for the ten years are not averaged.

Q Does this exhibit take into account recent midcourse increases or the interim increase?

A Take into account what increases?

Q Are you aware that the company received a midcourse increase last fall, last October, I believe, and also an interim rate increase in November? Are you aware of that?

A Yes. But what this does is get a relationship between receivables and revenues, and then I took the percentage relationship between the receivables and revenues and applied that to the company's 2008 projected revenue, which included any increase in fuel, purchased power, and any interim increase that the company would have reflected in its calculations.

So if you turn to the calculation on Page 10, you will see that I took the average of accounts receivable relationship to revenues for the 12-months ending August 2007, which was 6.24 percent, and they applied it to the percentage of the company's projected revenue for 2008 of 62,488,664, which includes any fuel increase. So it is substantially higher than the 12 months ended August -- well, not substantial. Well, about $9 million higher. So I took into consideration those increases.

Q You would agree that increases like that, like interims and the fuel contracts and others would cause the accounts receivable account to increase, or you would expect it to?

A Yes. In relationship to historical averages, though.

Q Okay. Thank you.

With respect to unbilled revenue?

A Yes.

Q And I believe you address that on Page 13 of your testimony. Just some clarification. Your adjustment is based on the apparent calculation factor of 3.5 percent, or you accept the 3.5 percent number, do you not, adjustment?

A Yes. I think the company miscalculated this.

Q Have you seen the rebuttal testimony from Mr. Mesite, filed by Mr. Mesite where he acknowledges that there was a mistake?

A I acknowledged -- would you repeat the question?

Q Sure.

Have you reviewed the rebuttal testimony filed by Mr. Mesite where he references the mistake? He used a 23.5 percent factor, did he not?

A Is this in his rebuttal testimony?

Q Yes.

A I don't remember reading that.

Q Okay. Would you agree -- if he acknowledges that mistake, would you agree with the 23.5 percent?

A No.

Q Would you agree that there would be an increase to the unbilled revenue as a result of an increase in base rates?

A There would be an increase in unbilled revenue, but it is difficult to tell what that increase would be because it is a factor of the number of days which remain unbilled at the end of the year, or the number of kilowatt hours that weren't billed.

Q Mr. Larkin, with respect to -- well, Mr. Larkin, I'm sure glad we were able to stipulate the issues with respect to FASB 158, because I was not looking forward to discussing that with you. So I thank you for that. But with respect to temporary services --

A Yes.

Q -- temporary services are charged pursuant to a tariff, are they not? Or do you know?

A I think -- I'm not sure that there is a tariff, because you can't tell from the temporary -- maybe the temporary service electric rate is subject to tariff, but the installation of the facilities that allow for temporary services cannot be subject to a tariff because you don't know what has to be installed.

So I would agree that the provision of the electric service is subject to a tariff, the rate for the kilowatt hours itself. But temporary services, in order to provide them you have to run a line, put in poles, put in transformers and whatever other facilities are necessary to provide the temporary services. That is all part of this account which must be collected from the person that is receiving the temporary service and not the ratepayer, and that is why I have taken it out.

Let me give you an example. If a circus comes to Marianna and they park out in a field, and they come to the company and they say we need electric service for three weeks to put on our circus. The company comes out with their trucks and they run poles, and then they run drops and they put in transformers. And all of that cost of installing that facility goes into temporary services. Then they charge the company, the circus company a rate based on the tariff for the electricity. But they also have to collect from that company the cost of installing that material, the cost of taking that material out, and any net cost that is not salvageable, and that is what they are not collecting.

They are asking the ratepayer to pay that cost. So the ratepayer would be better off if there were no temporary services. Then he wouldn't have to pay the $27,000 that has been incorporated in rates in this case.

Q All right. Mr. Larkin, the circus comes to town and the company goes out and does what you suggest. Now, if the installation of that temporary service is a tariffed item, then the company would not be able to charge or collect anything other than what is provided for in their tariff, would they?

A Well, then they should raise the tariff. But in any of case it shouldn't be flowed into these rates. The solution is not to take the difference and charge it to the ratepayer.

Q And your objection in that instance is the fact that the expenses exceed the revenues collected from that?

A That the account is a debit account and that the company states that it closes that debit account to miscellaneous services at the end of each year in December, and that is the basis of the adjustment.

Q What if the reverse is true; what if the revenues exceeded the expenses, would your proposal be different?

A But they don't. But if it did, then there wouldn't be an issue. And then there wouldn't be any working capital requirement because there would be a negative amount and that would be providing working capital reducing the revenue requirement, not increasing it.

Q Let's talk a little bit about rate case expense, if you will. You would agree as a general statement that rate case expense is an expense appropriate for recovery from the customers?

A Interest on underrecovery of fuel.

Q Rate case expense.

A Oh, rate case expense, I'm sorry.

Q Rate case expense. As a general statement --

A Yes.

Q Okay. Now, you are recommending that a portion of rate case expense with Christensen and Associates not be allowed for this rate case, is that correct?

A I am disallowing that portion which is in excess of the fixed fee contract that you entered into with Christensen Associates. The schedule showed a fixed fee contract of $160,000, then it showed another amount, 35,000 in case we go over that. And I am just taking out that fudge factor. I didn't take out the fixed fee contract.

Q In your adjustment you make no analysis of any work that was performed or any additional activities that were required, your adjustment is strictly on the basis it was fixed fee?

A On the information the company provided.

Q And you didn't care whether they may have provided services over and above that that was initially contemplated in the contract?

A Well, then it should have been contemplated and put into the contract. I mean, you don't enter into a fixed fee contract and then put a fudge factor in there over and above that.

Q Do you know what the charge for Christensen and Associates was with respect to this rate case?

A Well, I assume they got up to the entire 160,000.

Q No, I am more interested in what their responsibilities were. I am going to go by memory here, Mr. Larkin, for a second, but I seem to recall in your testimony you made reference to the fact that the case had been filed and presented and that they had worked up to that point.

A Yes.

Q Did they participate -- they participated in this case beyond the preparation and filing of the rate case, have they not?

A I assume that was covered by the contract, fixed fee contract.

Q But you don't know?

A I don't know, but what is the sense of having a fixed fee contract if you are going to run over it?

Q Let me ask it this way. But for the existence of the fixed fee contract, do you think the additional costs incurred by Christensen and Associates would be appropriate for consideration for inclusion as rate case expense?

A I would have to look at the total of what was incurred. The company incurred 160,000 fixed fee contract, another contract for 30,000, which would almost bring the total for the preparation of the rate case up to $200,000. I think that is a substantial amount of money.

Q You are already recommending that expenses associated with internal payments, auditors, and overtime pay not be recognized as rate case expense, correct?

A That's right. Internal auditors -- I'm sorry.

Q No, go ahead.

A Okay. You cannot add to rate case expense and expense you say, well, but for the rate case we incurred this expense over here, because nobody can ever verify that. Nobody could ever, ever, ever determine whether that is true or not. So when you say, well, we were here doing this, so we couldn't do this over here, so we will take this cost over here and we will add it onto the rate case expense. I don't think you can do things like that. Of course, that is up to the Commission. They can review that and agree to that, but I would not suggest that they start down the path where companies start saying, well, here is something over here we did, here is something over here we did. Let's pile it all on and call it rate case expense.

Q Well, you are not suggesting that is what this company has done, are you?

A I don't know that they have done that or not. I mean, it looks like an estimate to me.

Q But you have no reason to think that the company has piled anything in here to call it rate case expense just to bill that?

A Well, I just named one thing, internal audit costs.

Q Mr. Larkin, I believe in your testimony you say that the preparation and filing of -- with respect to employees, that preparation and filing of rate case expense is a normal cost incurred by a utility?

CHAIRMAN CARTER: Excuse me, Mr. Horton. I hate to break in on you. You are about to go into another line of questioning, is that correct?

MR. HORTON: It's similar, but I'm at a breaking point, if that is what you are --

CHAIRMAN CARTER: Yes, sir. I mean, one is to be cognizant of the court reporters, but also, too, I was trying to see if we were at a logical breaking point. It looked like you were shifting gears.

MR. HORTON: I'm fine.

CHAIRMAN CARTER: Not that I'm anal about time, but I'm anal about time.

Commissioners, why don't we just kind of go ahead now, since this is a logical breaking point, and we will return at 2:15. We're on recess.

MR. HORTON: Thank you.

(Recess.)

(Transcript continues in sequence with Volume 3.)

STATE OF FLORIDA)

: CERTIFICATE OF REPORTER

COUNTY OF LEON)

I, JANE FAUROT, RPR, Chief, Hearing Reporter Services Section, FPSC Division of Commission Clerk, do hereby certify that the foregoing proceeding was heard at the time and place herein stated.

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

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

DATED THIS 28th day of February, 2008.

JANE FAUROT, RPR
Official FPSC Hearings Reporter
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