BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

In the Matter of

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

2005 COMPREHENSIVE DEPRECIATION STUDY BY FLORIDA POWER & LIGHT COMPANY. DOCKET NO. 050188-EI

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PROCEEDINGS: HEARING

BEFORE: CHAIRMAN BRAULIO L. BAEZ
COMMISSIONER J. TERRY DEASON
COMMISSIONER RUDOLPH "RUDY" BRADLEY
COMMISSIONER LISA POLAK EDGAR

DATE: Monday, August 22, 2005

TIME: Commenced at 9:55 a.m.

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

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

APPEARANCES: (As heretofore noted.)

I N D E X

WITNESSES

DIRECT TESTIMONY

OF

PATRICIA W. MERCHANT, C.P.A.

On Behalf of the Office of Public Counsel

Before the

Florida Public Service Commission

Docket Nos. 050045-EI & 050188-EI

<u>INTRODUCTION</u>

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Patricia W. Merchant. My business address is Room 812, 111 West Madison Street, Tallahassee Florida, 32399-1400.

Q. BY WHOM ARE YOU EMPLOYED AND WHAT IS YOUR POSITION?

A. I am a Certified Public Accountant licensed in the State of Florida and employed as a Senior Legislative Analyst with the Office of Public Counsel (OPC). I began my employment with OPC in March, 2005.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.

A. In 1981, I received a Bachelor of Science degree with a major in accounting from Florida State University. In that same year, I became employed with the Florida Public Service Commission (PSC) as an auditor in the Division of Auditing and Financial Analysis. In 1983, I joined the PSC's Division of Water and Sewer as an analyst in the Bureau of Accounting. From May 1989 to February 2005, I was a regulatory supervisor in the Division of Water and Wastewater which evolved into the Division of Economic Regulation.

Q. ARE YOU SPONSORING AN EXHIBIT IN THIS CASE?

A. Yes. I am sponsoring an exhibit consisting of 3 documents, PWM-1 through PWM-3, which is attached to my direct testimony.

Q. HAVE YOU PREPARED AN EXHIBIT DESCRIBING YOUR QUALIFICATIONS?

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

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

A. Yes. I have also testified before the Division of Administrative Hearings as an expert witness.

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

A. The purpose of my testimony is to provide an opinion on the proper amount of annual storm damage accrual to be included in base rates. I will also provide testimony on the inclusion of GridFlorida Regional Transmission Organization (RTO) costs to be included in FPL's test year operating income.

STORM DAMAGE ACCRUAL

Q. HAVE YOU REVIEWED THE ANNUAL STORM ACCRUAL REQUESTED BY FPL?

A. Yes. FPL has requested that its annual storm damage accrual be increased from $20.3 million to $120 million. The $120 million is made up of the expected annual uninsured damage estimate of $74.7 million, with the remaining $45.3 million to replenish the reserve for storm damage. FPL

Witness Harris provided testimony regarding the determination of the expected annual damage estimate and the likelihood that the storm reserve will be sufficient for a five-year simulated period. FPL Witness Dewhurst provided testimony about the proper level of the annual storm accrual to be included in base rates and FPL's requested $500 million target reserve level.

Q. WHAT IS THE MAIN POINT THAT YOU BELIEVE THE COMMISSION SHOULD CONSIDER IN PROVIDING FOR RECOVERY OF STORM DAMAGES?

A. The crucial point for determining the storm damage accrual is to find the proper mix of recovery through base rates and other tools so that the storm reserve will be sufficient to provide recovery of a normal level of storm damage while concurrently not providing for unbounded growth in the storm reserve. In addition to base rate recovery, the Commission has a myriad of other tools available to address any insolvency in the reserve. My testimony also addresses the inputs into Mr. Harris' loss analysis, the relationship between base rate recovery and the use of other tools for recovery of storm costs, and the amount of historical storm damage costs that FPL has incurred. After this analysis, I will recommend an amount to be included in base rates for the annual storm accrual.

Q. CAN YOU PROVIDE AN OVERVIEW OF THE COMMISSION'S POLICY ON THE FPL'S STORM ACCRUAL SINCE 1992?

A. Yes. Prior to Hurricane Andrew in 1992, FPL had sufficient insurance to cover its transmission and distribution (T&D) system. After Hurricane Andrew, insurance coverage became inadequate and extremely expensive. As a result, FPL petitioned the Commission for permission to implement a self-insurance mechanism to recover the costs of restoring its T&D system in the event of major storm damage. By Order No. PSC-93-0918-FOF-EI, issued June 17, 1993, in Docket No. 930405-EI, the Commission approved the self-insurance plan and authorized FPL to resume and increase its contribution to the Storm and Property Insurance Reserve Fund by $7.1 million annually, net-of-tax. The Commission also ordered FPL to submit a study to determine the annual amount to contribute to the reserve and declined to authorize the implementation of a Storm Loss Recovery Mechanism that would guarantee 100% recovery of storm expenses from ratepayers, over and above the base rates in effect at the time of implementation.

On October 1, 1993, FPL submitted its study addressing the costs to be charged to the storm reserve. It also estimated that the expected annual damage from storms in 1992 dollars would be $20.3 million and included an analysis of four policies that could be used to determine the method of recovery of storm damages. The four policies are detailed below, with FPL's analysis of benefits:

1) Provide an annual accrual equal to the expected annual loss of $20.3 million, with no additional action taken if losses exceed the storm reserve. This method had the highest risk of intergenerational wealth transfer and storm insolvency.

2) Provide an accrual equal to FPL's expected annual loss of $20.3 million plus allow any additional payments necessary to return the reserve to the target level of $74 million recovered over a 5-year period without changing the annual accrual. This method had the

highest probability of reserve solvency but shifts the burden of future costs to current customers with high positive storm reserve balances.

3) Provide an annual accrual equal to $7.1 million and allow any assessment necessary to return the reserve to the target level of $74 million over a 5-year period without changing the annual accrual. This method was requested by FPL and was based on the consideration of fairness to stockholders as well as ratepayers as that was the current amount included in rates for insurance premiums at that time. This method also lessened the intergenerational inequities associated with the constant reserve growth associated with policy 2.

4) Provide no annual accrual with reserve deficiencies corrected with special assessments sufficient to return the reserve to the target level of $74 million over 5-year. This method was considered "pay-as-you-go" and illustrated that the amount chosen for annual accrual could be relatively arbitrary so long as it is within a range low enough so as not to result in unbounded growth in the storm reserve.

Q. DID THE COMMISSION APPROVE FPL'S STORM DAMAGE STUDY IN DOCKET NO. 930405-EI?

A. Yes. By Order No. PSC-95-0264-FOF-EI, issued February 27, 1995, the Commission approved FPL's storm study but made adjustments to its annual accrual. In analyzing the study, Commission staff agreed with FPL that policies 1 and 2 created intergenerational equity issues and suffered in areas regarding weather forecasting. Regarding Policy 3, Commission staff believed that special assessments put the burden of self-insurance on FPL's customers because the accrual was only 35% of the expected storm damages.

Staff believed that both FPL and its customers would be better insured if the annual accrual were increased and the reserve allowed to grow, which in turn would decrease the likelihood of implementing special assessments for material storm damage. After meetings with Commission staff and other parties, FPL submitted a proposed annual accrual of $10.1 million, or 50% of the expected annual storm loss. In its Order, the Commission approved the proposed agreement but found that the annual accrual and the solvency of the storm fund should be monitored in future proceedings.

Q. IS THE ACCRUAL LEVEL THAT FPL HAS REQUESTED IN THE CURRENT RATE CASE CONSISTENT WITH ANY OF THE POLICIES ADDRESSED BY FPL IN ITS STORM DAMAGE STUDY?

A. Yes, I believe that FPL's requested accrual in this rate case is most similar to policy 3 described in its study. I would note that this is the policy that FPL stated had the highest probability of reserve solvency and corresponding high reserve balances. Thus, this policy increased the likelihood of intergenerational inequities by shifting future costs to current customers.

Q. DID THE COMMISSION SUBSEQUENTLY ADDRESS ANY REQUESTS BY FPL TO INCREASE THE ANNUAL STORM ACCRUAL?

A. Yes. By Order No. PSC-95-1588-FOF-EI, issued December 27, 1995, in Docket No. 951167-EI, the Commission approved FPL's request to increase the storm accrual to $20.3 million to recognize the unavailability of insurance and that self-insurance was the only cost effective way to provide insurance to FPL and its customers.

FPL also petitioned the Commission to increase the storm reserve by $35 million in Docket No. 971237-EI. FPL stated that the expected annual damage estimate was $42.3 million at that time and the highest reasonable risk in any single year within the next 50 years was approximately $559 million. No inclusion in the expected damage estimate was provided for nuclear events. By Order No. PSC-98-0953-FOF-EI, issued July 14, 1998, the Commission denied FPL's request and found that FPL's financial resources from lines of credit and the storm fund were sufficient to cover most storm emergencies. Further, if FPL incurred catastrophic losses which caused a negative balance in the reserve, the Commission reiterated that the company could petition for emergency relief, as reflected in Order No. PSC-95-1588-FOF-EI. The Commission also found that the reserve could be used to cover the possibility of retrospective insurance assessments associated with FPL's nuclear facilities, but noted that the risk of incurring these assessments was low.

In Docket No. 001148-EI, which was opened to review FPL's level of earnings, FPL submitted minimum filing requirements which requested an increase in its storm accrual by $30 million, for a total of $50.3 million. This docket was resolved by the Commission's approval of a settlement agreement, which included a correction to the fuel clause adjustment and provided for rate reductions and a revenue sharing plan. In another component of the settlement, FPL agreed to withdraw its requested $30 million increase in the storm accrual, with an agreement that FPL could petition for recovery if it incurred storm costs which caused insufficient funds in the storm reserve. By

Order No. PSC-02-0501-AS-EI, issued April 11, 2002, the Commission approved the settlement agreement reached by several parties in the docket.

Q. **HOW DID THE 2004 STORM SEASON IMPACT FPL'S STORM RESERVE BALANCE?**

A. Prior to 2004, the only other catastrophic storm to impact FPL's territory in recent history was Hurricane Andrew, which hit in 1992. In 2004, four storms directly hit the State of Florida, with 3 causing combined levels of catastrophic damage in FPL's territory. Taken individually in one season, the damage sustained in each storm would have been higher than an average season but the storm reserve most likely would have remained solvent. The 2004 storm season was monumental and nothing like this has happened in America in the last 100 years with regard to hurricanes. The last time so many storms struck the same state in one season was in Texas with 4 direct hits from hurricanes in 1886. (See FPL's response to OPC Interrogatory No. 241).

As reflected in its current storm case, Docket No. 041291-EI, FPL estimated that it incurred $890 million in damages that caused the storm reserve to drop from a positive level of $354 million to a negative balance of $536 million at the end of 2004. The final vote on the regulatory treatment of those losses incurred is currently scheduled to be addressed by the Commission at its July 5, 2005, Agenda Conference.

Q. **WHAT IS YOUR OPINION ON MR. HARRIS' TESTIMONY REGARDING THE DETERMINATION OF THE ANNUAL STORM DAMAGE ESTIMATE?**

A. Mr. Harris has used a computer software program that uses input provided from many sources to determine the probabilities of the amount of expected damage that might be incurred in any given year. The model also projected how solvent the reserve would be in 5 years with FPL's requested $120 million annual storm accrual. Predicting the many variables that will impact FPL's territory is a difficult science and no one knows with certainty what the damage or costs will be until after the damage occurs. What is certain, however, is that storm damage in FPL's territory has occurred and is very likely to be incurred in the future.

Q. WHAT ARE THE COMMENTS THAT YOU WOULD LIKE TO MAKE REGARDING MR. HARRIS' LOSS ANALYSIS?

A. First, let me point out that I am not addressing the adequacy of the USWIND™ model. I do, however, have some comments that I would like the Commission to consider when it evaluates the reasonableness of the annual expected storm damage presented by Mr. Harris and requested by FPL.

First, Mr. Harris' model considers damage from all categories of storms including hurricanes, tropical storms and winter storms, as well as storm staging costs, windstorm insurance deductibles for non-T&D assets and potential retrospective assessments associated with FPL's insurance of its nuclear facilities. (Harris direct, page 4, lines 12-20). The model's damage estimate appears to be all inclusive and does not distinguish between the annual damages that are less costly and those that are extraordinary and catastrophic.

Q. DO SMALLER STORMS TYPICALLY IMPACT THE STORM RESERVE?

A. No. As evidenced in the past, FPL has recorded regularly recurring damage for less costly storms or staging costs related to storms that do not materially impact the service territory as normal operating expenses which would not flow through the storm reserve. Further, other than Hurricane Andrew in 1992 and the 3 hurricanes in 2004, FPL's storm reserve has been sufficient to allow recovery of the actual storm damages incurred and prior to 2004 had never been negative.

In its response to OPC's Interrogatory No. 11, FPL asserts that 20% to 30% of the expected annual damage of $73.7 million comes from large and high intensity storms that produce damage in excess of a billion that are extraordinary and less likely to occur. Thus, on a conservative basis, at least $14 million of the $73.7 million annual storm damage estimate is deemed by Mr. Harris as being extraordinary and not normally recurring.

Q. **DO YOU HAVE ANY OTHER COMMENTS REGARDING THE INPUT OF INFORMATION INTO THE STORM LOSS ANALYSIS?**

A. Yes. Although I am unable to provide any specifics regarding the method of estimating the amount of storm damage losses, FPL's method of charging damage to the storm reserve has been based on the full cost recovery methodology basis as outlined in FPL's recent storm recovery case in Docket No. 041291-EI. I believe that the charges to the storm reserve should be from those costs incurred above the normal level of budgeted labor and expenses.

Q. **OTHER THAN STORM DAMAGE RISKS, MR. HARRIS HAS INCLUDED 3 OTHER STORM RESERVE FUND EXPOSURES TO HIS EXPECTED ANNUAL LOSS ESTIMATE. WHAT ARE THESE EXPOSURES?**

A. In Exhibit SPH-1, Page 17 of 29, Mr. Harris lists three additional risks that FPL has requested to be included in the annual storm damage estimate. These are storm staging costs, retrospective insurance assessments from industry nuclear accidents, and losses in excess of insurance coverage from nuclear accidents at FPL plants.

Q. PLEASE DESCRIBE FPL'S REQUEST FOR STAGING COSTS FOR NON-LAND FALLING STORMS.

A. The requested staging costs are for pre-positioning personnel and equipment in anticipation of post hurricane storm restoration activities for storms that are forecasted to land inside but actually fall outside of FPL's territory. The requested staging costs were developed in 2000 using information provided by FPL, then updated to reflect FPL's recent 2004 hurricane experience and costs. The expected annual staging costs for non-land falling storms were estimated to be $3.5 million per year.

Q. DO YOU BELIEVE THAT THE STAGING COSTS FOR NON-LAND FALLING STORMS ARE EXTRAORDINARY COSTS?

A. Generally, no, I do not. Storm staging costs for storms that do not land in FPL's territory should be considered normal recurring events budgeted in operation and maintenance costs. Every year, during hurricane season, FPL must be monitoring all hurricane and tropical storms for the forecasted track. While certainly the decision of opening up a command center is crucial and involves incremental costs, these types of events often occur several times each hurricane season. However, in the event a command center is opened and the storm passes by FPL's territory, the overall cost of the staging with no significant transmission and distribution system damages incurred should be considered normal and recurring.

Q. DOES THE NORMAL BUDGETING PROCESS CONSIDER THESE TYPES OF EXPENSES?

A. Yes. FPL's budget process includes normal recurring, and excludes extraordinary, storm damage. According to FPL's response to OPC Interrogatory 15, "An extraordinary storm event begins when company management opens the General Office Command Center (GOCC). Once the GOCC is opened, the Accounting department issues a unique storm work order. In general, eligible losses would be charged to the work order in instances where the severity of damages results in restoration efforts of longer than three days, and or where full activation of FPL's command center and service center Storm Organization is required." Thus if the GOCC is not in full activation or the restoration efforts were completed in less than 3 days, then the charges would be considered normal, not extraordinary. By the above description, the company's own budget process would consider these staging costs as normal budget operations.

Q. HAS FPL PREVIOUSLY CHARGED THE STORM RESERVE FOR ANY NON-LAND FALLING STORM STAGING COSTS?

A. FPL stated that it charged staging costs along with damage incurred associated with Hurricane Floyd in 1999. In FPL's response to OPC Interrogatory No. 159, the company stated that even though Hurricane Floyd made landfall in North Carolina, FPL sustained damage to its T&D system. In addition to the T&D damage, FPL stated that it also recorded the staging costs associated with that storm. Of the $21 million charged to the storm reserve for Hurricane

Floyd, FPL did not state the amount incurred for the storm staging costs. Other than Hurricane Floyd, it does not appear that FPL recorded storm staging costs for non-land falling storms to the storm reserve. In OPC's Interrogatory No. 12, FPL was requested to:

> Provide a list of all hurricanes, tropical storms, winter storms, and any other major weather events that impacted FPL's service territory and caused damage to the transmission and distribution system for 1991-2004. For each storm or weather event listed, provide the date, a description of the storm, the percentage of FPL's service territory impacted, the total amount of direct or indirect pre-storm and restoration damaged incurred, and the amount of insurance proceeds received, and the amount of the damages expensed, capitalized or charged to the storm reserve.

Based on my review of FPL's response to OPC's Interrogatory No. 12, FPL did not delineate any amounts it incurred for non-land falling pre-storm staging costs when the T&D system did not suffer significant damage.

Q. WHAT DATA HAS FPL PROVIDED TO SUPPORT ITS ESTIMATED $3.5 MILLION FOR ANNUAL STORM STAGING COSTS?

A. FPL has only provided a general description that the storm staging costs were based on 2000 amounts and updated for 2004 storm events. FPL has not provided any documentation to show how it estimated the 2000 amounts or a break out of the storm staging costs incurred in 2004 for any of the storms in 2004. In OPC Interrogatory No. 117, FPL was requested to provide the amounts of estimated and actual costs to date for pre-storm staging costs incurred for each named storm in 2004. In its response, FPL stated that this information was not available and that it does not estimate or capture its actual pre-storm staging costs at this level of detail.

Q. WHAT IS YOUR RECOMMENDATION ON THE INCLUSION OF STORM STAGING COSTS IN THE EXPECTED ANNUAL ESTIMATE OF STORM DAMAGE?

A. I believe that these amounts should be considered normal and recurring operating costs which should have already been included in the budgeting process. Consistent with FPL's accounting policy, the storm reserve should account for the extraordinary costs associated with storm damage and accordingly, the storm staging costs from non-land falling storms should be removed from the expected annual estimate of storm damage. Further, if FPL does not maintain the support to estimate or account for these costs incurred for a major storm, I question the accuracy of FPL's estimate for any staging costs associated with a non-land falling storm. Last, since it appears that FPL has not recorded staging costs associated with non-land falling storms previously in the storm reserve account, I would assume that the costs have not been deemed extraordinary and have been flowed through normal operating accounts consistent with FPL's accounting policies.

Q. PLEASE DESCRIBE FPL'S REQUEST FOR RETROSPECTIVE INSURANCE ASSESSMENTS FROM INDUSTRY NUCLEAR ACCIDENTS, AND LOSSES IN EXCESS OF INSURANCE COVERAGE FROM NUCLEAR ACCIDENTS AT FPL PLANTS.

A. FPL included $1 million for losses from nuclear exposures. Mr. Harris stated that estimates of the frequency and the expected annual losses from these events are very low in comparison with storm related exposures. Further, he stated that he did not include those losses in the solvency analyses due to the extremely low likelihood of risk. See Exhibit SPH-1, Page 18 of 29. According to its response to OPC Interrogatory No. 160, FPL stated that:

> Mr. Harris did not include the probability of retroactive assessments from industry nuclear accidents nor losses in excess of insurance from FPL nuclear losses in his Storm Reserve Solvency Analysis because the probability of occurrence is so small as to have a negligible impact in the five-year time frame used by Mr. Harris in the Solvency Analysis.

Based on the negligible risk level, I believe that the nuclear costs should not be included in the annual average expected losses. However, I do believe that in the event that some nuclear loss arises, any prudent and material costs incurred should be charged the storm reserve, consistent with Rule 25-6.0143, Florida Administrative Code.

Q. **DO YOU HAVE ANY GUIDELINES THE COMMISSION SHOULD CONSIDER WHEN DETERMINING THE AMOUNT OF THE ANNUAL STORM ACCRUAL?**

A. Yes. Setting the proper storm accrual is crucial to balancing the long- and short-term goals of cost recovery while minimizing potential intergenerational inequities between customers over time. Intergenerational equities exist when each generation of customers pays for the costs related to the service from which they are benefiting. Another important consideration is to provide sufficient recovery of expenses in the most cost-effective manner. If the annual accrual is too high and storm damages are modest, the risk is that the current ratepayers assume more of the cost for future storm recovery costs. If you set the accrual too low and storm damages continue to exceed the reserve balance, then you are faced with the increased costs and regulatory lag associated with special assessments. Overall, the determination of the storm accrual will be somewhat arbitrary as we cannot know the actual storm events or damages that will impact the storm reserve in the future. The best regulatory policy is one that allows the Commission to estimate what a reasonable level for the storm accrual should be and periodically monitor the accrual and reserve balance to determine the success of the process.

Q. HOW SHOULD CATASTROPHIC STORM EVENTS BE HANDLED?

A. I believe that the annual storm accrual should be sufficient to cover the annual average cost of losses from moderate to extraordinary storm damage over time and provide for special assessments for catastrophic storms or years in which the storm reserve is depleted. As such, I believe that it is reasonable for the annual storm accrual in base rates to be set using an amount less than the average storm damage for minimal to above average cost storms but leaving the catastrophic storm damage to be recovered through a special assessment mechanism. This treatment is consistent with the method that FPL agreed to when the Commission established the accrual at its current level of $20.3 million in 1995.

Q. DO YOU AGREE WITH THE COMPANY'S POSITION REGARDING THE ANNUAL ACCRUAL LEVEL?

A. No I do not. Mr. Dewhurst testified, on page 40, lines 7-8, that "The current storm accrual is not, and has not been for some time, sufficient to cover expected annual storm losses." My reading of the prior Commission orders on this issue is that the annual accrual has been less than the damage estimate by design. The process contemplated that catastrophic and extraordinary damages would be recovered through special assessments. Accordingly, I disagree with Mr. Dewhurst that the storm accrual should be set to recover the annual expected storm damage plus an additional allowance to replenish the reserve.

Q. SHOULD THE ANNUAL ACCRUAL IN BASE RATES BE USED TO REPLENISH THE RESERVE THAT WAS DEPLETED BY THE 2004 STORMS?

A. No, I do not think it should. The damage incurred in 2004 was certainly catastrophic but I believe that the replenishment of the reserve should be on a more short-term basis rather than through base rate recovery. I believe that a more appropriate vehicle would be the use of a special assessment, such as the new securitization statute, which was signed into law on June 1, 2005. This method could allow the utility to replenish the reserve quickly, particularly in case another storm causes extraordinary damage before the storm reserve grows to a reasonable level. Using only base rates to replenish the reserve, even at the company's requested accrual level of $120 million, could still require the use of a special assessment if storm damage occurs in the next 1-2 years and exceeds the balance in the storm reserve. Another benefit of using securitization is that the repayment of the storm bonds would be borne by the current generation of customers instead of being spread over a longer period of base rate recovery.

Q. WHAT OTHER MECHANISMS ARE AVAILABLE TO FPL TO REPLENISH ITS RESERVE OUTSIDE OF BASE RATES?

A. In addition to securitization, the utility has other mechanisms available outside of base rates for extraordinary recovery and storm reserve replenishment. One mechanism is a storm proceeding to recover a reserve deficiency, consistent with FPL's request in Docket 041291-EI. FPL also can petition the Commission for recording some level of storm costs during a given year as normal operating costs, to offset earnings in excess of the FPL's authorized range. This last mechanism has been used by FPL on several occasions to reflect otherwise recordable storms costs as normal operating costs.

Q. DO YOU HAVE ANY CONCERNS ABOUT HOW THE RESERVE REPLENISHMENT AMOUNT SHOULD BE SET?

A. Yes. I would urge caution in determining what amount should be allowed to replenish the storm reserve either in this docket or through some other mechanism. If the amount added back to the storm reserve is too high and the storm damage in the next few years is less than average, the storm reserve could grow to become quite large in a short time.

Q. HOW DO YOU PROPOSE TO SET THE ANNUAL ACCRUAL LEVEL?

A. I have looked at two different ways in determining the level of the annual accrual. The first was to compare the level of historical damage incurred by FPL since 1992. This analysis has been provided in Exhibit PWM-2, entitled *Comparison of FPL's Average Historical Storm Costs*. In this exhibit, I have compiled the historical costs of storm damage incurred for each storm event for FPL from 1992 through 2004 and calculated several different average storm damage estimates. The source of this data was provided by FPL in OPC's Production of Document (POD) Request No. 25, Bate No. FPL019471. I first took the total accumulated storm damage and calculated an average storm cost per year of $106 million. This average included the catastrophic years of 1992 and 2004 and, accordingly, generated the greatest annual average cost. It should be noted that the majority of the storm damages incurred for Hurricane Andrew were covered by traditional insurance and did not flow through the storm reserve.

Q. **HAVE YOU CALCULATED ANY OTHER HISTORICAL AVERAGE LEVELS OF STORM DAMAGES?**

A. Yes, I did. For my second average, I removed the catastrophic events from 1992 and 2004 and calculated an average cost of $15 million, which was the lowest average cost on an annual basis. For a third approach, I took the damage from the non-catastrophic years of 1993-2003 and added back the cost for Hurricane Charley, the lowest cost storm in 2004. This generated an average of $31 million. The fourth average was similar to the third, but I instead used the damages from Hurricane Frances, which was the highest cost storm in 2004. This last comparison calculated an average annual cost of $41 million.

Q. **ARE YOU RECOMMENDING AN ACCRUAL BASED ON ONE OF THESE AVERAGE ANNUAL COSTS?**

A. Not completely. I am using these numbers for comparison purposes to reflect the range of damages that FPL has incurred in the past. I would like to point out that the use of historical costs, while useful to see what has occurred, does not necessarily reflect the pattern that will occur in the future. Another consideration is that these historical costs do not reflect the current replacement costs for storm restoration, nor do the averages account for the customer growth that has occurred in FPL's system.

Q. WHAT WAS THE OTHER ANALYSIS THAT YOU USED TO DETERMINE THE ANNUAL ACCRUAL FOR STORM DAMAGE?

A. I have compiled Exhibit No. PWM-3, entitled *Adjustments to Expected Annual Losses to FPL's Storm Reserve.* In this exhibit, I started with Mr. Harris' amount of Expected Annual Storm Losses of $74.7 million as shown on SPH-1, Page 19 of 29. I then removed the $3.5 million for the storm staging costs for storms that did not land in FPL's territory and $1 million for the nuclear damage estimates. This left an adjusted total of $70.2 million. I then remove 20% of the remaining costs ($14 million), which was FPL's conservative estimate of the costs related to the extraordinary and less likely levels of storm damage. This left an adjusted expected annual storm loss of $56.2 million. So even using Mr. Harris' storm analysis, the range of storm damage can vary from the requested $74.7 million to an adjusted level for normal, non-catastrophic storm damage of $56.2 million.

For considering what the prospective accrual level should be, I reduced each of the 3 expected storm damage estimates that I discussed in the above paragraph by 50%. This is consistent with the philosophy that FPL used in its settlement agreement to determine the appropriate annual accrual, which was approved by the Commission in Order No. PSC-95-0264-FOF-EI. As shown on Exhibit PWM-3, the storm accrual levels using the 50% ratio range from a low of $28.1 to a high of $37.4 million.

Q. BASED ON THE ABOVE ANALYSIS, WHAT IS YOUR RECOMMENDED LEVEL OF THE ANNUAL STORM ACCRUAL?

A. I believe that the proper level for the annual storm accrual should be $35 million, which results in a reduction to test year expenses of $85 million. This level recognizes that the costs for storm damage restoration have increased, and provides for a $14.7 million increase above the current accrual. This accrual level also reflects the 50% level of the adjusted storm damage estimate of $70.1 million, after removal of the staging costs and nuclear risks. I would note that this level falls between the normalized level of historical storm damage incurred from 1993 to 2004 with only one storm included in 2004 ($31 million for Hurricane Charley and $41 million for Hurricane Frances).

Q. WHAT IS YOUR OPINION ON MR. HARRIS' TESTIMONY REGARDING HIS SOLVENCY ANALYSIS?

A. Mr. Harris' solvency analysis was based on his estimates included in the storm loss estimate and the approval of an annual accrual of $120 million. His solvency analysis does not contemplate that the annual accrual might be lowered by the Commission or that the utility might utilitize another vehicle to replenish the storm reserve in a shorter timeframe. Unless you agree 100% with the assumptions included in his analysis, I do not believe that his solvency analysis should be relied upon.

<u>GRIDFLORIDA RTO</u>

Q. IN ITS MFRS, FPL HAS REQUESTED RECOVERY OF COSTS ASSOCIATED WITH FPL'S PARTICIPATION IN THE GRIDFLORIDA RTO. CAN YOU SUMMARIZE WHAT AMOUNTS HAVE BEEN INCLUDED IN THE TEST YEAR?

A. Yes. FPL has included $59 million as part of the 2006 budget with an adjustment to add $45 million, or a total test year expense of $104 million. FPL witness Mennes testifies to the inclusion of these amounts and how the estimates were derived.

Q. DOES MR. MENNES STATE WHY FPL IS REQUESTING RECOVERY OF THESE COSTS?

A. Yes. On page 20, lines 14-18, of his direct testimony, Mr. Mennes states that FPL will be required to buy transmission service from GridFlorida to serve its customers and the charges FPL will incur will only be partially offset by GridFlorida's payment to FPL for the use of FPL's transmission system. Mr. Mennes states that the remaining charges will be incremental transmission costs to FPL.

Q. WHAT TYPES OF COSTS HAS FPL REQUESTED TO BE RECOVERED THROUGH BASE RATES IN THIS PROCEEDING?

A. FPL has requested recovery of start-up costs, annual operating costs and cost shifting. The major costs associated with cost shifting are the revenue requirements associated with the Florida Municipal Power Authority and Seminole Electric Cooperative's existing transmission facilities located in FPL's zone, and the portion of revenue requirements associated with the transmission facilities of all the other transmission owners participating in the RTO. FPL has forecasted that the 2006 level of RTO costs will increase from the $59 million in 2006 to $148 million in 2010, an increase of $89 million. To request recovery of this, FPL has averaged the difference over 5 years and made an adjustment to add $45 million to the test year.

Q. CAN YOU PROVIDE AN OVERVIEW OF THE STATUS OF THE GRIDFLORIDA RTO?

A. Yes. Docket No. 020233-EI was opened by the Commission to review the GridFlorida RTO Proposal. In December, 1999, the Federal Energy Regulatory Commission (FERC) issued Order No. 2000, which required all public utilities that own, operate, or control interstate transmission facilities to file a proposal to participate in a RTO. By Order No. PSC-02-1199-PAA-EI (Order 02-1199), issued September 3, 2002, the Commission addressed the myriad of proposals submitted by the GridFlorida Applicants (FPL, Florida Power Corporation/Progress Energy, and Tampa Electric Company) as well as comments submitted by the numerous parties to the docket. The primary issues addressed were the structure and governance, planning and operations, transmission rate structure, cost shifting, recovery of incremental transmission costs, and the modified market design. Additionally, the Commission ordered that an expedited hearing would be held on the merits of the revised market design proposal submitted by the GridFlorida Applicants. Several protests and requests for hearing were filed with respect to Order No. 02-1199.

The hearing was scheduled to be held late-October, 2002. However, on October 3, 2002, OPC filed a notice of appeal of Order No. 02-1199. On October, 15, 2002, the Commission abated its proceedings pending the disposition of OPC's appeal of the order. On June 2, 2003, the Supreme Court of Florida dismissed OPC's appeal stating that it was "opposed to piecemeal review of single orders, especially when, as in this cause, the final and non-final actions contained in Order No. 02-1199 are intertwined." As such, the Court dismissed the appeal until all portions of that order are final. Citizens v. Jaber, 847 So. 2d 975 (Fla. 2003).

Q. WHAT ACTION DID THE COMMISSION TAKE SUBSEQUENT TO THE ISSUANCE OF THE COURT'S DECISION?

A. By Order No. PSC-03-1006-FOF-EI, issued September 8, 2003, the Commission addressed the outstanding motions for reconsideration, clarified one aspect of Order 02-1199, and left the docket open to "permit final disposition of this matter." By Order No. PSC-03-1414-PCO-EI, issued December 15, 2003, Chairman Jaber, as Prehearing officer, outlined the procedural posture for the case and encouraged the parties to continue to collaborate on moving the case forward. As such, she scheduled a series of workshops and requested that the parties file drafts of their respective positions and prepare written comments on other parties' positions. At the conclusion of each workshop, Commission staff would file a status report summarizing the workshop results, including the resolution of any issues and identification of specific outstanding issues. At the conclusion of all of the workshops, the Chairman would schedule the final hearing to resolve any outstanding issues to the extent any remained.

Q. WHEN DID THE COMMISSION HOLD THE WORKSHOPS?

A. The Commission held a workshop on March 17-18, 2004, to address pricing issues, cost recovery, cost shifting and a continued review of cost and benefits of the RTO. At this workshop, the Applicants proposed that an independent study be performed by ICF Consulting to review the costs and benefits of the GridFlorida RTO. On May 19-21, 2004, the Commission held a second workshop on the market design issues and also continued to review the costs and benefits of the RTO and the current regulatory/legislative benefits. A third workshop was held on June 30, 2004, to allow ICF to present the parameters of its study and to obtain comments from the parties. The scheduled August 5, 2004, workshop, which was designed to be the final workshop session, was cancelled to allow sufficient time for ICF to complete its cost/benefit analysis.

Q. HAS THE ICF COST BENEFIT ANALYSIS STUDY BEEN ISSUED?

A. No, but a draft of the study was released on April 27, 2005.

Q. WHAT WERE THE PRELIMINARY FINDINGS OF THE STUDY REGARDING THE COSTS AND BENEFITS?

A. For the Day 1 preliminary draft, ICF stated that the GridFlorida costs exceeded the benefits by as much as $700 million. For the Day 2 scenario, the costs exceeded the benefits by approximately $375 million. On May 23, 2005, the Commission held another workshop to allow ICF to present its draft report and to allow the parties to comment on ICF's preliminary results.

Q. WHAT COMMENTS DID FPL'S REPRESENTATIVE MAKE AT THE WORKSHOP?

A. Mr. Robert Croes concurred with Progress Energy's comments that the cost estimates were understated and the benefits were significantly overstated. Mr. Croes stated the model had no demand uncertainty and removed the inefficiencies associated with over and undercommittment, which does not exist in the real world. He also stated that the model overstated the benefits by using marginal cost bids. Further, "the bid markets that exist in today's RTO and ISO competitive markets were not modeled by ICF.

Q. WOULD YOU LIKE TO ADDRESS ANY OTHER COMMENTS MADE AT THE WORKSHOP?

A. Yes. Chairman Baez commented that he was receiving a general message from the Applicants that based on the ICF study, the GridFlorida RTO was not cost-effective and he questioned whether the pursuit of a Florida RTO should be continued. He also expressed concern about the utilities' compliance with FERC even when the current RTO project appeared to be cost-ineffective. Even the FERC representative at the workshop communicated that the costs were much too high and need to be reduced. The FERC representative suggested spreading some costs over a longer period of time and wanted to see a more reasonable analysis of the costs and benefits of a Florida RTO.

Q. **HOW DID THE COMMISSION CONCLUDE THE WORKSHOP?**

A. The Chairman addressed the need to have a final report issued. He also requested that the parties consider alternatives and left it to Commission staff to consider the procedural steps that need to be set up to complete the docket. Commission Staff communicated that they would like to review the transcript of the workshop prior to setting up a definitive schedule. The ending comments made were to take some time to gather more information, study other benefits that may be achieved by individual utilities that were not part of the cost benefit study, and to think about a process going forward.

Q. **WHAT IS YOUR ANALYSIS OF THE COMMENTS MADE AT THE MAY 23, 2005, WORKSHOP??**

A. I believe that the implementation of the GridFlorida RTO is unlikely in its present form and questionable as to whether it will be implemented at all. FPL's own representative stated that the costs would exceed the benefits even more that those projected by ICF.

Q. **HAS PROGRESS ENERGY FLORIDA, INC. REQUESTED RECOVERY OF ANY PROJECTED RTO COSTS IN ITS PENDING RATE CASE APPLICATION IN DOCKET NO. 050078-EI?**

A. No. It has not.

Q. **WHAT IS YOUR CONCLUSION ABOUT INCLUDING THE PROJECTED RTO COSTS IN FPL'S TEST YEAR?**

A. What costs might be incurred by FPL or the other Applicants at this time are unknown and any implementation date, if any, is too far in the future to make a reasonable estimate of prospective costs. I believe that including any costs for the GridFlorida RTO in FPL's rate case is speculative and certainly not known and measurable. Based on the above, I recommend that the requested $104 million for RTO costs be removed from test year expenses. Further, if any other costs are later shown to be included in the test year related to RTO costs, those amounts should also be removed.

Q. **DOES THIS COMPLETE YOUR TESTIMONY?**

A. Yes, it does.

DIRECT TESTIMONY OF HELMUTH W. SCHULTZ, III

ON BEHALF OF THE CITIZENS OF FLORIDA

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

DOCKET NOS. 050045-EI & 050188-EI

I. INTRODUCTION

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

A. My name is Helmuth W. Schultz, III, I am a Certified Public Accountant licensed in the State of Michigan and a senior regulatory analyst in the firm 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 wasterwater, gas and telephone utility cases.

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

A. Yes, I have testified before the Florida Public Service Commission. I have also testified a number of times before Public Service/Utility Commissions or Boards in other state jurisdictions.

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. ON WHOSE BEHALF ARE YOU APPEARING?

A. Larkin & Associates, PLLC, was retained by the Florida Office of Public Counsel (OPC) to review the rate request of Florida Power & Light Company (FPL or Company). Accordingly, I am appearing on behalf of the Citizens of Florida (Citizens).

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

A. Yes. Kim Dismukes, David Dismukes, J. Randall Woolridge, Michael Majoros, Patricia Merchant and Hugh Larkin, Jr. and Donna M. DeRonne, of my firm, are also presenting testimony.

Q. HOW WILL YOUR TESTIMONY BE ORGANIZED?

A. I am discussing the compensation and benefit cost included in the Company's rate request. First, I will discuss the various payroll components, then long-term incentive compensation and finally, benefit expense. Attached to my testimony are Schedules 1-7 that reflect the adjustments that I am recommending and Schedule 8 which provides a comparative analysis for informational purposes.

II. PAYROLL

Q. DID YOU REVIEW THE COMPANY'S PAYROLL AND BENEFIT SCHEDULE IN THE FILING?

A. Yes, I did review Schedule C-35. In addition, I reviewed a number of workpapers provided as supporting detail for Schedule C-35 and responses to a number of interrogatories and production of document requests.

Q. WHAT AMOUNT OF PAYROLL EXPENSE IS INCLUDED IN THE COMPANY'S REQUESTED O&M EXPENSE FOR 2006?

A. Based on the Company's response to Citizens Interrogatory 116, the amount of payroll expense included in the projected 2006 O&M expenses cannot be translated into the level of detail shown on MFR C-1. Schedule C-1, according to the Company, is a high level summary of income and expenses, the net of which is included in the Company's revenue deficiency calculation on MFR Schedule A-1. The total payroll in the MFR's, as shown on Schedule C-35, is $808,940,000. It consists of three components, base pay, overtime and variable pay.

Q. HOW CAN THE COMPANY CLAIM IT DOES NOT KNOW HOW MUCH OF THE PROJECTED O&M EXPENSE IN THEIR REQUEST IS PAYROLL RELATED?

A. In the response to Citizens Interrogatory 116 (Citizens 116) the Company asserts that the gross payroll on MFR Schedule C-35 is collected from the business units and it cannot be translated to the expense level on MFR Schedule C-1. This same representation is made in the Company's response to Citizens Interrogatory No. 236, where the Company states that "Payroll information for 2006 does not exist." The responses do not make sense and conflict with the response to Citizens Interrogatory No. 50 and the response to Citizens POD Nos. 51 and 52.

Q. HOW DOES THE RESPONSES CONFLICT WITH EACH OTHER?

A. The Company was requested in Citizens 116 to provide, by line, the amount of payroll and benefit from Company's Schedule C-35 that are included on Company Schedule C-1. The response to Citizens Interrogatory No. 116 stated that since payroll is not developed in the forecasting process at the FERC account level the jurisdictional amount cannot be calculated for forecast years 2005 and 2006. The response did not provide the total company O&M expense amount for 2006 or the jurisdictional payroll expense amount for 2006. However, in response to Citizens Interrogatory No. 50 the Company attempted to provide an expense amount for the 2006 total gross payroll. Also, in response to Citizen's POD Nos. 51 and 52, the Company provided O&M expense amount by business unit the total of which is reconcilable with the O&M expense on Schedule C-1. This response shows the expense by group and one group, group A, is identified as "Salary & Wages." Therefore, it appears that the Company should have been able to provide a quantification or, at the very least, a reasonable estimate of the payroll expense included in this rate request. It is not appropriate for ratepayers to have to pay rates on a unquantifiable amount of payroll expense. This is especially true since payroll represents approximately 40% of other O&M expense.

Q. ARE THERE CONCERNS WITH THE 2006 PAYROLL PROJECTIONS?

A. Yes. The Company's Schedule C-35 indicates that in 2004 there was an average employee count of 10,000. The Company has projected that there will be an average of 10,558 employees in 2006. Citizen's Interrogatory 111 (Citizens 111) requested the Company to provide a listing of the employee positions to be added during 2005 and 2006. The requested average increase of 558 positions reflected in the filing exceeds the 308 positions identified in the response to Citizens' Interrogatory 111 by 250 positions. Even if one were to add the 308 identified positions to the 10,092 employees on hand at December 2004, which I don't recommend, you would still only have 10,400 employees for 2006, which is 158 employees less than what is identified by the Company on Schedule C-35 as being included in the filing for 2006.

Q. HOW DID THE COMPANY DEVELOP ITS RATE YEAR EMPLOYEE COMPLEMENT?

A. According to the response to Citizens' POD No. 47 (Bates # FPL063873) the Company started with the 2004 actual year end FTE count of 10,025.5 employees and forecasted the 2005 and 2006 year end counts to be 10,476 and 10,639, respectively. Based on the 2005 and 2006 year end amounts the average for 2006 is the 10,558 employees referenced earlier. The Company's request for additional employees is actually 613.5 positions, the 10,639 employee count at the 2006 year end minus the 10,025.5, the 2004 year end count. As stated earlier the Company only identified 308 positions to be added during the two years 2005 and 2006. Assuming the 308 positions are justified and added to the 2004 complement that would leave 305.5 positions that are not identified and/or justified. It should also be noted that when the Company was requested in Citizens Interrogatory No. 44 to provide budgeted employee levels for 2005 and 2006 the response indicated that the year end budgeted count for 2005 and 2006 was 10,463 and

10,628, respectively. Therefore, the employee level calculation in the filing used higher year end employee levels than what was reflected in the budget.

Q. DID YOU INQUIRE AS TO WHY THERE WAS A DIFFERENCE IN THE NUMBER OF EMPLOYEES TO BE ADDED?

A. Yes. In Citizens' Interrogatory No. 256, the Company was asked to explain the difference between the 308 new positions identified in Citizens 111 and the 558 additional employees reflected in the filing. The response attributed the difference to authorized positions not yet filled and to including part-time and temporary positions as full-time equivalents for 2005 and 2006. The response states that Schedule C-35 "overstates the actual staffing growth."

Q. DOES THE RESPONSE PROVIDE SUFFICIENT JUSTIFICATION FOR THE EMPLOYEE LEVELS REFLECTED?

A. No. Basically the response says that in addition to hiring 308 new employees there are a number of vacancies that were authorized, but not filled, that will be filled. Based on the response to Citizens' Interrogatory No. 44 at December 31, 2004 that vacancy number is estimated to be 236 positions. The Company has included compensation in the filing for the vacancies as if vacancies do not exist. Vacancies existed in the past and will exist in the future, the fact that a position is authorized does not mean the position will be filled. Compensation for recurring vacancies should not be included in the cost of service.

With respect to the claim that part-time and temporary positions are being counted as full-time equivalents, there are inconsistencies in the numbers. For example, the 2004 year end count of 10,025.5 used in the average calculation that yields the 10,558 average is less than the 2004 year end headcount of 10,092 reported in the response to Citizens' Interrogatory No. 44. Finally, contrary to the response's suggestions that the number is based on a count and not FTE's, the workpapers provided in response to POD No. 47 verify that the 10,025.5 is based on FTE's and not head counts. There has not been an explanation provided that justifies the employee complement in the filing.

Q. WOULD THE BUDGETED LEVEL OF EMPLOYEES BE A MORE APPROPRIATE EMPLOYEE COUNT TO BE ALLOWED IN RATES?

A. No. The percent of actual employees to budgeted employees for the year end 2002, 2003 and 2004 was 94.4%, 99% and 97.7%, respectively. A simple average indicates that 97% of the budgeted employee count at year end has been filled. Assuming that 97% of the 2005 and 2006 year end budgeted employee positions were filled, the Company would have an average of 10,229 positions in 2006. Compared to the 10,558 average in the filing the Company has included an excessive number of employees in its rate request.

Q. ARE YOU RECOMMENDING AN ADJUSTMENT TO PAYROLL EXPENSE BASED ON THE EMPLOYEE COMPLEMENT?

A. Yes. As shown on Schedule 1, a base pay reduction of at least $8,563,751 is recommended. That adjustment is based on a reduction of 228 positions from the Company's 2006 average number of employees of 10,558. That adjustment assumes that 299 positions will be added to the 2004 average of 10,031 positions for a total employee complement of 10,330 in 2006. The 299 positions represent 97% of the 308 positions the Company identified in Citizens' Interrogatory No. 111.

Q. WHY SHOULD THE COMMISSION ACCEPT YOUR ADJUSTMENT?

A. The Company's 2006 payroll assumes the Company will hire not only the 308 positions identified in the response to Interrogatory No. 111, but also a number in excess of the 230 vacancies the Company had at December of 2004. The Company's assumption is not realistic. My adjustment for employees assumes 97% of the identified new positions will be filled despite a lack of evidence that the positions will, in fact, be filled. My adjustment is also conservative since it calculates the average pay based on the Company employee number which the Company has stated is overstated.

Q. ARE YOU PROPOSING ANY ADDITIONAL ADJUSTMENT TO PAYROLL?

A. Yes. The amount of overtime in 2006 is excessive when compared to historical overtime. In 2001 overtime pay was $100,325,968, in 2002 overtime pay declined to $91,085,264 and in 2003 overtime pay was $102,031,660. There is no justification for the 2006 overtime pay level of $109,674,090.

Q. WHAT ADJUSTMENT ARE YOU RECOMMENDING TO OVERTIME PAY?

A. As shown on Schedule 2, total overtime should be reduced $1.5 million and O&M expense should be reduced $936,304 on a jurisdictional basis.

Q. HOW DID YOU DETERMINE YOUR ADJUSTMENT?

A. The actual overtime for 2001-2003 was inflated using the highest annual percentage pay increases from the response to Citizens' Interrogatory No. 47. The adjusted overtime was averaged and the difference between the average and the Company's 2006 overtime was the $1.5 million. As shown on Schedule 2, the $1.5 million was apportioned to O&M and then jurisdictionalized.

Q. ARE THERE ANY CONCERNS WITH THE AMOUNT OF VARIABLE PAY?

A. Yes. First, the level of variable pay is high, and second what the Company has included as variable pay is not readily identifiable and quantifiable.

Q. WHAT DO YOU MEAN THE AMOUNT INCLUDED IS NOT READILY IDENTIFIABLE AND QUANTIFIABLE?

A. Citizens' Interrogatory No. 49 requested a breakdown of historical and projected payroll by salary and wages, overtime, premium pay, incentive compensation, long-term incentive, etc. that was to reconcile with the Company's Schedule C-35 in the filing. The response did provide base pay, overtime pay and a total that tied into the Schedule C-35 amount. The other compensation detail requested was lumped into a "Variable Pay" classification. I will note that the response also stated that long-term incentive is "generally not reflected" in the payroll in MFR C-35.

Q. DID YOU TRY TO GET MORE INFORMATION ON WHAT WAS INCLUDED IN THE VARIABLE PAY?

A. Yes, I did and part of the reason for getting the added information was because two responses to interrogatories specific to incentive compensation amounts, which is a significant portion of the variable amount, were not consistent. In Citizens' Interrogatory No. 255 (Citizens 255) the Company was requested to provide the breakdown of variable pay originally requested in Citizens' Interrogatory No. 49. In addition the Company was requested to provide an explanation and reconciliation if the incentive compensation amount, in the breakdown requested, was different from that provided in Citizens' Interrogatories Nos. 43 and 76 (Citizens 43 and Citizens 76).

Q. DID YOU GET A RESPONSE THAT PROVIDED WHAT YOU REQUESTED?

A. No. Instead the response provided a different amount for base pay, overtime and variable pay for each of the years in the original request. As shown on Schedule 8, the differences between the amounts in Citizens 49 and Citizens 28 are significant. While the response to Citizens' No. 255 did reconcile the incentive pay in Citizens 255 to revised Citizen 43 amounts it did not provide a reconciliation with Citizens 76. Since all the components were different the identity and amounts for variable pay included in the filing remain unknown.

Q. WHAT DID YOU ASCERTAIN ABOUT THE VARIABLE PAY?

A. In 2006, variable pay represents 10.19% of the $808.9 million of the projected payroll. Based on Citizens 49 and Citizens 255, I believe that included in variable pay, but not limited to, is other earnings, annual incentive pay and signing or retention bonuses. As shown on Schedule 8, there is one consistency, that consistency is, historically the annual incentive compensation amount remained level for the last four years at approximately $36 million. However, the Company ignored that trend and increased the annual incentive compensation in 2006 by 20% to $43,297,600. This increase is not justified.

Q. WHAT IS INCLUDED IN OTHER EARNINGS?

A. Other earnings include lump sum merit payments, geographic differentials, severance pay, final vacation pay, bonuses, relocation payments, tax gross ups, opt out benefit pay and miscellaneous earnings. Historically, from 2001-2004, the other earnings ranged from $18 million to $23.9 million. There is no information identifying what level is included in 2006, so this cost remains an unquantified concern.

Q. WHAT IS THE RANGE IN COSTS FOR SIGNING OR RETENTION BONUSES?

A. For the years 2001-2004 the cost ranged from $1.5 million to $5.2 million. In 2004 the bonus was $2.9 million. The payment of this bonus is excessive when you consider the compensation levels in general and the amount in 2006 is not known.

Q. WHAT ADJUSTMENT TO VARIABLE PAY ARE YOU RECOMMENDING?

A. I am recommending two adjustments to the annual incentive compensation. First, at a minimum the 2006 total annual incentive amount of $43,297,600 should be reduced by $7,189,830 to the four year average of $35,952,383. As shown on Schedule 3, Page 1 of 2, O&M expense should be reduced $4,619,385, on a jurisdictional basis. Adjusting the 2006 incentive compensation to the four year average is appropriate and takes into consideration the fact that over the last four years the cost of this plan has remained flat.

Q. WHAT IS YOUR SECOND ADJUSTMENT TO ANNUAL INCENTIVE COMPENSATION?

A. I am recommending a 50/50 sharing of the incentive compensation for the remaining $35,952, 383. As shown on Schedule 3, Page 2 of 2, the sharing results in a reduction to O&M expense of $11,549,500 on a jurisdictional basis.

Q. WHY ARE YOU RECOMMENDING AN EQUAL SHARING OF INCENTIVE COMPENSATION COSTS?

A. Incentive compensation is theoretically intended to reward for performance. The key performance indicator is generally net income. In order to claim success the performance must be measured by accomplishing a set of goals. The goals must be set as a level that requires performance above previous accomplishments. All of FPL goals do not meet that challenge. For example, 2005 Annual Incentive Plan allows a 100% payout of the target award if net income is $662 million. The Company achieved that level of income in 2001, 2002, 2003 and 2004 according to the response to Citizens' POD No. 82. Based on history, there is no incentive to increase net income. Similarly, some performance goals previously achieved have not been raised to require extra performance.

Another reason for sharing is that the benefit from the outstanding performance that contributed to the Company's success is, in theory, to be shared by ratepayers and shareholders. Ratepayers theoretically receive the benefit through lower rates because the cost of service is less. Shareholders benefit by earning a return on their investment. And if the performance is outstanding enough that shareholders ROE is in excess of the allowed ROE, shareholders receive an additional benefit. In recent years FPL shareholders have received this additional benefit. An equal sharing of the risk and benefits associated with this theoretically discretionary cost is appropriate.

III. OTHER COMPENSATION

Q. ARE YOU MAKING ANY RECOMMENDATION FOR THE TREATMENT OF LONG-TERM INCENTIVE COMPENSATION?

A. Yes. As shown on Schedule 4, my primary recommendation is that the entire $29,717,000 projected cost in 2006 be removed. On a jurisdictional basis that would be a reduction to O&M expense of $29,391,450. As an alternative and at a minimum, the cost of service should be reduced $21,414,703 on a jurisdictional basis.

Q. WHY ARE YOU RECOMMENDING THE LONG-TERM INCENTIVE COMPENSATION BE DISALLOWED ENTIRELY?

A. In response to Citizens POD No. 82 the Company provided copies of the respective plans. The purpose of the long-term plan is as follows:

> SECTION 1. Purpose. The purpose of this Amended and Restated Long Term Incentive Plant (the "Plan") of FPL Group, Inc. (together with any successor thereto, the "Company") is (a) to promote the identity of interests between <u>shareholders and employees</u> of the Company by encouraging and creating significant ownership of common stock of the Company by officers and other salaried employees of the Company and its subsidiaries; (b) to enable the Company to attract and retain qualified officers and employees who contribute to the Company's success by their ability, ingenuity and industry; and (c) to provide meaningful long-term incentive opportunities for officers and other employees who are responsible for the success of the Company and who are in a position to make significant contributions toward its objectives. (Emphasis added.)

The following is part of the overview of the Non-Qualified Stock Option Program:

> The stock option program is the latest addition to our performance-based pay program, and it provides a long-term component to our total compensation package. While short-term (annual) rewards provide immediate payback to employee contributions, <u>this program allows individuals with key talents to receive a personal reward that is tied to FPL's stock price and shareholder interests.</u>

> It is FPL's philosophy that an enhanced sense of employee ownership, and a shared focus on growing the Company and <u>increasing shareholder value,</u>

> are important elements of our long-term success. We would like you to have an opportunity to share in the continued growth of FPL through this stock option grant under the FPL Group, Inc. Long-Term Incentive Plan (the "Plan"). The following represents a brief description of your stock option grant followed by information about your grant written in a question and answer format.* (Emphasis added.)

It must be noted that there is no mention of customer service quality or reliability in the long-term incentive plan purpose statement. In fact, ratepayers are not even mentioned in the purpose or the plan. The overview of the non-qualified stock option program is focused on increasing shareholder value. No mention of quality of customer service or reliability is made. It is clear that the purpose of the plans is to enhance shareholder value and because shareholders are the intended direct beneficiary the shareholder should be responsible for the cost associated with receiving that benefit. The entire cost of the long-term incentive plan should be borne by shareholders. The adjustment recommended is appropriate.

Q. IF THE SHAREHOLDERS VALUE IMPROVES, ISN'T THERE SOME BENEFIT TO RATEPAYERS?

A. That may be true to some extent, but the value of shares can increase without benefiting ratepayers. For example, maintenance could be deferred to increase profits. I am not saying that is what has occurred or will occur, but it is a possibility. The main factor is that the focus, as stated, is shareholders and a select group of employees with no mention of improving customer service. For cost that are to be included in rates, the costs are to be for the benefit of ratepayers and there is no evidence that the long-term incentive plans provide a benefit to ratepayers or are even intended to benefit ratepayers. In fact, the cost in question may not even require a real cash outlay and the end result of the benefit may be a cost to be borne twice by ratepayers.

Q. PLEASE EXPLAIN WHY THE COMPANY MAY NOT HAVE A REAL CASH OUTLAY AND HOW RATEPAYERS MAY BE PAYING TWICE.

A. The issuance of stock as an added benefit can come from designated shares that are authorized but unissued. The only cash outlay by the Company for this extra benefit to a select employee group is administrative in nature. Once issued common equity is increased which impacts the capital structure and requires a return from ratepayers for a return on the increased common equity. Ratepayers have supplied capital to the Company as part of the rates charged to them even though the Company has not expended the funds. Then ratepayers are required to pay a return on essentially the same funds they provided to the Company. This is not appropriate.

Q. COULD YOU EXPLAIN WHY YOU OFFERED AN ALTERNATIVE ADJUSTMENT?

A. Yes. The Commission may be convinced during the hearing that there is some benefit and some of the cost is justified and if that is the case, the Commission must decide on what level of cost is reasonable. The alternative recommendation first adjusts for the excessiveness of the amount requested. From 2002-2004 the costs, similar to the annual incentive plan, were relatively flat. The cost of the long-term incentives ranged from \$14.5 million to \$17.4 million while averaging \$16,130,200. The Company's request in 2006 is for \$29,717,000, an increase of 84.2%. The only way such an increase could be justified by the company, based on the purpose of the plans, is the approval of the rate increase requested, which will fulfill the purpose of the plans by increasing shareholder value. The excess costs should not be allowed. Also, after adjusting for the excessive request then at least fifty percent of the remaining $16,130,200 or $7,976,747 on a jurisdictional basis, should be disallowed as being shareholder related. There should be no doubt that the long-term incentive plan is for the enhancement of shareholder value and therefore at a minimum an adjustment of $21,414,703, on a jurisdictional basis, is justified.

IV. FRINGE BENEFITS

Q. WHAT HAS THE COMPANY IDENTIFIED AS FRINGE BENEFITS?

A. The Company identified a number of benefits on Company Schedule C-35. The benefits listed include, but are not limited to, medical insurance, pension plan, employee savings plan, payroll taxes, workers compensation insurance, post retirement medical benefits and employee welfare costs.

Q. ARE YOU RECOMMENDING ANY ADJUSTMENTS TO THE BENEFITS IDENTIFIED?

A. Yes. Some adjustments are recommended based on the direct relationship to payroll and my recommended payroll adjustments, and other adjustments are recommended based on either the Company's calculation and or the excessiveness of the amount in question.

Medical Insurance

Q. ARE YOU RECOMMENDING AN ADJUSTMENT BE MADE TO THE COST FOR MEDICAL INSURANCE?

A. Yes. As shown on Schedule 5, the medical insurance expense should be reduced $2,409,020 on a jurisdictional basis. The adjustment takes into consideration changes in employee numbers, changes in assumptions and inconsistency in the Company filing.

Q. PLEASE EXPLAIN THE INCONSISTENCY AND CHANGES?

A. The Company, in response to Citizens POD No. 7, had a correspondence (Bates No. FPL051976 and FPL051977) that indicates the Company projected benefit costs are based on a different headcount than the headcount incorporated in the business unit forecast. Presumably, the benefits cost is based on a headcount of 10,424 according to the correspondence. The inconsistency is that the response to Citizens Interrogatory No. 51 states that medical costs for 2006 were based on an approximate 3% increase in covered employees in 2005 and a 1% increase in 2006. However, the response to Citizens Interrogatory No. 36 indicates the 401(k) benefit reflected a 1% change in participants in 2005 and again in 2006. The changes that I am reflecting include actual FPL 2004 per employee costs from a March 2005 Hewitt Health Value Initiative study (Citizens POD No. 143) and the projected per employee cost for 2005. The change in employee numbers in the benefit compensation is consistent with my recommended payroll complement of 10,330. Unlike the Company's different counts of either 10,424, 10,628 (business unit count per POD No. 7) or the 10,558 on Company Schedule C-35. The change in assumption referred to is my use of the March 2005 Hewitt Health Value Initiative reflecting a 10% increase for 2005 instead of the 13% the Company claims that they reflected in their projection.

Q. WAS THERE ANYTHING ELSE YOU CONSIDERED IN DETERMINING THE REASONABLENESS OF THE COMPANY'S PROJECTION?

A. Yes. In response to Citizens POD NO. 56 a document identified as Human Resources/Corporate Services 2005 Budget Review with the words "Final Approved" on it, indicated the 2005 budget for medical was based on an 11.4% increase and not the 13% increase used by the Company, and the employee participant increase in the budget was 1% instead of the 3%, reportedly used by the Company in the filing.

Q. HOW DID YOU DETERMINE YOUR ADJUSTMENT?

A. The Company's response to Citizens POD No. 143 included the March 2005 Hewitt study referred to earlier. The study included the 2004 employers cost and employees covered as shown on lines 1 and 2 of Schedule 5. From that information the average cost per employee was calculated to be $5,786. The study projected the 2005 cost to be $6,386 or about a 10% increase over 2004. The Company in its response to Citizens Interrogatory No. 51 utilized a 15% increase for 2006. The same 15% was applied to the 2005 projected cost of $6,386 resulting in an average employer cost per employee of $7,344 for the year 2006. That $7,344 average was multiplied by the recommended 2006 complement of 10,330 resulting in a cost of $75,862,847. That calculated cost is $3,749,513 less than the Company's projection of $79,612,000. After applying the respective O&M factor and jurisdictional factor a $2,409,020 reduction to expense results. The adjustment should be adopted because it is based on more current information and reflects a more accurate employee count.

Pensions

Q. ARE YOU RECOMMENDING AN ADJUSTMENT TO THE PENSION EXPENSE CREDIT REFLECTED BY THE COMPANY"

A. Yes. Based on the February 2005 actuarial determination the Company's pension credit for 2006 should be increased (reducing O&M expense) by $4,759,000 on a jurisdictional basis.

Q. WHAT DID YOU ANALYZE TO MAKE YOUR DETERMINATION?

A. The Company's response to Citizens POD No. 108 provided the detail utilized by the Company for making the projections for 2006. A February 2005 Actuarial Report reflected the same pension credit for 2004 and 2005 as shown in Citizens POD No. 108. The common factor noted in the recent studies is that the projection for the 2006 pension credit is the worst case scenario being forecasted for the years 2006-2010. It was also noted that for 2005 the original pension credit was less than the revised pension credit. The pension credit projection for 2006 will not be the same as the actuarial determination of the pension credit for 2006. The February 2005 actuarial determination provides an amount for 2005 that is known and measurable. The forecast for the years 2006-2010 averages out to about the same as 2005. Based on the forecast and the 2005 determination it is recommended that the 2006 pension credit be based on the 2005 credit, the last actuarially determined amount. The adjustment of $4,759,000 as shown on Schedule 6, is simply the difference between the 2005 and 2006 credits reflected on Company Schedule C-35 multiplied by the O&M expense factor and the jurisdictional allocation factor.

Payroll Tax Expense

Q. ARE YOU MAKING AN ADJUSTMENT TO PAYROLL TAX EXPENSE BASED ON THE RECOMMENDED PAYROLL ADJUSTMENT?

A. Yes. As shown on Schedule 7 taxes other should be reduced $1,803,271 on a jurisdictional basis. The adjustment utilizes the same 6.98% effective pay rate used by the Company multiplied by the sum of the various payroll adjustments recommended. That result is then multiplied by the Company's jurisdictional factor for payroll taxes as shown on Company Schedule C-4.

Q. DOES THAT CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

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

A. My name is J. Randall Woolridge and my business address is 120 Haymaker Circle, State College, PA 16801. I am a Professor of Finance and the Goldman, Sachs & Co. and Frank P. Smeal Endowed University Fellow in Business Administration at the University Park Campus of the Pennsylvania State University. I am also the Director of the Smeal College Trading Room and the President of the Nittany Lion Fund, LLC. In addition, I am affiliated with the Columbia Group Inc., a public utility consulting firm based in Georgetown, CT. A summary of my educational background, research, and related business experience is provided in Appendix A.

I. SUBJECT OF TESTIMONY AND SUMMARY OF RECOMMENDATIONS

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

A. I have been asked by the Florida Office of Public Counsel to provide an opinion as to the overall fair rate of return or cost of capital for Florida Power and Light Company ("FPL" or "Company") and to evaluate FPL's rate of return testimony in this proceeding.

Q. PLEASE REVIEW YOUR COST OF CAPITAL RETURN FINDINGS.

A. I have independently arrived at a cost of capital for the Company. I have established an equity cost rate of 8.8% for FPL primarily by applying the Discounted Cash Flow ("DCF") approach to a group of electric utility companies. I have also performed a Capital Asset Pricing

Model ("CAPM") study. Utilizing my equity cost rate, capital structure ratios, and senior capital cost rates, I am recommending an overall fair rate of return for the Company of 7.34%. This recommendation is summarized in Exhibit_(JRW-1).

Q. PLEASE SUMMARIZE YOUR ASSESSMENT OF THE COMPANY'S RATE OF RETURN POSITION.

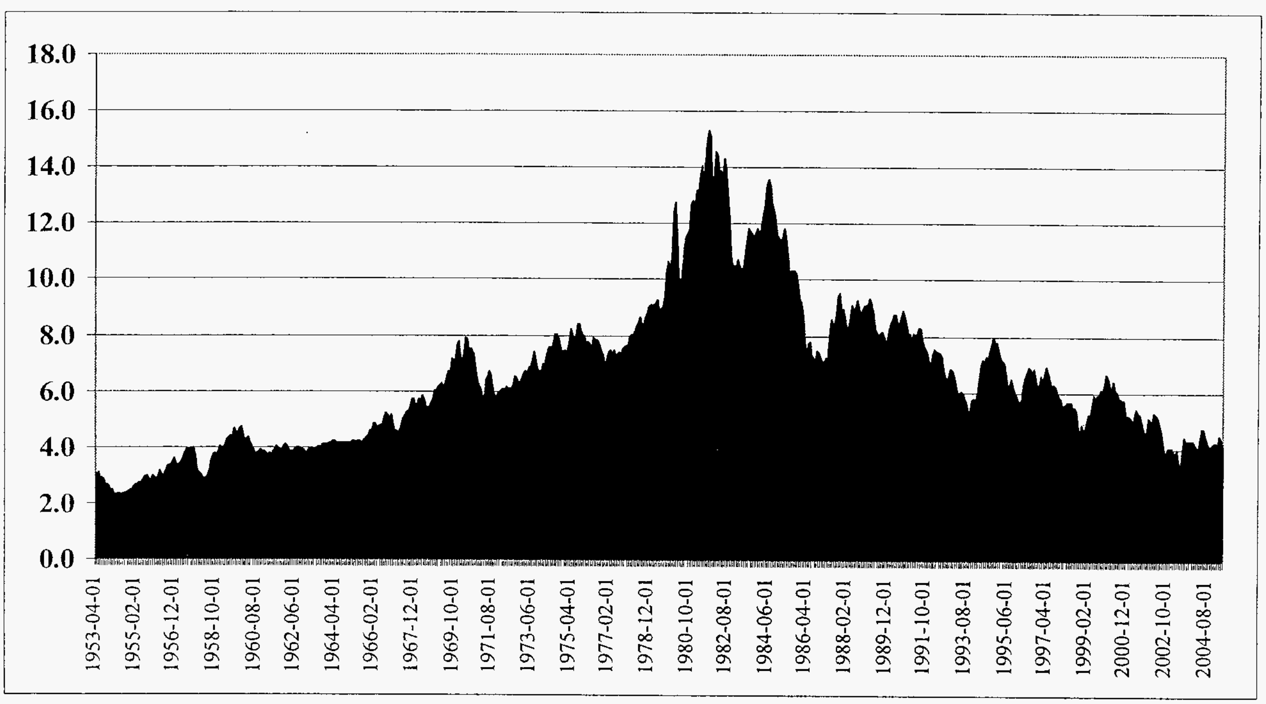
A. The Company's rate of return testimony is offered by Mr. Moray P. Dewhurst, the Company's Chief Financial Officer (CFO), and Dr. William E. Avera, a consultant. The Company's proposed rate of return is excessive due to an inflated long-term debt cost rate and an overstated equity cost rate. Mr. Dewhurst's long-term debt cost rate of 5.89% includes four proforma financings at interest rates well above current market yields. His capital structure contains a common equity ratio which is higher than other operating electric utility companies and is much higher than the common equity ratios of publicly-held electric companies. The Company's requested return on equity of 12.3% includes a 50 basis point performance incentive on top of Dr. Avera's estimated equity cost rate of 11.8%. Dr. Avera's 11.8% is unreasonably high due to (1) an upwardly-biased expected growth rate in his DCF equity cost rate, (2) the use of forecasted interest rates that are well in excess of the current long-term market yields, (3) excessive risk premium estimates in his various risk premium approaches, and (4) the lack of a financial risk adjustment as well as an inappropriate flotation cost adjustment.

Q. PLEASE DISCUSS CAPITAL COSTS IN TODAY'S MARKETS.

A. Capital cost rates for U.S. corporations are currently at their lowest levels in more than four decades. Corporate capital cost rates are determined by the level of interest rates and the risk premium demanded by investors to buy the debt and equity capital of corporate issuers. The base level of interest rates in the US economy is indicated by the rates on U.S. Treasury bonds. The benchmark for long-term capital costs is the rate on ten-year Treasury bonds. The rates are provided in the graph below from 1953 to the present. As indicated, prior to the secular decline in rates that began last year, the 10-year Treasury had not been in the 4-5 percent range since the 1960s.

Yields on Ten-Year Treasury Bonds

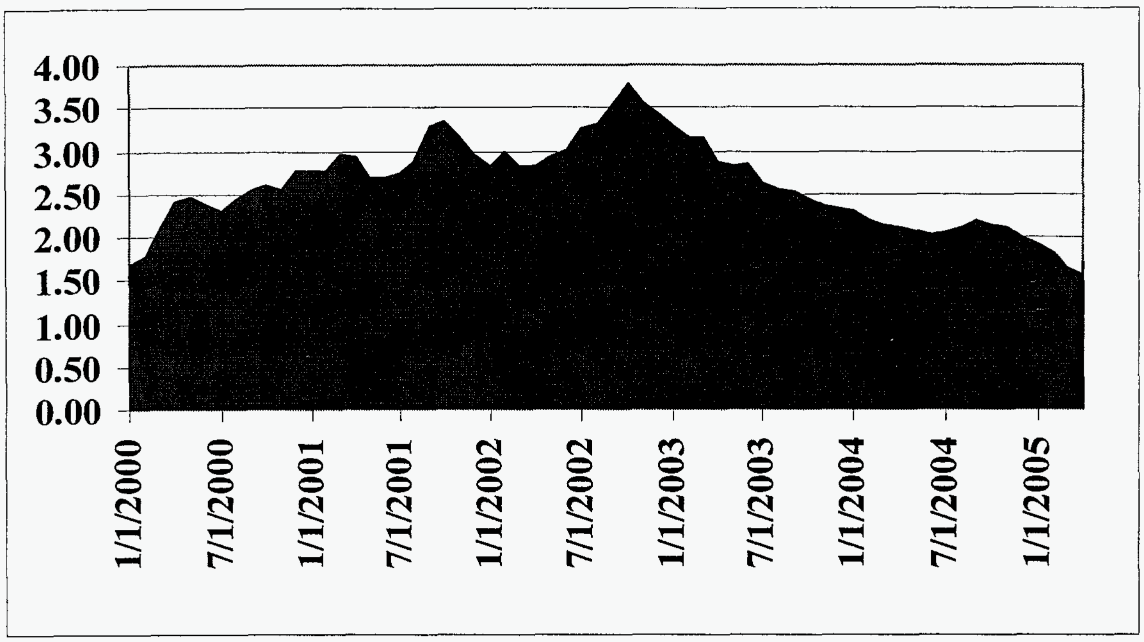
1953-Present



Source: http://research.stlouisfed.org/fred2/data/GS10.txt

The second base component of the corporate capital cost rates is the risk premium. The risk premium is the return premium required by investors to purchase riskier securities. Risk premiums for bonds are the yield differentials between different bond classes as rated by agencies such as Moody's, and Standard and Poor's. The graph below provides the yield differential between Baa-rate corporate bonds and 10-year Treasuries. This yield differential peaked at 350 basis points (BPs) in 2002 and has declined significantly since that time. This is an indication that the market price of risk has declined and therefore the risk premium has declined in recent years.

Corporate Bond Yield Spreads
Baa-Rated Corporate Bond Yield Minus Ten-Year Treasury Bond Yield



Source: http://www.treas.gov/offices/domestic-finance/debt-management/interest-rate/index.html

The equity risk premium is the return premium required to purchase stocks as opposed to bonds. Since the equity risk premium is not readily observable in the markets (as are bond risk premiums), and there are alternative approaches to estimating the equity premium, it is the subject of much debate. One way to estimate the equity risk premium is to compare the mean returns on bonds and stocks over long historic periods. Measured in this manner, the equity risk premium has been in the 5-7 percent range. But recent studies by leading academics indicate the forward-looking equity risk premium is in the 3-4 percent range. These authors indicate that historic equity risk premiums are upwardly biased measures of expected equity risk premiums. Jeremy Siegel, a Wharton finance professor and author of the popular book *Stocks for the Long Term*, published a study entitled "The Shrinking Equity Risk Premium."[1] He concludes:

> The degree of the equity risk premium calculated from data estimated from 1926 is unlikely to persist in the future. The real return on fixed-income assets is likely to be significantly higher than estimated on earlier data. This is confirmed by the yields available on Treasury index-linked securities, which currently exceed 4%. Furthermore, despite the acceleration in earnings growth, the return on equities is likely to fall from its historical level due to the very high level of equity prices relative to fundamentals.

Even Alan Greenspan, the Chairman of the Federal Reserve Board, indicated in an October 14, 1999, speech on financial risk that the fact that equity risk premiums have declined during the past decade is "not in dispute." His assessment focused on the relationship between information availability and equity risk premiums.

[1] Jeremy J. Siegel, "The Shrinking Equity Risk Premium," *The Journal of Portfolio Management* (Fall, 1999), p.15.

> There can be little doubt that the dramatic improvements in information technology in recent years have altered our approach to risk. Some analysts perceive that information technology has permanently lowered equity premiums and, hence, permanently raised the prices of the collateral that underlies all financial assets.
>
> The reason, of course, is that information is critical to the evaluation of risk. The less that is known about the current state of a market or a venture, the less the ability to project future outcomes and, hence, the more those potential outcomes will be discounted.
>
> The rise in the availability of real-time information has reduced the uncertainties and thereby lowered the variances that we employ to guide portfolio decisions. At least part of the observed fall in equity premiums in our economy and others over the past five years does not appear to be the result of ephemeral changes in perceptions. It is presumably the result of a permanent technology-driven increase in information availability, which by definition reduces uncertainty and therefore risk premiums. This decline is most evident in equity risk premiums. It is less clear in the corporate bond market, where relative supplies of corporate and Treasury bonds and other factors we cannot easily identify have outweighed the effects of more readily available information about borrowers.[2]

In sum, the relatively low interest rates in today's markets as well as the lower risk premiums required by investors indicate that capital costs for U.S. companies are the lowest in decades. In addition, the 2003 tax law further lowered capital cost rates for companies.

Q. HOW DID THE *JOBS AND GROWTH TAX RELIEF RECONCILIATION ACT of 2003* REDUCE THE COST OF CAPITAL FOR COMPANIES?

[2] Alan Greenspan, "Measuring Financial Risk in the Twenty-First Century," Office of the Comptroller of the Currency Conference, October 14, 1999.

A. On May 28th of 2003, President Bush signed the *Jobs and Growth Tax Relief Reconciliation Act of 2003.* The primary purpose of this legislation was to reduce taxes to enhance economic growth. A primary component of the new tax law was a significant reduction in the taxation of corporate dividends for individuals. Dividends have been described as "double-taxed." First, corporations pay taxes on the income they earn before they pay dividends to investors, then investors pay taxes on the dividends that they receive from corporations. One of the implications of the double taxation of dividends is that, all else equal, it results in a higher cost of raising capital for corporations. The tax legislation reduced the effect of double taxation of dividends by lowering the tax rate on dividends from the 30 percent range (the average tax bracket for individuals) to 15 percent.

Overall, the 2003 tax law reduced the pre-tax return requirements of investors, thereby reducing corporations' cost of equity capital. This is because the reduction in the taxation of dividends for individuals enhances their after-tax returns and thereby reduces their pre-tax required returns. This reduction in pre-tax required returns (due to the lower tax on dividends) effectively reduces the cost of equity capital for companies. The 2003 tax law also reduced the tax rate on long-term capital gains from 20% to 15%. The magnitude of the reduction in corporate equity cost rates is debatable, but my assessment indicates that it could be as large as 100 basis points. (See Exhibit_(JRW-2)).

II. COMPARISON GROUP SELECTION

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

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

Q. PLEASE DESCRIBE YOUR ELECTRIC UTILITY COMPANIES.

A. I am using the group of electric companies employed by FPL Witness Avera. This group includes twenty one publicly-traded electric utility companies. Summary financial statistics for the group are provided in Exhibit_(JRW-3). On average, the group has operating revenues of $6,948M, earns a return on equity of 11.0%, and sells at a market-to-book value ratio of 1.64.

III. DEBT COST RATES AND CAPITAL STRUCTURE RATIOS

Q. WHAT ARE THE COMPANY'S PROPOSED CAPITAL STRUCTURE RATIOS AND SENIOR CAPITAL COST RATES?

A. Mr. Dewhurst has proposed a capital structure based on a thirteen month pro forma capitalization consisting of 0.55% short-term debt, 43.62% long-term debt, and 55.83% common equity. He has also proposed a long-term debt cost rate of 5.89% and a short-term debt cost rate of 8.73%. This position is summarized on page 1 of Exhibit_(JRW-4).

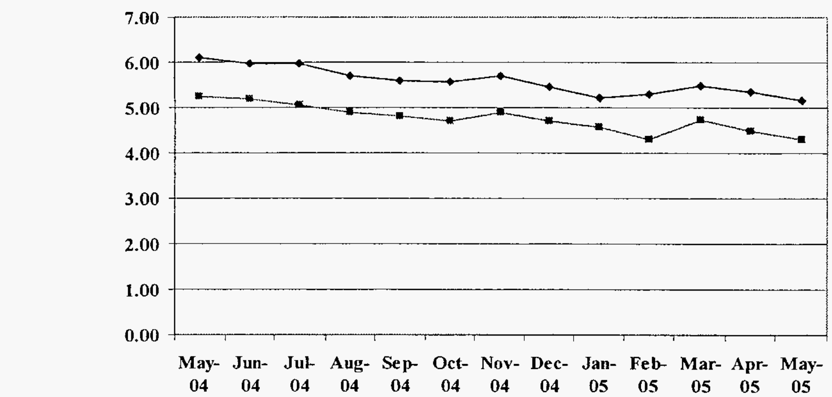
Q. ARE YOU ADOPTING THE COMPANY'S PROPOSED SENIOR CAPITAL COST RATES?

A. I am using the short-term debt cost rate of 8.73% at this time. It is abnormally high relative to short-term interest rates due to (1) the fixed financing commitment fees and (2) the low projected balances of short-term debt.

I am not employing the Company's proposed long-term debt cost rate of 5.89%. It is unrealistic because of the projected yields on four proforma debt offerings. Page 2 of Exhibit_(JRW-4) provides the Company's long-term debt outstanding as provided in FPL Schedule D-4a, page 1. These debt issues, listed as First Mortgage bond issues number 9, 10, 11, and 12, are to be sold between December 2005 and December 2006 and have projected yields of 6.8%, 6.8%, 7.2%, and 7.2%, respectively. As shown in the graph below, since the Company filed its testimony, long-term interest rates have decreased and thus these projected rates are well in excess of current market interest rates.

30-Year Bond Yields

A-Rated Public Utility and Treasury Bond Yields



	5/31/2004	6/30/2004	7/31/2004	8/31/2004	9/30/2004	10/31/2004	11/30/2004	12/31/2004	1/31/2005	2/28/2005	3/31/2005	4/30/2005	5/31/2005
30-Year 'A' Utility	6.11	5.99	5.97	5.71	5.60	5.57	5.72	5.46	5.21	5.31	5.49	5.35	5.16
30-Year Treasury	5.25	5.18	5.06	4.88	4.80	4.70	4.89	4.71	4.56	4.30	4.72	4.49	4.31

30-Year 'A' Utility — 30-Year Treasury

Source: Bloomberg

The yield on 30-year A-rated public utility bonds was 5.16% as of the end of May. Considering the current yields on these bonds as well as the recent trends in interest rates, I will use 5.25% as the yield on the four proforma bond issues of the Company. As developed on page 2 of Exhibit_(JRW-4), using this rate for these four bond issues provides an overall long-term debt cost rate to 5.45% for the Company.

Q. ARE YOU ADOPTING THE COMPANY'S PROPOSED CAPITAL STRUCTURE RATIOS?

A. Yes, with a very important caveat. FPL's proposed capital structure includes a common equity ratio of 55.83% which is high by industry standards. FPL's actual common equity ratio is 61.92%. The 55.83% ratio is adjusted according to rating agency standards to reflect the Company's fixed charges associated with purchased power contracts. This figure was used for limited purposes in FPL's 1999 Stipulation and Settlement Agreement between FPL and the OPC. As discussed at length by Mr. Dewhurst, this equity-rich capitalization has provided the Company with a very strong financial position.

The caveat on adopting FPL's capital structure is that the Company's financial risk is (1) lower than other operating electric utilities and (2) much lower than publicly-held electric companies. This lower financial risk allows for a lower allowed return on common equity for FPL.

Q. PLEASE SUMMARIZE YOUR PROPOSED CAPITAL STRUCTURE RATIOS AND SENIOR CAPITAL COST RATES.

A. My recommended structure and senior capital cost rates which are shown below.

Florida Power & Light Company
Proposed Capital Structure and Senior Capital Cost Rates

Source of Capital	Capitalization Ratio	Cost Rate
Short-Term Debt	0.55%	8.73%
Long-Term Debt	43.62%	5.45%
Common Equity	55.83%	

IV. THE COST OF COMMON EQUITY CAPITAL

A. OVERVIEW

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

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

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

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

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

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

James M. McTaggart, founder of the international management consulting firm Marakon Associates, has described this essential relationship between the return on equity, the cost of equity, and the market-to-book ratio in the following manner:[3]

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

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

however, the business earns an ROE consistently less than its cost of equity, it is economically unprofitable and its market value will be less than book value.

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

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

A. Exhibit_(JRW-5) provides indicators of public utility equity cost rates over the past decade. Page 1 shows the yields on 10-year, 'A' rated public utility bonds. These yields peaked in the Dewhurst 1990s at 10%, and have generally declined since that time. In particular, over the past two years they have declined from the seven percent range to the 4.5 to 5.0 percent range. Page 2 provides the dividend yields for the fifteen utilities in the Dow Jones Utilities Average over the past decade. These yields peaked in 1994 at 6.7%. Since that time they have declined and have remained in the 4.5-5.0 percent range in recent years.

Average earned returns on common equity and market-to-book ratios are given on page 3 of Exhibit_(JRW-5). Over the past decade, earned returns on common equity have consistently been in the 10.0 - 13.0 percent range. The low point was 10.3 % in 1997 and they have increased to 12.5 percent range as of the year 2003. Over the past decade, market-to-book ratios for this group bottomed out at 128% in 1994 and they have increased to the 150-180 percent range in recent years.

The indicators in Exhibit_(JRW-5), coupled with the overall decrease in interest rates, suggest that capital costs for the Dow Jones Utilities have decreased over the past decade. Specifically for the equity cost rate, the significant increase in the market-to-book ratios, coupled with only a much smaller increase in the average return on equity, suggests a substantial decline in the overall equity cost rate.

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

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

Q. HOW DOES THE INVESTMENT RISK OF ELECTRIC UTILITY COMPANIES COMPARE WITH THAT OF OTHER INDUSTRIES?

A. Due to the essential nature of their service as well as their regulated status, public utilities are exposed to a lesser degree of business risk than other, non-regulated businesses. The relatively low level of business risk allows public utilities to meet much of their capital requirements through borrowing in the financial markets, thereby incurring greater than average financial risk. Nonetheless, the overall investment risk of public utilities is below most other industries. Exhibit_(JRW-6) provides an assessment of investment risk for 100 industries as measured by beta, which according to modern capital market theory is the only relevant measure of investment risk that need be of concern for investors. These betas come from the *Value Line Investment Survey* and are compiled by Aswath Damodoran of New York University. They may be found on the Internet at http://www.stern.nyu.edu/~adamodar/. The study shows that the investment risk of public utilities is relatively low. The average beta for electric utilities in the Eastern U.S. is 0.72. This figure ranks in the bottom quarter of the 100 industries in terms of beta. As such, the cost of equity for the electric utility industry is among the lowest of all industries in the U.S.

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

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

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

Models have been developed to ascertain the cost of common equity capital for a firm. Each model, however, has been developed using restrictive economic assumptions. Consequently, judgment is required in selecting appropriate financial valuation models to estimate a firm's cost of common equity capital, in determining the data inputs for these models, and in interpreting the models' results. All of these decisions must take into consideration the firm involved as well as conditions in the economy and the financial markets.

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

A. I rely primarily on the Discounted Cash Flow ("DCF") model to estimate the cost of equity capital. I believe that the DCF model provides the best measure of equity cost rates for public utilities. I have also performed a Capital Asset Pricing Model (CAPM) study, but I give these results less weight because I believe that risk premium studies, of which the CAPM is one form, provide a less reliable indication of equity cost rates for public utilities.

B. DISCOUNTED CASH FLOW ANALYSIS

Q. BRIEFLY DESCRIBE THE THEORY BEHIND THE TRADITIONAL DCF MODEL.

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

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

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

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

A. Yes. Virtually all investment firms use some form of the DCF model as a valuation technique. One common application for investment firms is called the three-stage DCF or dividend discount model (DDM). The stages in a three-stage DCF model are discussed below. This model presumes that a company's dividend payout progresses initially through a growth stage, then proceeds through a transition stage, and finally assumes a steady state stage. The dividend payment stage of a firm depends on the profitability of its internal investments, which, in turn, is largely a function of the life cycle of the product or service. These stages are depicted in the graphic below labeled the Three Stage DCF Model.[4]

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

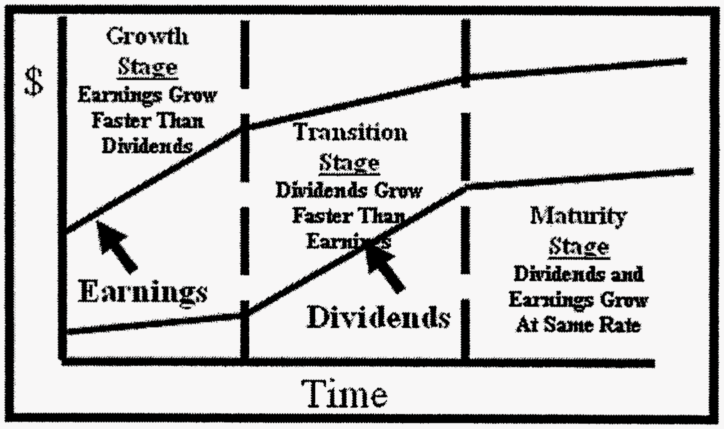
2. **Transition stage**: In later years, increased competition reduces profit margins and earnings growth slows. With fewer new investment opportunities, the company begins to pay out a larger percentage of earnings.

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

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

Three-Stage DCF Model

[4] This description comes from William F. Sharp, Gordon J. Alexander, and Jeffrey V. Bailey, *Investments* (Prentice-Hall, 1995), pp. 590-91.



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

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

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

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

$$D_1$$

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

Given the regulated status of public utilities, and especially the fact that their returns on investment are effectively set through the ratemaking process, the industry would be in the steady-state stage of a three-stage DCF. The DCF valuation procedure for companies in this stage is the constant-growth DCF. In the constant-growth version of the DCF model, the current dividend payment and stock price are directly observable. Therefore, the primary problem and controversy in applying the DCF model to estimate equity cost rates entails estimating investors' expected dividend growth rate.

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

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

Q. PLEASE DISCUSS EXHIBIT_(JRW-7).

A. My DCF analysis is provided in Exhibit_(JRW-7). The DCF summary is on page 1 of this Exhibit and the supporting data and analysis for the dividend yield and expected growth rate are provided on the following pages.

Q. WHAT DIVIDEND YIELD DO YOU EMPLOY IN YOUR DCF ANALYSIS FOR YOUR GROUP OF ELECTRIC UTILITY COMPANIES?

A. The dividend yields on the common stock for the companies in the group are provided on page 2 of Exhibit_(JRW-7) for the five-month period ending May, 2005. Over this period, the average monthly dividend yield for the group is 4.0%. As of May, 2005, the mean dividend yield for the group is 4.0%. For the DCF dividend yields for the group, I use the average of the five month and May, 2005 dividend yields. As such, the average DCF dividend yield for the group is 4.0%

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

A. According to the traditional DCF model, the dividend yield term relates to the dividend yield over the coming period. As indicated by Professor Myron Gordon, who is commonly associated with the development of the DCF model for popular use, this is obtained by (1) multiplying the expected dividend over the coming quarter by 4, and (2) dividing this dividend by the current stock price to determine the appropriate dividend yield for a firm, which pays dividends on a quarterly basis.[5]

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

The appropriate adjustment to the dividend yield is further complicated in the regulatory process when the overall cost of capital is applied to a projected or end-of-future-test-year rate base. The net effect of this application is an overstatement of the equity cost rate estimate derived from the DCF model. In the context of the constant-growth DCF model, both the adjusted dividend yield and the growth component are overstated. Put simply, the overstatement results from applying an equity cost rate computed using current market data to a future or test-year-end rate base which includes growth associated with the retention of earnings during the year.

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

A. I will adjust the dividend yield for the electric utility group by 1/2 the expected growth so as to reflect growth over the coming year.

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

A. There is much debate as to the proper methodology to employ in estimating the growth component of the DCF model. By definition, this component is investors' expectation of the long-

[5] *Petition for Modification of Prescribed Rate of Return*, Federal Communications Commission, Docket No. 79-05,

term dividend growth rate. Presumably, investors use some combination of historic and/or projected growth rates for earnings and dividends per share and for internal or book value growth to assess long-term potential.

Q. WHAT GROWTH DATA HAVE YOU REVIEWED FOR THE GROUP OF ELECTRIC UTILITY COMPANIES?

A. I have analyzed a number of measures of growth for the electric utility companies. I calculated historic growth rates in sales, earnings, dividends, and book value per share growth rates for the companies in the group. I have reviewed *Value Line's* historic and projected growth rate estimates for earnings per share (EPS), dividends per share (DPS), and book value per share (BVPS). In addition, I have utilized earnings growth rate forecasts as provided by Zacks, Reuters, and First Call. These services solicit 5-year earning growth rate projections for securities analysts and compile and publish the averages of these forecasts on a monthly basis. They are readily available on the Internet. Finally, I have also assessed prospective growth as measured by prospective earnings retention rates and earned returns on common equity.

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

A. Historic growth rates for EPS, DPS, and BVPS are readily available to virtually all investors and presumably an important ingredient in forming expectations concerning future growth. However, one must use historic growth numbers as measures of investors' expectations with

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Direct Testimony of Myron J. Gordon and Lawrence I. Gould at 62 (April 1980).

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

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

Q. PLEASE SUMMARIZE YOUR ANALYSIS OF *VALUE LINE'S* HISTORIC AND PROJECTED GROWTH RATES FOR THE GROUP OF ELECTRIC UTILITY COMPANIES.

A. Historic growth rates for the companies in the group, as published in the *Value Line Investment Survey*, are provided in Panel A, page 3 of Exhibit_(JRW-7). Due to the presence of outliers among the historic growth rate figures, both the mean and medians are used in the analysis. Historic growth in EPS, DPS, and BVPS for the twenty-one company group, as measured by the means and medians, ranges from -0.6% to 5.07%, with an average of 2.6%.

Projections of EPS, DPS, and BVPS growth for the group are shown in Panel B. As above, due to the presence of outliers, both the mean and medians are used in the analysis. For the group, the average of the means and medians of the projections is 5.0%. Also provided in Panel B is prospective internal growth for the group as measured by *Value Line*'s average projected retention rate and return on shareholders' equity. The average prospective internal growth rate for the group is 4.8%.

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

A. Zacks, First Call, and Reuters collect, summarize, and publish Wall Street analysts' projected 5-year EPS growth rate forecasts for companies. These forecasts are provided for the group of electric utility companies on page 4 of Exhibit_(JRW-7). Since there is considerable overlap in analyst coverage between the three services, I have averaged the expected 5-year EPS growth rates from the three services for each company to arrive at an expected EPS growth rate for each company. For the twenty-one company electric utility group, the average of the projected 5-year EPS growth rates is 5.0%.

Q. PLEASE SUMMARIZE YOUR ANALYSIS OF THE HISTORIC AND PROSPECTIVE GROWTH OF THE GROUP OF ELECTRIC UTILITY COMPANIES.

A. For the company group of electric utility companies, the average of historic growth rate measures in EPS, DPS, and BVPS is 2.6%. Projected growth is higher. The average of *Value Line* projected growth rates and prospective internal growth rates for the group are 5.0% and 4.8%, and the average of the analysts' projected 5-year EPS growth rate forecasts for these companies is 5.0%. Giving greater weight to the projected growth rate figures, an expected growth rate in the range of 4.5-5.0 percent is reasonable. I will use the midpoint of this range – 4.75% - as the expected growth rate for the electric utility group.

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

A. My DCF-derived equity cost rate for the group is:

$$\text{DCF Equity Cost Rate (k)} = \frac{D}{P} + g$$

	Dividend Yield	½ Growth Adjustment	DCF Growth Rate	Equity Cost Rate
Twenty-One Electric Utility Group	4.0%	1.02375	4.75%	8.8%

These results are summarized on page 1 of Exhibit_(JRW-7).

C. CAPITAL ASSET PRICING MODEL RESULTS

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

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

$$k = R_f + RP$$

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

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

$$K = (R_f) + \beta_{ibm} * [E(R_m) - (R_f)]$$

Where:

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

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

Q. PLEASE DISCUSS EXHIBIT_(JRW-8).

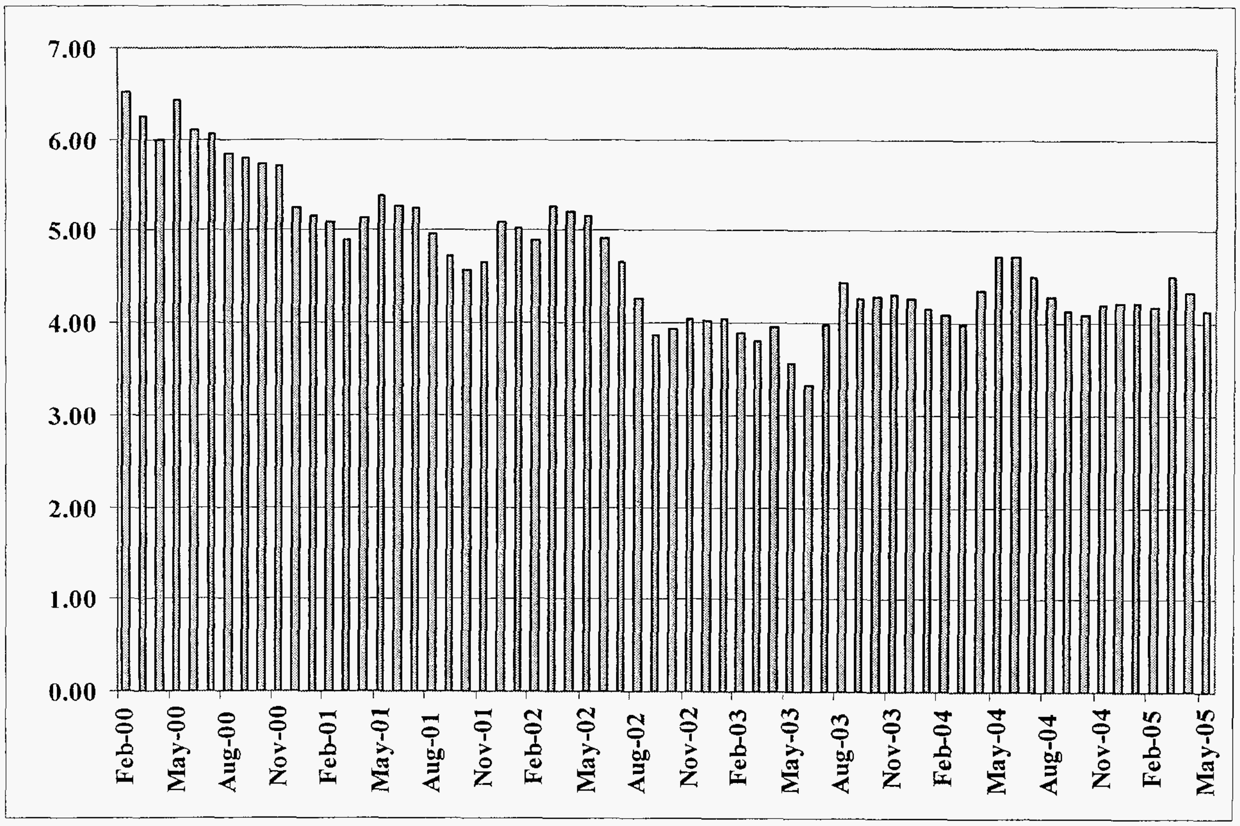
A. Exhibit_(JRW-8) provides the summary results for my CAPM study. Page 1 gives the results, and the following pages contain the supporting data.

Q. PLEASE DISCUSS THE RISK-FREE INTEREST RATE IN YOUR CAPM.

A. The yield on long-term Treasury bonds has usually been viewed as the risk-free rate of interest in the CAPM. The yield on long-term Treasury bonds, in turn, was normally considered to be the yield on Treasury bonds with 30-year maturities. However, in recent years, the yield on 10-year Treasury bonds has replaced the yield on 30-year Treasury bonds as the benchmark long-term Treasury rate. The 10-year Treasury yields over the past five years are shown in the chart below. These rates hit a 60-year low in the summer of 2003 at 3.33%. They increased with the rebounding economy to 4.75% in June of last year, and have since remained in the 4.0-4.50

percent range. As of May 2005, these rates have been near the lower boundry of this range (4.0%). Given this recent range and recent movement, as well as the potential for higher long-term rates, I will use 4.50% as the risk-free rate, or R_f, in my CAPM.

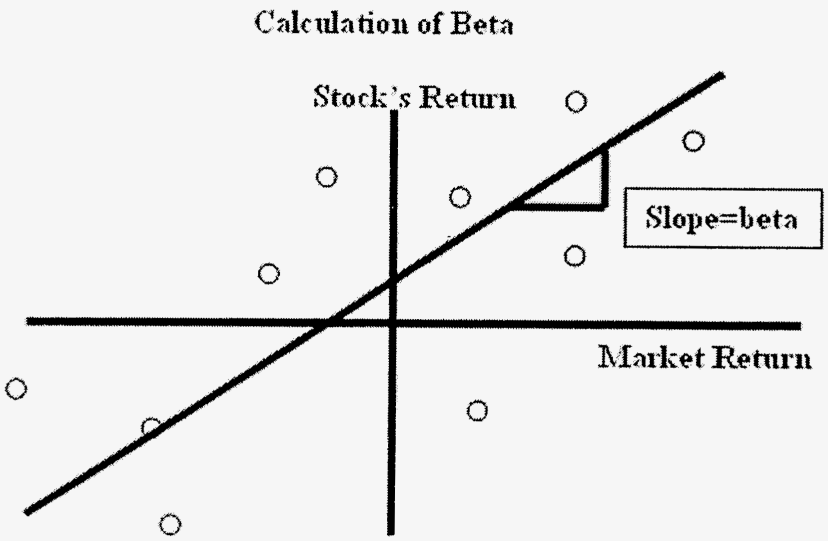
Ten-Year U.S. Treasury Yields
January 2000-May 2005



Source: http://www.federalreserve.gov/releases/h15/current/h15.pdf

Q. WHAT BETAS ARE YOU EMPLOYING FOR THE ELECTRIC UTILITY GROUP IN YOUR CAPM?

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



The slope of the regression line is the stock's ß. A steeper line indicates the stock is more sensitive to the return on the overall market. This means that the stock has a higher ß and greater than average market risk. A less steep line indicates a lower ß and less market risk.

Numerous online investment information services, such Yahoo and Reuters, provide estimates of stock betas. Usually these services report different betas for the same stock. The differences are usually due to (1) the time period over which the ß is measured and (2) any adjustments that are made to reflect the fact that betas tend to regress to 1.0 over time. In estimating an equity cost rate for the group of electric utility companies, I am using the average betas for the companies as provided in the *Value Line Investment Survey*. As shown on page 2 of Exhibit_(JRW-8), the average for the eleven company group is 0.78.

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

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

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

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

Risk Premium Approaches

	Historical Ex Post Excess Returns	Surveys	Ex Ante Models and Market Data
Means of Assessing the Equity-Bond Risk Premium	Historical average is a popular proxy for the ex ante premium – but likely to be misleading	Investor and expert surveys can provide direct estimates of prevailing expected returns/premiums	Current financial market prices (simple valuation ratios or DCF-based measures) can give most objective estimates of feasible ex ante equity-bond risk premium
Problems/Debated Issues	Time variation in required returns and systematic selection and other biases have boosted valuations over time, and have exaggerated realized excess equity returns compared with ex ante expected premiums	Limited survey histories and questions of survey representativeness. Surveys may tell more about hoped-for expected returns than about objective required premiums due to irrational biases such as extrapolation.	Assumptions needed for DCF inputs, notably the trend earnings growth rate, make even these models' outputs subjective. The range of views on the growth rate, as well as the debate on the relevant stock and bond yields, leads to a range of premium estimates.

Source: Antti Ilmanen, Expected Returns on Stocks and Bonds," *Journal of Portfolio Management*, (Winter 2003).

The use of historic returns as market expectations has been criticized in numerous academic studies.[6] The general theme of these studies is that the large equity risk premium discovered in historic stock and bond returns cannot be justified by the fundamental data. These studies, which fall under the category "Ex Ante Models and Market Data," compute ex ante expected returns using market data to arrive at an expected equity risk premium. These studies have also been called "Puzzle Research" after the famous study by Mehra and Prescott in which the authors first questioned the magnitude of historic equity risk premiums relative to fundamentals.[7]

Q. PLEASE BRIEFLY SUMMARIZE SOME OF THE NEW ACADEMIC STUDIES THAT DEVELOP EX ANTE EQUITY RISK PREMIUMS.

A. Two of the most prominent studies of ex ante expected equity risk premiums were by Eugene Fama and Ken French (2002) and James Claus and Jacob Thomas (2001). The primary debate in these studies revolves around two related issues: (1) the size of expected equity risk premium, which is the return equity investors require above the yield on bonds; and (2) the fact that estimates of the ex ante expected equity risk premium using fundamental firm data (earnings and dividends) are much lower than estimates using historic stock and bond return data. Fama and French (2002), two of the most preeminent scholars in finance, use dividend and earnings growth models to estimate expected stock returns and ex ante expected equity risk premiums.[8] They compare these results to actual stock returns over the period 1951-2000. Fama and French estimate

[6] The problems with using ex post historic returns as measure of ex ante expectation will be discussed at length later in my testimony.

[7] Rahnish Mehra and Edward Prescott, "The Equity Premium: A Puzzle," *Journal of Monetary Economic* (1985).

[8] Eugene F. Fama and Kenneth R. French, "The Equity Premium," *The Journal of Finance*, April 2002. This paper may be downloaded from the Internet at: http://papers.ssrn.com/sol3/papers.cfm?abstract_id=236590.

that the expected equity risk premium from DCF models using dividend and earnings growth to be between 2.55% and 4.32%. These figures are much lower than the ex post historic equity risk premium produced from the average stock and bond return over the same period, which is 7.40%.

Fama and French conclude that the ex ante equity risk premium estimates using DCF models and fundamental data are superior to those using ex post historic stock returns for three reasons: (1) the estimates are more precise (a lower standard error); (2) the Sharpe ratio, which is measured as the [(expected stock return – risk-free rate)/standard deviation], is constant over time for the DCF models but more than doubles for the average stock-bond return model; and (3) valuation theory specifies relationships between the market-to-book ratio, return on investment, and cost of equity capital that favor estimates from fundamentals. They also conclude that the high average stock returns over the past 50 years were the result of low expected returns and that the average equity risk premium has been in the 3-4 percent range.

The study by Claus and Thomas of Columbia University provides direct support for the findings of Fama and French.[9] These authors compute ex ante expected equity risk premiums over the 1985-1998 period by (1) computing the discount rate that equates market values with the present value of expected future cash flows, and (2) then subtracting the risk-free interest rate. The expected cash flows are developed using analysts' earnings forecasts. The authors conclude that over this period the ex ante expected equity risk premium is in the range of 3.0%. Claus and Thomas note that, over this period, ex post historic stock returns overstate the ex ante expected equity risk premium because as the expected equity risk premium has declined, stock prices have risen. In other words, from a valuation perspective, the present value of expected future returns increase when the required rate of return decreases. The higher stock prices have produced stock returns that have exceeded investors' expectations and therefore ex post historic equity risk premium estimates are biased upwards as measures of ex ante expected equity risk premiums.

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

A. Richard Derrig and Elisha Orr (2003) recently completed the most comprehensive paper to date which summarizes and assesses the many risk premium studies.[10] Appendix B of their study, which provides summary statistics for the different studies, is included as page 3 of Exhibit_(JRW-8). The risk premium studies listed under the 'Social Security' and 'Puzzle Research' sections are primarily ex ante expected equity risk premium studies. Most of these studies are performed by leading academic scholars in finance and economics. A review of the 'ERP Estimate' column in Appendix B of the Derrig and Orr study suggests that the average ex ante equity risk premium estimate is in the 4.0% range.

Q. GIVEN THIS BACKGROUND INFORMATION, HOW WILL YOU ESTIMATE AN EQUITY RISK PREMIUM FOR YOUR CAPM?

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[9] James Claus and Jacob Thomas, "Equity Risk Premia as Low as Three Percent? Empirical Evidence from Analysts' Earnings Forecasts for Domestic and International Stock Market," *Journal of Finance*. (October 2001).
[10] Richard Derrig and Elisha Orr, "Equity Risk Premium: Expectations Great and Small," Working Paper (version 3.0), Automobile Insurers Bureau of Massachusetts, August 28, 2003.

A. My equity risk premium is the average of: (1) the 4.0% average ex ante expected equity risk premiums from the studies covered in the Derrig and Orr (2003) study, and (2) an ex ante expected equity risk premium developed using Ibbotson and Chen's "building blocks methodology."

Q. PLEASE DISCUSS THE EX ANTE EXPECTED EQUITY RISK PREMIUM COMPUTED USING THE "BUILDING BLOCKS METHODOLOGY."

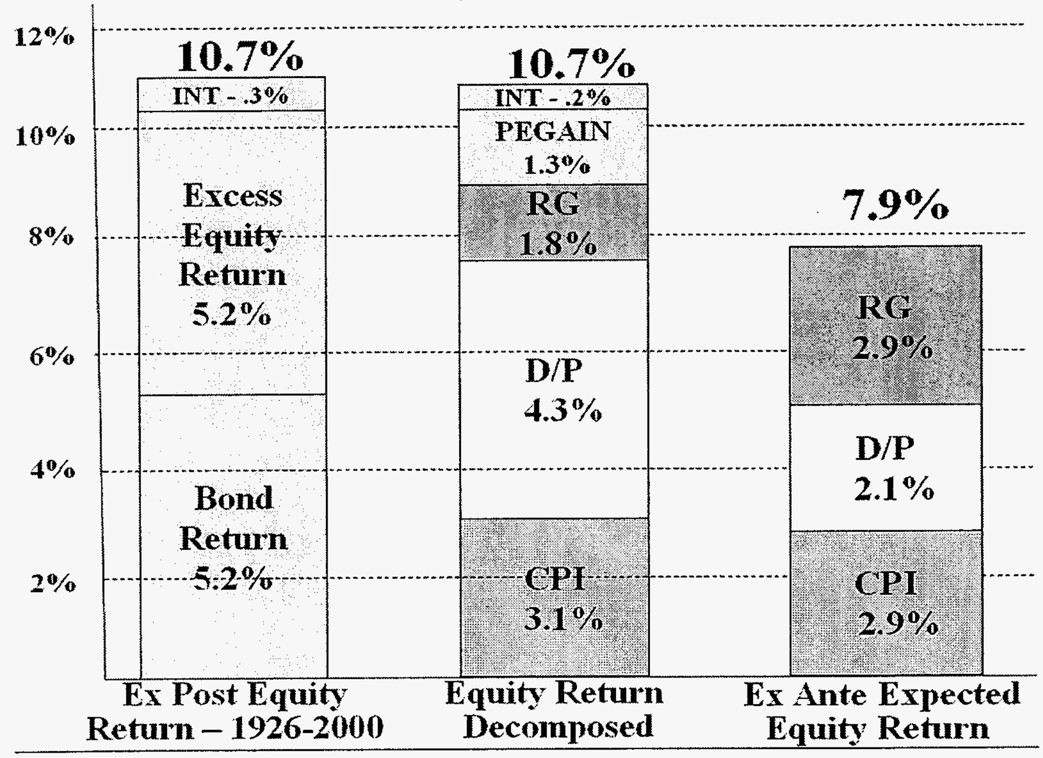
A. Ibbotson and Chen (2002) evaluate the ex post historic mean stock and bond returns in what is called a "building blocks methodology."[11] They use 75 years of data and relate the compounded historic returns to the different fundamental variables employed by different researchers in building ex ante expected equity risk premiums. Among the variables included were inflation, real EPS and DPS growth, ROE and book value growth, and P/E ratios. By relating the fundamental factors to the ex post historic returns, the methodology bridges the gap between the ex post and ex ante equity risk premiums. Ilmanen (2003) illustrates this approach using the geometric returns and five fundamental variables – inflation (CPI), dividend yield (D/P), real earnings growth (RG), repricing gains (PEGAIN) and return interaction/reinvestment (INT).[12] This is shown in the graph below. The first column breaks the 1926-2000 geometric mean stock return of 10.7% into the different return components demanded by investors: the

[11] Roger Ibbotson and Peng Chen, "Long Run Returns: Participating in the Real Economy," *Financial Analysts Journal*, January 2003.

[12] Antti Ilmanen, Expected Returns on Stocks and Bonds," *Journal of Portfolio Management*, (Winter 2003), p. 11.

historic Treasury bond return (5.2%), the excess equity return (5.2%), and a small interaction term (0.3%). This 10.7% annual stock return over the 1926-2000 period can then be broken down into the following fundamental elements: inflation (3.1%), dividend yield (4.3%), real earnings growth (1.8%), repricing gains (1.3%) associated with higher P/E ratios, and a small interaction term (0.2%).

Decomposing Equity Market Returns
The Building Blocks Methodology

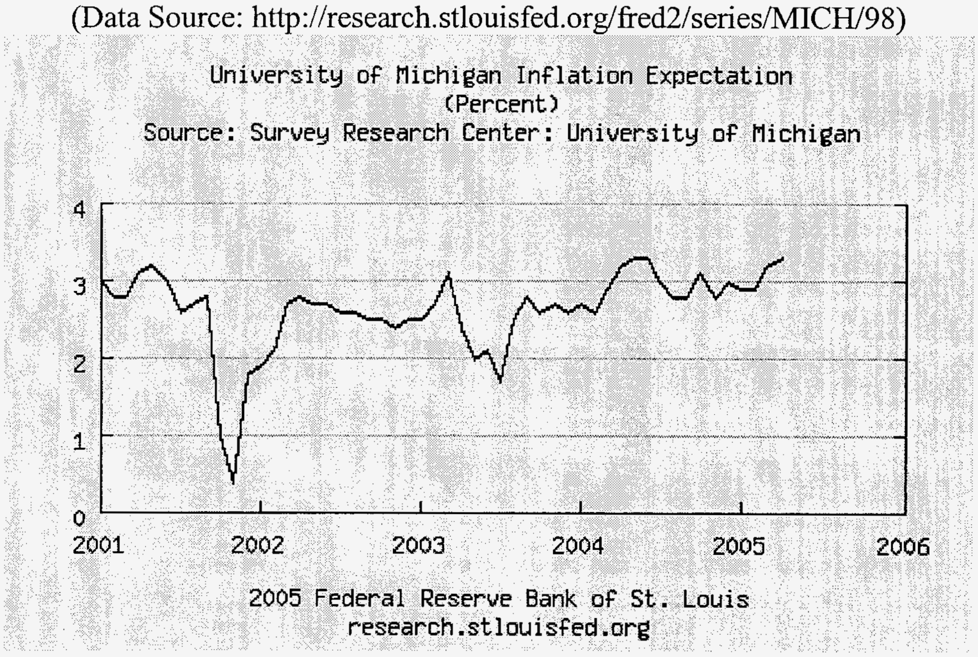


Q. HOW ARE YOU USING THIS METHODOLOGY TO DERIVE AN EX ANTE EXPECTED EQUITY RISK PREMIUM?

A. The third column in the graph above shows current inputs to estimate an ex ante expected market return. These inputs include the following:

CPI – To assess expected inflation, I have employed expectations of the short-term and long-term inflation rate. The graph below shows the expected annual inflation rate according to consumers, as measured by the CPI, over the coming year. This survey is published monthly by the University of Michigan Survey Research Center. In the most recent report, expected one-year ahead inflation rate was 3.3%.

Expected Inflation Rate
University of Michigan Consumer Research
(Data Source: http://research.stlouisfed.org/fred2/series/MICH/98)



Longer term inflation forecasts are available in the Federal Reserve Bank of Philadelphia's publication entitled *Survey of Professional Forecasters*.[13] This survey of professional economists has been published for almost 50 years. While this survey is published quarterly, only the first quarter survey includes long-term forecasts of GDP growth, inflation, and market returns. In the first quarter, 2005 survey, published on February 14, 2005, the median long-term (10-term) expected inflation rate as measured by the CPI was 2.45% (see page 4 of Exhibit_(JRW-8)).

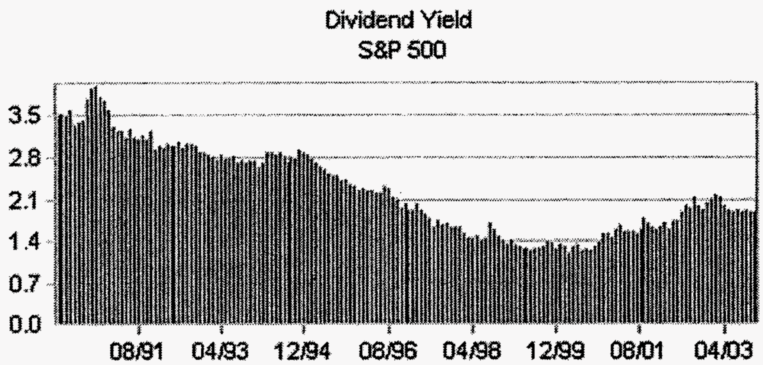
Given these results, I will use the average of the University of Michigan and Philadelphia Federal Reserve's surveys (3.30% and 2.45%), or 2.90%.

D/P – As shown in the graph below, the dividend yield on the S&P 500 has decreased gradually over the past decade. Today, it is far below its norm of 4.3% over the 1926-2000 time period. Whereas the S&P dividend yield bottomed out at less than 1.4% in 2000, it is currently at 2.1% which I use in the ex ante risk premium analysis.

S&P 500 Dividend Yield

(Data Source: http://www.barra.com/Research/fund_charts.asp)

[13]Federal Reserve Bank of Philadelphia, *Survey of Professional Forecasters,* February 14, 2005. The *Survey of Professional Forecasters* was formerly conducted by the American Statistical Association (ASA) and the National Bureau of Economic Research (NBER) and was known as the ASA/NBER survey. The survey, which began in 1968, is conducted each quarter. The Federal Reserve Bank of Philadelphia, in cooperation with the NBER, assumed responsibility for the survey in June 1990.



RG – To measure expected real growth in earnings, I use (1) the historic real earnings growth rate for the S&P 500, and (2) expected real GDP growth. The S&P 500 was created in 1960. It includes 500 companies which come from ten different sectors of the economy. Over the 1960-2003 period, nominal growth in EPS for the S&P 500 was 6.88%. On page 5 of Exhibit_(JRW-8), real EPS growth is computed using the CPI as a measure of inflation. As indicated by Ibbotson and Chen, real earnings growth over the 1926-2000 period was 1.8%. The real growth figure over 1960-2003 period for the S&P 500 is 2.5%.

The second input for expected real earnings growth is expected real GDP growth. The rationale is that over the long-term, corporate profits have averaged a relatively consistent 5.50% of US GDP.[14] Real GDP growth, according to McKinsey, has averaged 3.5% over the past 80 years. Expected GDP growth, according to the Federal Reserve Bank of Philadelphia's *Survey of Professional Forecasters,* is 3.3% (see page 4 of Exhibit_(JRW-8)).

Given these results, I will use the average of the historic S&P EPS real growth and the

[14]Marc H. Goedhart, Timothy M. Koller, and Zane D. Williams, "The Real Cost of Equity," *McKinsey on Finance* (Autumn 2002), p.14. Available at http://www.corporatefinance.mckinsey.com/.

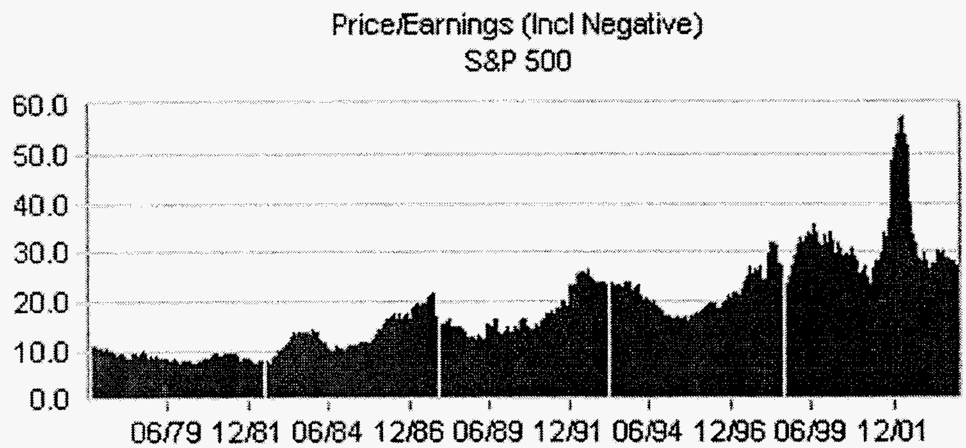
historic real GDP growth (and as supported by the Philadelphia Federal Reserve survey of expected GDP growth) (2.5% and 3.3%), or 2.9%, for real earnings growth.

PEGAIN – the repricing gains associated with increases in the P/E ratio accounted for 1.3% of the 10.7% annual stock return in the 1926-2000 period. In estimating an ex ante expected stock market return, one issue is whether investors expect P/E ratios to increase from their current levels. The graph below shows the P/E ratios for the S&P 500 over the past 25 years. The run-up and eventual peak in P/Es is most notable in the chart. The relatively low P/E ratios (in the range of 10) over two decades ago are also quite notable. As of May, 2005 the P/E for the S&P 500, using the trailing 12 months EPS, is in the range of 21.0 to 22.0 according to www.investor.reuters.com.

Given the current economic and capital markets environment, I do not believe that investors expect even higher P/E ratios. Therefore, a PEGAIN would not be appropriate in estimating an ex ante expected stock market return. There are two primary reasons for this. First, the average historic S&P 500 P/E ratio is 15 – thus the current P/E exceeds this figure by nDewhurst 50%. Second, as previously noted, interest rates are at a cyclical low not seen in almost 50 years. This is a primary reason for the high current P/Es. Given the current market environment with relatively high P/E ratios and low relative interest rate, investors are not likely to expect to get stock market gains from lower interest rates and higher P/E ratios.

S&P 500 P/E Ratios

(Data Source: http://www.barra.com/Research/fund_charts.asp)



Q. GIVEN THIS DISCUSSION, WHAT IS YOUR EX ANTE EXPECTED MARKET RETURN AND EQUITY RISK PREMIUM USING THE "BUILDING BLOCKS METHODOLOGY"?

A. My expected market return is represented by the last column on the right in the graph entitled "Decomposing Equity Market Returns: The Building Blocks Methodology" found earlier in my testimony. As shown on page 36, my expected market return is 7.90% which is composed of 2.90% expected inflation, 2.10% dividend yield, and 2.90% real earnings growth rate.

Expected Inflation	Dividend Yield	Real Earnings Growth Rate	Expected Market Return
2.90%	2.10%	2.90%	7.9%

Q. GIVEN THAT THE HISTORIC COMPOUNDED ANNUAL MARKET RETURN

IS IN EXCESS OF 10%, WHY DO YOU BELIEVE THAT YOUR EXPECTED MARKET RETURN OF 7.90% IS REASONABLE?

A. As discussed above in the development of the expected market return, stock prices are relatively high at the present time in relation to earnings and dividends and interest rates are relatively low. Hence, it is unlikely that investors are going to experience high stock market returns due to higher P/E ratios and/or lower interest rates. In addition, as shown in the decomposition of equity market returns, whereas the dividend portion of the return was historically 4.3%, the current dividend yield is only 2.1%. Due to these reasons, lower market returns are expected for the future.

Q. IS YOUR EXPECTED MARKET RETURN OF 7.90% CONSISTENT WITH THE FORECASTS OF MARKET PROFESSIONALS?

A. Yes. The only survey of market professionals dealing with forecasts of stock market returns is published by the previously-referenced Federal Reserve Bank of Philadelphia. In the first quarter, 2005 survey, published on February 14, 2005, the median long-term expected return on the S&P 500 was 7.00 (see page 4 of Exhibit_(JRW-8)). This is clDewhurst consistent with my expected market return of 7.90%.

Q. GIVEN THIS EXPECTED MARKET RETURN, WHAT IS YOUR EX ANTE EQUITY RISK PREMIUM USING THE "BUILDING BLOCKS METHODOLOGY"?

A. Previously I noted that I am using a risk-free interest rate of 4.50%. My ex ante equity risk premium is simply the expected market return from the "building blocks methodology" minus this risk-free rate:

Ex Ante Equity Risk Premium = 7.90% - 4.50% = 3.40%

Q. WHAT EQUITY RISK PREMIUM ARE YOU USING IN YOUR CAPM?

A. I am employing the average of the Derrig-Orr mean (4.00%) and my building blocks approach (3.40%), or 3.70%.

Q. IS YOUR EX ANTE EQUITY RISK PREMIUM CONSISTENT WITH THE EQUITY RISK PREMIUMS OF LEADING INVESTMENT FIRMS?

A. Yes. One of the first studies in this area was by Stephen Einhorn, one of Wall Street's leading investment strategists.[15] His study showed that the market or equity risk premium had declined to the 2.0 to 3.0 percent range by the early 1990s. Among the evidence he provided in support of a lower equity risk premium is the inverse relationship between real interest rates (observed interest rates minus inflation) and stock prices. He noted that the decline in the market risk premium has led to a significant change in the relationship between interest rates and stock prices. One implication of this development was that stock prices had increased higher than would be suggested by the historic relationship between valuation levels and interest rates.

The equity risk premiums of some of the other leading investment firms today support the

[15] Steven G. Einhorn, "The Perplexing Issue of Valuation: Will the Real Value Please Stand Up?" *Financial Analysts Journal* (July-August 1990), pp. 11-16.

result of the academic studies. An article in *The Economist* indicated that some other firms like J.P. Morgan are estimating an equity risk premium for an average risk stock in the 2.0 to 3.0 percent range above the interest rate on U.S. Treasury Bonds.[16]

Q. IS YOUR EX ANTE EQUITY RISK PREMIUM CONSISTENT WITH THE EQUITY RISK PREMIUMS USED BY CORPORATE CHIEF FINANCIAL OFFICERS (CFOs)?

A. Yes. John Graham and Campbell Harvey of Duke University surveyed CFOs to ascertain their ex ante equity risk premium. In Graham and Harvey's 2003 survey, the average ex ante 10-year equity risk premium of the CFOs was 3.8%.[17]

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

A. Yes. The financial forecasters in the previously-referenced Federal Reserve Bank of Philadelphia survey project both stock and bond returns. As shown on page 4 of Exhibit_(JRW-8)), the median long-term expected stock and bond returns were 7.00% and 5.00%, respectively. This provides an ex ante equity risk premium of 2.00%.

Q. IS YOUR EX ANTE EQUITY RISK PREMIUM CONSISTENT WITH THE EQUITY RISK PREMIUMS USED BY THE LEADING CONSULTING FIRMS?

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[16] For example, see "Welcome to Bull Country," *The Economist* (July 18, 1998), pp. 21-3, and "Choosing the Right Mixture," *The Economist* (February 27, 1999), pp. 71-2.

[17] John R. Graham and Campbell Harvey, "Expectations of Equity Risk Premia, Volatility, and Asymmetry," Duke University Working Paper, 2003.

A. Yes. McKinsey & Co. is widely recognized as the leading management consulting firm in the world. They recently published a study entitled "The Real Cost of Equity" in which they developed an ex ante equity risk premium for the US. In reference to the decline in the equity risk premium, as well as what is the appropriate equity risk premium to employ for corporate valuation purposes, the McKinsey authors concluded the following:

> We attribute this decline not to equities becoming less risky (the inflation-adjusted cost of equity has not changed) but to investors demanding higher returns in real terms on government bonds after the inflation shocks of the late 1970s and early 1980s. We believe that using an equity risk premium of 3.5 to 4 percent in the current environment better reflects the true long-term opportunity cost of equity capital and hence will yield more accurate valuations for companies.[18]

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

A. This is summarized on page 1 of Exhibit_(JRW-8). Using a risk-free rate of 4.50% and a beta of 0.78 for twenty-one company electric utility group, my CAPM estimated equity cost rate is:

$$K = (R_f) + \beta_{ibm} * [E(R_m) - (R_f)]$$

	Risk-Free Rate	Beta	Equity Risk Premium	Equity Cost Rate
Twenty-One Company Electric Utility Group	4.50%	0.78	3.70%	7.39%

[18] Marc H. Goedhart, Timothy M. Koller, and Zane D. Williams, "The Real Cost of Equity," *McKinsey on Finance* (Autumn 2002), p.15. Available at http://www.corporatefinance.mckinsey.com/.

D. EQUITY COST RATE SUMMARY

Q. PLEASE SUMMARIZE YOUR EQUITY COST RATE STUDY.

A. The results for my DCF and CAPM analyses for the group of electric utility companies are indicated below:

Group	DCF	CAPM
Twenty-One Company Electric Utility Group	8.8%	7.39%

Q. GIVEN THESE RESULTS, WHAT EQUITY COST RATE RECOMMENDATION ARE YOU MAKING FOR FPL?

A. Giving primary weight to the DCF results, these results indicate that a fair equity cost rate for FPL is 8.8%. I will use this figure as the equity cost rate for the Company.

Q. HAVE YOU MADE ANY ADJUSTMENTS TO RECOGNIZE THE LOWER FINANCIAL RISK INCUMBENT IN FPL'S PROPOSED CAPITAL STRUCTURE?

A. No. As discussed below, FPL's proposed capitalization contains much less financial risk than the peer group of electric utilities. However, I am not making any explicit downward adjustments to my equity cost rate to reflect the lower financial risk. Hence, my recommendation is very fair in light of my adoption of FPL's capital structure.

Q. ISN'T YOUR RECOMMENDED RETURN LOW BY HISTORIC STANDARDS?

A. Yes it is, and appropriately so. My recommended rate of return is low by historic standards for three reasons. First, as discussed above, current capital costs are very low by historic standards, with interest rates at a cyclical low not seen since the 1960s. Second, the 2003 tax law, which reduces the tax rates on dividend income and capital gains, lowers the pre-tax return required by investors. And third, as discussed below, the equity or market risk premium has declined.

Q. FINALLY, PLEASE DISCUSS THIS RECOMMENDATION IN LIGHT OF RECENT YIELDS ON 'A' RATED PUBLIC UTILITY BONDS.

A. In recent months the yields on long-term 'A' rated public utility bonds have been in the 5.25 percent range. My equity return recommendation of 8.8% may appear to be too low given these yields. However, as previously noted, my recommendation must be viewed in the context of the significant decline in the market or equity risk premium. As a result, the return premium that equity investors require over bond yields is much lower than today. This decline was previously reviewed in my discussion of capital costs in today's markets. In addition, it will be examined in more depth in my critique of Dr. Avera's testimony.

Q. HOW DO YOU TEST THE REASONABLENESS OF YOUR 8.8% RECOMMENDATION?

A. To test the reasonableness of my 8.8% recommendation, I examine the relationship between the return on common equity and the market-to-book ratios for the group of electric utility companies.

Q. WHAT DO THE RETURNS ON COMMON EQUITY AND MARKET-TO-BOOK

RATIOS FOR THE GROUP INDICATE ABOUT THE REASONABLENESS OF YOUR 8.8% RECOMMENDATION?

A. Exhibit_(JRW-3) provides financial performance and market valuation statistics for the group of electric utility companies. The average current returns on equity and market-to-book ratios for the group are 11.0% and 1.64, respectively. These results clearly indicate that, on average, these companies are earning returns on equity significantly above their equity cost rates. As such, this observation provides evidence that my recommended equity cost rate of 8.8% is reasonable and fully consistent with the financial performance and market valuation of the gas companies.

V. CRITIQUE OF FPL'S RATE OF RETURN TESTIMONY

Q. PLEASE SUMMARIZE FPL'S OVERALL RATE OF RETURN RECOMMENDATION.

A. Mr. Dewhurst develops the company's proposed capital structure and senior capital cost rates, and Dr. Avera has recommended the equity cost rate. FPL's proposed rate of return is:

Capital Source	Ratio	Cost Rate	Weighted Cost Rate
Short-Term Debt	0.55%	8.73%	0.048%
Long-Term Debt	43.62%	5.89%	2.569%
Common Equity	55.83%	11.8%	6.04%
Total	100.00%		9.81%

Q. PLEASE EVALUATE THE COMPANY'S RATE OF RETURN POSITION.

A. The proposed rate of return is too high due to an inflated long-term debt cost rate and an overstated equity cost rate. Mr. Dewhurst's long-term debt cost rate of 5.89% includes four projected financings at interest rates well above current market yields. Dr. Avera's recommended return on common equity of 11.8% is unreasonably high due to (1) an upwardly-biased expected growth rate in his DCF equity cost rate, (2) the use of a forecasted interest rates that are well above current long-term market yields, (3) excessive risk premium estimates in his various risk premium approaches, and (4) the lack of a adjustment to reflect FPL's lower financial risk as well as an inappropriate flotation cost adjustment.

Q. WHAT ISSUES ARE YOU ADDRESSING IN YOUR REBUTTAL TESTIMONY?

A. I am addressing the following issues: (1) Mr. Dewhurst's proposed long-term debt cost rate and capital structure, and (2) Dr. Avera's equity cost rate approaches and results.

Long-Term Debt Cost Rate and Capital Structure

Q. WHY IS MR. DEWHURST'S LONG-TERM DEBT COST RATE INAPPROPRIATE

A. Mr. Dewhurst's long-term debt cost rate of 5.89% is excessive because of it includes four proforma debt offerings with projected yields well above current market interest rates. These debt issues, listed as First Mortgage bond issues number 9, 10, 11, and 12 on page 2 of Exhibit_(JRW-

4), have projected yields of 6.8%, 6.8%, 7.2%, and 7.2%, respectively. As discussed above, the yield on A-rated public utility bonds is now below 5.25%.

Q. PLEASE DISCUSS THE COMPANY'S PROPOSED CAPITAL STRUCTURE RATIOS.

A. FPL's proposed capital structure includes an adjusted common equity ratio of 55.83% which was used for limited purposes in FPL's 1999 Stipulation and Settlement Agreement between FPL and the OPC. This ratio is adjusted to reflect the Company's fixed charges associated with purchased power contracts. As discussed above, FPL's actual common equity ratio is 61.92%. Both the actual and adjusted common equity ratios are high by industry standards.

Q. BETWEEN PAGES 60 AND 73 OF HIS TESTIMONY, DR. AVERA ATTEMPTS TO JUSTIFY FPL'S PROPOSED CAPITAL STRUCTURE. PLEASE COMMENT.

A. Dr. Avera's attempts to demonstrate that FPL's proposed capital structure is similar to that of the peer group of electric utilities from which he estimates FPL's cost of common equity. Unfortunately, his analysis is seriously flawed and erroneous. The errors in his analysis include:

1. He uses the capital structures of the operating electric utilities and not the capital structures of the parent companies whose common stock trades in the market. Hence, he is comparing 'apples and oranges;'

2. His analysis excludes short-term debt; and

3. Whereas FPL's capitalization has been adjusted for fixed charges associated with purchased power contracts, the capital structures of the operating electric utilities have not.

To assess the magnitude of the differences in the capital structures, I have provided a comparison in the table below. The comparison shows the following capital structures: FPL's adjusted and actual, the operating electric utilities, and the publicly-traded electric companies (as found on page 1 of Exhibit_(JRW-9). The differences are dramatic. FPL's actual capital structure has a common equity ratio (61.92%) which is 17 percentage points above that of the publicly-traded electric companies.

Florida Power & Light Company

Capital Structure Study

Capital Source	FPL's Adjusted Capital Structure	FPL's Actual Capital Structure	Operating Co. Capital Structure	Publicly-Traded Capital Structure
Short-Term Debt	0.55%	0.61%	0.6%%	6.5%
Long-Term Debt	43.62%	37.47%	45.1%	47.9%
Preferred Stock			2.5	1.6%
Common Equity	55.83%	61.92%	51.8%	44.0%

Q. WHAT DOES THIS INDICATE ABOUT FPL'S CAPITALIZATION RELATIVE TO THAT OF THE PEER GROUP OF ELECTRIC COMPANIES?

A. This clearly shows that FPL's common equity ratio is significantly higher that that of the average of the peer group of publicly-traded electric utilities that are used to determine FPL's cost of equity capital. In fact, as indicated by Dr. Avera, FPL's debt ratio is below the S&P standards for A-rated electric utilities. Overall, this indicates that FPL has less financial risk than the peer group.

<u>Equity Cost Rate Approaches and Results</u>

Q. PLEASE REVIEW DR. AVERA'S EQUITY COST RATE APPROACHES.

A. Dr. Avera employs a DCF approach and various risk premium approaches, including analyses of allowed returns and realized rates of returns as well as an application of the CAPM using forward looking and historic equity risk premiums.

Q. PLEASE SUMMARIZE DR. AVERA'S EQUITY COST RATE RESULTS.

A. Dr. Avera's equity cost rate estimates for FPL are summarized below:

<u>Summary of Equity Cost Rate Approaches and Results</u>

Approach	Period	Result
DCF		
	Current	9.4%
Risk Premium		
Authorized Returns	Current	10.6%
Authorized Returns	Test Year	11.3%
Historic Returns	Current	9.7%
Historic Returns	Test Year	10.9%
CAPM - Forward Looking	Current	11.8%
CAPM - Forward Looking	Test Year	12.0%
CAPM – Historic	Current	10.1%
CAPM – Historic	Test Year	11.3%

Based on these figures, he concludes that the appropriate equity cost rate for FPL is 11.8%.

Q. WHAT ARE THE PRIMARY ERRORS IN DR. AVERA'S ANALYSES.

A. Dr. Avera's recommended return on equity of 11.8% is unreasonably high due to (1) an upwardly-biased expected growth rate in his DCF equity cost rate, (2) the use of forecasted interest rates that are well in excess of the current long-term market yields, (3) excessive risk premium estimates in his various risk premium approaches, and (4) the lack of a financial risk adjustment as well as an inappropriate flotation cost adjustment.

Q. PLEASE INITIALLY ADDRESS ISSUE (4) INVOLVING THE ADJUSTMENTS. DOES DR. AVERA MAKE A FINANCIAL RISK ADJUSTMENT FOR FPL?

A. No. Furthermore, as discussed above, since his financial risk study is so flawed, he does not even acknowledge or recognize the difference in financial risk between FPL and his group of electric utilities. The bottom line is that FPL's has less financial risk than the electric utility group, and hence Dr. Avera should recognize the difference and provide for a lower return on common equity.

Q. PLEASE ADDRESS DR. AVERA'S CONTENTION THAT FPL REQUIRES A 30 BASIS POINT ADJUSTMENT TO THE OVERALL ROE FOR EQUITY FLOTATION COSTS.

A. Dr. Avera also argues that FPL deserves an extra 30 basis points for flotation costs. Based on FPL's proposed rate base and rate of return, this adds about $20M in revenues annually to account for flotation cost. Such an adjustment is totally unwarranted. Flotation costs are one-time expenses which are incurred when a Company sells additional stock. They are not a recurring annual item. Furthermore, Dr. Avera has not even indicated if FPL intends to sell additional shares to investors. If so, the flotation costs should be accounted for and added to the Company's rate request just like other expenses.

Q. PLEASE SUMMARIZE DR. AVERA'S DCF ESTIMATES.

A. On pages 30 to 41 of his testimony and in Documents WEA-3, WEA-4, and WEA-5, Dr. Avera performs a DCF analysis using his electric utility proxy group The three models and their results are summarized below.

. DCF Results
Electric Company Proxy Group

		Model (1) L-T Growth GDP Forecasts
Dividend Yield		4.1%
Growth		
Projected EPS Growth	4.9%	
Sustainable Growth	5.6%	
Average		5.3%
DCF Equity Cost Rate		**9.4%**

Q. PLEASE ASSESS DR. AVERA'S DCF APPROACH.

A. Initially it should be highlighted that Dr. Avera appears to have given little weight to his DCF results in arriving at his recommended equity cost rate for FPL. His overall designated range of 10.0-12.0 percent is above the results of his DCF study. Furthermore, his DCF study is subject to errors that inflate his results. His specific errors include: (1) he has relied on analysis' forecasts of EPS growth and (2) his sustainable growth figure is excessive and overstated.

Q. PLEASE DISCUSS GROWTH AS INDICATED BY ANALYSTS' EPS GROWTH RATE FORECASTS.

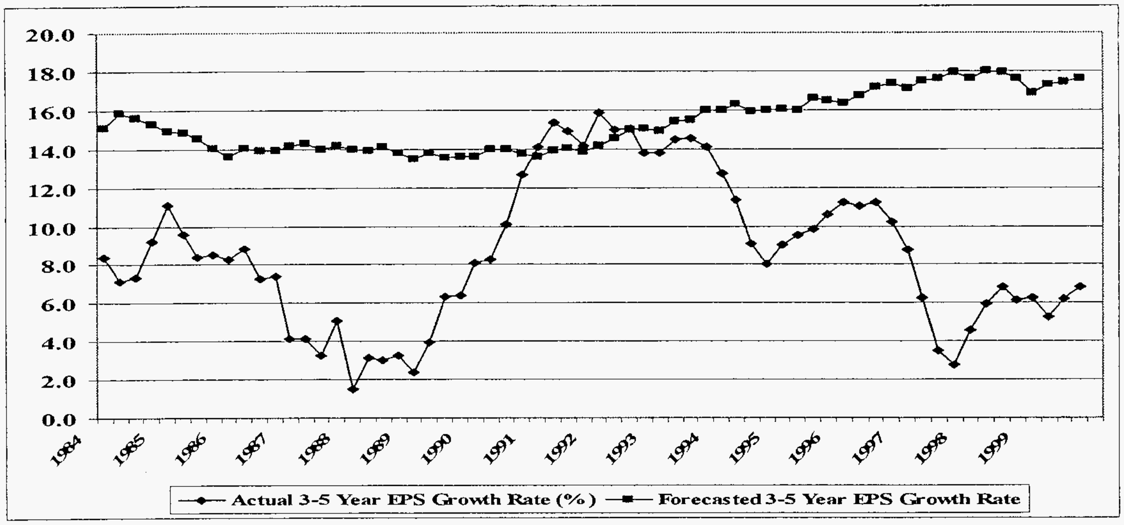
A. Dr. Avera has used the EPS growth rate forecasts of Wall Street analysts. He has ignored other indicators of expected growth, especially historic growth. It seems highly unlikely that investors today would rely exclusively on the forecasts of securities firms and analysts, and ignore historic growth, in arriving at expected growth. In the academic world, the fact that the EPS forecasts of securities' analysts are overly optimistic and biased upwards has been known for years.

Q. PLEASE REVIEW THE BIAS IN ANALYSTS' GROWTH RATE FORECASTS.

A. Analysts' growth rate forecasts are collected and published by Zacks, First Call, I/B/E/S, and Reuters. These services retrieve and compile EPS forecasts from Wall Street Analysts. These analysts come from both the sell side (Merrill Lynch, Paine Webber) and the buy side (Prudential Insurance, Fidelity).

The problem with using these forecasts to estimate a DCF growth rate is that the objectivity of Wall Street research has been challenged, and many have argued that analysts' EPS forecasts are overly optimistic and biased upwards. To evaluate the accuracy of analysts' EPS forecasts, I have compared actual 3-5 year EPS growth rates with forecasted EPS growth rates on a quarterly basis over the past 20 years for all companies covered by the I/B/E/S data base. In the graph below, I show the average analysts' forecasted 3-5 year EPS growth rate with the average actual 3-5 year EPS growth rate. Because of the necessary 3-5 year follow-up period to measure actual growth, the analysis in this graph only (1) covers forecasted and actual EPS growth rates through 1999, and (2) includes only companies that have 3-5 years of actual EPS data following the forecast period. The following example shows how the results can be interpreted. As of the first quarter of 1995, analysts were projecting an average 3-5-year annual EPS growth rate of 15.98%, but companies only generated an average annual EPS growth rate over the next 3-5 years of 8.14%. This 15.98% figure represented the average projected growth rate for 1,115 companies, with an average of 4.70 analysts' forecasts per company. The only periods when firms met or exceeded analysts' EPS growth rate expectations were for six consecutive quarters in 1991-92 following the one-year economic downturn at the turn of the decade. Over the entire time period, Wall Street analysts have continually forecasted 3-5-year EPS growth rates in the 14-18 percent range (mean = 15.32%), but these firms have only delivered an average EPS growth rate of 8.75%.

Analysts' Forecasted 3-5-Year Forecasted Versus Actual EPS Growth Rates
1984-1999

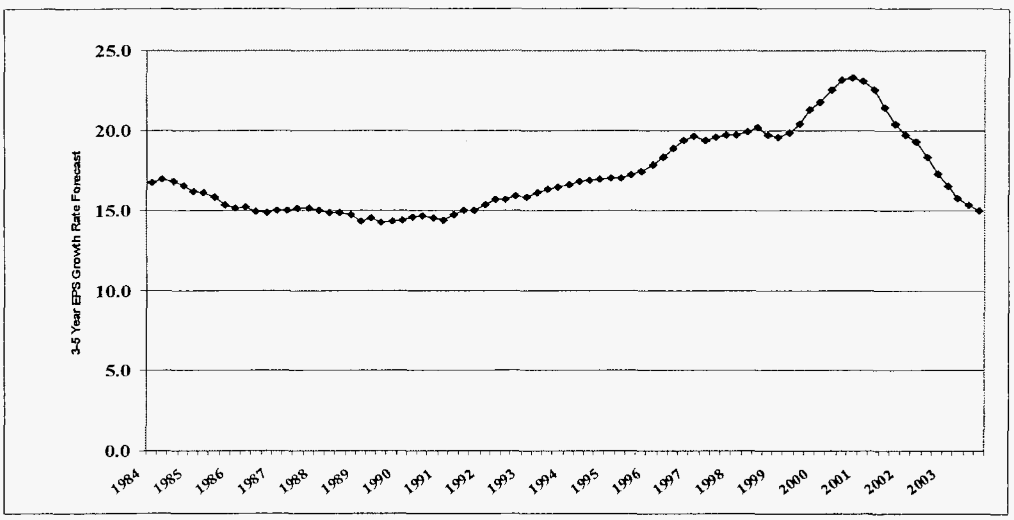


Source: J. Randall Woolridge.

The post-1999 period has seen the boom and then the bust in the stock market, an economic recession, 9/11, and the Iraq war. Furthermore, and highly significant in the context of this study, we have also had the Elliott Spitzer investigation of Wall Street firms and the subsequent Global Securities Settlement in which nine major brokerage firms paid a fine of $1.5B for their biased investment research.

To evaluate the impact of these events on analysts' forecasts, the graph below provides the average 3-5-year EPS growth rate projections for all companies provided in the I/B/E/S database on a quarterly basis from 1985 to 2004. In this graph, no comparison to actual EPS growth rates is made and hence there is no follow-up period. Therefore, 3-5 year growth rate forecasts are shown until 2004 and, since companies are not lost due to a lack of follow-up EPS data, these results are for a larger sample of firms.[19] Analysts' forecasts for EPS growth were higher for this larger sample of firms, with a more pronounced run-up and then decline around the stock market peak in 2000. The average projected growth rate hovered in the 14.5%-17.5% range until 1995, and then increased dramatically over the next five years to 23.3% in the fourth quarter of the year 2000. Forecasted growth has since declined to the 15.0% range.

Mean Analysts' 3-5-Year Forecasted EPS Growth Rates
1985-2004



Source: J. Randall Woolridge.

While analysts' EPS growth rates forecasts have subsided since 2000, these results suggest that, despite the Elliot Spitzer investigation and the Global Securities Settlement, analysts' EPS forecasts are still upwardly biased. The actual 3-5 year EPS growth rate over time has been about one half the projected 3-5 year growth rate forecast of 15.0%. Furthermore, as discussed above,

[19] The number of companies in the sample grows from 2,220 in 1984, peaks at 4,610 in 1998, and then declines to 3,351 in 2004. The number of analysts' forecasts per company averages between 3.75 to 5.10, with an overall mean of 4.37.

historic growth in GNP and corporate earnings has been in the 7% range. As such, an EPS growth rate forecast of 15% does not reflect economic reality. This observation is support by a *Wall Street Journal* article entitled "Analysts Still Coming Up Rosy – Over-Optimism on Growth Rates is Rampant – and the Estimates Help to Buoy the Market's Valuation." The following quote provides insight into the continuing bias in analysts' forecasts:

> Hope springs eternal, says Mark Donovan, who manages Boston Partners Large Cap Value Fund. 'You would have thought that, given what happened in the last three years, people would have given up the ghost. But in large measure they have not.'
>
> These overly optimistic growth estimates also show that, even with all the regulatory focus on too-bullish analysts allegedly influenced by their firms' investment-banking relationships, a lot of things haven't changed: Research remains rosy and many believe it always will.[20]

Q. ARE *VALUE LINE*'S GROWTH RATE FORECASTS SIMILARILY UPWARDLY BIASED?

A. I am not aware of any studies that test for a bias in *Value Line*'s forecasts. However, it is my experience that *Value Line*'s projected EPS and overall market return forecasts are inflated and unrealistic. I believe that it is because *Value Line* rarely projects a decline in EPS and/or the market, despite the fact that the economy and stock market go through cycles over time.

Q. PLEASE DISCUSS THE ISSUES WITH DR. AVERA'S SUSTAINABLE GROWTH

[20] Ken Brown, "Analysts Still Coming Up Rosy – Over-Optimism on Growth Rates is Rampant – and the Estimates Help to Buoy the Market's Valuation." *Wall Street Journal*, (January 27, 2003), p. C1.

ANALYSIS.

A. Dr. Avera's sustainable growth rate analysis, as found in Document WEA-5, indicates a growth rate for the group of 5.6%. I have three issues with this analysis: (1) his average growth rate figure of 5.6% is affected by outliers such as Sempra's 10.7%. In such cases, one uses the median and not the mean as a measure of central tendency. The median figure for his group is only 4.9%; (2) his sustainable growth rate figures (column h in WEA-5) are higher than *Value Line*'s projected annual change figures (column h in WEA-5), which suggests that his methodology is flawed in that it produces higher sustainable growth rates (using *Value Line* data) than *Value Line* actually is forecasting. For example, the median 'Annual Change' figure is only 4.7%; and (3) Dr. Avera's sustainable growth rates are even higher than analysts' projected EPS growth rate figures and, as indicated above, it is well known analysts' growth rates are upwardly biased. Hence, it is unlikely that investors would expect growth to be even higher than analysts' EPS growth rate estimates.

Q. PLEASE PROVIDE A SUMMARY OF DR. AVERA'S VARIOUS RISK PREMIUM APPROACHES, INCLUDING THE CAPM.

A. The tables below provide the results of Dr. Avera's applications of the risk premium approach. Since the CAPM is simply a special form of the risk premium approach, I will critique these approaches and results jointly. These tables provide the group of companies employed, the individual inputs, and the overall results.

Allowed Risk Premium Results
Electric Utility Companies

	Electric Utility Companies Current	Electric Utility Companies 2006 Estimate
Moody's A Bond Rate	5.8%	7.0%
Allowed Return Premium	4.8 %	4.29 %
Allowed RP Equity Cost Rate	**10.6%**	**11.3%**

Historic Risk Premium Results
Moody's Electric Utility Stocks

	Moody's Electric Utility Stocks Current	Moody's Electric Utility Stocks 2006
	5.8%	7.0%
Historic Return Premium	3.87%	3.78%
Hist Equity Cost Rate	9.7%	10.9%

CAPM Forward Results
Electric Utility Proxy Group

	Electric Utility Proxy Group Current	Electric Utility Proxy Group 2006
Risk-Free Rate	4.6%	5.8%
Average Beta	.77	.77
Market Risk Premium	9.3%	8.1%
Equity Cost Rate	11.8%	12.0%

CAPM Historic Results
Electric Utility Proxy Group

	Electric Utility Proxy Group Current	Electric Utility Proxy Group 2006
Risk-Free Rate	4.6%	5.8%
Average Beta	.77	.77
Market Risk Premium	7.2%	7.2%
Equity Cost Rate	10.1%	11.3%

Q. HOW ARE YOU EVALUATING THESE APPROACHES?

A. There are certain common elements to these approaches that I am initially discussing. Then I provide additional commentary on the individual approaches. The common elements include the base interest rate and the use of historic risk premiums.

Q. PLEASE DISCUSS THE BASE INTEREST RATE IN DR. AVERA'S VARIOUS RISK PREMIUM APPROACHES.

A. Dr. Avera uses the 30-tear Treasury rate as well as the 30-year Moody's A bond rate as the base yield in his various risk premium approaches. These are summarized below. The 'Current' column is the rate when he filed his testimony, the '2006' column is projected for 2006, and 'May 31, 2006' column is as of that date.

Base Interest Rate in Risk Premium Approaches

	Approach	Current	2006	May 31, 2006*
30-Year Moody's A Bond Rate	Auth. Returns Historic Ret.	5.8%	7.0%	5.16%
30-Year Treasury Rate	CAPM Forward CAPM Historic	4.6%%	5.8%	4.31%

*** Source: Bloomberg**

Q. ARE THESE BASE YIELDS APPROPRIATE AT THIS TIME?

A. No. They are well in excess of today's interest rates. Contrary to many interest rate forecasts, concerns over the direction of the economy have led to declines in interest rates in recent months. The 'May 31, 2006' column shows that the 30-Year public utility A rate has declined to 5.16% and the 30-year Treasury rate has declined to 4.31%. Hence, his base yields and therefore overall risk premium equity cost rates are grossly overstated. Given the uncertainty over the economy and interest rates, he should be employing the current 30-year public utility and Treasury yields.

Q. PLEASE ADDRESS THE ISSUE INVOLVING THE USE OF HISTORIC STOCK AND BOND RETURNS TO COMPUTE A FORWARD-LOOKING OR EX ANTE RISK PREMIUM.

A. In his Realized Rate of Return (RRR) and 'CAPM Historic' approaches Dr. Avera has used historic stock and bond returns to compute an expected market risk premium. In his RRR approach, he computes a risk premium as the difference between the returns on the Moody Electric Utility stocks and the yield on 'A' rated Moody's bonds. In his CAPM Historic approach, he computes the equity risk premium as the historic arithmetic mean difference between stock and bond returns over the 1926-2003 period bonds. This historic evaluation of stock and bond returns is often called the "Ibbotson approach" after Professor Roger Ibbotson who popularized this method of assessing historic financial market returns

Using the historic relationship between stock and bond returns to measure an ex ante equity risk premium is erroneous and, especially in this case, overstates the true market equity risk premium. The equity risk premium is based on expectations of the future and when past market conditions vary significantly from the present, historic data does not provide a realistic or accurate barometer of expectations of the future. At the present time, using historic returns to measure the ex ante equity risk premium ignores current market conditions and masks the dramatic change in the risk and return relationship between stocks and bonds. This change suggests that the equity risk premium has declined.

Q. PLEASE DISCUSS THE ERRORS IN USING HISTORIC STOCK AND BOND RETURNS TO ESTIMATE AN EQUITY RISK PREMIUM.

A. There are a number of flaws in using historic returns over long time periods to estimate expected equity risk premiums. These issues include:

(A) Biased historic bond returns;

(B) The arithmetic versus the geometric mean return;

(C) Unattainable and biased historic stock returns;

(D) Survivorship bias;

(E) The "Peso Problem;"

(F) Market conditions today are significantly different than the past; and

(G) Changes in risk and return in the markets.

These issues will be addressed in order.

Biased Historic Bond Returns

Q. HOW ARE HISTORIC BOND RETURNS BIASED?

A. An essential assumption of these studies is that over long periods of time investors' expectations are realized. However, the experienced returns of bondholders in the past violate this critical assumption. Historic bond returns are biased downward as a measure of expectancy because of capital losses suffered by bondholders in the past. As such, risk premiums derived from this data are biased upwards.

The Arithmetic versus the Geometric Mean Return

Q. PLEASE DISCUSS THE ISSUE RELATING TO THE USE OF THE ARITHMETIC VERSUS THE GEOMETRIC MEAN RETURNS IN THE IBBOTSON METHODOLOGY.

A. The measure of investment return has a significant effect on the interpretation of the risk premium results. When analyzing a single security price series over time (i.e., a time series), the best measure of investment performance is the geometric mean return. Using the arithmetic mean overstates the return experienced by investors. In a study entitled "Risk and Return on Equity: The Use and Misuse of Historical Estimates," Carleton and Lakonishok make the following observation: "The geometric mean measures the changes in wealth over more than one period on a buy and hold (with dividends invested) strategy."[21] Since Dr. Avera's study covers more than one period (and he assumes that dividends are reinvested), he should be employing the geometric mean and not the arithmetic mean.

Q. PLEASE PROVIDE AN EXAMPLE DEMONSTRATING THE PROBLEM WITH USING THE ARITHMETIC MEAN RETURN.

A. To demonstrate the upward bias of the arithmetic mean, consider the following example. Assume that you have a stock (that pays no dividend) that is selling for $100 today, increases to

[21] Willard T. Carleton and Josef Lakonishok, "Risk and Return on Equity: The Use and Misuse of Historical Estimates," *Financial Analysts Journal* (January-February, 1985), pp. 38-47.

$200 in one year, and then falls back to $100 in two years. The table below shows the prices and returns.

Time Period	Stock Price	Annual Return
0	$100	
1	$200	100%
2	$100	-50%

The arithmetic mean return is simply (100% + (-50%))/2 = 25% per year. The geometric mean return is $((2 * .50)^{(1/2)}) - 1 = 0\%$ per year. Therefore, the arithmetic mean return suggests that your stock has appreciated at an annual rate of 25%, while the geometric mean return indicates an annual return of 0%. Since after two years, your stock is still only worth $100, the geometric mean return is the appropriate return measure. For this reason, when stock returns and earnings growth rates are reported in the financial press, they are generally reported using the geometric mean. This is because of the upward bias of the arithmetic mean. Therefore, Dr. Avera's arithmetic mean return measures are biased and should be disregarded.

<u>Unattainable and Biased Historic Stock Returns</u>

Q. YOU NOTE THAT HISTORIC STOCK RETURNS ARE BIASED USING THE IBBOTSON METHODOLOGY. PLEASE ELABORATE.

A. Returns developed using Ibbotson's methodology are computed on stock indexes and therefore (1) cannot be reflective of expectations because these returns are unattainable to investors, and (2) produce biased results. This methodology assumes (a) monthly portfolio rebalancing and (b) reinvestment of interest and dividends. Monthly portfolio rebalancing presumes that investors rebalance their portfolios at the end of each month in order to have an equal dollar amount invested in each security at the beginning of each month. The assumption would obviously generate extremely high transaction costs and, as such, these returns are unattainable to investors. In addition, an academic study demonstrates that the monthly portfolio rebalancing assumption produces biased estimates of stock returns.[22]

Transaction costs themselves provide another bias in historic versus expected returns. The observed stock returns of the past were not the realized returns of investors due to the much higher transaction costs of previous decades. These higher transaction costs are reflected through the higher commissions on stock trades, and the lack of low cost mutual funds like index funds.

Survivorship Bias

Q. HOW DOES SURVIVORSHIP BIAS AFFECT DR. AVERA'S HISTORIC EQUITY RISK PREMIUM?

A. Using historic data to estimate an equity risk premium suffers from survivorship bias. Survivorship bias results when using returns from indexes like the S&P 500. The S&P 500 includes only companies that have survived. The fact that returns of firms that did not perform so well were dropped from these indexes is not reflected. Therefore these stock returns are upwardly

[22] See Richard Roll, "On Computing Mean Returns and the Small Firm Premium," *Journal of Financial Economics* (1983), pp. 371-86.

biased because they only reflect the returns from more successful companies.

The "Peso Problem"

Q. WHAT IS THE "PESO PROBLEM" AND HOW DOES IT AFFECT HISTORIC RETURNS AND EQUITY RISK PREMIUMS?

A. Dr. Avera's use of historic return data also suffers from the so-called "peso problem." The 'peso problem' issue was first highlighted by the Nobel laureate, Milton Friedman, and gets its name from conditions related to the Mexican peso market in the Dewhurst 1970s. This issue involves the fact that past stock market returns were higher than were expected at the time because despite war, depression, and other social, political, and economic events, the US economy survived and did not suffer hyperinflation, invasion, and the calamities of other countries. As such, highly improbable events, which may or may not occur in the future, are factored into stock prices, leading to seemingly low valuations. Higher than expected stock returns are then earned when these events do not subsequently occur. Therefore, the 'peso problem' indicates that historic stock returns are overstated as measures of expected returns.

Market Conditions Today are Significantly Different than in the Past

Q. FROM AN EQUITY RISK PREMIUM PERSPECTIVE, PLEASE DISCUSS HOW MARKET CONDITIONS ARE DIFFERENT TODAY.

A. The equity risk premium is based on expectations of the future. When past market conditions vary significantly from the present, historic data does not provide a realistic or accurate barometer of expectations of the future. As noted previously, stock valuations (as measured by P/E) are relatively high and interest rates are relatively low, on a historic basis. Therefore, given the high stock prices and low interest rates, expected returns are likely to be lower on a going forward basis.

Changes in Risk and Return in the Markets

Q. PLEASE DISCUSS THE NOTION THAT HISTORIC EQUITY RISK PREMIUM STUDIES DO NOT REFLECT THE CHANGE IN RISK AND RETURN IN TODAY'S FINANCIAL MARKETS.

A. The historic equity risk premium methodology is unrealistic in that it makes the explicit assumption that risk premiums do not change over time based on market conditions such as inflation, interest rates, and expected economic growth. Furthermore, using historic returns to measure the equity risk premium masks the dramatic change in the risk and return relationship between stocks and bonds. The nature of the change, as I will discuss below, is that bonds have increased in risk relative to stocks. This change suggests that the equity risk premium has declined in recent years.

Page 1 of Exhibit_(JRW-10) provides the yields on long-term U.S. Treasury bonds from 1926 to 2004. One very obvious observation from this graph is that interest rates increase dramatically from the mid-1960s until the Dewhurst 1980s, and since have returned to their 1960 levels. The annual market risk premiums for the 1926 to 2004 period are provided on page 2 of Exhibit_(JRW-10). The annual market risk premium is defined as the return on common stock minus the return on long-term Treasury Bonds. There is considerable variability in this series and a clear decline in recent decades. The high was 54% in 1933 and the low was -38% in 1931. Evidence of a change in the relative riskiness of bonds and stocks is provided on page 3 of Exhibit_(JRW-10) which plots the standard deviation of monthly stock and bond returns since 1930. The plot shows that, whereas stock returns were much more volatile than bond returns from the 1930s to the 1970s, bond returns became more variable than stock returns during the 1980s. In recent years stocks and bonds have become much more similar in terms of volatility, but stocks are still a little more volatile. The decrease in the volatility of stocks relative to bonds over time has been attributed to several stock related factors: the impact of technology on productivity and the new economy; the role of information (see Federal Reserve Chairman Greenspan's comments referred to earlier in this testimony) on the economy and markets; better cost and risk management by businesses; and several bond related factors; deregulation of the financial system; inflation fears and interest rates; and the increase in the use of debt financing. Further evidence of the greater relative riskiness of bonds is shown on page 4 of Exhibit_(JRW-10), which plots real interest rates (the nominal interest rate minus inflation) from 1926 to 2004. Real rates have been well above historic norms during the past 10-15 years. These high real interest rates reflect the fact that investors view bonds as riskier investments.

The net effect of the change in risk and return has been a significant decrease in the return premium that stock investors require over bond yields. In short, the equity or market risk premium has declined in recent years. This decline has been discovered in studies by leading academic scholars and investment firms, and has been acknowledged by government regulators. As such, using a historic equity risk premium analysis is simply outdated and not reflective of current investor expectations and investment fundamentals.

Q. NOW TURN TO YOUR SPECIFIC COMMENTS ON DR. AVERA'S VARIOUS RISK PREMIUM APPROACHES. PLEASE INITIALLY ASSESS DR. AVERA'S EXAMINATION OF AUTHORIZED RETURNS ON EQUITY.

A. Dr. Avera provides his evaluation of allowed risk premiums on pages 42-46 of his testimony and in Document WEA-6. There are two major issues with this analysis: (1) his 30-year Moody's A rates of 5.8% current and 7.0% for 2006, and (2) his conclusion regarding the appropriate risk premium from the study. The base yield was addressed above as a common issue in his risk premium studies. On the second issue, Dr. Avera's approach involves circular reasoning since the results of other electric rate cases are employed to derive a risk premium in this proceeding. If such an approach is used in this and other jurisdictions, then no one will be testing to evaluate whether the ROE recommendation is above or below investors' required rate of return. Furthermore, Dr. Avera has not performed any analysis to examine whether the annual allowed ROEs are above, equal to, or below investors' required return. As discussed above, if a firm's return on equity is above (below) the return that investor's require, the market price of its stock will be above (below) the book value of the stock. Since Dr. Avera has not evaluated the market-to-book ratios for electric utilities involved in the annual rate cases, he cannot indicate whether these allowed ROEs are above or below investors' requirements. As a general notion, however, since the market-to-book ratios for electric utility companies have been in excess of 1.0 for some time, it would indicate that the allowed ROE's are above equity cost rates.

Q. PLEASE REVIEW DR. AVERA'S REALIZED RATE OF RETURN OR HISTORIC RISK PREMIUM ANALYSIS.

A. On pages 46 to 48 of his testimony and in Document WEA-8, Dr. Avera performs a realized rate of return or a historic risk premium analysis using Moody's Electric Utility stocks and A-rated bonds. There are three problems with his historic risk premium analysis: (1)) his 30-year Moody's A rates of 5.8% current and 7.0% for 2006, and (2) the historic risk premium methodology. These issues were addressed above as common issues in his risk premium studies.

Q. PLEASE DISCUSS DR. AVERA'S USE OF THE CAPITAL ASSET PRICING MODEL.

A. On pages 48 to 51 of his testimony and in Documents WEA-9 and WEA-10, Dr. Avera applies the CAPM his proxy group of electric utility companies. His CAPM-Historic uses the historic stock-bond return difference as the equity risk premium and his CAPM-Forward approach uses a forward looking equity risk premium. I have three concerns with Dr. Avera's CAPM analyses: (1) his risk-free interest rates of 4.6% current and 5.8% for 2006, (2) the historic risk premium in his CAPM-Historic approach, and (3) the expected risk premium in his CAPM-Forward approach. The first two issues were addressed above as common issues in his risk premium studies. The third is discussed below.

Q. PLEASE DISCUSS THE EXPECTED EQUITY RISK PREMIUM IN DR. AVERA'S

CAPM-FORWARD APPROACH.

A. Dr. Avera has computed an expected equity risk premium of 9.3% using the current risk-free rate of 4.6% and of 8.1% using a projected 2006 risk-free rate of 5.8%. The expected risk premium is based on an expected annual return for the S&P 500 of 13.9%.

Q. PLEASE SUMMARIZE DR. AVERA'S PROSPECTIVE MARKET RETURN OF 13.9%.

A. Dr. Avera computes an expected return of 13.9% for the S&P 500 using a dividend yield of 1.8% and an expected EPS growth rate of 12.1%. The growth rate represents the projected EPS growth rates as provided by IBES for the stocks in the S&P 500.

Q. PLEASE EVALUATE THIS EXPECTED MARKET RETURN of 13.9%.

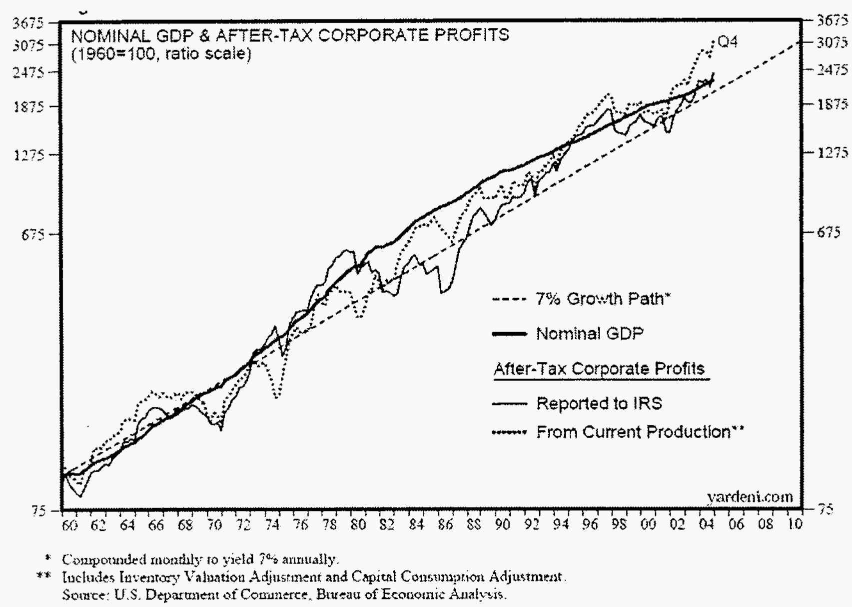
A. An expected annual market return of 13.9% is out of line with historic norms and is inconsistent with current market conditions. The primary reason is that the expected growth rate of 12.1% is clearly excessive and inconsistent with economic and earnings growth in the U.S.

The average historic compounded return on large company stocks in the U.S. has been 10.4% according to the 2005 SBBI Yearbook. To suggest that investors are going to expect a return that is 300 basis points above this is not logical. This is especially so given current market conditions. As discussed above, at the present time stock prices (relative to earnings and dividends) are high while interest rates are historic lows. Major stock market upswings which produce above average returns tend to occur when stock prices are low and interest rates are high. Thus, historic norms and current market conditions do not suggest above average stock returns. Consistent with this observation, the financial forecasters in the Federal Reserve Bank of Philadelphia survey expect a market return of 7.00% over the next ten years.

Q. WHAT EVIDENCE CAN YOU PROVIDE THAT INDICATES DR. AVERA'S GROWTH RATES IS EXCESSIVE?

A. Dr. Avera's expected EPS growth rate of 12.1% for the S&P 500 is based on analysts' EPS growth rate forecasts, which I previously demonstrated are upwardly biased. Reflecting this upward bias, an expected EPS growth rate of 12.1% is grossly overstates historic economic and earnings growth in the U.S. This is especially true when you consider that in a DCF framework, the growth rate is for a long period of time. The long-term economic and earnings growth rate in the U.S. has only been about 7%. Edward Yardeni, a well-known Wall Street economist, calls this the "7% Solution" to growth in the U.S. The graph below comes from his analysis of GNP and profit growth since 1960.

The 7% Solution
Nominal GNP and Profit Growth since 1960



Source: Edward Yardeni, Strategists Handbook, Oak Associates, April 2005

As further evidence of the long-term growth rate in the U.S., I have performed a study of the growth in nominal GNP, S&P 500 stock price appreciation, and S&P 500 EPS and DPS growth since 1960. The results are provided on page 1 of Exhibit_(JRW-9) and a summary is given in the table below.

GNP, S&P 500 Stock Price, EPS, and DPS Growth
1960-Present

Nominal GNP	7.22%
S&P 500 Stock Price Appreciation	7.15%
S&P 500 EPS	7.23%
S&P 500 DPS	5.32%
Average	6.73%

The results offer compelling evidence that a long-run growth rate of about 7% is appropriate for companies in the U.S. Dr. Avera's long-run growth rate projections are clearly not realistic. His estimates suggest that companies in the U.S. would be expected to (1) nearly double their growth rate of EPS in the future, and (2) maintain that growth indefinitely in an economy that is expected to growth at about one half his projected growth rates. Such a scenario lacks rationale.

Q. PLEASE SUMMARIZE YOUR ASSESSMENT OF DR. AVERA'S CAPM AND RISK PREMIUM ANALYSES.

A. Dr. Avera's risk premium studies are flawed and exaggerate the required return and equity cost rate for FPL. In general, he uses an inflated base yield or interest rate that is well in excess of current market interest rates and his equity risk premium estimates are excessive and do not reflect the realities of the economy and the stock and bond markets. Hence, Dr. Avera's risk premium analyses are erroneous and should be disregarded in estimating FPL's equity cost rate.

Q. PLEASE SUMMARIZE DR. AVERA'S RISK PREMIUM STUDIES IN LIGHT OF THE EVIDENCE ON RISK PREMIUMS IN TODAY'S MARKETS.

A. The primary issue in both his risk premium and CAPM analyses is the magnitude of the equity or market risk premium. Dr. Avera's risk premium estimates should be ignored because they are totally out of line with the equity risk premium estimates (1) discovered in recent academic studies by leading finance scholars and (2) employed by leading investment banks, management consulting firms, financial forecasters and corporate CFOs. In both his risk premium and CAPM studies, a more realistic market risk premium is in the 2-4 percent range above Treasury yields.

Q. PLEASE DISCUSS DR. AVERA'S COMPARABLE EARNINGS ANALYSIS.

A. On page 84 of his testimony, Dr. Avera attempts to justify FPL's equity cost rate request of 12.3% using the comparable earnings (CE) approach. His methodology involves observing the prospective returns on common equity for a group of companies "comparable" in risk to his group of electric utility companies. To determine comparable risk, Dr. Avera used Value Line's 'Safety Ranking" system, and screened *Value Line's* database for companies with a Safety Ranking of 1 or 2 (the average for his electric utility group is 2). In response to OPC POD No. 208, Dr. Avera provided the list of over 283 companies that met the Safety Rank criteria along with the returns on equity projected for 2007-2009.

Q. PLEASE CRITIQUE DR. AVERA'S COMPARABLE EARNINGS ANALYSIS.

A. There are several problems with this methodology and approach. First, it must be emphasized that Dr. Avera has provided no studies to demonstrate why *Value Line*'s safety ranking system is likely to produce a group of companies that are comparable to FPL. A brief review of the companies he viewed as "comparable" to FPL highlights this flaw. These companies include Allergan, Amgen, Baxter International, Bed, Bath, and Beyond, BRE Properties, First Data, Goldman Sachs, IBM, Medtronic, Microsoft, Pitney Bowes, Polaris, Stryker, UnitedHealth Group, and Wyeth. These companies are not only diverse in terms of business but also in terms of size, growth, risk, and performance. It is inconceivable that any investor would conclude that they are 'comparable' to FPL. Furthermore, Dr. Avera has performed no other studies to demonstrate that these companies are comparable to FPL. As such, his methodology is defective.

Furthermore, the CE approach itself is fundamentally flawed. Since Dr. Avera has not evaluated the market-to-book ratios for these companies, he cannot indicate whether the past and projected returns on common equity are above or below investors' requirements. These returns on common equity are excessive if the market-to-book ratios for these companies are above 1.0. For example, Coca-Cola and Kellogg are two of the 'comparable' companies identified by Dr. Avera. The projected returns on equity for these two companies are 33.0% and 47.0%, respectively. But, it is doubtful that any financial analyst, including Dr. Avera, would suggest that this is the equity cost rates for the company. Indeed, the market-to-book ratio for these companies are in excess of 10X which indicates that the company's return on equity is well above its equity cost rate.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes it does.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

TESTIMONY

OF

STEPHEN A. STEWART

Q. Please state your name, address and occupation?

A. My name Stephen A. Stewart. My address is 2904 Tyron Circle, Tallahassee, Florida, 32309. I am testifying as a consultant for AARP in this docket.

Q. Please describe your educational background and business experience?

A. I graduated from Clemson University with a Bachelor of Science degree in Electrical Engineering in December 1984. I received a Master's degree in Political Science from Florida State University in August 1990.

From January 1985 until October 1988, I was employed by Martin Marietta Corporation and Harris Corporation as a Test Engineer. In July 1989, I accepted an internship with the Science and Technology Committee in the Florida House of Representatives. Upon expiration of the internship I accepted employment with the Office of the Auditor General in August 1990, as a program auditor. In this position I was responsible for evaluating and analyzing public programs to determine their impact and cost-effectiveness.

In October 1991, I accepted a position with the Office of Public Counsel ("Public Counsel") with the responsibility for analyzing accounting, financial, statistical, economic and engineering data of Florida Public Service Commission ("Commission")-regulated companies and for identifying issues and positions in matters addressed by the Commission. I left the Public Counsel in 1994 and worked as a consultant for the Florida Telephone Association for one year.

Since 1995 I have been employed by two privately held companies, United States Medical Finance Company ("USMED") and Real Estate Data Services Inc. I worked with USMED for approximately four years as Director of Operations. I founded Real Estate Data Services in 1999 and I am currently its President and CEO.

Over the last ten years I have also worked for the Public Counsel on a number of utility related issues.

Q. What is the purpose of your testimony?

A. I am appearing on behalf of AARP in opposition to FPL's request for a rate increase. More specifically, I address five issues, which, taken alone, I believe demonstrate Florida Power & Light Company's ("FPL's") requested annual rate increase of $430.2 million is unreasonable and should be denied. The first FPL request that should be dismissed is the $100 million a year it is asking the Commission to require its customers to pay to support FPL's participation in the GridFlorida Regional Transmission Organization ("RTO"). Without regard to whether GridFlorida will ever be implemented or whether it will be cost-effective if implemented, GridFlorida is not now operational and FPL has failed to support the "costs" it alleges it has in connection with the RTO as being reasonable, necessary and prudent in producing electricity. Next, I believe another large portion of FPL's increase should be dismissed because it is related to an excessive requested return on equity ("ROE"). The excessiveness of FPL's ROE request consists of two elements: (1) the base mid-point ROE request of 11.8 percent is excessive as compared to what this Commission has historically granted, and (2) the additional 50 basis points requested as a "ROE Performance Incentive" appears unwarranted. Eliminating the 50 basis point reward will remove $50 million of FPL's request and setting rates on a mid-point ROE of 10.38 percent (the maximum I believe supported by Commission precedent) will reduce the annual revenue increase by approximately another $140 million, for a total annual revenue reduction related to ROE of $190 million. I hasten to add that my 10.38 percent recommendation is a maximum ROE (MROE) based on an analysis of the relationship between public utility bond yields and the Commission's ROE awards over the last 25 years. For purposes of an actual current required ROE, AARP supports the 8.8 percent ROE testified to by Public Counsel's cost of equity expert, Dr. Woolridge.

I next address the analysis of FPL witness Steven Harris, which is used to support the utility's request for an annual storm accrual of $120 million. I provide an analysis using historic storm costs and various annual accrual levels to evaluate the corresponding levels for FPL's Storm Reserve Fund. My analysis indicates that an increase in the accrual is warranted but that a reasonable and acceptable annual accrual for FPL would be $40 million, not the $120 million requested by FPL.

Lastly, I believe the Commission should treat FPL's very significant depreciation reserve surplus in a manner consistent with the way it has historically handled depreciation reserve deficiencies. That is, the Commission should rebalance, or correct, the depreciation reserve by flowing back the surplus to the benefit of customers over five years – as it often has with deficiencies – as opposed to over the remaining lives of the associated assets. Using just the utility's reported surplus of $1.6 billion and a five year rebalancing period, would result in reducing FPL's requested annual revenues by hundreds of millions of dollars, which, in conjunction with AARP's other suggested adjustments, would defeat any revenue increase and result in a net reduction in FPL's retail rates.

Q. Are the revenue reductions you testify to intended to be the total reductions supported by AARP?

A. No. My testimony is intended to demonstrate to the Commission that analysis of just five areas of FPL's request is sufficient to suggest that the utility should be entitled to no permanent rate increase. It is my understanding that the complete and thorough analysis of FPL's filing by Public Counsel will result in Public Counsel recommending a substantial reduction in FPL's base rates and that AARP will support all of Public Counsel's adjustments.

GRIDFLORIDA

Q. What is AARP's position with regards to FPL's request to recover expenses associated with GridFlorida?

A. AARP's position is that it is premature for FPL to recover expenses associated with GridFlorida. Mr. Mennes, the FPL witness on this issue, states that GridFlorida is a "proposed RTO" for Florida and bases the utility's requested cost recovery entirely on estimates. His "support" for this $100 million a year request is contained in just three pages of testimony and two one-page exhibits. In addition, there are no formal documents provided by FPL indicating when this proposed RTO will become operational. In fact, it has yet to be determined if the proposed RTO is actually cost-beneficial and ever will be implemented. Despite the eventual cost-effectiveness of GridFlorida, it is AARP's position that FPL has simply failed to prove that expenses associated with the RTO are real and that any known expenses are recurring and should properly be included in rates at this time.

Q. Do any other Florida investor-owned electric utilities have a component of base rates allocated to expenses associated with GridFlorida?

A. No, not that I am aware of. In fact, Progress Energy Florida ("PEF") has filed for rate relief in Docket No. 050045-EI and GridFlorida cost recovery is not a component of its requested increase. More specifically, at Page 10 of its Petition, which was filed on April 29, 2005, PEF said the following with respect to GridFlorida:

> 19. By this Petition, PEF has not requested the recovery of any post commercial in-service costs resulting from its participation in the GridFlorida regional transmission organization pursuant to the Federal Energy Regulatory Commission ("FERC") transmission

independence initiative and this Commission's Order No. PSC-01-2489-FOF-EI in Docket No. 000824-EI directing the investor-owned utilities in Florida to file a proposed Independent System Operator structure. The timing and nature of GridFlorida has not enabled PEF to determine when and the extent to which contributions will be required and, therefore, the Company has not included any such costs in its MFRs. The Company reserves the right to seek recovery of such costs at a later time and in any manner appropriate for recovery, including this proceeding if necessary, when the Company is better able to identify and quantify the costs.

(Emphasis supplied.)

I am not aware that PEF has filed a supplemental request identifying GridFlorida costs it is seeking in its base rates revenue request nor am I aware of any proceedings in this Commission's GridFlorida docket that would make Grid Florida's implementation a certainty justifying any rate increases associated with the RTO, let alone in the amount of $100 million a year.

RETURN ON EQUITY

Q. Do you consider yourself to be an "expert" on either cost of capital or return on equity and are you testifying to a recommended ROE number on behalf of AARP?

A. No. I do not consider myself to be an expert on either cost of capital or return on equity matters and I am not offering an opinion on what the current required ROE is. As I said earlier, AARP adopts the ROE recommendation of Public Counsel witness Dr. Woolridge of 8.8 percent. The number I am offering, 10.38 percent, is what I believe should be the ceiling, or absolute maximum, the Commission should grant FPL as a mid-point for setting rates in this case. This recommendation is based on my analysis indicating that the Commission's ROE awards over the last 25 years in major electric utility cases have had a strong and consistent relationship to the average public utility bond yields at the time of the Commission's ROE decisions. While I believe the Commission should consider ROE testimony in the traditional manner, I also believe my analysis provides a reasonable basis for determining the maximum ratesetting ROE (MROE) the Commission should approve in this case if it is to remain consistent with its precedents of the last 25 years.

Q. Why do you believe your analysis provides a reasonable basis for the ROE award the Commission should ultimately approve in this case?

A. The Commission has never to my knowledge awarded a utility a ROE for ratesetting purposes that was exactly what was testified to by an expert by either the utility or customer intervenors. Rather, typically there is a relatively large spread between the ROE testified to by the experts and usually the Commission makes an award that is somewhere within the range testified to by the experts. For example, in this case Mr. Avera for FPL has testified to an 11.8 percent ROE, excluding the efficiency reward, and I am told Dr. Woolridge for the Public

Counsel will testify to a ROE of 8.8 percent resulting in a spread between these two witnesses of 300 basis points.

Tracking the Commission's ROE awards over the years relative to the experts' recommendations, I was curious as to whether the Commission's decisions bore some discernable relationship to published economic or financial indicators. I believe I found one that does.

Using public utility bond yield data from FPL witness Avera's testimony, I have constructed a methodology, which I believe reveals a strong and consistent relationship between average public utility bond yields and the equity awards the Commission has made in major electric cases over the last 25 years.

Q. Describe the methodology used to support your MROE recommendation.

A. There are four stages to the methodology I employed to analyze the MROE for FPL. First, I developed a regression model of the relationship between the average public utility bond yield and the allowed ROE in major rate case decisions across the United States over the period 1980 to 2004. A table of this data, the regression statistics, and the components of the regression model is in Document SAS-1. As indicated on my exhibit, I took the "allowed ROE" numbers in Column 2 and the "average public utility bond yields" in Column 3 from Mr. Avera's Document WEA-6, Page 1 of 2.

Second, I researched and tabulated the Commission's ROE decisions for FPL since 1981. This tabulation is in columns 1, 2, & 3 in the table in Document SAS-2.

Third, I used the regression model from the first stage of my analysis to develop ROE estimates for the years that the Commission awarded an ROE to FPL. These estimates are in column 5 (Model Generated ROE) of the table in Document SAS-2. I compared the model estimates to the Commission's decisions in columns 6 and 7 in the table in Document SAS-2.

Fourth, I used the model to estimate what the MROE would be based on the average public utility bond yields for the most recent 6 months of reported data. This calculation is located at the bottom of Document SAS-2 for FPL.

Q. Please describe your findings?

A. In the first stage, I developed a regression model using data between 1981 and 2004. The model, detailed in Document SAS-1, provides an algorithm which, based on the R-square value (the closer the R-square is to 1.0, the more the variation is explained by the model), demonstrates a strong relationship between the average public utility bond yield and allowed ROE's. These findings indicate the average public utility bond yield is a strong predictor of allowed ROE's over the period of the analysis.

In the third stage I used the regression model to develop an estimate of the ROE for FPL during the various time periods the Commission assigned an actual allowable ROE. These estimates were based on the corresponding average public utility bond yield when each of the awards was made. I compared these estimates with the actual ROE's allowed by the Commission. The findings indicate that the model does a remarkably good job of predicting the Commission-allowed ROE. Column 6 in the table in Document SAS-2 shows the difference between the model generated ROE and the FPSC allowed ROE. I have also included a chart in Document SAS-3 that plots the Commission-allowed ROE's and the regression model estimates. The plot supports the finding that the regression model was very successful in predicting the ROE decisions of the Commission.

In the fourth stage I used the regression model to estimate the MROE, using the available public utility bond yield data for the most recent six months. The MROE was calculated to be 10.38%. In a variation of the chart in Document SAS-4, I created another chart and added the MROE estimate and the FPL requested ROE as data points. Referring to this chart in Document SAS-4, the MROE estimate follows the downward trend line beginning in 1985. The FPL requested ROE varies significantly from that trend line.

These findings indicate that for the Commission to be consistent with its prior decisions, and absent other well-defined mitigating factors, the *maximum* ROE that should be allowed for ratesetting purposes in this case is 10.38%.

Q. Did you complete any other analysis?

A. Yes. I wanted to verify that the regression model I used was reliable. So I gathered ROE data for all of this Commission's ROE decisions over the last twenty-five years for the four major Florida investor-owned electric utilities and developed a model using the same average public utility bond yield data I employed in the first model. The tabulation of the data, the regression statistics, and the components of the regression model is in Document SAS-5. The results were almost identical, although this model did have a higher R-squared value.

This result validates the first model I developed and provides additional support for my recommendation.

Q. Please summarize AARP's position on the appropriate ROE for FPL.

A. AARP adopts the ROE recommendation of the Public Counsel witness Woolridge of 8.8 percent. However, if the Commission should not accept this recommendation, I have provided on behalf of AARP, an analysis based on prior Commission decisions indicating that the *maximum* ROE the Commission should consider allowing in this case is 10.38%. Such an adjustment would necessarily reduce FPL's requested annual revenue increase by $140 million (using FPL witness Dewhurst's calculation that 50 basis points equates to approximately $50 million in revenue requirements) as compared to the utility's base ROE request of 11.8 percent.

ROE PERFORMANCE INCENTIVE

Q. What is your understanding of the ROE Performance Incentive requested by FPL in this case?

A. FPL witness Mr. Moray Dewhurst states at Page 20 of his testimony that "the purpose of the incentive is to recognize FPL's past superior performance and to encourage continued strong operational performance over the long-term." He adds at Pages 25-26 that the 50 basis performance incentive FPL is seeking "equates to approximately $50 million in revenue requirements."

Q. What is AARP's position on the Commission granting FPL an additional $50 million a year through higher customer rates in order to

recognize its past superior performance and to encourage its strong operational performance in the future?

A. AARP's position is that the Commission should deny the requested $50 million incentive. First, as Mr. Dewhurst noted in his testimony, FPL has been receiving an incentive for its past performance through the "revenue-sharing" plans included in the settlement agreements approved by the Commission in 1999 and 2002. It would appear unfair to customers for FPL to be rewarded a second time for its past performance if, indeed, it has already been recognized through the revenue-sharing plans. Secondly, AARP takes the position that FPL has a statutory obligation to provide "efficient" service to its monopoly customers and that the Commission's traditional equity awards are more than adequate to compensate the utility's shareholders, especially given the continuing reduction of risks they are exposed to.

Q. What is the statutory obligation you refer to?

A. Section 366.03, Florida Statutes, provides, in part:

> 366.03 General duties of public utility.--Each public utility shall furnish to each person applying therefore reasonably sufficient, adequate, and <u>efficient service</u> upon terms as required by the commission. **(Emphasis supplied.)**

Q. What are you referring to with respect to the basic equity return being adequate especially given the reduced level of risk exposure?

A. What I am referring to is that electric utilities regulated by this Commission now have a very large percentage of their revenues that are subject to 100 percent cost recovery through rates with the result that shareholders are not subject to risk of loss when these various costs experience increases. Examples include fuel cost expenses, conservation cost recovery expenses, environmental compliance costs, many security related costs and an apparently strong likelihood now that electric utilities will be held entirely harmless for storm damage occurring between rate cases when the costs of repairs exceed their storm damage reserves. In short, the "risk" of utility shareholders seeing their profits diminished by increases in a large number of the costs of providing service is substantially less than it was previous to these cost recovery clauses. Arguably FPL's requested ROE should be lower to account for the reduced risks but I do not recall that Mr. Avera recommended such a reduction. AARP's position is that the Commission should not give FPL a $50 million a year incentive over and above what it would consider fair and reasonable rates to spur it to operate efficiently.

STORM ACCURAL

Q. Please summarize Mr. Harris's recommendation for the annual storm accrual.

A. Mr. Harris' Loss Analysis concluded that the expected annual uninsured cost to FPL's system from all windstorms is estimated to be $73.7 million. In addition, the analysis indicates that an accrual level of $120 million would result in an expected Storm Reserve Balance of $367 million and a probability of insolvency of 8% at the end of a five-year time horizon. The current annual accrual to the Storm Reserve Fund is approximately $20 million.

Q. Did you complete an analysis on the issue of the proper level of the annual accrual for the Storm Reserve Fund?

A. Yes. I developed a table, shown in Document SAS-6, to determine what the impact on the Storm Reserve Fund would have been if Mr. Harris' proposal had been implemented in 1990. In column 2 of the table I have listed the annual storm costs incurred by FPL due to storms. Column 3 in the table shows the actual balance of the Storm Reserve Fund for every year since 1990. Column 4 in the table shows the balance of the Storm Reserve Fund for every year since 1990 assuming a $120 million annual accrual and the recovery of a negative balance over a two year period. The table shows that the balance after the hurricane season of 2004 would have been $ 745.5 million.

Q. What other analysis did you complete.

A. Using the same approach, I calculated what the balance in the Storm Reserve Fund would be given various annual accrual amounts. For example, Column 5 shows that an annual accrual of $80 million would have resulted in a Storm Reserve Balance at the end of 2004 of $150.9 million. For an annual accrual of $40 million, the Storm Reserve Balance at the end of 2004 is calculated to have a deficit of $369.7 million.

Q. How do you think this Commission should determine the proper annual accrual for FPL in this case?

A. The decision made by this Commission should be based on what is viewed as an acceptable balance in the Storm Reserve Fund. It is my view that the annual accrual should not be set so that the Storm Reserve Fund will cover expenses associated with extraordinary events, such as Hurricane Andrew and the hurricane season of 2004. Rather, the accrual should be set to cover normal recurring storm costs.

Q. How does your analysis help the Commission reach their decision?

A. The analysis I have provided will allow the Commission to review the yearly balances based on varying levels of annual accrual. For example the Commission can look at the levels of the Storm Reserve Fund in 2003 to get an idea of what accrual level would be the most appropriate. In 2003, the Storm Reserve Fund balance would have been $1.480 billion assuming an accrual of $120 million, $953.7 million for an accrual of $80 million and $497 million for an accrual of $40 million. I believe the analysis indicates that the FPL request of $120 million would result in an over funding of the Storm Reserve Fund.

Q. Based on this analysis, what is your recommendation for an annual accrual level?

A. I would recommend an annual accrual of $40 million. Absent extraordinary events, history shows that this annual accrual coupled with the recovery of a negative balance over a two-year period will adequately fund the FPL Storm Reserve.

DEPRECIATION RESERVE SURPLUS

Q. What is your understanding of FPL's depreciation reserve surplus and what position does AARP take on how it should be addressed?

A. First, let me state that AARP supports the Office of Public Counsel's determination that the depreciation reserve surplus is significantly larger than reported in FPL's depreciation study. Specifically, AARP adopts the Office of Public Counsel's position that the depreciation reserve surplus is, in fact, \$2.4 billion. However, even if the Commission were to accept the FPL-reported surplus of \$1.6 billion, treating that surplus consistently with the Commission's prior treatment of depreciation deficiencies would necessarily result in a substantial reduction of the utility's expenses and a net rate decrease if AARP's other requested adjustments are accepted.

Q. How are you recommending that the Commission address the depreciation reserve surplus?

A. As I said, I am recommending that the Commission treat the depreciation reserve surplus in the same manner it has historically addressed depreciation reserve deficits. From my review of this Commission's prior orders addressing adjustments to depreciation reserve accounts, it appears that the Commission has repeatedly allowed the electric utilities to recover depreciation reserve deficiencies over as few as three to five years and not made the utilities wait to collect the deficiencies over the remaining lives of the related assets. This treatment necessarily caused a greater increase in allowable expenses as compared to the remaining life option. So, if a utility were requesting rate relief in conjunction with a depreciation reserve "correction," rebalancing, or correcting the reserve, over three to five years would increase allowable expenses and with them the revenue requirement and rates. Between rate cases, an adjustment over three to five years would, as opposed to the remaining life option, pull down reported earnings without affecting cash flow. Obviously increasing depreciation expense and reported profits would be more important during periods in which a utility was over earning or close to its profit ceiling. Simple fairness should require the Commission to use the shorter period of years to reduce revenue requirements to the advantage of FPL's customers if it has repeatedly used the shorter term to increase required revenues to the advantage of the utility.

Q. Aside from consistency with its treatment of past depreciation reserve deficiencies, what advantages do you see from correcting the reserve position over a shorter period of years?

A. I think the advantage to consumers is that it gives current customers the benefit of the return of the depreciation expense overpayments they have made and avoids the intergenerational inequity necessarily associated with correcting the reserve over the remaining lives of the related assets. Fundamentally, however, the Commission should be consistent in its treatment of this issue regardless of what direction a correction is required.

Q. Why are you suggesting correcting the depreciation reserve surplus over five years?

A. To be consistent with the number of years often used by this Commission when addressing depreciation reserve deficiencies. It appears that five years is the longest period of years typically used by the Commission when correcting depreciation reserve deficiencies.

Q. Are you recommending a specific revenue adjustment related to the depreciation reserve surplus?

A. No I am not. I have not attempted to calculate the overall revenue impact, which necessarily would include a related increase in rate base. The adjustment would depend on the surplus found by the Commission based on the record, as well as the number of years used to make the correction. Again, I am recommending a five year correction because it is consistent with this Commission's precedents in treating reserve deficiencies.

Q. What is the total revenue reduction you are recommending from your five adjustments?

A. A total of $370 million from the first four, consisting of $100 million requested for FPL's RTO participation, $50 million associated with the ROE Performance Incentive, $140 million associated with the recommended reduction from 11.8 percent to my MROE of 10.38 percent and $80 million for the reduction in FPL's requested annul storm accrual. The depreciation reserve surplus adjustment will necessarily reduce FPL's allowable expenses by an additional several hundred million dollars a year and, thus, turn its remaining positive revenue increase case into a rate reduction case.

Q. Do you believe that these are the only downward adjustments necessary to FPL's request?

A. No. This total is only related to the five items I have discussed in my testimony. AARP plans to adopt the other downward adjustments proposed by the Office of Public Counsel.

Q. Does this conclude your testimony?

A. Yes.

Before the

Florida Public Service Commission

In Re: Petition for Rate Increase by Florida Power & Light Company	)	**Docket No. 050045-EI**
In Re: 2005 Comprehensive Depreciation Study by Florida Power & Light Company	)	**Docket No. 050188-EI**

<u>Direct Testimony of James T. Selecky</u>

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A James T. Selecky; 1215 Fern Ridge Parkway, Suite 208; St. Louis, Missouri, 63141.

Q WHAT IS YOUR OCCUPATION AND BY WHOM ARE YOU EMPLOYED?

A I am a consultant in the field of public utility regulation and a principal in the firm of Brubaker & Associates, Inc., energy, economic and regulatory consultants.

Q PLEASE STATE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

A These are set forth in Appendix A to this testimony.

Q ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS PROCEEDING?

A I am presenting testimony on behalf of the Commercial Group. Member companies of the Commercial Group are substantial purchasers of electricity from The Florida Power & Light Company (FPL or the Company).

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

A The purpose of my testimony is to address certain revenue requirement issues, cost of service and rate design proposals put forth by FPL. I will also address FPL's ratemaking treatment proposal for Turkey Point Unit 5. The fact that an issue is not addressed in my testimony should not be construed as an endorsement of FPL's position.

Q PLEASE SUMMARIZE YOUR CONCLUSIONS AND RECOMMENDATIONS.

A The summary of my conclusions and recommendations is listed below:

1. FPL's requested return on equity of 12.30% is excessive and the proposed 50 basis point return on equity (ROE) performance incentive adder is unwarranted and unnecessary.

2. FPL's proposal to increase the annual storm damage reserve accrual amount from $20.3 million to $120 million, an increase of almost 500%, is excessive and should be rejected.

3. FPL's proposal to add an additional $45 million of operating and maintenance expense to reflect <u>potential</u> increases related to GridFlorida RTO expenses in the next five years should be rejected. This is speculative and assumes no other change in FPL operations. FPL could experience load growth or other changes over the next five years that could obviate the need for this revenue increase.

4. FPL's cost of service study classified investment in distribution facilities as almost entirely demand-related. This is inconsistent with cost-causation and generally accepted costing methodology. The Commission should direct FPL to develop a cost of service study that classifies a portion of distribution lines as customer-related.

5. FPL should be directed to allocate any approved base rate revenue increase among the rate classes in such a way that no rate class receives greater than 150% of the system average base rate increase. This has traditionally been the Florida Public Service Commission's rule of thumb and there is no reason to depart from this practice. FPL has not had a base rate increase since 1985. Attempting too large a movement toward cost of service at the first rate case in 20 years could result in rate shock. A more gradual movement toward cost-based rates would still provide proper price signals.

6. FPL should not be permitted to group separate rate classes together for revenue allocation and rate design purposes. FPL combined rate

schedules CS-1, CS-2, GSD-1, GSLD-1 and GSLD-2 into one group, which it calls the distribution voltage demand metered commercial and industrial customer group. As a group, the proposed percent increase is within 150% of the system average percent increase of 9.7%. However, this is a function of FPL's proposed increase of 13.3% or approximately 140% of the system average, to rate schedule GSD-1, which is a very large rate class. The other four rate classes in the group would receive significantly higher than 150% of the total system increase. FPL should be directed to allocate any approved revenue increase among these rate classes individually, and not as a group.

7. FPL is proposing that the rate classes CS-1, CS-2, GSD-1, GSLD-1 and GSLD-2 have the same demand and energy charge. The only difference among these five rate classes would be the customer charge. The unit cost study filed by FPL does not support this proposal and it should be rejected.

8. For rate classes CS-1, CS-2, GSD-1, GSLD-1 and GSLD-2, FPL is proposing to recover the proposed revenue increase by increasing the customer and non-fuel energy charges and leaving the demand charge at the present level. FPL's own unit cost analysis does not support this proposal. According to FPL's analysis, only 52% of the demand-related cost for Rate GSLD-1 would be recovered through the demand charge under the Company's proposed rates. FPL's current rates recover a significant amount of demand-related cost through the energy charge. FPL's proposed rates for GSLD-1 exacerbate this problem, moving both the demand and energy charges even further away from cost-based rates. Any revenue increase approved by the Commission should be recovered via an increase to the demand charge as well as the customer and non-fuel energy charge, as justified by the unit cost study results.

9. FPL's proposed new High Load Factor Tariff (HLFT) rate should be accepted with one modification. FPL designed the HLFT rate such that customers would benefit from the new rate if they had a load factor of 70% or greater. A 70% load factor breakeven point is arbitrary and unduly limiting. FPL should be directed to redesign the rate so that customers with a load factor of 65% or greater would benefit from the new rate. Expanding the availability of this rate would make it more useful to commercial customers.

10. FPL's proposal to increase base rates in mid-2007 to recover the cost of Turkey Point Unit 5 should be rejected. This is an example of single-issue ratemaking. FPL should be directed to file for a rate increase when it gets closer to the time that the unit will be in operation. However, if the Commission were to approve FPL's proposal to establish rates for Turkey Point Unit 5 cost recovery at this time, then FPL's proposal to recover the cost on an energy or per kWh basis should be rejected. The fixed cost of the unit is classified as primarily demand-related and allocated using the 12CP and 1/13th energy allocation method. Cost recovery should be consistent with cost allocation. FPL should be directed to follow this basic precept and recover a portion of the cost on a per kW basis.

Revenue Requirement

Q HAVE YOU REVIEWED FPL'S PROPOSED RATE INCREASE FOR 2006 AND 2007?

A Yes. I have reviewed FPL's proposed rate increase for 2006 and the proposed rate adjustment for 2007 to reflect Turkey Point Unit 5 being put into rate base in June of 2007. FPL is proposing a base revenue increase for 2006 of $359 million, or 9.7%, relative to present base revenue of $3.7 billion. The total proposed increase is $385 million, including the increase in service charges and the change in unbilled revenue. However, this amount is net of certain adjustments made to the recovery of costs in the Capacity Cost Recovery Clause (Capacity Clause) and the Fuel Cost Recovery Clause (Fuel Clause). FPL's total requested increase, without those adjustments, would be $430 million, or 11.1%, of present operating revenue. Stated another way, FPL is seeking recovery of an additional $45 million of the total proposed increase through adjustment clauses rather than base rates.

Q ARE YOU FAMILIAR WITH THE COMPONENT PARTS OF FPL'S PROPOSED RATE INCREASE FOR 2006?

A Yes. FPL is proposing to increase base rates by approximately $359 million, service charges by $24 million and unbilled revenues by $1 million (for a total of $385 million). The proposed base rate increase reflects FPL's requested return on equity (ROE) of 12.30%, a 55.83% equity ratio and an overall rate of return (ROR) of 8.22%. According to FPL, absent the requested rate increase, the 2006 ROE would be 8.47%.

Q IS FPL'S REQUESTED ROE REASONABLE?

A No. FPL's requested 12.30% ROE is excessive when compared to ROEs authorized in 2004 for other electric investor-owned utilities in the United States. The Regulatory Research Associates, Inc. Regulatory Focus dated January 14, 2005 states that, "The average equity return authorized electric utilities in 2004 approximated 10.7%." There were 19 electric utility ROE determinations in 2004. I have attached a copy of the report to my testimony as Exhibit JTS-1. It should be noted that the report is a proprietary study and should not be used by others outside of this case.

The requested ROE of 12.30% also includes a proposed 50 basis point ROE performance incentive adder. However, even without the adder, the requested ROE is over 100 basis points in excess of the average ROE authorized in 2004.

FPL is requesting the adder in recognition of "superior performance and to provide an incentive for future superior performance" (Dewhurst 11). According to the Company, such an action would have the additional benefit of providing a signal to other companies that outstanding performance will be "encouraged, recognized and rewarded" (Dewhurst 20).

Q WOULD YOU CHARACTERIZE FPL'S PERFORMANCE AS SUPERIOR?

A No. Rates are a significant yardstick by which customers measure a utility's performance. Based on a comparison of residential, commercial and industrial rates among various utilities in the Southeastern U.S., FPL's performance is not superior (see Exhibit JTS-2). FPL's rates are in the top quartile. A panel of Commercial Group (CG) customers taking service from FPL has also filed testimony in this proceeding on this issue. Their testimony concludes that FPL should not receive an ROE performance incentive adder.

Q IS FPL CURRENTLY OPERATING ON A FORM OF INCENTIVE REGULATION?

A Yes. FPL has been operating under revenue sharing plans approved by the Commission in 1999 and 2002. The current plan is scheduled to expire at the end of 2005. According to FPL, these plans have been favorable for customers. Since 1999, FPL has reduced retail base rates by $600 million in annual revenue requirement and provided refunds to customers of more than $220 million (Dewhurst 22).

Q DOES THE COMPANY EXPLAIN WHY IT IS PROPOSING AN ALTERNATIVE FORM OF INCENTIVE REGULATION?

A Not really. The Company makes a rather vague comment that revenue sharing agreements hold less appeal for utilities having to make large investments in infrastructure to maintain reliability.

Q IN WHAT AREAS DOES FPL DEEM ITS PERFORMANCE OUTSTANDING?

A FPL believes that its performance in the areas of reliability of service, quality of customer service and operating and maintenance costs merits recognition. According to the Company, it achieved unprecedented reductions in operating expenses during the decade of the 1990s.

Q DOES THIS RECORD SUPPORT THE NEED FOR AN ROE PERFORMANCE ADDER?

A No. FPL's professed outstanding performance was achieved without an ROE performance incentive adder. If anything, this indicates that such an adder is unnecessary. However, if the Commission believes an incentive program is necessary to continue improving FPL's performance, it may want to consider renewing the sharing plan FPL has operated under since 1999. It appears that the series of rate adjustments implemented while the plan was in place demonstrated that both FPL and customers derive benefits under such an arrangement.

Q ARE YOU RECOMMENDING THAT THE COMMISSION IMPLEMENT A FORM OF INCENTIVE REGULATION?

A No. Before any form of incentive regulation is implemented it must be thoroughly evaluated to determine if it is fair to both FPL and the customers. I have not evaluated the current plan. However, I do not see how customers benefit by increasing the ROE by 50 basis points.

Q DO YOU HAVE ANY OTHER CONCERNS WITH PARTICULAR ITEMS INCLUDED IN FPL'S PROPOSED REVENUE INCREASE?

A Yes. I would like to address FPL's proposed increase in annual storm damage accrual and the increase in Operating & Maintenance expense related to GridFlorida RTO.

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Storm Damage Accrual

Q IS FPL PROPOSING TO INCREASE ITS ANNUAL ACCRUAL TO ITS STORM RESERVE THAT IS REFLECTED IN ITS BASE RATES?

A Yes. FPL is proposing that the Commission provides for an annual accrual for storm damage reserve in base rates of $120 million. This is an increase from the current level of $20.3 million, or 500%.

Q WHAT WAS THE BASIS FOR ESTABLISHING THE ANNUAL ACCRUAL OF $120 MILLION?

A This amount is based on an expected amount of annual storm losses of $73.7 million and establishing a target storm damage reserve level of $500 million. FPL indicates in its testimony that the expected balance of the storm reserve would be approximately $367 million after five years.

Q HOW DID THE COMPANY DETERMINE THE ANNUAL STORM LOSS AMOUNT OF $73.7 MILLION?

A This is based on a statistical analysis performed by FPL witness Steven Harris. This analysis produces an annual storm loss amount that is excessive when compared to historic levels prior to the extraordinary losses in the 2004 season.

ABS Consulting performed a study which concluded that the expected average annual cost for windstorm losses is roughly $73.7 million, far less than the $120 million being requested by FPL. The study did not recommend any particular target reserve level. FPL has arbitrarily chosen a $500 million target storm damage reserve level. According to its own consultant's analysis, at its proposed annual accrual level of $120 million, there is an almost 40% probability that the storm fund will exceed the $500 million target level in five years.

Q **WHAT IS YOUR SUPPORT FOR STATING THAT THE HISTORICAL STORM DAMAGE COSTS HAVE BEEN SUBSTANTIALLY LESS THAN $73.7 MILLION ANNUALLY?**

A Historical data indicates that the annual storm costs charged to the reserve have been below $73.7 million for 14 of the past 15 years. In response to Data Request OPC No. 12, FPL provided an analysis of its storm reserve balance from 1990 through 2004. A review of that data indicates that over the last ten years, storm costs charged to the reserve, excluding 2004, have been approximately $15 million per year. For the five-year period from 1999 through 2003, the storm costs charged to the reserve have been approximately $23 million.

Q **HAS FPL'S CURRENT ANNUAL STORM DAMAGE ACCRUAL BEEN SUFFICIENT IN THE PAST?**

A Yes. Since at least the early 1990s, FPL's current storm damage reserve accrual level has been sufficient. Even though the annual accrual has been significantly less than the then expected annual costs of restoration, the storm damage reserve increased (Dewhurst 38). Restoration costs actually incurred over the last decade have all been funded by the storm damage reserve, even while the reserve increased. FPL claims that this has only been possible because of very favorable storm experience over the last decade.

Q WHAT ABOUT THE HURRICANE SEASON IN 2004?

A The current estimated cost for all three storms in 2004, net of insurance proceeds is $890 million. The storm damage reserve of $354 million has been completely depleted and there is a deficit of $533 million. Also, the 2004 hurricane season has reduced the amount of vegetation and this reduction should to some extent reduce the damage to the distribution system associated with post-2004 storms.

Q HASN'T FPL REQUESTED COMMISSION APPROVAL FOR A SPECIAL SURCHARGE TO COVER THE STORM DAMAGE COST FROM 2004?

A Yes. In Docket 041291-EI, the Commission authorized FPL to implement a storm surcharge effective February 17, 2005, subject to refund. An Order in this proceeding is due in July. FPL has the option to petition for relief in the event of a major storm and it has done so. Also, Florida has passed legislation that allows utilities to petition regulators to issue bonds to cover losses from storm damage and restore depleted storm reserves.

Q WHAT IS YOUR RECOMMENDATION IN THIS PROCEEDING?

A The Commission should approve an annual storm damage accrual amount that more appropriately balances the interests of customers against those of the Company. Rather than reacting to what was admittedly an unusually harsh hurricane season in 2004 by dramatically increasing the annual storm damage reserve accrual amount, the Commission should direct FPL to consider an accrual level that produces the lowest long-term cost to customers.

My recommendation is that, at minimum, the storm reserve accrual amount proposed by FPL should be reduced by $50 million. This reflects an annual storm cost of approximately $23 million, which corresponds to actual annual storm cost for the 1998-2003 period. That is, the Commission should authorize a storm damage accrual not to exceed $70 million. This exceeds the expected expense by approximately $50 million and allows for a build up in the reserve. However, this should not be construed as an endorsement of how fast the reserve should be built up.

GridFlorida RTO

Q WHAT IS FPL'S PROPOSAL WITH RESPECT TO THE INCREMENTAL COSTS ASSOCIATED WITH GRIDFLORIDA RTO?

A According to the Company, FPL's share of GridFlorida start-up costs will be $59 million in 2006, which could increase to $148 million by 2010. FPL is proposing an additional $45 million increase to the O&M expense included in its 2006 test year forecast revenue requirement to reflect an average of the annual GridFlorida RTO expenses over the next five years. This is speculative and assumes no other changes in FPL operations that could serve to offset the need for this increase in expense will occur. Therefore, the additional $45 million increase to O&M expense should be rejected.

Cost of Service

Q ARE YOU FAMILIAR WITH FPL'S COST OF SERVICE STUDY AS SUBMITTED IN THIS PROCEEDING?

A Yes. I have reviewed the cost of service study submitted by FPL in this proceeding. The Company filed a cost of service study with a projected test period ending December 31, 2006.

Q WHAT DOES THE STUDY PURPORT TO SHOW ABOUT FPL'S COST RECOVERY FROM COMMERCIAL CUSTOMERS?

A Supposedly, FPL is under-recovering its costs from some commercial customers.

Q DO YOU HAVE ANY COMMENT ABOUT FPL'S COST OF SERVICE STUDY?

A Yes. I disagree with the method FPL used to classify distribution plant. If FPL uses the correct method, it will show that commercial customers, particularly GSLD customers, are paying a higher percentage of the costs that FPL incurs to serve such customers.

In addition, the relationship between the level of residential rates and the level of commercial and industrial rates indicate that for FPL, the commercial and industrial classes' rates are high as compared to this relationship for other utilities. This is based on the per unit costs shown on Exhibit JTS-2. Commercial customers' per unit costs (and rates) are typically lower than residential customers because they use more energy per location, tend to have higher load factors, are served at higher delivery voltage and use less of the distribution system. Since my experience has been that commercial and industrial rates are normally above cost of service, I am surprised by the results of FPL's cost of service. FPL's cost of service study indicates that certain commercial/industrial rates are below cost of service study. Table 1 summarizes the results of the comparison of the commercial and industrial rates with residential rates.

TABLE 1

Ratio of Commercial and Industrial Rates
with Residential Rates as Reported by EEI

	Commercial 500 kW 180,000 kWh	Industrial 1,000 kW 650,000 kWh
FPL	.85	.73
Average of Utilities	.80	.63

Source: Exhibit JTS-2

As Table 1 shows, the ratio of commercial and industrial rates to the residential rates is closer for FPL than for the average utility shown in Exhibit JTS-2. These rates could even get closer to residential if the requested increases are implemented.

Q **HOW DID FPL CLASSIFY DISTRIBUTION PLANT IN ITS COST OF SERVICE STUDY?**

A FPL's cost of service study classifies distribution lines as essentially 100% demand-related. This is inconsistent with cost-causation and generally accepted costing methodology.

The primary purpose of the distribution system is to deliver power from the transmission grid to the customer. Certain distribution investments must be made just to attach a customer to the system. These investments are customer-related.

Q **IS IT COMMON PRACTICE TO CLASSIFY A PORTION OF THE DISTRIBUTION NETWORK AS CUSTOMER-RELATED?**

A Yes, the NARUC Electric Utility Cost Allocation Manual (NARUC Manual) states that:

> Distribution plant Accounts 364 through 370 involve demand and customer costs. The customer component of distribution facilities is that portion of costs which varies with the number of customers. Thus, the number of poles, conductors, transformers, services, and meters are directly related to the number of customers on the utility's system. As shown in Table 6-1, each primary plant account can be separately classified into a demand and customer component. Two methods are used to determine the demand and customer components of distribution facilities. They are, the minimum-size-of-facilities method, and the minimum-intercept cost (zero-intercept or positive-intercept cost, as applicable) of facilities (NARUC Manual, page 90).

Table 6-1 from the NARUC Manual is included as Exhibit JTS-3. It shows that Distribution Plant Accounts 364, 365, 366, 367 and 368 have a customer component. FPL must incur costs to construct a distribution network irrespective of the amount (i.e., energy) or rate (i.e., demand) of electricity usage. The costs of this minimum size network are properly classified as customer-related. The remaining distribution investment is needed to provide sufficient capacity to meet customers' demands when they arise. This portion of the distribution investment is demand-related. FPL allocates total distribution facilities' investment almost 100% on demand.

Q PLEASE DEFINE THE MINIMUM SYSTEM METHOD FOR CLASSIFYING DISTRIBUTION PLANT.

A The minimum system method determines the minimum size distribution system that could be built to serve the minimum load requirements of customers on the system. The method involves determining the minimum size pole, conductor, cable and transformer that is currently installed by the utility. The cost of the minimum size facilities is classified as customer-related. The demand-related cost is the difference between the total cost and the customer-related cost.

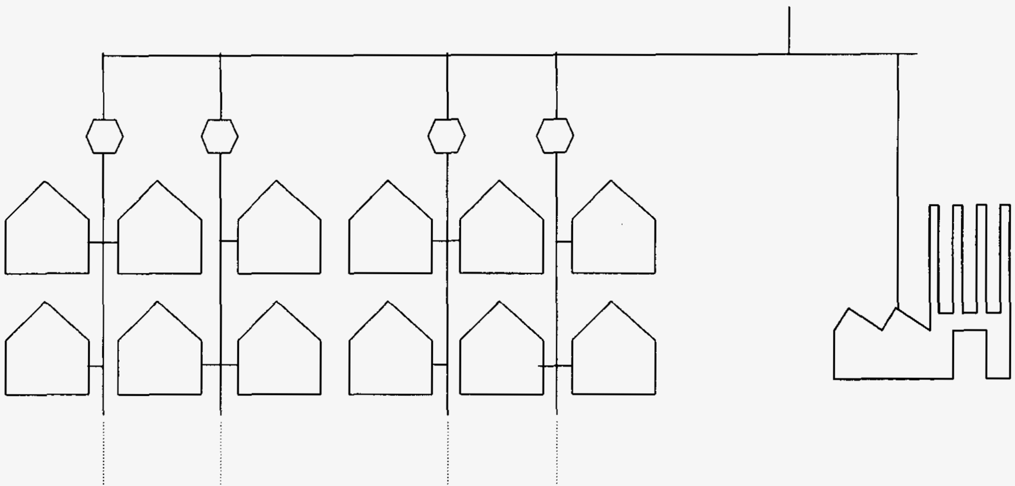
Q CAN YOU PROVIDE A SIMPLE ILLUSTRATION THAT SUPPORTS THE CLASSIFICATION OF A PORTION OF THE DISTRIBUTION SYSTEM AS CUSTOMER-RELATED?

A Yes. The diagram on page 16, for example, shows the distribution network for a utility with two customer classes, A and B. The physical distribution network necessary to attach Class A is designed to serve 12 customers, each with a 10-kilowatt load, having a total demand of 120 kW. This is the same total demand as is imposed by Class B, which consists of a single customer. Clearly, a much more extensive distribution system is required to attach the multitude of small customers (Class A), than to attach the single larger customer (Class B), even though the total demand of each customer class is the same.

Although some additional customers can be attached without additional investment in certain areas of the system, it is obvious that attaching a large number of customers requires investment in facilities, not only initially but on a continuing basis for maintenance and repair.

To the extent that the distribution system components must be sized to accommodate additional load beyond the minimum, the balance is a demand-related cost. Thus, the distribution system is classified as both demand-related and customer-related.

Classification of Distribution Investment



Total Demand = 120 kW
Class A

Total Demand = 120 kW
Class B

Q **HAVE UTILITY COMMISSIONS ADOPTED THE MINIMUM SYSTEM METHOD FOR CLASSIFYING DISTRIBUTION PLANT?**

A Yes. For example, the minimum system method (or, a variant of minimum system called the zero-intercept method) has been adopted in Connecticut, Colorado, Hawaii, Indiana, Maine, Missouri, North Carolina, Oregon, Pennsylvania and Texas. Distribution Plant Accounts 364 through 368 are classified as customer- and demand-related in Georgia.

Q **HAS THE FPSC ADDRESSED THIS ISSUE?**

A Yes. The FPSC rejected the use of the minimum system method in a Gulf Power case in June of 2002 but accepted the zero intercept method in a rate case involving Choctawhatche Electric Coop (CEC) in August 2002. It is my understanding that the Commission has rejected the minimum system method numerous times over the years but noted certain characteristics of CEC that justified its use in that case.

Q DID YOU PREPARE YOUR OWN COST OF SERVICE STUDY?

A No. FPL declined to provide an electronic version of its cost of service study and so I was unable to replicate the study without investing significant time and expense.

Q HAVE YOU ESTIMATED THE IMPACT ON RATE GSLD-1 OF CLASSIFYING A PORTION OF THESE DISTRIBUTION PLANT ACCOUNT COSTS AS CUSTOMER-RELATED?

A No. However, rate schedule GSLD-1 represents over 8% of the distribution demand and less than 0.1% of the number of customers. Reclassifying a portion of distribution costs from demand-related to customer-related, as described above, would have a significant impact on rate class GSLD-1's ROR, and would provide a more accurate view of the costs that commercial customers impose on the FPL system.

Q WHAT IS YOUR RECOMMENDATION WITH RESPECT TO DISTRIBUTION LINES CLASSIFICATION?

A The Commission should direct FPL to develop a cost of service study that classifies a portion of distribution lines as customer-related, based on a minimum system analysis. The revised cost of service study should then be used as a guide in revenue allocation and rate design.

Revenue Allocation

Q HOW IS FPL PROPOSING TO ALLOCATE ITS PROPOSED BASE RATE INCREASE AMONG THE RATE CLASSES?

A FPL's proposed allocation of the base rate increase is shown on Exhibit JTS-4. FPL used its cost of service study as a guide in determining the proposed level of revenue by rate class. As discussed above, that study overallocates costs to some classes with respect to classification of distribution line costs and should be adjusted before any decision is made as to how to allocate any potential revenue increase. In any event, according to FPL "the allocation of any revenue increase should be assessed in terms of its impact on the parity between rate classes."

Q HAS THE FPSC RECOGNIZED OTHER FACTORS IN ADDITION TO THE COST OF SERVICE STUDY WHEN ALLOCATING ITS PROPOSED REVENUE INCREASE TO THE RATE CLASSES?

A Yes. In the past, the FPSC has found it appropriate to use a rule-of-thumb that limits increases to individual rate classes to no more than 150% of the system average increase and to restrict any rate class from receiving a decrease when the utility receives a rate increase.

Q IS FPL'S PROPOSED REVENUE ALLOCATION IN COMPLIANCE WITH THIS RULE OF THUMB?

A No. As shown on Exhibit JTS-5, FPL's allocation of its proposed revenue increase results in increases to certain rate classes that are significantly greater than 150% of the system average percent increase. Some rate classes would receive rate increases in excess of 200% of the system average increase under FPL's proposal.

Q DOES FPL OFFER ANY JUSTIFICATION FOR NOT ADHERING TO THE 150% RULE OF THUMB?

A FPL claims that it is not limiting the individual rate class increases to 150% of the system average increase because it has not had a rate proceeding for a number of years and doing so would allow extreme subsidies among the rate classes to continue.

Q IS THIS A REASONABLE JUSTIFICATION FOR INCREASING RATES TO INDIVIDUAL RATE CLASSES BY MORE THAN 150% OF THE SYSTEM AVERAGE INCREASE?

A No. Progress toward parity is desirable, but not to the extent of creating rate shock. According to the filed cost study, FPL apparently allowed rates to diverge from cost of service over the last ten years, and it should realize that it will take time to rectify that problem.

Q WHICH RATE CLASSES WOULD RECEIVE INCREASES GREATER THAN 150% OF THE SYSTEM AVERAGE INCREASE UNDER FPL'S PROPOSAL?

A As shown on Exhibit JTS-5, FPL's proposed revenue allocation would result in an increase of greater than 150% of the system average increase to the following rate classes – CS-1, CS-2, GSLD-1, GSLD-2, MET, OL-1, OS-2 and SL-1.

Q IS FPL GIVING ANY RATE CLASS A DECREASE?

A Yes. FPL claims that no rate class would receive a decrease under its proposal. However, this is accurate only when the increase in service charges is included in addition to the proposed base rate changes. If base rates are considered alone, rate class GS-1 is proposed to receive a decrease of $2.0 million.

Q DOES FPL PROVIDE ANY JUSTIFICATION FOR THE RATE DECREASE TO GS-1 CUSTOMERS?

A No. However, it appears that the decrease is the result of GS-1 customers migrating to General Service Constant Use (GSCU-1). It is my understanding the GSCU-1 is for small commercial customers with high load factors and relatively constant use, such as customers in the television and cable industries.

Q WHAT INCREASE IS FPL PROPOSING FOR RATE CLASS GSLD-1?

A FPL is proposing to increase base rates to GSLD-1 customers by 17.5%, or over 180% of the system average increase of 9.7%.

Q WHAT IS YOUR RECOMMENDATION WITH RESPECT TO REVENUE ALLOCATION?

A The Commercial Group recommends that FPL adhere to the generally accepted FPSC rule of thumb that limits the base rate increase to any individual rate class to no more than 150% of the system average percent increase. Of course, once FPL performs the corrected cost of service study as proposed herein, these underlying ROR figures would change, and the resulting revenue allocation could be less than the 150% maximum for some rate classes.

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Q DO YOU AGREE WITH FPL'S STATED GOAL OF MOVING ALL RATE CLASSES CLOSER TO PARITY?

A Yes. FPL proposes using +/- 10% of parity as a goal in determining the target revenue by rate class. However, it may not be attainable within the confines of one rate proceeding every ten years. This is also affected by the level of increase being proposed, which is significant in this case. Even FPL is only able to move 11 out of 20 rate classes within this range under its own rate proposal. It would be more appropriate to use +/- 10% of parity as an initial target over the course of the next few rate proceedings while limiting the increase to any individual rate class in any one rate proceeding in order to avoid rate shock. However, it should be noted that the Commercial Group supports rates based on cost of service. According to FPL, limiting the rate increase to 150% of system average would result in six rather than eleven rate classes having a parity index within the +/- 10% range. Balancing the desire for rate parity with the need to avoid rate shock, as long as there is some movement toward parity, is acceptable.

Q DOES FPL FOLLOW THE +/- 10% OF PARITY RULE IN A STRICT MANNER?

A No. First, FPL tempers this rule where it would produce base rate increases in excess of 25%, i.e., FPL is proposing to cap the base rate increase to any one class at 25% or less. This is reasonable and would not be necessary if FPL adheres to the 150% of system average increase limit. Second, FPL chose to combine certain rate classes together into a group for revenue allocation purposes. In the case of distribution voltage demand metered commercial/industrial customers, the +/- 10% guideline is applied to the rate classes as a group rather than individually. The rate classes included in this group include CS-1, CS-2, GSD-1, GSLD-1 and GSLD-2. The Company is not proposing to eliminate any of these rate schedules. They are only being combined for revenue allocation purposes.

Q WHAT RATIONALE DOES FPL PROVIDE FOR COMBINING THESE RATE CLASSES INTO ONE GROUP FOR REVENUE ALLOCATION PURPOSES?

A FPL claims that: (1) customers may migrate among these rate classes depending on their maximum demand during any twelve-month period, and (2) these rate classes have historically shared a very similar rate structure. Presumably this means that each of the rate classes have a customer charge, a demand charge and an energy charge.

Q IS THIS RATIONALE PERSUASIVE?

A No, neither of these reasons provides a sufficient justification for combining individual rate classes into one group for purposes of establishing a target revenue level. The reality is that one of the rate classes, GSD-1, is proposed to receive an increase that is significantly less than 150% of the system average increase; whereas, the other four rate classes are proposed to receive increases that are significantly greater than 150% of the system average increase. Since GSD-1 is a large rate class, combining this rate class with the other four masks the impact of the dramatic increase to those four rate classes. This is pure optics, plain and simple.

Q WHAT IS YOUR RECOMMENDATION WITH REGARD TO REVENUE ALLOCATION FOR THE CS, GSD AND GSLD RATE CLASSES?

A The Commission should reject FPL's treatment of the CS, GSD and GSLD rate classes as one group for revenue allocation purposes, and require that each class should be allocated an increase, if any, on a standalone basis that reflects the cost to serve that class.

Rate Design

Q HOW DOES FPL PROPOSE TO ACHIEVE ITS TARGET REVENUES?

A FPL proposes to: (1) increase existing base rates, (2) add three new optional rates, and (3) increase service charges.

In addition, FPL adjusted each rate class's base rates to remove the embedded gross receipts tax. According to FPL, it is the only electric investor-owned utility (IOU) in Florida that has not increased base rates since the gross receipts tax was increased in 1992. As a result, FPL is the only electric IOU with a portion of its gross receipts tax embedded in base rates. FPL is proposing to remove the portion of GRT from base revenue and include it with the GRT already shown as a line item on the customer's bill. This is a reasonable and appropriate adjustment.

Q WHAT RATE DESIGN CHANGES IS FPL PROPOSING FOR RATE CLASS GSLD-1?

A A comparison of present and proposed rates for the CS, GSD and GSLD rate classes is provided on Exhibit JTS-6. For GSLD-1, FPL is proposing to increase the customer charge by about 290%, increase the non-fuel energy charge by 39% and leave the demand charge at existing levels.

FPL is proposing to set the base demand charge and energy charge the same for customers on rate schedules CS-1, CS-2, GSD-1, GSLD-1 and GSLD-2. The only difference among the five rate schedules would be the customer charge. Currently, these rate schedules all share the same base demand charge while the energy charges vary inversely with the classes' kW threshold. As noted by FPL, the existing demand charge was generally below the classes' demand unit costs. The energy charges approved for these schedules were designed to recover any demand costs not recovered through the demand charge. According to FPL, the Commission's decision to approve this rate structure relied, in part, on the fact that the coincident peak contribution of these classes tended to be more highly correlated with the kWh sales than with their billing kW. FPL argues that this makes the recovery of a portion of demand costs through the energy charges appropriate.

Q WHAT JUSTIFICATION DOES FPL OFFER FOR PROPOSING A SINGLE SET OF DEMAND AND ENERGY CHARGES FOR THESE FIVE RATE CLASSES?

A FPL claims that the cost of service study does not support charging these rate classes the same demand charge while charging a lower energy charge based on the rate schedule's kW threshold. FPL claims that it is proposing the same demand and energy charges for rate classes CS-1, CS-2, GSD-1, GSLD-1 and GSLD-2 in order to simplify rates where appropriate.

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Q DOES FPL'S OWN UNIT COST ANALYSIS SUPPORT THIS PROPOSAL?

A No, it does not. The Company's unit cost analysis does not support the proposal to increase the energy charges and leave demand charges at their existing levels. As shown on Exhibit JTS-7, FPL's proposal is moving rates away from and not toward cost-based rates. This sends customers the wrong price signal. For Rate GSLD-1, the demand charge at current rates is roughly 58% of demand-related unit cost (with unit cost measured at equal rates of return, i.e., at cost of service) and the energy charge is 224% of energy-related unit cost. Increasing the energy charge while holding the demand charge constant means that even more of the demand-related cost is being recovered through the energy charge at proposed rates. Under FPL's proposed rates, only 52% of demand-related unit cost is recovered through the demand charge and 298% of energy-related unit cost is recovered through the energy charge. This shifts more of the cost recovery to higher load factor customers.

Q WHAT IS YOUR RECOMMENDATION?

A FPL should be directed to allocate any approved revenue increase in a manner that more closely aligns individual demand and energy charges with the relevant cost components. As a result, the demand charges should be increased if FPL is granted a rate increase.

Q IS FPL OFFERING ANY NEW RATE OPTIONS THAT COULD BE ATTRACTIVE TO THE COMMERCIAL GROUP CUSTOMERS?

A Yes. FPL is offering two new time-of-use (TOU) rates. They are the High Load Factor TOU (HLFT) rate and the Seasonal Demand TOU (SDTR) rider. FPL claims that these new rates/riders will provide expanded opportunities for customers seeking a time-of-use alternative. The other new rate offering is an optional rate for small commercial customers with relatively constant electric usage (GSCU-1).

Q PLEASE DESCRIBE THE HIGH LOAD FACTOR TOU RATE.

A The HLFT rate will be available to commercial and industrial customers with at least 21 kW of billing demand. FPL expects likely participants to be manufacturers, grocery stores and hospitals. The standard TOU hours will apply. Under the HLFT rate, the distribution demand-related costs are recovered through a maximum charge equal to 50% of the unit cost for distribution plant. The on-peak demand charge includes the on-peak unit cost for production and transmission plant along with 50% of the on-peak unit cost for demand-related distribution plant. Both charges are based on the average combined unit cost of rate classes GSDT-1, GSLDT-1 and GSLDT-2. The off-peak energy charge is set equal to the system average energy cost. Derivation of the on-peak energy charge is the result of a break-even calculation with the otherwise applicable rate at a 70% load factor.

Q DO HIGH LOAD FACTORS PROVIDE ANY BENEFIT TO THE SYSTEM?

A A customer with a high load factor will generally be cheaper to serve than a customer with a lower load factor. On a per unit basis, a high load factor provides more kWh to spread the fixed demand- and customer-related costs of production, transmission and distribution.

Q **DID FPL PROVIDE ANY JUSTIFICATION FOR THE USE OF A 70% LOAD FACTOR IN THE DETERMINATION OF THE BREAK-EVEN CALCULATION?**

A No. The choice of a 70% load factor for the break-even calculation was arbitrary and limiting. As discussed in the CG panel testimony, there have been few FPL rate schedules tailored to the needs of the group's facilities. Therefore, the Commercial Group appreciates FPL's proposed HLFT rate schedule. However, the 70% break-even load factor would greatly limit the usefulness of this schedule. Customers with a load factor of 65% would find the HLFT attractive. Reducing the load factor break-even point would therefore expand the availability of this new TOU rate to more customers and make it more useful to commercial customers.

Turkey Point Unit 5

Q **WHAT IS FPL PROPOSING WITH RESPECT TO TURKEY POINT UNIT 5?**

A FPL is requesting an annual base rate increase of $123 million associated with the cost of Turkey Point Unit 5 being placed into service in 2007. FPL claims that addressing the addition of Turkey Point Unit 5 in this proceeding will serve to mitigate the "drop" in the Company's rate of return and the "immediate, substantial, negative" effect on FPL's earnings in 2007. Does FPL have a crystal ball? How can it know the extent to which earnings will be impacted in two years? FPL has forecasted an increase in capital costs and O&M expense associated with placing Turkey Point Unit 5 into commercial operation in June 2007 of $66 million. Therefore, the annualized base rate increase requested is $123 million. FPL is proposing to adjust base rates 30 days after Turkey Point Unit 5 goes into commercial operation.

The test year for FPL's rate case is the twelve months ending December 31, 2006. The rate increase is requested to go into effect on January 1, 2006. Turkey Point Unit 5 is not even scheduled to be placed in service until June 2007. FPL's proposed adjustment to recover this cost would be for the projected twelve months ending May 31, 2008, assuming the unit is completed on schedule. This adjustment is outside the test period and would be better addressed within a base rate case proceeding closer to the actual in service date. At that time, the Commission can determine if a base rate increase is needed for FPL to have the opportunity to earn its authorized rate of return.

Q DO YOU SUPPORT THIS ADJUSTMENT?

A No. FPL claims that the adjustment is conservative because it does not take into account increases in other costs of service. What FPL ignores is the point that the Company could experience decreases in other costs, or load growth, or a change in other variables that could offset the increased costs due to Turkey Point Unit 5. What's more, even FPL acknowledges that, given a base rate increase in 2006, FPL's projected earned ROE is 11.5%, which is within the range of return of 11.3% to 12.3% requested in this proceeding. FPL claims that its ROE could drop well below that range in 2008. However, 2008 is three years away. The number of variables that could change in the meantime is too great to give any certainty to claims about earnings at that point in time. As FPL puts it, "all other things being equal." The point is that all other things won't be equal in three years. That is why the Commission sets rates based on a test year, i.e., so that all costs and revenues during a given period can be examined.

Q WHAT IS YOUR RECOMMENDATION WITH RESPECT TO THE RATE INCREASE FOR TURKEY POINT UNIT 5?

A This proposal should be rejected. However, if the PSC accepts this proposal, the cost should not be recovered on a per kWh basis. The fixed cost of the unit is classified as almost entirely demand-related and allocated using the 12CP and 1/13th energy allocation factor. The recovery of the Turkey Point Unit 5 costs should mirror the allocation of these costs. That is, the costs should be recovered primarily through increases in the demand charges.

Q DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A Yes.

Q. Please state your names and positions.

A. My name is Teresa Civic. I am the Manager of Energy for BJ's Wholesale Club, Inc. ("BJ's"). My name is Jess Galura. I am the Senior Regulatory Analyst for Wal-Mart Stores East, LP ("Wal-Mart"). We are testifying on behalf of the Commercial Group that is composed of BJ's, Lowe's Home Centers, Inc., J.C. Penney Company, Inc. and Wal-Mart.

Q. Have you provided outlines of your background and professional experience?

A. Yes, these are attached as Appendix A hereto.

Q. Are you sponsoring any exhibits with your testimony?

A. No.

Q. Please describe generally your operations in the State of Florida.

A. Together our companies operate approximately 400 retail establishments in Florida, including a number of distribution centers. A substantial number of these facilities receive retail electric service from Florida Power & Light Company ("FPL"). We employ well over 100,000 employees at our Florida operations alone and purchase several billion dollars annually in goods and services from Florida suppliers. In a period in which industrial job creation may be slowing, large commercial facilities such as ours are one of the key drivers of the Florida economy. Indeed, our companies continue to grow and pay billions of dollars in annual salaries and benefits to our Florida employees and taxes into the state of Florida.

Q. Please describe your operations.

A. Our companies operate retail facilities across the country. These facilities receive electric service from hundreds of electric providers under varied rate schedules and are subject to varying degrees of regulation by state public service commissions.

Q. Please describe the purpose of your testimony and summarize your testimony.

A. Our panel is providing testimony limited to whether FPL deserves a 50 basis point ROE performance incentive adder for superior service and the impact FPL's proposed rate increase would have on our facilities and operations. In general, we find FPL's customer service to be adequate and comparable to that of other electric providers that serve our facilities. We have not found that FPL's rates are substantially lower than these other providers nor that FPL's rate schedules are tailored to our facilities better than those of our other electric providers. With respect to how the proposed rate increase would affect our facilities, the potential cost impact would indeed be great.

Q. Do you believe that FPL should receive an extra return on investment as a reward for superior service?

A. No. As mentioned above, our facilities are served by hundreds of electric service providers across the country. In our experience, FPL provides average to good electric service and we generally have a positive relationship with FPL. However, we do not find FPL's service to be superior to that of other comparable electric service providers. For example, with respect to electric bills that we receive from FPL, the Company's rates are substantially higher than many similar electric utilities, particularly those in the Southeast. See CG Exhibit No. __ (JTS-2). We note by way of example that Georgia Power Company recently received a substantial ($500 million) fuel rate increase. Nevertheless, even after that increase, the fuel rates that FPL charges us are nearly double nearly double those of Georgia Power Company (2.42¢/kWh), which obviously is another significantly sized electric utility in the Southeast. With respect to customer service, we acknowledge that FPL's customer service is good and we appreciate that service. Nevertheless, we cannot say that the customer service of FPL is superior to that of most other electric providers of its size.

Q. Do you have examples of any concerns you have with FPL's service?

A. Yes. For example, FPL sent us discovery requests in this case concerning our use of FPL's real time pricing ("RTP") rate schedule. A number of us were surprised by the request because we were not aware that FPL provides or has provided RTP pricing to its commercial customers. We would expect that service superior to most other electric providers would involve explaining the real time pricing opportunity that may have been available to us. Once again, we are not complaining about FPL's service, but we do not find it superior to that of most other major electric service providers.

Q. Do you have any further examples?

A. Yes. A number of electric providers offer rate schedules that fit our facility load profiles and that enable large commercial customers like our companies to capture benefits from our substantial in-house energy management efforts. We are disappointed that FPL does not offer rate schedules that better fit our facilities load and operating characteristics. In addition, the potential for customers to monitor load profiles, manage building loads and propose both economic and energy efficient load management strategies is limited by our ability to obtain interval data. We are disappointed that, although FPL does offer interval metering options, our practical experience is that FPL's field installation of pulse capable metering has taken over a year and a half and 98% of our metering requests have gone unfulfilled.

Q. Has FPL proposed any new rate schedules in this proceeding that might better fit the load profiles of your facilities?

A. Yes. FPL has proposed a high load factor ("HLF") rate schedule that would benefit customers with very high load factors. We appreciate and support this effort by FPL. However, we believe that the 70% load factor break-even point is too high and should be lowered to better fit the needs of commercial customers. Many of our facilities have what we understand to be some of the highest load factors for large commercial establishments. However, few of our facilities would qualify under the new proposed HLF rate schedule. Accordingly, our consultant, James Selecky is recommending that the HLF load factor "break-even" point be lowered to at least 65 percent.

Q. Are there other initiatives you believe FPL should pursue?

A. We are encouraged by FPL's development of a residential solar photovoltaic program and support FPL's efforts to develop wind power in other states. However, we encourage FPL to take advantage of solar opportunities in the state of Florida and to pursue a leadership role in the development of renewable energy, particularly solar power.

Q. You mentioned that you are concerned with the rate increase that FPL has proposed. How would the proposed increase affect your operations?

A. As we mentioned above, FPL's fuel rates are already significantly higher than those of many other electric providers. We understand that FPL is proposing to increase GSD-1 rates by 12.9% and GSLD-1 rates by 16.9%. Energy costs are the second highest operating costs at our facilities and such a large increase in rates will greatly impact our operations. For operations such as distribution centers that can locate in other states or service territories, utility costs are a significant factor toward our choosing a non-FPL location. We urge the Commission to take a hard look at the proposed rate increase and act to minimize rate shock to any customer group.

Q. Does this complete your testimony?

A. Yes, it does.

STATE OF FLORIDA
BEFORE THE
PUBLIC SERVICE COMMISSION

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

DIRECT TESTIMONY OF DR. DENNIS W. GOINS ON BEHALF OF THE FEDERAL EXECUTIVE AGENCIES

INTRODUCTION AND QUALIFICATIONS

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

A. My name is Dennis W. Goins. I operate Potomac Management Group, an economics and management consulting firm. My business address is 5801 Westchester Street, Alexandria, Virginia 22310.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND.

A. I received a Ph.D. degree in economics and a Master of Economics degree from North Carolina State University. I also earned a B.A. degree with honors in economics from Wake Forest University. From 1974 through 1977 I worked as a staff economist at the North Carolina Utilities Commission. During my tenure at the Commission, I testified in numerous cases involving electric, gas, and telephone utilities on such issues as cost of service, rate design, intercorporate transactions, and load forecasting. While at the Commission, I also served as a member of the Ratemaking Task Force in the national Electric Utility Rate Design Study sponsored by the Electric Power Research Institute (EPRI) and the National Association of Regulatory Utility Commissioners (NARUC).

Since 1978, I have worked as an economic and management consultant to firms and organizations in the private and public sectors. My assignments focus primarily on market structure, planning, pricing, and policy issues involving firms that operate in energy markets. For example, I have conducted detailed analyses of product pricing, cost of service, rate design, and interutility planning, operations, and pricing; prepared analyses related to utility mergers, transmission access and pricing, and the emergence of competitive markets; evaluated and developed regulatory incentive mechanisms applicable to utility operations; and assisted clients in analyzing and negotiating interchange agreements and power and fuel supply contracts. I have also assisted clients on electric power market restructuring issues in Arkansas, New Jersey, New York, South Carolina, Texas, and Virginia.

I have participated in more than 100 proceedings before state and federal agencies as an expert in cost of service, rate design, utility planning and operating practices, regulatory policy, and competitive market issues. These agencies include the Federal Energy Regulatory Commission (FERC), the General Accounting Office, the Circuit Court of Kanawha County, West Virginia, the First Judicial District Court of Montana, and regulatory agencies in Arkansas, Arizona, Colorado, Georgia, Illinois, Kentucky, Louisiana, Maine, Massachusetts, Minnesota, Mississippi, New Jersey, New York, North Carolina, Ohio, Oklahoma, South Carolina, Texas, Utah, Vermont, Virginia, and the District of Columbia. A summary of my professional qualifications and case participation is shown in Exhibit No.___(DWG-2).

Q. ON WHOSE BEHALF ARE YOU APPEARING IN THIS PROCEEDING?

A. I am appearing on behalf of the Federal Executive Agencies (FEA), which is comprised of all Federal facilities served by Florida Power & Light Company (FPL). Some of the largest FEA facilities include Patrick Air Force Base, Cape Canaveral Air Station, and the Kennedy Space Center. FPL currently serves these facilities under different commercial and industrial rate schedules.

Q. WHAT ASSIGNMENT WERE YOU GIVEN WHEN YOU WERE RETAINED?

A. I was asked to undertake two primary tasks:

1. Review FPL's proposed cost-of-service analyses and related rates.
2. Identify any major deficiencies in the cost analyses and proposed rates and suggest recommended changes.

Q. WHAT SPECIFIC INFORMATION DID YOU REVIEW IN CONDUCTING YOUR EVALUATION?

A. I reviewed FPL's application, testimony, exhibits, and responses to requests for information and production of documents. I also reviewed documents and information found on web sites operated by the Commission and FPL.

CONCLUSIONS

Q. WHAT CONCLUSIONS HAVE YOU REACHED?

A. On the basis of my review and evaluation, I have concluded the following regarding FPL's cost-of-service analyses and proposed interruptible service options:

1. Classification and allocation of demand-related generation and transmission costs. In this case, FPL has proposed classifying all generation and transmission plant costs (except for transmission pull-offs required to connect transmission customers to the grid) using the 12 CP and $1/13^{th}$ methodology. Under this methodology, FPL classifies approximately 92 percent (12/13) of these costs as demand-related costs and the remaining 8 percent (1/13) as energy-related costs. FPL allocates the demand-related costs to customer classes using the 12 CP methodology—that is, the contribution of each class to FPL's 12 monthly coincident system peaks during the test year. FPL allocates the energy-related costs to customer classes using kWh sales adjusted for losses. The Florida Commission has approved the 12 CP and $1/13^{th}$ methodology in prior FPL rate cases, and even requires utilities to use the methodology in filing a rate increase application under the Commission's Minimum Filing Requirements (MFRs).

2. Revenue Spread. FPL notes that in past cases the Commission has adopted a rule-of-thumb for revenue spread that limits a customer class' base rate increase to no more than 150 percent of the system average increase and restricts any class from receiving a rate decrease. In this case, FPL has abandoned this rule-of-thumb and instead proposed moving each class's rate of return to within 10 percent of the system average rate of return (that is, to a rate of return index between 90 and 110), but to ensure that the base rate increase to no class exceeds 25 percent. As a result of FPL's revenue spread decision, customers served under several of FPL's proposed rate schedules will receive base rate increases exceeding

the Commission's rule-of-thumb limiting increases to 150 percent of the system average increase.

3. Commercial/Industrial Load Control (CILC) Rate. Under FPL's CILC program, customers can buy interruptible[1] (nonfirm) service if they are willing to curtail (through active load reductions) or displace (through on-site generation) at least 200 kW of load during peak periods when requested by FPL. In exchange for agreeing to interrupt load during peak periods, customers pay a discounted price for their nonfirm (that is, Load Control) loads. Part of this price discount reflects FPL's demand-related unit cost of gas turbine production capacity assigned to each customer class. However, the price discount does not reflect the energy-related unit cost of gas turbine production capacity assigned to each customer class. In this case, FPL has proposed major increases in the Load Control On-Peak Demand charge in its CILC rates ranging from 52 percent to 58 percent.[2] At the same time, FPL has proposed reducing the energy charges for secondary and primary distribution CILC customers, while increasing the energy charge for CILC customers served at transmission.

RECOMMENDATIONS

Q. WHAT DO YOU RECOMMEND ON THE BASIS OF THESE CONCLUSIONS?

A. I recommend that the Commission:

1. Approve FPL's 12CP and 1/13th allocation methodology. As FPL notes, the Commission has approved the 12CP and 1/13th

[1] In my testimony I use *interruptible* and *curtailable* interchangeably in discussing nonfirm service.
[2] See MFR Schedule A-3, page 7.

methodology in previous rate cases for FPL and other utilities in Florida. I prefer an allocation methodology that reflects only the principal factors—coincident peak demands—driving the need for generation and transmission capacity. However, in this case I find no compelling reason to reject FPL's recommended 12CP and $1/13^{th}$ methodology, particularly given the Commission's past support.

2. Reject FPL's proposed revenue spread. Instead, the Commission should require FPL to spread its proposed revenue increase such that no rate receives an increase greater than 150 percent of the average system increase. This so-called rule-of-thumb revenue spread moves each class closer to cost of service without the unacceptably high base rate increases imposed on some classes under FPL's proposed spread.

3. Reject the proposed energy charges in FPL's proposed CILC rates. Instead, as shown later in my testimony, the proposed energy charges should be reduced by the appropriate energy-related unit cost of gas turbine production capacity assigned to CILC-1G, CILC-1D, and CILC-1T customers. This adjustment is necessary to:

    - Reflect the role of the CILC program in reducing capacity requirements during peak periods.
    - Be consistent with excluding demand-related unit costs of gas turbine production capacity in the CILC Load Control On-Peak demand charges.

COST OF SERVICE

Q. DID FPL CONDUCT A RETAIL CLASS COST-OF-SERVICE STUDY IN DEVELOPING ITS PROPOSED RATES?

A. Yes. In developing its proposed retail rates for this case, FPL first conducted a detailed cost-of-service study using data (adjusted in many cases) for the test year ending December 31, 2006. In this cost analysis, FPL allocated and/or directly assigned its retail jurisdictional costs to functional segments of its retail electric business, and then allocated and/or directly assigned these costs to its major customer classes. FPL then used these class costs to develop its proposed rates.

Q. IS THE COST-OF-SERVICE STUDY THAT FPL CONDUCTED REASONABLE?

A. Yes. The cost study generally follows guidelines in the NARUC *Electric Utility Cost Allocation Manual*.[3]

Q. WHY IS THE REASONABLENESS OF A COST-OF-SERVICE METHODOLOGY IMPORTANT?

A. Cost of service identifies and assigns cost responsibility to customer classes. Specific rates can then be developed to recover each class' cost-based revenue requirement, resulting in prices that recover the utility's cost of service in an equitable and efficient manner. If the cost-of-service methodology does not allocate and assign cost responsibility in a reasonable manner, then interclass revenue subsidies are created and specific class rates are either over- or under-priced—thereby causing customers to make inefficient electricity investment and consumption decisions. In my opinion, FPL has employed a reasonable cost-of-service

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[3] National Association of Regulatory Utility Commissioners, *Electric Utility Cost Allocation*

methodology in this case to allocate and assign its production and transmission plant costs to customer classes.

Q. HOW DID FPL CLASSIFY ITS PRODUCTION AND TRANSMISSION CAPACITY COSTS AND ALLOCATE THEM TO CUSTOMER CLASSES?

A. In this case, FPL classified its production and transmission plant costs (except for transmission pull-offs required to connect transmission customers to the grid) using the 12 CP and 1/13th methodology. Under this capital substitution methodology, most (approximately 92 percent or 12/13) of these costs was first classified as demand-related costs, while the remainder (8 percent or 1/13) was classified as energy-related costs. FPL then allocated the demand-related costs to customer classes using the 12 CP methodology, which reflects each class' contribution to FPL's 12 monthly coincident system peaks during the test year. FPL next allocated the energy-related costs to customer classes using kWh sales adjusted for losses.

Q. IS THE 12CP AND 1/13TH METHODOLOGY DISCUSSED IN THE NARUC COST MANUAL?

A. Yes. The method FPL chose to classify and allocate production and transmission capacity costs is one of several capital substitution methodologies discussed in the NARUC cost manual.[4]

Manual, Washington, DC, January 1992.

[4] For the specific discussion of the 12CP and 1/13th methodology, see the NARUC cost manual at pages 58-59.

Q. DO YOU SUPPORT FPL'S CHOICE OF THIS CLASSIFICATION AND ALLOCATION METHODOLOGY?

A. I do not support capital substitution classification and allocation methodologies—including FPL's 12CP and 1/13th methodology. I generally prefer a fixed/variable approach to classify production and transmission plant costs, and an allocation methodology that emphasizes coincident peak demands as the principal factors driving the need for generation and transmission capacity. However, the 12CP and 1/13th methodology is probably one of the least objectionable of the capital substitution methodologies, and it is recognized as an acceptable costing approach in the NARUC cost manual. In addition, according to FPL, the Commission has approved the 12CP and 1/13th methodology in past rate cases involving FPL and other utilities in Florida. As a result, replacing the 12CP and 1/13th methodology should be considered only if another costing approach clearly provides a more compelling linkage between customer demands and FPL's bulk power system costs.

Q. SHOULD THE COMMISSION ADOPT FPL'S 12CP AND 1/13TH METHODOLOGY?

A. Yes. In my opinion, FPL's recommended 12CP and 1/13th methodology provides a reasonable compromise for classifying and allocating demand-related generation and transmission costs. As I noted earlier, I prefer methodologies that focus on class contributions to system peak demands. However, FPL's 12CP and 1/13th methodology represents a middle ground between methodologies that emphasize peak demand (which I prefer) and those that rely primarily on energy measures to develop demand allocation factors. Because it recognizes both demand and energy factors, FPL's 12CP and 1/13th methodology can be seen as a reasonable compromise between peak demand costing advocates and energy-only costing advocates.

REVENUE SPREAD

Q. HOW DID FPL SPREAD ITS PROPOSED RATE INCREASE?

A. In this case, FPL has used a 2-step approach to spread its proposed rate increase:

- Move each class' rate of return to within 10 percent of the system average rate of return (that is, to a rate of return index between 90 and 110),
- Limit any class' maximum base rate increase to 25 percent.

Q. IS FPL'S PROPOSED REVENUE SPREAD CONSISTENT WITH PAST COMMISSION PRACTICE?

A. No. FPL notes that in past cases the Commission has adopted a rule-of-thumb for revenue spread that limits a customer class' base rate increase to no more than 150 percent of the system average increase and restricts any class from receiving a rate decrease.

Q. DOES FPL'S PROPOSED REVENUE SPREAD PRODUCE UNACCEPTABLE RATE INCREASES FOR SELECTED CUSTOMERS?

A. Yes. As a result of FPL's revenue spread decision, customers served under several of FPL's proposed rate schedules will receive base rate increases exceeding the Commission's rule-of-thumb limiting increases to 150 percent of the system average increase. More specifically, under

FPL's proposed revenue spread, seven rates are increased more than 20 percent, while three rates get the maximum 25-percent increase.[5]

Q. IS FPL'S PROPOSED REVENUE SPREAD NECESSARY TO MOVE RATES SIGNIFICANTLY CLOSER TO COST OF SERVICE?

A. No. FPL's witness Rosemary Morley's testimony demonstrates that rates for all classes can be moved significantly closer to cost of service simply by using the Commission's 150 percent rule-of-thumb revenue spread.[6] In my opinion, moving rates closer to cost of service without resorting to 25-percent rate increases for some classes limits the chance of rate shock and is consistent with the generally accepted ratemaking principle of gradualism.

Q. SHOULD THE COMMISSION REJECT FPL'S PROPOSED REVENUE SPREAD?

A. Yes. FPL's proposed revenue spread reflects a good faith effort to move rates closer to cost of service. However, FPL's revenue spread produces unacceptably high rate increases for selected customers. I recommend a more gradual—but significant—movement toward this cost-of-service goal using the Commission's 150 percent rule-of-thumb revenue spread.

INTERRUPTIBLE SERVICE

Q. WHAT IS INTERRUPTIBLE OR NONFIRM SERVICE?

A. Interruptible service is a separately identifiable utility product that allows a supplier to interrupt or curtail customer loads when reliability is impaired. Interruptible load enables a supplier to maximize the value of its existing

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[5] See MFR Schedule E-8.

[6] Rosemary Morley, direct testimony, Document No. RM-6, page 1.

reserve capacity and to avoid installing new capacity. The available supply of interruptible service depends on the relationship between available capacity and firm service demands. That is, if firm demands command all available generating capacity, the supply of interruptible service falls to zero. When firm demands are significantly less than available capacity, the supply of interruptible service is significantly greater. Interruptible service can only be produced and sold by the utility supplier. End-use customers are the buyers of interruptible service—not the suppliers.

Q. DOES FPL OFFER INTERRUPTIBLE SERVICE TO COMMERCIAL AND INDUSTRIAL CUSTOMERS UNDER ITS CURRENT RATES?

A. Yes. FPL currently offers interruptible service to customers that can interrupt at least 200 kW of load when requested by FPL. FPL's interruptible service options include Rate Schedules CS-1, CST-1, CS-2, CST-2, CS-3, CST-3, and CILC-1, plus Rider CDR. These rates and rider incorporate either explicit billing demand discounts (the CS, CST, and CDR options) or implicit discounts reflected in a reduced price for interruptible demand (the CILC option).

Q. DOES FPL DERIVE BENEFITS FROM INTERRUPTIBLE CUSTOMERS?

A. Yes. By excluding interruptible load from its peak-load capacity requirements, FPL achieves capacity-cost savings by not having to build capacity to serve the interruptible load. The avoided capacity includes not only capacity required to serve the interruptible load, but also reserve capacity that would have been built to provide reliability if interruptible customers had chosen firm service.[7] Capacity-cost savings attributable to interruptible load break down into two major categories associated with the avoided capacity:

- Avoided fixed costs. These include capital costs (including return), insurance, interest, taxes, and fixed nonfuel operation and maintenance (O&M) expense.
- Avoided variable costs. These include fuel and variable O&M expense.

Q. DOES INTERRUPTIBLE LOAD OFFER BENEFITS RELATIVE TO COMBUSTION TURBINE CAPACITY?

A. Yes. First, environmental impacts of constructing and operating combustion turbines are avoided if interruptible load displaces the need for such capacity. Second, selling interruptible service reduces a utility's short- and long-term financial investment risk relative to building capacity to serve an equivalent amount of firm service. For example, remaining customers may be forced to absorb stranded generation investment costs associated with the loss of a large firm-service load. Such costs cannot occur if an interruptible customer leaves the system.

Q. SHOULD AN INTERRUPTIBLE RATE RECOVER ANY EMBEDDED OR FIXED PRODUCTION AND TRANSMISSION COSTS?

A. No. Fundamental economic theory demonstrates that interruptible customers do not cause the utility to incur embedded production and bulk transmission costs. For example, Professor James C. Bonbright, a

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[7]Under certain conditions, a utility can use interruptible load to meet not only part of its installed reserve requirement, but also part of its operating reserve requirement.

recognized pricing authority, advocated pricing interruptible service to reflect no capacity-related cost of service:

> Interruptible service has been used by both gas and electric companies for peak shaving. The costs cannot be accurately determined because it is a byproduct resulting from generating and bulk transmission facilities built and operated for firm service (see Nissel, 1983). As a result, only the customer cost (e.g., customer-connected spur lines and substations) and energy costs (e.g., fuel and incremental maintenance cost) actually incurred and ***no capacity pricing cost should be included in pricing interruptible service***.
>
> While some feel that it is an impropriety to treat interruptible customers as if they were firm customers, they still opine that it would be fair and reasonable to obtain a small contribution from them for capacity costs. This is debatable.[8] (Emphasis added.)

Q. ARE INTERRUPTIBLE CUSTOMERS "FREE RIDERS" IF THEY PAY NO DEMAND-RELATED PRODUCTION COSTS?

A. No. As noted by Professor Bonbright, eliminating all or most embedded fixed-cost recovery may raise fallacious but politically attractive "free rider" arguments. As a result, most electric rates for interruptible service are designed to recover a portion of the utility's fixed production and bulk transmission costs. However, under an efficient pricing scheme, customers should only pay for costs attributable to their demands. Since a utility is not required to build or acquire generating or transmission capacity to serve interruptible load, only firm service customers should pay

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[8] James C. Bonbright, Albert L. Danielsen, and David R. Kamerschen, *Principles of Public Utility Rates*, Arlington, Virginia: Public Utilities Reports, Inc., 1988, page 502.

for the demand-related costs of this capacity. If interruptible rates recover part of the fixed costs of capacity built to serve only firm loads, then interruptible customers cannot be "free riders."

Q. DOES FPL PRICE ITS INTERRUPTIBLE SERVICE ON THE BASIS OF EMBEDDED OR MARGINAL COST OF SERVICE?

A. Prices reflected in FPL's current rates are based on embedded costs used in its cost-of-service analyses, and reflect either explicit billing demand discounts or implicit discounts reflected in a reduced price relative to firm service. Because the discounts are below stated billing demand charges for firm service, FPL ensures that interruptible customers make a major contribution to recovery of its fixed production and/or transmission costs.

Q. IS THE VALUE OF INTERRUPTIBLE LOAD REDUCED IF FPL DOES NOT INTERRUPT ALL INTERRUPTIBLE CUSTOMERS DURING SYSTEM PEAKS?

A. No. Interruptible load has both long- and short-term value. As I noted earlier, its long-term value is reflected in the capacity-cost savings (including the cost of planning reserves) that a utility avoids. Its short-term value is reflected in the operating reserve and system reliability benefits, fuel cost savings, variable O&M savings, and system losses that a utility avoids. The relevant issue is FPL's right to interrupt load—not whether the load is actually interrupted.

Q. ARE ANY FEA CUSTOMERS SERVED UNDER FPL'S INTERRUPTIBLE SERVICE OPTIONS?

A. Yes. At least one account for each of the major FEA customers I noted earlier is served at transmission voltage under Rate CILC-1T. These FEA customers began taking service under Rate CILC-1T before FPL closed the rate to new customers in 2000.

Q. UNDER WHAT CONDITIONS CAN FPL INTERRUPT CILC CUSTOMERS?

A. Under Rate CILC, FPL can interrupt load whenever an interruption is necessary to:

- Alleviate a power supply or transmission emergency condition or capacity shortage.
- Keep FPL from operating its generators above their continuous rated output.

Q. HAS FPL PROPOSED A MAJOR INCREASE IN THE CILC RATES?

A. Yes. In this case, FPL has proposed major increases for Rates CILC-1D and CILC-1T. These increases are due primarily to FPL's proposed increases—ranging from 52 percent to 58 percent—in the Load Control On-Peak Demand charge in its CILC rates.[9] At the same time, FPL has proposed reducing the energy charges for secondary and primary distribution CILC customers, while increasing the energy charge for CILC customers served at transmission.

Q. DO YOU AGREE WITH HOW FPL HAS PRICED CILC INTERRUPTIBLE SERVICE?

A. In general, I do agree. In particular, FPL's decision to exclude demand-related unit production costs from Rate CILC's Load Control On-Peak demand charge is consistent with Professor Bonbright's recommended interruptible pricing strategy. However, under FPL's 12CP and $1/13^{th}$

methodology, part of the capacity costs of gas turbine production capacity is classified as energy and reflected in the unit energy costs for the CILC rates. As a result, CILC customers avoid paying demand-related gas turbine production costs incurred to meet peak loads, but are required to pay the energy-related gas turbine production costs through the CILC energy charges.

Q. SHOULD THE ENERGY-RELATED COMPONENT OF GAS TURBINE PRODUCTION COSTS BE EXCLUDED FROM THE CILC ENERGY CHARGES?

A. Yes. FPL's CILC interruptible service option is primarily used to reduce peaking (that is, gas turbine) capacity requirements. Requiring CILC customers to pay energy-related nonfuel gas turbine production costs is inconsistent with excluding demand-related gas turbine production costs from the CILC Load Control On-Peak demand charges.

Q. WHAT CILC ENERGY CHARGES WOULD RESULT IF YOUR RECOMMENDATION WERE ADOPTED?

A. The CILC energy charge applicable to a customer's firm load would remain unchanged from FPL's proposed energy charge.[10] However, the energy charge applicable to CILC nonfirm loads would be reduced by the estimated energy-related gas turbine production costs included in FPL's proposed energy charge. The resulting energy charges following this adjustment to Rates CILC-1G, CILC-1D, and CILC-1T are shown in Exhibit No.___(DWG-1).

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[9] See MFR Schedule A-3, page 7.

[10] This statement assumes that the Commission approves FPL's requested revenue level and cost allocation to CILC customers.

Q. HOW WOULD FPL IMPLEMENT YOUR RECOMMENDED ENERGY CHARGE MODIFICATION IN BILLING CILC CUSTOMERS?

A. If a CILC customer's total load is interruptible, the CILC energy charge would simply be the applicable adjusted energy charge shown in Exhibit No.___(DWG-1). If a CILC customer has a specified firm load, the firm component of a customer's monthly kWh usage would equal the firm demand at a 100 percent load factor. This firm kWh component would be billed at FPL's proposed CILC energy charge. All remaining kWh would be considered Load Control (nonfirm) kWh and billed at the applicable adjusted energy charge.

Q. WHAT WOULD BE THE MAXIMUM REVENUE IMPACT OF YOUR RECOMMENDED ENERGY CHARGE MODIFICATION?

A. As shown in Exhibit No.___(DWG-1), the maximum revenue impact would be approximately $2 million. However, this impact would be significantly less since the recommended energy charge modification would only be applicable to the nonfirm component of a CILC customer's monthly kWh usage.

Q. SHOULD THE COMMISSION APPROVE RATE SCHEDULE CILC AS FILED?

A. No. The Commission should require FPL to implement my recommended adjustment to the CILC energy charge applicable to a customer's nonfirm load.

Q. SHOULD THE SAME ENERGY CHARGE MODIFICATION BE MADE IN FPL'S OTHER INTERRUPTIBLE RATE OPTIONS?

A. I am not sure that such a modification is necessary. Unlike Rate CILC, FPL's CS and CST rates and CDR rider incorporate explicit demand charge discounts to applicable firm service rates. FPL's filing contains no information showing how these explicit demand charge discounts were derived. As a result, at this time I am not recommending modifications to energy charges in the CS, CST, and CDR options similar to the energy charge modification I have recommended for the CILC option.

Q. DOES THIS COMPLETE YOUR DIRECT TESTIMONY?

A. Yes.

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

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

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

DATED THIS 24TH DAY OF AUGUST, 2005.

Linda Boles

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