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January 18, 2002
VIA HAND DELIVERY

Blanca S. Bayo, Director
Division of Records and Reporting
Betty Easley Conference Center
4075 Esplanade Way
Tallahassee, Florida 32399-0870

Re: Docket No.: 000824-EI

Dear Ms. Bayo:

On behalf of the Florida Industrial Power Users Group (FIPUG), enclosed for filing and distribution are the original and 15 copies of the following:

- PUBLIC Intervenor Testimony of Thomas J. Regan on Behalf of the Florida Industrial Power Users Group; 00691-02
- Intervenor Testimony and Exhibits of Michael Gorman on Behalf of Florida Industrial Power Users Group, 00692-02
- Intervenor Testimony and Exhibits of Jeffry Pollock on Behalf of Florida Industrial Power Users Group. 00693-02

Please acknowledge receipt of the above on the extra copy and return the stamped copies to me. Thank you for your assistance.

Sincerely,

Vicki Gordon Kaufman

Vicki Gordon Kaufman

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FPSC-BUREAU OF RECORDS

Before the
Florida Public Service Commission

In re: Review of Florida Power Corporation's Earnings, Including Effects of Proposed Acquisition of Florida Power Corporation by Carolina Power & Light	))))	**Docket No. 000824-EI**

Intervenor Testimony and Exhibits of

Michael Gorman

On behalf of

Florida Industrial Power Users Group

January 18, 2002
Project 7718

BRUBAKER & ASSOCIATES, INC.
ST. LOUIS, MO 63141-2000

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Intervenor Testimony of Michael Gorman

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A My name is Michael Gorman and my business address is 1215 Fern Ridge Parkway, Suite 208, St. Louis, MO 63141-2000.

Q WHAT IS YOUR OCCUPATION?

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

Q PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

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

Q ON WHOSE BEHALF ARE YOU APPEARING IN THIS PROCEEDING?

A I am appearing on behalf of the Florida Industrial Power Users Group (FIPUG).

Q **PLEASE DESCRIBE THE PURPOSE OF YOUR DIRECT TESTIMONY IN THIS PROCEEDING?**

A I will address various issues relating to the appropriate revenue requirement reflected in Florida Power Corporation's (FPC or Company) Minimum Filing Requirement (MFRs). As set out below, I describe adjustments to its MFRs that reduce FPC's claimed revenue entitlement.

Q **PLEASE SUMMARIZE YOUR TESTIMONY IN THIS PROCEEDING.**

A The adjustments I propose to make to the Company's revenue requirements included in its MFRs are summarized as follows:

1. The elimination of the Company's proposed inclusion of an acquisition adjustment to its revenue requirement of $58.7 million on an FPC basis, and $55.4 million on a Florida retail basis.

2. In an adjustment that removed fuel revenue and expense from its MFRs base rate filing, FPC's adjustment resulted in reducing base revenue net operating income by $9.63 million. This increased its estimated base revenue deficiency by $15.7 million. FPC's fuel revenue and expense adjustment should be modified to have no impact on the base revenues.

3. The Company's proposal to modify its 2002 sales forecast to reflect a deepening of the expected economic recession in the 2002 test year should be rejected. FPC's 2002 sales forecast should reflect normal sales levels.

4. The Tiger Bay accelerated amortization of $9 million should be removed from base rates.

5. The Company's Crystal River Unit 3 capital structure adjustment should be rejected.

6. The Company's proposed return on common equity of 13.2% should be rejected. Instead, I recommend a fair return on common equity for FPC of 10.5%.

7. The Company's MFRs for 2002 should not be adjusted to reflect the in-service cost of the Hines Power Block Unit 2. Nor should the Company be awarded a revenue increase that would go into effect on the date that the Hines Power Block Unit 2 is expected to be in service. This adjustment is a post-test year change to the Company's cost of service, and the Commission should not order a rate increase for a single item without looking at all expenses and revenue projected for the 2003 calendar year.

8. FPC's proposed earnings sharing mechanism (ESM) should be rejected.

Q PLEASE SUMMARIZE THE REVENUE REQUIREMENT ADJUSTMENTS YOU ARE PROPOSING TO FPC'S MFRs IN THIS PROCEEDING.

A FPC witness Myers claims that the Company's current rates produce a revenue deficiency of $40 million. Based on the recommendations I am making in this proceeding, I find the Company has overstated its revenue requirement by $194.3 million, and FPC's rates should be adjusted to collect $154.3 million less revenue. Also, other parties may propose adjustments that further reduce FPC's revenue requirement. Each of the revenue requirement adjustments supporting my total revenue requirement adjustment to the Company's MFRs is detailed below in Table 1.

TABLE 1

Summary of Revenue Requirement Adjustment

	Florida Retail Amount (Millions)
FPC's Claimed Revenue Deficiency	$40.0
Adjustments	
Acquisition Adjustment	$55.4
Recoverable Fuel	15.7
Sales Forecast	14.4
Tiger Bay Accelerated Recovery	9.0
CR3 Capital Structure Adjustment	18.2
Reduce ROE to 10.5%	81.6
Total	$194.3
Adjusted Revenue Deficiency/(Excess)	$(154.3)

Each of the items related revenue requirement impact on the Company's RFP will be discussed below.

ACQUISITION ADJUSTMENT

Q PLEASE DESCRIBE THE COMPANY'S RECOMMENDATION CONCERNING RECOVERY OF AN ACQUISITION ADJUSTMENT IN ITS MFRs.

A The Company has included in its MFRs an acquisition adjustment as an operating expense. The acquisition adjustment is set equal to the Company's estimate of the level of synergies, or acquisition cost savings, FPC claims are incorporated in its 2002 budget and MFRs filing.

Q WHY HAS THE COMPANY INCLUDED AN ADJUSTMENT TO ITS MFRs REVENUE REQUIREMENT TO PROVIDE RECOVERY OF ITS ESTIMATED ACQUISITION ADJUSTMENT?

A Company witnesses Myers and Cicchetti argue that in order for the Company to continue to enter into business transactions which result in a reduction to its cost of service, it must be allowed an opportunity to recover the costs it incurs to create savings. The Company believes that sharing the net synergy savings, which the Company defines as the difference between total savings produced less the cost to achieve those savings, will benefit both customers (because savings will ultimately be passed on to customers via lower rates) and investors (because they will be fully compensated for the costs incurred to produce the savings).

Q **WHY DID FPC INCLUDE AN ACQUISITION ADJUSTMENT EQUAL TO ACQUISITION SAVINGS RATHER THAN DIRECTLY INCLUDE ACQUISITION COSTS?**

A FPC witness Myers contends that including an acquisition cost equal to FPC's expected merger cost reduction in its MFRs accomplishes two purposes. First, he argues that it presents the MFRs and the resulting revenue requirement on a pre-merger basis which allows for a more focused analysis of on-going operations. Second, he believes that this treatment allows the Commission to evaluate the acquisition adjustment and its impact on the Company's MFRs.

Q **IS THE COMPANY'S REQUEST FOR AN ACQUISITION ADJUSTMENT IN ITS MFRs REASONABLE?**

A No. The Company's proposed acquisition adjustment should be rejected for at least the following reasons:

- The Company has not proven that its estimated merger savings could not be achieved absent the acquisition. Hence, the Company has not shown that recovering the acquisition adjustment from customers is economically justified.
- A comparison of the Company's retail jurisdictional non-fuel O&M expenses in 2002 to those over the last several years does not show a discernable decrease to non-fuel O&M expenses. Contrary to FPC's claims, the merger does not appear to have produced cost savings that have been reflected in the MFRs which justify the inclusion of an acquisition adjustment in FPC's rates. Therefore, including the acquisition adjustment in FPC's 2002 MFRs will harm customers because it results in a net increase in FPC's cost of service and rates.
- Progress Energy may have an opportunity to receive a fair rate of return on its investment in Florida Progress Corp., even if the proposed acquisition adjustment is not recovered in FPC's retail jurisdictional cost of service. Therefore, the rejection of FPC's proposal to include an acquisition adjustment in its Florida retail rates will not inhibit the economic justification to pursue future mergers and acquisitions that make economic sense.
- FPC's proposal does not reasonably share projected merger savings. Under FPC's proposal, shareholders will keep at least a 91.5% of estimated merger

savings while customers are allocated only 8.5%. This is not a reasonable allocation of expected savings.

Q WHY IS IT IMPORTANT FOR THE COMPANY TO PROVE THAT ITS ESTIMATED MERGER SAVINGS COULD NOT HAVE BEEN ACHIEVED ABSENT THE MERGER?

A The Company's estimated merger savings come at a substantial cost to customers. The Company is proposing to include an extraordinary item in its cost of service, the acquisition adjustment. Under the Company's proposal, it includes a $55.4 million acquisition adjustment in its retail Florida cost of service in this proceeding. The Company is proposing to include this acquisition adjustment in its cost of service over the next 15 years. Over that 15-year time period, if approved by the Commission, customers' rates will provide the Company with over $830 million (15 * $55.4 million) of revenue above its traditional cost of service. By any measure, the Company's proposal creates substantial burdens on customers.

To justify the recovery of the significant acquisition costs, it should be incumbent on FPC to show that the merger created savings that are greater than the merger costs, and said savings could not have been produced absent the merger. Further, it should show that the net merger savings are the best option to improve productivity and reduce FPC's operating costs. For example, if any of the savings could have been produced by outsourcing administrative or operating functions, rather than creating a larger company via the merger, then it may have been possible to create many of the estimated merger savings without incurring the significant merger costs. Even if possible savings, absent the merger, are lower than the estimated merger savings, if outsourcing created greater net savings, then customers would be better off without the merger. If the merger is not shown to be the least cost means of reducing the Company's cost of service and enhancing its productivity, then the Company's proposed merger acquisition costs should not be reflected in its rate filing.

Q **HAS FPC MADE THIS SHOWING?**

A No.

Q **PLEASE EXPLAIN WHY THE NON-FUEL OPERATION AND MAINTENANCE (O&M) LEVELS INCLUDED IN THE COMPANY'S 2002 FORECAST DO NOT SUPPORT FPC'S CLAIM THAT MERGER SAVINGS ARE REFLECTED IN ITS MFRs.**

A Quite simply, the non-fuel O&M expense shown in its MFRs do not support FPC's claim that the merger created cost reductions that are reflected in its 2002 forecast. Note, that FPC's quantified merger cost reductions are all non-fuel related. Therefore, the proper test to determine if the merger created cost reductions is to compare the MFRs non-fuel O&M expenses to the historical year and FPC's expenses historically.

FPC's Florida retail non-fuel O&M in the 2000 historical year is $406.9 million, and the 2002 test year non-fuel O&M is $498.7 million including the acquisition adjustment, and $443.3 million excluding the acquisition adjustment. (Section C, Schedule 2). Contrary to FPC's claim of merger cost reductions reflected in its MFRs, its non-fuel O&M increased at an annual rate of 10.7% including the acquisition adjustment, and 4.4% excluding the acquisition adjustment. These expense growth rates are considerably higher than the projected inflation rate of less than 2.5% per year over this same period.[1] The non-fuel O&M annual growth is excessive in both cases. Thus, FPC's request to include the acquisition adjustment in rates is not economically justified.

As further support for my contention that the Company's O&M expenses in its MFRs do not reflect a discernable decrease in costs over the last few years, I have compared the retail jurisdictional O&M costs contained in its 2002 MFRs to the retail jurisdictional O&M expenses reflected in the Company's surveillance reports since 1994. This is shown on my Exhibit MPG-1, Schedule 1. As shown on this schedule, the

[1] The Value Line Investment Survey, January 4, 2002, at 694.

Company's retail jurisdictional expenses are higher in 2002 than they have been in any year since 1994 in most cases by a wide margin. As shown in Column 3 of this same schedule, even if the acquisition adjustment included in the 2002 forecast is removed, FPC's non-fuel O&M expenses included in its MFRs are high in comparison to those since 1999. A comparison of the Company's projected non-fuel O&M expenses included in its 2002 MFRs does not support FPC's contention that the 2002 O&M expenses have decreased through synergies derived from the merger.

Q **WHAT ARE THE COST SAVINGS THE COMPANY HAS ESTIMATED WILL BE CREATED BY THE MERGER?**

A On Page 15 of his September testimony, Mr. Myers lists six categories supporting the Company's estimate of $58.7 million of FPC's merger savings. Approximately $40 million of the $58.7 million savings are attributable to shared corporate and administrative services and power operations.

Q **HAS FPC SHOWN THAT IT COULD ONLY HAVE PRODUCED THE SAVINGS VIA A MERGER?**

A No. In his deposition, FPC witness Myers stated that FPC did not investigate if the merger savings could have been produced in some other way. Further, the Company's filing does not show conclusively that these savings could not have been achieved absent the merger. Specifically, the Company should provide evidence that it could not have outsourced the shared corporate administrative services and produced similar savings at a much lower cost to customers. Indeed, even if the annual savings would be lower under an outsourcing methodology, compared to the Company's estimated merger savings, the net savings to customers might be greater if the cost of outsourcing these shared corporate and administrative services was lower than the very significant merger costs the Company seeks recovery of in this proceeding. Similarly, the Company's assessment of transmission and distribution, customer service, nuclear operations and energy venture savings are also problematic. The Company's assessment representation that these savings produced are only attributable to the merger has not been proven.

Q IN HIS SEPTEMBER TESTIMONY, FPC WITNESS DR. CICCHETTI REPRESENTS THAT THE COMPANY'S ESTIMATED MERGER SAVINGS HERE ARE SIMILAR TO MERGER SAVINGS OF OTHER UTILITY MERGERS INCLUDED IN HIS HISTORICAL DATA BASE. DOES THIS SUPPORT THE COMPANY'S CONTENTION THAT ITS ESTIMATED MERGER SAVINGS COULD ONLY HAVE BEEN REALIZED BY THE MERGER?

A No. Dr. Cicchetti's conclusion based on other utility mergers is highly questionable. Dr. Cicchetti's analysis is based on utilities' original <u>expected</u> merger synergies, not <u>actual</u> synergy savings estimates. Consequently, Dr. Cicchetti's historical data base shows nothing more than FPC's projections are in line with other utilities' projections. However, it provides no benchmark that utility projections reflect real cost reductions.

Q DOES THE COMPANY'S PROPOSED ACQUISITION COST ADJUSTMENT CREATE RISKS TO CUSTOMERS?

A Yes. The Company's proposal is to include some form of an acquisition adjustment in its cost of service over the next 15 years. This is outside the normal treatment of acquisition related costs in rate proceedings. As FPC witness Cicchetti's own testimony finds acquisition cost recovery is typically done over a three to seven-year period, if at all. A 15-year recovery period is above the norm, thus indicating that the Progress Energy merger cost is excessive in relation to its estimated savings.

Q DOES THE COMPANY'S PROPOSED TREATMENT OF ACQUISITION COST AND BENEFITS CREATE A FAIR SHARING OF PROJECTED MERGER SAVINGS?

A No. Under the Company's proposal, the Company will be allowed to include 100% of the expected merger synergies in its cost of service, or approximately $58.7 million. To compensate customers, the Company is proposing a $5 million per year rate credit. However, FPL has not included this credit in its MFRs and has not proposed a method to pass this credit onto customers. (FPL response to FIPUG's 1st Set of Interrogatories, Item 4.). Under the Company's proposal, 8.5% of projected merger savings may be passed on to customers ($5÷$58.7 million), while 91.5% ($3.7/$58.7) of the savings would be retained by the Company as compensation for the acquisition cost. Clearly, the Company's plan is not a balanced approach because it retains the lion's share of expected merger synergies for the benefit of shareholders.

Q PLEASE EXPLAIN HOW PROGRESS ENERGY COULD BE FULLY COMPENSATED FOR ITS INVESTMENT IN FLORIDA PROGRESS WITHOUT RECOVERING A PORTION OF THE ACQUISITION PREMIUM IN FPC'S RETAIL ELECTRIC COST OF SERVICE.

A The Company's proposed acquisition cost is based on the 20% stock market price premium Progress Energy paid for Florida Progress. The Company argues that in order to justify paying this premium, it should be allowed to recover the stock market price premium in part from Florida retail customers. However, the stock price premium can be justified by many factors other than the expectation of increasing FPC's cash flow by allowing it to recover a portion of the acquisition adjustment.

For example, the Company lists as one benefit of the proposed merger a reduction in the business and financial risk of the combined utility companies. If FPC's risk is lowered by the merger, its cost of capital, including its market return on common equity, will decline to correspond to the lower investment risk. All else equal, if you reduce FPC's required return on common equity, the value of its stock will increase. Consequently, Progress Energy will be fully or at least partially compensated for paying a stock market price premium for Florida Progress simply by reducing FPC's investment risk. No further recognition need be made in FPC's cost of service.

An example will help illustrate this point. Consider a utility before and after it is acquired by another utility. Assume also, consistent with FPL's representations, that the merger reduces the utility's risk and cost of capital. This example is shown below in Table 2:

TABLE 2

Stock Valuation

Line	Description	Pre-Merger (1)	Post-Merger (Scenario 1) (2)	Post-Merger (Scenario 2) (3)
1	Current Dividend (D)	$3.00	$3.00	$3.00
2	Investor Required Return (K)	11.0%	10.0%	10.0%
3	Dividend Growth (g)	3.0%	3.0%	3.5%
4	Market Price*	$37.50	$42.90	$46.50
5	Market Price Percent Change		14%	24%

* P = D/(K-g)

As shown in Table 2, the stock price before a merger reduces a Company's risk and cost of capital is based on the dividend of $3.00, an expected growth rate of 3%, and an investor required return (i.e., cost of common equity) of 11.0%. Given these parameters, the market price of the utility's stock before the merger is $37.50. The market value is estimated using a discounted cash flow model which is explained in detail later in my testimony.

Now assume that a merger takes place that causes a reduction to the investment risk of the utility. Thus, its cost of common equity declines from 11.0% down to 10.0%. The dividend and growth rate are unchanged. As shown in Column 2 of Table 2, the market price of the utility after the merger would increase to $42.90. The estimated reduction in the risk of the utility and corresponding reduction to the investor required return increased the value of this company's stock from $37.50 to $42.90, or 14.3%.

Consider also, that if the merger and risk reduction also created greater earnings stability and outlooks (i.e., more likely to earn its authorized common equity return), then the growth rate of the company could be positively impacted by the merger as well. As shown in Column 3 in Table 2, if an additional assumption is made based on a reduction to this utility that not only the investor required return was decreased, but the growth rate expectation increased to 3.5% from 3.0%, then the post-merger value of the company's stock would increase to $46.15, or a premium to the pre-acquisition market price of 24%.

Hence, Progress Energy's ability to be fully compensated for its investment in Florida Progress may be realized simply by the reduction in FPC's investment risk and cost of capital, strengthening of the cash flows of the two operating utilities, and improving its growth outlook. Therefore, no extraordinary cost item, i.e., an acquisition adjustment, need be included in FPC's cost of service in order to provide Progress Energy an opportunity to earn a fair risk adjusted market return on its investment in Florida Progress.

REMOVE FUEL REVENUE AND EXPENSES

Q PLEASE DESCRIBE FPC'S PROPOSED ADJUSTMENT TO REMOVE RECOVERABLE FUEL EXPENSE FROM ITS 2002 BASE RATE MFRs.

A As shown on its Schedule C-3A, Page 1, Column B, the Company removed recoverable fuel revenue and expenses from its total company projected operating expenses for 2002. The net effect of this adjustment was to reduce its base rate net operating income by $9.63 million, and increased the non-fuel revenue requirement by $15.7 million ($9.63 grossed up by the Company's composite tax rate of 38.575%).

Q WHY DID THE REMOVAL OF RECOVERABLE FUEL EXPENSE FROM THE COMPANY'S 2002 MFRs RESULT IN A REDUCTION TO THE NET OPERATING INCOME?

A The Company noted in response to the FIPUG's First Set of Data Requests, Item 16, that the fuel expense was removed from the filing because it is recovered through the fuel clause, and not in base rates. The Company argues that the reduction in net operating income of $9.63 million primarily represents interest on the Tiger Bay regulatory asset, fuel recoveries and line losses.

Q WOULD IT BE APPROPRIATE TO INCREASE BASE REVENUES TO RECOVER INTEREST ON THE TIGER BAY REGULATORY ASSET AND LINE LOSSES?

A No. These costs are allowed to be recovered through the fuel clause. They should not be included in FPC's base rate revenue requirement.

<u>SALES FORECAST</u>

Q PLEASE DESCRIBE THE ISSUE YOU HAVE WITH THE COMPANY'S SALES FORECAST.

A In the Company's updated November filing, it proposes to reduce its projected 2002 sales level based on its expectation of a reduction to the already depressed sales forecast for 2002. The Company's testimony explains that it believes sales in 2002 will be further reduced based on the economic consequences of the September 11, 2001 terrorist attacks.

Q SHOULD THE COMPANY'S PROPOSED REDUCTION IN ITS ORIGINAL SALES ESTIMATE FOR 2002 BE ACCEPTED?

A No. First, the Company's 2002 sales level should be based on a <u>normalized</u> sales level. The sales should not be based on a year that reflects depressed sales levels due to a temporarily depressed economic outlook. The Company's own filing indicates that the expectations for a depressed service area in 2002 will be reversed at the end of the test year, and into 2003. One of the Company's 2002 sales projection assumptions reads as follows:

> "The assumption that the national economy will skirt a full blown recession is based upon the belief that the U.S. Congress and Federal Reserve Board (FRB) will enact an appropriate mixture of fiscal and monetary policy actions. Economic stimulus from the Federal tax cut, while marginal in short term, has been enacted. Swift and significant reductions to government-controlled interest rates by the Federal Reserve Board during the first half of 2001 assures most economists that the economy will react (with a lag) <u>and pick up by year end</u>." (Emphasis added) (Section F, Schedule F-17, page 2)

In its November testimony, however, based predominately on the tragic events of September 11, 2001, FPC revised its 2002 sales projection, expecting significant further sliding in the economy based on waning consumer confidence. In its updated analysis, FPC is now projecting a recession scenario for 2002 similar to the recession levels of 1990 and 1991, and reflects correspondingly reduced levels of Florida real personal income, commercial/manufacturing sector employment, and industrial production. FPC reduced its 2002 sales projections by 614 gigawatthours in energy sales (Don B. Crisp, November testimony, Page 15).

Q **IS THE COMPANY'S PROPOSED LEVEL OF FORECASTED SALES FOR THE 2002 TEST YEAR REASONABLE?**

A No. The Company's 2002 sales forecast should be based on normalized sales. While the Company's projected sales for 2002 may be reasonable for that year, these sales projections do not reflect normal economic activity and, therefore, will not result in the development of just and reasonable rates. The Company's own evidence shows that it is expecting the depression of 2002 economic activity to pick up by year end 2002. Since the rates described here will be in effect for a period beyond 2002, the MFRs sales levels should be normalized. That is, they should not reflect an abnormally high level, nor an abnormally low level of economic activity.

Using a sales forecast reflecting normalized sales activity in the test year will ensure that rates produced in this proceeding will fully recover the Company's operating expenses and provide it with an opportunity to earn a fair return.

Because I have not performed a normalized sales forecast for the Company for the 2002 test year, I am not recommending an adjustment to its original sales forecast reflected in its MFRs. I am, however, recommending that the November sales adjustment recommended by Mr. Myers, based on Mr. Crisp's updated sales forecast reflecting a further economic depression in the Company's service area for 2002, be rejected. While I understand that the Company's MFRs already reflects depressed economic conditions for 2002, the Company's updated expectation that suggests that the Country may slip into a recession during the test year results in a totally unreasonable sales forecast to be used to set rates.

Q WHAT IS THE REVENUE REQUIREMENT IMPACT OF YOUR PROPOSED SALES ADJUSTMENT?

A In his November testimony, on Exhibit MAM-5, Mr. Myers estimates the revenue impact of the sales forecast update to be $14.4 million, and the impact on the rate base to be $688,000. I recommend that the reduction to revenue and rate base proposed by Mr. Myers on this issue be rejected.

<u>HINES POWER BLOCK UNIT 2</u>

Q PLEASE DESCRIBE FPC WITNESS MYERS'S TESTIMONY CONCERNING THE HINES POWER BLOCK UNIT 2.

A Mr. Myers identifies a significant increased revenue requirement in 2003 related to the in-service of a new generating station, Hines Power Block Unit 2. Mr. Myers notes that the projected in-service date for this new generating unit is November 2003. In his deposition, Mr. Myers recommended that the Commission provide for a rate increase to recover the Hines Power Block Unit 2 as of its in-service date, which is currently projected for November 2003.

Q **SHOULD THE COMMISSION GRANT MR. MYERS REQUEST AND AWARD THE COMPANY A $51 MILLION REVENUE INCREASE FOR HINES POWER BLOCK UNIT 2 IN 2003?**

A No. The Company's rate filing in this proceeding is based on a 2002 test year. FPC's MFRs concern the Company's cost of service in 2002. Based on the MFRs, the Commission, its Staff and all intervenors can review all the Company's revenues and expenses in total for 2002 to assess the appropriateness of the Company's current rates. A similar analysis should be made in 2003 if the Company believes a rate change for that year can be supported.

It simply has not been proven that a rate increase will be necessary in 2003 to support FPC's costs for Hines Power Block Unit 2. The Company's projections show significant revenue growth in 2003 relative to 2002, and there may be other cost of service decreases which offset a cost increase associated with this new generating unit. Consequently, the Company has provided no proof that the rates determined in this proceeding will not be adequate to provide full cost recovery of all the Company's operating expenses in the year 2003, including its costs associated with operating the Hines Power Block Unit 2 once it is placed in service.

Q **IS MR. MYERS' REQUEST TO INCREASE RATES IN 2003 COINCIDENT WITH THE EXPECTED IN-SERVICE DATE OF THE HINES POWER BLOCK UNIT 2 WITHIN THE BOUNDS OF TRADITIONAL RATEMAKING PRACTICES?**

A No. In his deposition, Mr. Myers could not cite any Commission precedent for granting an increase in the utility's rates for a projected post-test year cost increase. This request is simply not consistent with the regulatory practice of setting rates which reasonably balance the interests of customers and shareholders. The Company has not proven that rates developed in this proceeding will not be appropriate to recover all costs in the year 2003, including Hines Power Block Unit 2, and no rate increase should be awarded for 2003 until the Company proves an increase is reasonable. Per Mr. Myers' proposal, customers would be afforded little to no regulatory protection against a utility requesting rates that are unjust and unreasonable.

TIGER BAY REGULATORY ASSET

Q PLEASE DESCRIBE THE COMPANY'S PROPOSED ADJUSTMENTS TO ITS 2002 TEST YEAR MFRs RELATED TO AN ACCELERATED AMORTIZATION EXPENSE FOR THE TIGER BAY REGULATORY ASSET.

A The Company is proposing to include in the development of its base rates, $9 million of accelerated recovery of the Tiger Bay regulatory asset (MFRs Schedule C-3A, Page 3).

Q IS THE COMPANY'S PROPOSAL TO INCLUDE $9 MILLION OF ACCELERATED RECOVERY OF TIGER BAY INCLUDED IN ITS BASE RATE FILING?

A No. Based on the Company's response to Staff's Sixth Set of Data Requests, Item 172, the Company is projecting that it will fully recover its Tiger Bay regulatory asset in the year 2003. This recovery reflects the projected accelerated recovery of $9 million in 2002, and $5.3 million in 2003. No accelerated recovery of this asset should be built into base rates.

Further, the Commission should reconsider its decision to allow FPC to record accelerated recovery of the Tiger Bay regulatory asset recovered through its fuel clause. To the extent FPC's rates produce excess earnings, these excess earnings should be passed back to customers via rate credits. Requiring current customers to pay FPC's full cost of service, plus accelerated recovery of its Tiger Bay asset, creates unnecessary cost burdens on current customers. While future customers may benefit, current customers pay all the costs and receive little to no benefits from the pay down of this regulatory asset. Consequently, the Commission's original decision to amortize the Tiger Bay regulatory asset through the year 2007 should be followed. Rate credits and reductions are particularly appealing now with difficult economic times, and the indefinite delay of customer choice. Reducing rates, and rate credits, are good for FPC, the Florida economy, and FPC's customers.

Q IF THE TIGER BAY ACCELERATED RECOVERY IS BUILT INTO BASE RATES, WOULD THE COMPANY'S RATES BE SET AT A JUST AND REASONABLE LEVEL?

A No. Since the Tiger Bay regulatory asset is expected to be fully recovered by the end of year 2003, one year after this rate filing period, the Company's rates set in this proceeding would not reflect the Company's ongoing continuing cost of service. In other words, recovery of the Tiger Bay regulatory asset is not an ongoing cost of service item which is expected to remain in effect during the period rates determined in this proceeding will be in effect. Therefore, reflecting accelerated recovery of Tiger Bay in base rates is an unreasonable request.

CR3 CAPITAL STRUCTURE ADJUSTMENT

Q WHAT CAPITAL STRUCTURE IS THE COMPANY PROPOSING TO USE TO SET ITS EARNINGS ENTITLEMENT IN THIS PROCEEDING?

A FPC's proposed capital structure was provided on its Section D, Schedule D-1.

Q PLEASE DESCRIBE FPC'S PROPOSED CR3 CAPITAL STRUCTURE ADJUSTMENT?

A FPC's proposed capital structure reflects a $109 million increase to common equity and a decrease to long-term debt based on its Crystal River Unit 3 (CR3) adjustment.

Q IS THE COMPANY'S PROPOSED CR3 ADJUSTMENT TO ITS CAPITAL STRUCTURE REASONABLE?

A No. The CR3 settlement has expired and this adjustment is not appropriate, because it increases FPC's common equity balance which is already excessive. Therefore, the CR3 adjustment should be rejected.

Q WHY DO YOU CONCLUDE THAT FPC'S PROPOSED CAPITAL STRUCTURE CONTAINS TOO MUCH COMMON EQUITY?

A FPC's proposed capital structure is heavily weighted with common equity. As shown on my Exhibit MPG-1, Schedule 2, FPC's proposed capital structure includes a common equity ratio of total utility investor capital of 61.15%. This is shown under Column H on Line 16. The Company's debt ratio of total investor capital is 37.9%.

FPC's proposed capital structure contains significantly more common equity than needed to achieve its target bond rating and financial integrity The Company stated in response to a data request that its target bond rating is "A". (FPL's response to FIPUG's 1st Set of Interrogatories, Item 8.) FPC's current Standard & Poor's rating is BBB+. Per Standard & Poor's, the median debt ratio for vertically integrated utility companies with an "A and "BBB" rating are 45% and 56%, respectively.[2] Also, in its matrix financial benchmark used to establish utility bond ratings, S&P maintains that a utility with a business position ranking of 4, FPC's current business position ranking can have a total

[2] Global Utilities Rating Service, Industry Commentary, Standard & Poor's, May 1997.

debt ratio in the range of 43% to 49.5%, and 49.5% to 57%, to be consistent with the financial criteria to maintain a "A" and "BBB" bond rating, respectively.

S&P's total debt ratio range is designed to include off balance sheet debt equivalent obligations which are not reflected in FPC's capital structure. Nevertheless, FPC's debt ratio included in its capital structure is significantly understated in order to meet its target "A" bond rating, or to preserve its existing "BBB" rating from Standard & Poor's.

Q IS FPC'S CAPITAL STRUCTURE REASONABLE IF THE CR3 ADJUSTMENT IS REDUCED?

A The Company's proposed capital structure adjusted to remove its CR3 adjustment is shown on my Exhibit MPG-1, Schedule 3. As shown on this schedule, after removing CR3 common equity and debt adjustments, the Company's common equity ratio as a function of total utility investor capital is 57.7% (column h, line 16). Its total debt ratio, after the CR3 adjustment is removed, is 31.4%. Hence, the capital structure even after the CR3 adjustment is removed is still heavily weighted with common equity and under weighted with debt. Therefore, the Company's CR3 adjustment is unreasonable and should be rejected.

Q WHY DO YOU BELIEVE YOUR PROPOSED CAPITAL COST WILL LOWER FPC'S COSTS RELATIVE TO ITS PROPOSED CAPITAL STRUCTURE?

A Using a capital structure which contains too much common equity will unnecessarily increase the Company's overall cost of capital and its rates. By using a reasonable balance of debt and equity in the capital structure, the Company can minimize its overall rate of return and rates it charges to its customers, while preserving its financial integrity and credit standing. The capital structure I am proposing will maintain and support the Company's efforts to achieve an "A" bond rating. My proposed capital structure will meet these objectives at a substantially lower cost than the Company's proposed capital structure.

My proposed adjusted capital structure will lower FPC's MFRs revenue requirements by $18.2 million per year.

<u>COST OF COMMON EQUITY</u>

Q WHAT IS YOUR RECOMMENDATION?

A I recommend FPC be authorized a return on common equity of 10.5%.

Q PLEASE DESCRIBE THE FRAMEWORK FOR DETERMINING A REGULATED COMPANY'S COST OF COMMON EQUITY.

A In general, determining a fair cost of common equity for a regulated utility has been framed by two decisions of the U.S. Supreme Court, in <u>Bluefield Water Works</u> vs <u>West Virginia PSC</u> (1923) and <u>Federal Power Commission</u> vs <u>Hope Natural Gas Company</u> (1944).

These decisions identify the general standards to be considered in establishing the cost of common equity for a public utility. Those general standards are that the authorized return should: (1) be sufficient to maintain financial integrity, (2) attract capital under reasonable terms, and (3) be commensurate with returns investors could earn by investing in other enterprises of comparable risk.

Q **PLEASE DESCRIBE WHAT IS MEANT BY THE TERM "UTILITY'S COST OF COMMON EQUITY."**

A The utility's cost of common equity is the return investors expect, or require, in order to make an investment. Investors expect to achieve their return requirement from receiving dividends and stock price appreciation.

Q **PLEASE DESCRIBE THE METHODS YOU HAVE USED TO ESTIMATE THE COST OF COMMON EQUITY FOR FPC.**

A I have used several models based on financial theory to estimate FPC's cost of common equity. These models are: (1) the constant growth discounted cash flow (DCF) model, (2) the non-constant growth DCF model, (3) the bond yield plus equity risk premium model, and (4) a capital asset pricing model (CAPM). I have applied these models to a group of publicly traded utilities that I have determined to represent the investment risk of an electric utility similar to FPC.

Q **HOW WILL YOU DEVELOP A DISCOUNTED CASH FLOW ANALYSIS AND RISK PREMIUM ESTIMATES FOR FPC?**

A I relied on a broad based group of electric utility companies in which to estimate FPC's return on equity.

Q **HOW DID YOU SELECT A BROAD BASED GROUP OF ELECTRIC UTILITY COMPANIES?**

A I started with all the electric and combination electric and gas utilities followed by the C.A. Turner Utility Reports. I limited the comparable group to the utilities which met the following criteria: (a) had at least 80% of their revenues from the provision of electric utility service; (b) an investment grade bond rating from both Standard & Poor's and Moody's, (c) currently paying a dividend, and (d) utilities that have an earnings growth rate published by IBES.

As shown on my Exhibit MPG-1, Schedule 4, this selection criteria produced a broad-based group of electric utilities from which to estimate a fair return for FPC.

DISCOUNTED CASH FLOW (DCF) MODEL

Q PLEASE DESCRIBE THE DCF MODEL.

A The DCF model posits that a stock price is valued by summing the present value of expected future cash flows discounted at the investor's required rate of return (ROR) or cost of capital. This model is expressed mathematically as follows:

$$P_o = \frac{D_1}{(1+K)^1} + \frac{D_2}{(1+K)^2} \;....\; \frac{D_\infty}{(1+K)^\infty} \quad \text{where} \qquad \text{(Equation 1)}$$

P_o= Current stock price
D = Dividends in periods 1 - ∞
K = Investor's required return

This model can be rearranged in order to estimate the discount rate or investor required return, "K." If it is reasonable to assume that earnings and dividends will grow at a constant rate, then Equation 1 can be rearranged as follows:

$$K = D_1/P_o + G \qquad \text{(Equation 2)}$$

K = Investor's required return
D_1 = Dividend adjusted for growth
P_o = Current stock price
G = Expected constant dividend growth rate

Equation 2 is referred to as the "constant growth" annual DCF model.

CONSTANT GROWTH DCF MODEL

Q **PLEASE DESCRIBE THE INPUTS TO YOUR CONSTANT GROWTH DCF MODEL.**

A As shown under Equation 2 above, the DCF model requires a current stock price, expected dividend, and expected growth rate in dividends.

Q **WHAT STOCK PRICE AND DIVIDEND HAVE YOU RELIED ON IN YOUR CONSTANT GROWTH DCF MODEL?**

A I relied on the average of the weekly high and low stock prices over a 13-week period ending December 24, 2001. An average stock price is less susceptible to market price variations than is a spot price. Therefore, an average stock price is less susceptible to aberrant market price movements, which may not be reflective of the stock's long-term value.

I used the most recently paid quarterly dividend, as reported in the Value Line Investment Survey. This dividend was annualized (multiplied by 4) and adjusted for next year's growth to produce the D_1 factor for use in Equation 2 above.

Q **WHAT DIVIDEND GROWTH RATES HAVE YOU USED IN YOUR DCF MODEL?**

A There are several methods which one can use in order to estimate the expected growth in dividends. However, for purposes of determining the market required return on common equity, one must attempt to estimate what the consensus of investors believe the dividend or earnings growth rate will be, and not what an individual investor or analyst may use to form individual investment decisions.

Security analyst growth estimates have been shown to be more accurate predictors of future returns than growth rates derived from historical data.[3] Because they are more reliable estimates, and assuming the market, in general, makes rational investment decisions, analysts' growth projections are the most likely growth estimates that are built into stock prices.

For my constant growth DCF analysis, I have relied on a consensus, or mean, of professional security analysts' earnings growth estimates as a proxy for the investor consensus dividend growth rate expectations. My growth estimates were taken from Institutional Brokers Estimate System (IBES) on December 29, 2001, as reported on-line by thomsonfn.com. IBES surveys security analysts and publishes a simple arithmetic average or mean of surveyed analysts' earnings growth forecast. A simple average of the IBES growth forecast gives equal weight to all surveyed analysts' projections. It is problematic as to whether any particular analyst's forecast is most representative of general market expectations. Therefore, a simple average, or arithmetic mean, analyst forecast is a good proxy for market consensus expectations.

Q WHAT ARE THE RESULTS OF YOUR CONSTANT GROWTH DCF MODEL?

A The results of my DCF analyses are shown on Exhibit MPG-1, Schedule 5. As shown on Schedule 5, the average DCF cost of common equity for the comparable group is 12.06%.

[3] See, for example, David Gordon, Myron Gordon, and Lawrence Gould, "Choice Among Methods of Estimating Share Yield," The Journal of Portfolio Management, Spring 1989.

Q DO YOU HAVE ANY COMMENTS CONCERNING THE RESULTS OF YOUR DCF ANALYSIS?

A Yes. My constant growth DCF analysis is, in my judgment, overstated because the current group average five-year IBES projected growth rate is not a reasonable estimate of sustainable growth. The comparable group average IBES five-year growth rate is 6.82%. This growth rate is too high to be sustainable over an indefinite period of time. The growth rate cannot be sustained because it is exceeds the growth rate of the overall U.S. economy. A company cannot grow, indefinitely, at a faster rate than the market in which it sells its products. Based on consensus economic projections, as published by Blue Chip Financial Forecasts, the U.S. economy is estimated to grow at a rate of 5.7%.[4] The U.S. economy growth projection represents a ceiling for a sustainable growth rate for a utility over an indefinite period of time. Therefore, it is reasonable to expect the growth rate for my comparable electric utility group to eventually slow to a growth rate no higher than the growth of the U.S. economy. This expectation for changes to the DCF growth rate will be captured in my non-constant DCF model below.

Q DO YOU HAVE ANY OTHER CONCERNS ABOUT THE APPROPRIATENESS OF A NON-CONSTANT GROWTH DCF ANALYSIS AT THIS TIME?

A Yes. In a constant growth analysis, dividends and earnings are expected to grow at approximately the same rate. If this occurs, the utility's payout ratio will stay relatively constant. However, Value Line's projections for the dividends and earnings for the companies included in my comparable group are not expected to grow at a constant rate over the next five years.

[4] Blue Chip Financial Forecast, December 1, 2001 at 2 (Real GDP: 3.5%, GDP Price Deflator: 2.1%).

As shown on my Exhibit MPG-1, Schedule 6, the payout ratio, or dividends divided by earnings, for my comparable group is 78% for the year 2001. Value Line's projections for these companies during the period 2004 through 2006 show a higher expected growth in earnings than in dividends. Consequently, the payout ratio for the companies three to five years in the future is projected to decline to 57%. Consequently, the constant growth assumption that earnings and dividends will grow at a constant rate over the next five years does not hold. Therefore, a non-constant growth DCF model should be considered.

NON-CONSTANT GROWTH DCF MODEL

Q WHY SHOULD THE COMMISSION CONSIDER THE RESULTS OF A NON-CONSTANT GROWTH DCF MODEL IN THIS PROCEEDING?

A For the reasons discussed above, the growth rates traditionally used in a constant growth DCF model are not reasonable proxies for a sustainable long-term growth rate. Hence, the constant growth DCF results are biased upwards because of the unusually high earnings growth rate expectations for electric utility securities over the next five years. Also, Value Line's dividend and earnings projections indicate that the utilities in my comparable group are not in a constant growth period. Since the constant growth DCF model requires a growth rate estimate which is sustainable indefinitely, an analysis must be made to assess the impact on the constant growth model by use of growth rates that are not sustainable. It is important to note that many Commissions have considered non-constant growth DCF models when the constant growth DCF model results were judged to be either too low or too high.

Q PLEASE DESCRIBE YOUR NON-CONSTANT GROWTH DCF MODEL.

A In my non-constant growth DCF model, I capture the potential expectation investors believe that electric utility stocks are not currently in a constant growth period (i.e., dividends and earnings will not grow at the same rate, on average, over time). In this model, I assume two growth periods: a short-term growth period which reflected the first five years of the analysis, and a long-term growth period which started in year six and continued indefinitely.

The short-term growth rate was set equal to the comparable group average IBES's projected growth rate. The long-term growth rate was based on Blue Chip Financial Forecasts (December 1, 2001) projected nominal growth to the U.S. economy of 5.7%. The stock price and initial dividend used in this non-constant growth analysis is the comparable electric utility group average used in my constant growth analysis.

Q WHY DID YOU ASSUME THAT YOUR LONG-TERM STEADY STATE GROWTH RATE WOULD BE ACHIEVED AFTER ONLY FIVE YEARS?

A For several reasons. First, the use of a non-constant growth DCF analysis based on today's market and company financial conditions is problematic. The average dividend payout ratio of the companies included in my comparable group in 2001 was 78%. The group payout ratio is projected to decline to 57% in three to five years. At that time, the payout ratio will be in line with the Value Line projected 55% industry payout ratio projection.

Q WHAT ARE THE RESULTS OF YOUR NON-CONSTANT GROWTH DCF ANALYSIS?

A As shown on my Exhibit MPG-1, Schedule 7, the non-constant growth DCF analysis produces a return of 10.9%.

RISK PREMIUM MODEL

Q PLEASE DESCRIBE YOUR BOND YIELD PLUS RISK PREMIUM MODEL.

A This model is based on the principle that investors require a higher ROR to assume greater risk. Common equity investments have greater risk than bonds because bonds have more security of payment in bankruptcy proceedings than common equity and the coupon payments on bonds represent contractual obligations. In contrast, companies are not required to pay dividends on common equity, or to guarantee returns on common equity investments. Therefore, common equity securities are considered to be more risky than bond securities.

This risk model is based on both the difference between the required return on utility common equity investments and Treasury bonds. The difference between the required return on common equity and the bond yield is the risk premium. I estimated the risk premium on an annual basis for each year over the period 1986 through year-end 2000. The common equity required returns were based on regulatory commission-authorized returns for electric utility companies. Authorized returns are typically based on expert witnesses' estimate of the contemporary investor required return.

Based on this analysis, as shown on my Exhibit MPG-1, Schedule 8, the average indicated equity risk premium of authorized electric utility common equity returns over U.S. Treasury bond yields has been 4.75%. Of the 15 observations, 11 indicated risk premiums fall in the range of 4.0% to 5.5%. Since the risk premium can vary depending upon market conditions, I believe using an estimated range of risk premiums provides the best method to measure the current return on common equity using this methodology.

Q HOW DID YOU ESTIMATE FPC'S COST OF COMMON EQUITY WITH THIS MODEL?

A I added to my estimated equity risk premium a projected 30-year Treasury bond yield. Blue Chip Financial Forecasts projects 30-year Treasury bond yields to be 5.7%, and a 10-year Treasury bond to be 5.4%. Using the 30-year bond yield of 5.7%, and an equity risk premium of 4.0% to 5.5%, produces an estimated common equity return in the range of 9.7% to 11.2%, with a mid-point estimate at 10.5%.

<u>CAPITAL ASSET PRICING MODEL</u>

Q PLEASE DESCRIBE THE CAPM.

A The CAPM method of analysis is based upon the theory that the market required ROR for a security is equal to the risk-free ROR, plus a risk premium associated with the specific security. This relationship between risk and return can be expressed mathematically as follows:

$R_i = R_f + B_i \times (R_m - R_f)$ where:

$R_i =$ Required ROR for stock i
$R_f =$ Risk-free rate
$R_m =$ Expected return for the market portfolio
$B_i =$ Measure of the risk for stock I

The stock specific risk term in the above equation is beta. Beta represents the investment risk that cannot be diversified away when the security is held in a diversified portfolio. When stocks are held in a diversified portfolio, firm-specific risks can be eliminated by balancing the portfolio with securities that react in opposite direction to firm-specific risk factors (e.g., business cycle, competition, product mix and production limitations).

The risks that cannot be eliminated when held in diversified portfolio are nondiversifiable risks. Nondiversifiable risks are related to the market in general and are referred to as systematic risks. Risks that can be eliminated by diversification are regarded as unsystematic risks. In a broad sense, systematic risks are market risks, and unsystematic risks are business risks. The CAPM theory suggests that the market will not compensate investors for assuming risks that can be diversified away. Therefore, the only risk that investors will be compensated for are systematic or nondiversifiable risks. The beta is a measure of the systematic or nondiversifiable risks.

Q **PLEASE DESCRIBE THE INPUTS TO YOUR CAPM.**

A The CAPM requires an estimate of the market risk-free rate, the company's beta, and the market risk premium.

Q **WHAT DID YOU USE AS AN ESTIMATE OF THE MARKET RISK-FREE RATE?**

A I used Blue Chip Financial Forecasts projected Treasury bond yield of 5.7% (December 1, 2001 at 2).

Q **WHY DID YOU USE TREASURY BOND YIELDS AS AN ESTIMATE OF THE RISK-FREE RATE?**

A Treasury securities are backed by the full faith and credit of the United States government. Therefore, long-term Treasury bonds are considered to have negligible credit risk. Also, long-term Treasury bonds have an investment horizon similar to that of common stock. As a result, investor-anticipated long-run inflation expectations are reflected in both common stock required returns and long-term bond yields. Therefore, the nominal risk-free rate (or expected inflation rate and real risk-free rate) included in a long-term bond yield is a reasonable estimate of the nominal risk-free rate included in common stock returns.

Treasury bond yields, however, do include risk premiums related to unanticipated future inflation and interest rates. Therefore, a Treasury bond yield is not a risk-free rate. Risk premiums related to unanticipated inflation and interest rates are systematic or market risks. Consequently, for companies with betas less than one, using the Treasury bond yield as a proxy for the risk-free rate in the CAPM analysis can produce an overstated estimate of the CAPM return.

Q WHAT BETA DID YOU USE IN YOUR ANALYSIS?

A I relied on the group average beta estimate for the comparable group. Group average beta is more reliable than a single company beta and will, therefore, produce a more reliable CAPM estimate.

A group average beta has stronger statistical parameters that better describe the systematic risk of the group, than does an individual company beta. For this reason, a group average beta will produce a more reliable return estimate.

As shown on Exhibit MPG-1, Schedule 9, the group average beta estimate is 0.54.

Q HOW DID YOU DERIVE YOUR MARKET PREMIUM ESTIMATE?

A I derived two market premium estimates, a forward-looking estimate and one based on a long-term historical average.

The forward-looking estimate was derived by estimating the expected return on the market (S&P 500) and subtracting the risk-free rate from this estimate. I estimated the expected return on the S&P 500 by adding an expected inflation rate to the long-term historical arithmetic average real return on the market. The real return on the market represents the achieved return above the rate of inflation.

The Ibbotson and Associates' Stocks, Bonds, Bills and Inflation 2000 Year Book publication estimates the historical arithmetic average real market return over the period 1926-2000 as 9.7%. A current consensus analyst inflation projection, as measured by the Consumer Price Index, is 2.5% through 2002 (Blue Chip Financial Forecasts, December 1, 2001). Using these estimates, the expected market return is 12.4%. The market premium then is the difference between the 12.4% expected market return, and my 5.7% risk-free rate estimate, or 6.7%.

The historical estimate of the market risk premium was also estimated by Ibbotson and Associates in the Stock, Bonds, Bills and Inflation, 2000 Year Book. Over the period 1926 through 2000, Ibbotson's study estimated that the arithmetic average of the achieved total return on the S&P 500 was 13.0%, and the total return on long-term Treasury bonds was 5.7%. The indicated equity risk premium is 7.3% (13.0% - 5.7% = 7.3%).

Q WHAT ARE THE RESULTS OF YOUR CAPM ANALYSIS?

A As shown on Exhibit MPG-1, Schedule 10, based on the prospective market risk premium estimate of 6.5% and historical estimate of 7.3%, the CAPM estimated return on equity is 9.3% and 9.6%, respectively.

RETURN ON EQUITY SUMMARY

Q BASED ON THE RESULTS OF YOUR RATE OF RETURN ON COMMON EQUITY ANALYSES DESCRIBED ABOVE, WHAT RETURN ON COMMON EQUITY DO YOU RECOMMEND FOR FPC?

A Based on my analyses, I estimated an appropriate return on equity for FPC in the range of 10% to 11%, with a mid-point estimate of 10.5%. The high end of my estimated range, 11%, is based on my non-constant growth DCF analysis, and the bottom of my range is based on an average of my CAPM and risk premium analyses.

TABLE 3

Return on Common Equity Summary

Description	Percent
Constant Growth DCF	12.0%
Non-Constant Growth DCF	10.9%
Risk Premium	10.5%
CAPM	9.6%

RESPONSE TO FPC'S RETURN ON COMMON EQUITY ANALYSIS

Q WHAT RATE OF RETURN ON COMMON EQUITY IS FPC PROPOSING IN THIS PROCEEDING?

A FPC is proposing a return on common equity of 13.2%. FPC's recommended return on common equity is supported by its witness Dr. James H. Vander Weide. Dr. Vander Weide has estimated FPC's return on common equity to be in the range of 12.46% to 13.9% using a discounted cash flow model, and two forms of a risk premium model.

Q ARE DR. VANDER WEIDE'S RETURN OF EQUITY ESTIMATES FOR FPC REASONABLE?

A No. Dr. Vander Weide's methodology overstates FPC's return on common equity. The issues I take with Dr. Vander Weide's estimate of a fair return on common equity for FPC are summarized as follows:

- The electric and gas utility samples are not reasonable risk proxies for FPC.
- His discounted cash flow analysis produces an overstated result because the growth rate is too high to be a reasonable estimate of sustainable growth rate, and his quarterly compounding assumption produces a rate of return which is too high for ratemaking purposes.
- The risk premium analyses produce risk premium estimates which overstate FPC's risk.

Q PLEASE EXPLAIN WHY THE COMPARABLE GROUPS DR. VANDER WEIDE USED TO ESTIMATE FPC'S RETURN ON EQUITY ARE NOT RISK COMPARABLE TO FPC.

A Dr. Vander Weide's electric sample group contains companies that are diversified energy companies that do not derive a significant portion of their revenues from the provision of electric service. As shown on my Exhibit MPG-1, Schedule 11, on average the companies in this group only derive about 54% of their revenues from the provision of electric service. This compares to my comparable that is made up of companies that derive at least 80% of their revenues from the provision of electric service. The business profile and business risk of these companies is not reasonably comparable to FPC.

Q PLEASE EXPLAIN WHY DR. VANDER WEIDE'S DCF ANALYSIS OVERSTATES A FAIR RETURN FOR FPC.

A Dr. Vander Weide's DCF analysis is overstated because the average group growth rates relied on to produce his constant growth DCF analysis is too high to be a reasonable estimate of a sustainable growth rate. The average growth rate for his comparable electric group is 7.35%, and his gas group is 6.82%. (The average of the IBIS growth rate shown on his Schedule 1 and Schedule 3.) His group average growth rates are very high in comparison to the projected growth rate of the U.S. economy of 5.7%. It is not rational to expect that these companies can grow indefinitely at a rate that is significantly higher than the projected growth rate to the economy at which they will sell their services. By overstating the growth rate, Dr. Vander Weide has overstated the DCF result for these companies.

Secondly, Dr. Vander Weide has relied on a quarterly version of the DCF model. This model overstates a reasonable rate of return to use for ratemaking purposes and FPC's cost of capital. Using a quarterly DCF model to set a rate of return for regulatory purposes provides investors with an opportunity to receive dividend reinvestment return twice: once through the regulated authorized return on equity; and a second time when the investors receive quarterly dividend payments and actually reinvest them to enhance their annual return.

An illustration will help explain this point. Assume the utility has a bond with an interest cost of 8%, which pays two semi-annual coupon payments of $40, and a face value of $1,000. To service the cost of this bond, the utility must recover the two $40 semi-annual coupon payments from customers. The utility's annual cost of service for this bond is $80. Hence, the utility's cost of capital of this bond is 8% ($80 divided by $1,000).

However, in pricing this bond, investors will recognize that they will receive two semi-annual coupon payments of $40. Hence, the investor required return on this bond will be 8.16%. Investors will expect to receive two $40 coupon payments from the utility and expect to be able to reinvest the first coupon payment of $40 for six months at their required return of 8%. The cash flows received by the investors will be $80 in coupons from the utility, and $1.60 of interest earned on the reinvested coupon received in mid-year ($40 X 8% X 1/2 years). The $1.60 is, however, not a cost to the utility for this bond. The annual return to the bondholder, then is 8.16% (81.6 ÷ 1,000).

If the utility's rates are designed to recover the coupon payments and the coupon reinvestment return, as Dr. Vander Weide proposes, then the utility will overrecover its cost of capital on this bond. In similar fashion, if the return on equity for a utility is designed to include dividend reinvestment returns, the utility will overrecover its cost of common equity.

Since Dr. Vander Weide has included the dividend in reinvestment return in his estimated return on equity for FPC, his DCF overstates FPC's cost of capital.

Q PLEASE EXPLAIN WHY DR. VANDER WEIDE'S RISK PREMIUM OVERSTATES A FAIR RETURN FOR FPC.

A Dr. Vander Weide's estimated return on equity based on his risk premium approaches is overstated because he has overstated a reasonable estimate of an equity risk premium for an electric utility company. Dr. Vander Weide's equity risk premium described on his Schedule 4 is based on his DCF return on natural gas distribution companies in 20-year treasury bonds. This risk premium analysis is unreliable for at least two reasons. First, he has not shown that the natural gas distribution companies are comparable in risk to FPC. Therefore, the equity risk premium is not shown to be applicable to FPC. Second, Dr. Vander Weide's DCF result can be biased depending on the reasonableness of the growth rates used to derive the DCF return estimate. If the growth rate used to derive these estimates is unreasonably high, then the DCF return will be overstated and the risk premium derived from this analysis would be overstated. Dr. Vander Weide has not shown that the growth rates used in his risk premium analysis are reasonable.

Similarly, the equity risk premium derived on Dr. Vander Weide's Schedule 5 is not reasonable. Dr. Vander Weide estimated an S&P 500 stock return premium over Moody's A-rated public utility bonds. FPC is not risk comparable to the S&P 500. Therefore, the equity risk premium derived in this methodology does not produce a fair return for FPC. Indeed, based on Beta estimate for electric utilities, equity risk premium for a utility will be approximately 50% to 60% of the equity risk premium derived from the S&P 500. Using Dr. Vander Weide's 6 percentage point equity risk premium for the S&P 500 over Moody's A rated treasury bond yields would suggest appropriate equity risk premium for an electric utility is approximately 3 to 3.6 percentage points.

<u>FPC'S PROPOSED EARNINGS SHARING PLAN</u>

Q PLEASE DESCRIBE FPC'S PROPOSED EARNINGS SHARING PLAN AS PROPOSED IN THIS PROCEEDING.

A The Company's earnings sharing mechanism is described by FPC witness Cicchetti in his September 14, 2001 testimony. Mr. Cicchetti describes the plan in five steps:

- Set FPC's return on common equity at 13.2%.
- Create a 100 basis point deadband established around either side of the authorized return on equity for general rate case purposes.
- Provide FPC the authority to recover the merger transaction costs with a debt carrying charge over 15 years. As such, the Company would be allowed to reflect an after-tax amount for ratemaking and regulatory surveillance purposes of $25.31 million per year.

- The Company will guarantee ratepayers a merger savings credit of $5 million per year.

- After the merger transaction costs are recovered, the Company will share earnings on a progressive scale depending on FPC's rate of return. The proposed progressive earnings sharing mechanism is described as follows:

  - Earnings between 12.2% and 14.2% would fall in the deadband. No earnings would be shared within this deadband.

  - If FPC's earnings are 14.21% to 14.7%, customers will receive 80% and shareholders will receive 20% of the excess earnings within this range.

  - If earnings are 14.71% to 15.2%, customers receive 50% and shareholders receive 50% of the excess earnings within this range.

  - For earnings above 15.2%, customers receive 20% and shareholders receive 80% of the excess earnings.

Q **SHOULD FPC'S PROPOSED EARNINGS SHARING MECHANISM BE ADOPTED IN THIS PROCEEDING?**

A No. An earnings sharing mechanism which allows the Company an opportunity to recover its merger transaction costs without proving the existence of savings which could only have been achieved by the merger is inappropriate for the reasons discussed above. Also, the Company's proposed return levels within its earnings sharing band are excessive. An earnings sharing mechanism should not be based on an unreasonable authorized return on equity.

Q **IS THERE ANOTHER INCENTIVE REGULATORY MECHANISM WHICH WOULD MORE PROPERLY BALANCE THE INTERESTS OF SHAREHOLDERS AND CUSTOMERS?**

A Possibly. However, the most important measure in developing an appropriate incentive mechanism is to thoroughly recalibrate FPC's rates at the beginning of the plan to ensure that the Company's rates are expected to recover only the Company's prudent and reasonable cost of service. If rates are excessive, the Company may be allowed to retain excess revenues or earnings which are not the result of superior management performance. To the extent management achieved cost reductions or sales enhancements that exceed reasonable expectations, then it may be appropriate to reward management through a sharing of excess revenues or earnings.

A revenue sharing mechanism such as that approved for Florida Power & Light Company's settlement in Docket No. 990067-EI, and described in Order No. ESC-99-0519-AS-EI, may be a suitable mechanism for FPC going forward. However, as described above, an earnings sharing mechanism should be designed after the Commission determines the appropriate level of base rates and base revenues for FPC in this proceeding. After the development of a just and reasonable level of base revenues, the Commission can design a revenue band under which the Company will retain a portion of excess revenues through a sharing mechanism for revenues outside of this band.

Q DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A Yes.

FLORIDA POWER CORPORATION

Retail Non-Fuel O&M Expense

Year	Non Fuel Expense (1)	Acquisition Adjustment (2)	Adjusted Non Fuel Expense (3)
1994	$385,353,763		$385,353,763
1995	$365,980,688		$365,980,688
1996	$390,339,548		$390,339,548
1997	$497,445,451		$497,445,451
1998	$450,328,001		$450,328,001
1999	$430,447,075		$430,447,075
2000	$407,472,250		$407,472,250
2001	$470,557,238		$470,557,238
2002	$498,721,000	$55,441,000	$443,280,000

Source: Various FPC Rate of Return Reports

FLORIDA POWER CORPORATION

Cost of Capital - 13-Month Average
Projected Test Year Ended 12/31/02
Docket No. 000824-EI

As Filed by FPC

Line	Description	System Per Books (A)	Non-Utility (B)	Net Elect System Per Books (C)	Proforma Adjs (D)	Adjusted System (E)	Pro Rata Adjust-ments (F)	FPSC Adj Retail (G)	Ratio (H)	Cost Rate (I)	Weighted Cost (J)
1	Common Equity	$2,075,128	($7,121)	$2,068,007	$109,589	$2,177,596	$211,390	$1,966,206	53.64%	13.20%	7.08%
2	Preferred Stock	33,497		33,497		33,497	3,252	30,245	0.83%	4.51%	0.04%
3	Long-Term Debt										
4	Fixed Rate Debt	1,452,748		1,452,748	(112,353)	1,340,395	130,119	1,210,276	33.02%	7.14%	2.36%
5	Variable Rate Debt	119,634		119,634	(112,745)	6,889	669	6,220	0.17%	4.92%	0.01%
6	Short Term Debt	4,638		4,638	(2,126)	2,512	244	2,268	0.06%	4.92%	0.00%
7	Customer Deposits										
8	Active	112,388		112,388		112,388		112,388	3.07%	6.13%	0.19%
9	Inactive	387		387		387		387	0.01%	0.00%	0.00%
10	Investment Tax Credit	49,999		49,999		49,999	4,854				
11	Post '70 - Equity							28,053	0.77%	13.07%	0.10%
12	Post '70 - Debt							17,092	0.47%	7.13%	0.03%
13	Deferred Income Taxes	358,946		358,946	(3,393)	355,553	34,515	321,038	8.76%	0.00%	0.00%
14	FAS 109 Liability - Net	(29,548)		(29,548)	(2,210)	(31,758)	(3,083)	(28,675)	-0.78%	0.00%	0.00%
15	Total Capital Structure	$4,177,817	($7,121)	$4,170,696	($123,238)	$4,047,458	$381,960	$3,665,498	100.00%		9.81%

Utility Investor Capital Structure

16	Common Equity	$2,075,128	$2,068,007	56.22%	$1,966,206	61.15%
17	Preferred Stock	$33,497	$33,497	0.91%	$30,245	0.94%
18	Long-Term Debt	$0	$0	0.00%	$0	0.00%
19	Fixed Rate Debt	$1,452,748	$1,452,748	39.49%	$1,210,276	37.64%
20	Variable Rate Debt	$119,634	$119,634	3.25%	$6,220	0.19%
21	Short Term Debt	$4,638	$4,638	0.13%	$2,268	0.07%
22	Total	$3,685,645	$3,678,524	100.00%	$3,215,215	100.00%

Exhibit MPG-1
Schedule 2

FLORIDA POWER CORPORATION

Cost of Capital - 13-Month Average
Projected Test Year Ended 12/31/02
Docket No. 000824-EI

CR3 Adjustment Removed

Line	Description	System Per Books (A)	Non-Utility (B)	Net Elect System Per Books (C)	Proforma Adjs (D)	Adjusted System (E)	Pro Rata Adjust-ments (F)	FPSC Adj Retail (G)	Ratio (H)	Cost Rate (I)	Weighted Cost (J)
1	Common Equity	$2,075,128	($7,121)	$2,068,007	$0	$2,068,007	$211,390	$1,856,617	50.65%	10.50%	5.32%
2	Preferred Stock	33,497		33,497		33,497	3,252	30,245	0.83%	4.51%	0.04%
3	Long-Term Debt										
4	Fixed Rate Debt	1,452,748		1,452,748	(112,353)	1,340,395	130,119	1,210,276	33.02%	7.14%	2.36%
5	Variable Rate Debt	119,634		119,634	(3,156)	116,478	669	115,809	3.16%	4.92%	0.16%
6	Short Term Debt	4,638		4,638	(2,126)	2,512	244	2,268	0.06%	4.92%	0.00%
7	Customer Deposits										
8	Active	112,388		112,388		112,388		112,388	3.07%	6.13%	0.19%
9	Inactive	387		387		387		387	0.01%	0.00%	0.00%
10	Investment Tax Credit	49,999		49,999		49,999	4,854				
11	Post '70 - Equity							28,053	0.77%	10.40%	0.08%
12	Post '70 - Debt							17,092	0.47%	7.13%	0.03%
13	Deferred Income Taxe	358,946		358,946	(3,393)	355,553	34,515	321,038	8.76%	0.00%	0.00%
14	FAS 109 Liability - Net	(29,548)		(29,548)	(2,210)	(31,758)	(3,083)	(28,675)	-0.78%	0.00%	0.00%
15	Total Capital Structure	$4,177,817	($7,121)	$4,170,696	($123,238)	$4,047,458	$381,960	$3,665,498	100.00%		8.17%

Utility Investor Capital Structure

Line	Description	System Per Books (A)	Net Elect System Per Books (C)		FPSC Adj Retail (G)	Ratio (H)
16	Common Equity	$2,075,128	$2,068,007	56.22%	$1,856,617	57.7%
17	Preferred Stock	$33,497	$33,497	0.91%	$30,245	0.9%
18	Long-Term Debt	$0	$0	0.00%	$0	0.0%
19	Fixed Rate Debt	$1,452,748	$1,452,748	39.49%	$1,210,276	37.6%
20	Variable Rate Debt	$119,634	$119,634	3.25%	$115,809	3.6%
21	Short Term Debt	$4,638	$4,638	0.13%	$2,268	0.1%
22	Total	$3,685,645	$3,678,524	100.00%	$3,215,215	100.00%

Exhibit MPG-1
Schedule 3

FLORIDA POWER CORPORATION

Comparable Electric and Electric & Gas Utility Group

Line	Utility	Value Line [1] Safety Rank	At Least 80% Electric Revenues [2] (1)	Bond Ratings [2] S&P (2)	Bond Ratings [2] Moody's (3)	Common Equity Ratios Value Line [1] (4)	Common Equity Ratios C.A. Turner [2] (5)
1	Ameren Corporation	1	91%	A+	Aa2	51%	49%
2	DPL Inc.	2	99%	BBB+	A2	27%	25%
3	Empire District Electric Co.	2	100%	A-	Baa1	47%	34%
4	Entergy Corp.	2	85%	BBB	Baa2	48%	44%
5	FPL Group Inc.	2	88%	A	Aa3	58%	47%
6	Great Plains Energy	2	93%	A	A1	42%	34%
7	NSTAR	1	84%	A	A3	40%	32%
8	Pinnacle West Capital Corp.	1	97%	A-	A3	53%	46%
9	Sierra Pacific Resources	3	96%	A-	A3	43%	33%
10	Southern Company	2	87%	A+	A1	43%	38%
11	**Average**	**2**	**92%**			**45%**	**38%**
	Reference:						
12	**Progress Energy**	**1**	**79%**	**BBB+**	**A1**	**40%**	**38%**

Sources:
[1] The Value Line Investment Survey dated, 10/5/01, 11/16/01 and 12/7/01
[2] C. A. Turner Utility Reports, 1/02

Notes:
The following companies have been excluded from the analysis since they are either below investment grade, are not paying dividends or have no IBES growth rates: Central Vermont, El Paso Electric Co., Green Mountain Power, Niagara Mohawk, UniSource Energy Corp., Unitil Corp. and Western Resources, Inc.

FLORIDA POWER CORPORATION

13-Week Average Stock Price
Constant Growth DCF Model

Line	Utility	13 Week Average Price [1] (1)	IBES Long-Term Growth % [2] (2)	Annual Dividend [3] (3)	Adjusted Yield (4)	Constant Growth DCF (5)
1	Ameren Corporation	39.95	4.83%	$2.54	6.67%	11.50%
2	DPL Inc.	23.44	8.49%	$0.94	4.35%	12.84%
3	Empire District Electric Co.	20.49	6.00%	$1.28	6.62%	12.62%
4	Entergy Corp.	37.40	9.33%	$1.26	3.68%	13.01%
5	FPL Group Inc.	54.04	6.79%	$2.24	4.43%	11.22%
6	Great Plains Energy	24.32	4.67%	$1.66	7.14%	11.81%
7	NSTAR	42.68	6.60%	$2.06	5.15%	11.75%
8	Pinnacle West Capital Corp.	40.66	8.00%	$1.60	4.25%	12.25%
9	Sierra Pacific Resources	14.50	5.50%	$0.80	5.82%	11.32%
10	Southern Company	23.87	6.32%	$1.34	5.97%	12.29%
11	**Average**	**32.14**	**6.65%**	**$1.57**	**5.41%**	**12.06%**

Sources:
[1] Prices downloaded from Yahoo.com, historical quotes
[2] IBES LTG estimates downloaded from ThomsonFN.com
[3] The Value Line Investment Survey, 10/5/01, 11/16/01 and 12/7/01

FLORIDA POWER CORPORATION

Payout Ratios

Line	Utility	Year 2001 Dividends Per Share (1)	Year 2001 Earnings Per Share (2)	Payout Ratio (3)	Projections 2004-06 Dividends Per Share (4)	Projections 2004-06 Earnings Per Share (5)	Projections 2004-06 Payout Ratio (6)
1	Ameren Corporation	2.54	3.35	76%	2.62	3.75	70%
2	DPL Inc.	0.94	1.75	54%	1.00	2.50	40%
3	Empire District Electric Co.	1.28	0.80	160%	1.32	1.95	68%
4	Entergy Corp.	1.28	3.10	41%	1.52	3.70	41%
5	FPL Group Inc.	2.24	4.65	48%	2.55	5.25	49%
6	Great Plains Energy	1.66	1.60	104%	1.66	2.25	74%
7	NSTAR	2.08	3.50	59%	2.32	4.25	55%
8	Pinnacle West Capital Corp.	1.53	3.85	40%	1.93	4.30	45%
9	Sierra Pacific Resources	0.40	0.35	114%	1.10	2.00	55%
10	Southern Company	1.34	1.60	84%	1.52	2.10	72%
11	**Average**	**1.53**	**2.46**	**78%**	**1.75**	**3.21**	**57%**

Source: The Value Line Investment Survey dated, 10/5/01, 11/16/01 and 12/7/01

FLORIDA POWER CORPORATION

Non-Constrant Growth DCF

Line	Description		Amount (1)
1	Average Price	$	32.14
2	Average Dividend	$	1.57
3	5 Year Growth		6.65%
4	Long-Term Growth		5.70%
5	Non-Constant Growth DCF		10.9%

FLORIDA POWER CORPORATION

Equity Risk Premium

Line	Year	U.S. 30 Yr. Treasury Bond Yield [1] (1)	Authorized Electric Returns [2] (2)	Indicated Risk Premium (3)
1	1986	7.78%	13.93%	6.15%
2	1987	8.59%	12.99%	4.40%
3	1988	8.96%	12.79%	3.83%
4	1989	8.45%	12.97%	4.52%
5	1990	8.61%	12.70%	4.09%
6	1991	8.14%	12.55%	4.41%
7	1992	7.67%	12.09%	4.42%
8	1993	6.59%	11.41%	4.82%
9	1994	7.37%	11.34%	3.97%
10	1995	6.88%	11.55%	4.67%
11	1996	6.71%	11.39%	4.68%
12	1997	6.61%	11.40%	4.79%
13	1998	5.58%	11.66%	6.08%
14	1999	5.87%	10.77%	4.90%
15	2000	5.94%	11.43%	5.49%
16	**Average**	**7.32%**	**12.06%**	**4.75%**

Sources:

[1] Economic Report of the President, January, 2001 and the St. Louis Federal Reserve Bank website

[2] Regulatory Research Associates, Inc., Regulatory Focus

FLORIDA POWER CORPORATION

Comparable Group
Beta

Line	Utility	Value Line Beta
1	Ameren Corporation	0.55
2	DPL Inc.	0.60
3	Empire District Electric Co.	0.45
4	Entergy Corp.	0.50
5	FPL Group Inc.	0.45
6	Great Plains Energy	0.55
7	NSTAR	0.55
8	Pinnacle West Capital Corp.	0.45
9	Sierra Pacific Resources	0.75
10	Southern Company	NMF
11	**Average**	**0.54**

Source:
The Value Line Investment Survey, 10/5/01, 11/16/01 and and 12/7/01

FLORIDA POWER CORPORATION

CAPM Return Estimate

Line	Description	Historical Premium
1	CAPM	9.6%
2	Rf	5.7%
3	Risk Premium	7.3%
4	Beta	0.54

		Prospective Premium
5	CAPM	9.3%
6	Rf	5.7%
7	Risk Premium	6.7%
8	Beta	0.54
9	CAPM Average	9.5%

Sources:
The Value Line Investment Survey, dated 10/5/01,11/16/01 and 12/7/01.

FLORIDA POWER CORPORATION

Electric Revenues as a Percent of Total Revenues

Line	Utility Company	Percent Electric Revenues
1	Allegheny Energy, Inc.	25%
2	ALLETE	40%
3	Ameren Corporation	91%
4	American Electric Power Company	79%
5	CINergy Corporation	60%
6	Cleco Corporation	60%
7	CMS Energy Corporation	18%
8	Dominion Resources	29%
9	DPL Inc.	99%
10	DQE, Inc.	76%
11	DTE Energy Company	58%
12	Duke Energy Corporation	8%
13	FPL Group, Inc.	88%
14	Hawaiian Electric Industries, Inc.	74%
15	IDACORP, Inc.	70%
16	Great Plains Energy (KCPL)	93%
17	MDU Resources Group, Inc.	6%
18	NiSource Inc.	13%
19	NSTAR	84%
20	Pinnacle West Capital Corp.	97%
21	Progress Energy Inc.	79%
22	Public Service Enterprise Group	23%
23	Reliant Energy, Inc.	12%
24	Southern Company	87%
25	TECO Energy, Inc.	56%
26	TXU Corporation	26%
27	UIL Holdings Corporation	63%
28	Vectren Corporation	16%
29	Xcel Energy Inc.	48%
30	Average	54%

Source: C.A. Turner Utility Reports, January 2002

Qualifications of Michael Gorman

Q **PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.**

A Michael P. Gorman. My business mailing address is P. O. Box 412000, 1215 Fern Ridge Parkway, Suite 208, St. Louis, Missouri 63141-2000.

Q **PLEASE STATE YOUR OCCUPATION.**

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

Q **PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND WORK EXPERIENCE.**

A In 1983 I received a Bachelors of Science Degree in Electrical Engineering from Southern Illinois University, and in 1986, I received a Masters Degree in Business Administration with a concentration in Finance from the University of Illinois at Springfield. I have also completed several graduate level economics courses.

In August of 1983, I accepted an analyst position with the Illinois Commerce Commission (ICC). In this position, I performed a variety of analyses for both formal and informal investigations before the ICC, including: marginal cost of energy, central dispatch, avoided cost of energy, annual system production costs, and working capital. In October of 1986, I was promoted to the position of Senior Analyst. In this position, I assumed the additional responsibilities of technical leader on projects, and my areas of responsibility were expanded to include utility financial modeling and financial analyses.

In 1987, I was promoted to Director of the Financial Analysis Department. In this position, I was responsible for all financial analyses conducted by the staff. Among other things, I conducted analyses and sponsored testimony before the ICC on rate of return, financial integrity, financial modeling and related issues. I also supervised the development of all Staff analyses and testimony on these same issues. In addition, I supervised the Staff's review and recommendations to the Commission concerning utility plans to issue debt and equity securities.

In August of 1989, I accepted a position with Merrill-Lynch as a financial consultant. After receiving all required securities licenses, I worked with individual investors and small businesses in evaluating and selecting investments suitable to their requirements.

In September of 1990, I accepted a position with Drazen-Brubaker & Associates, Inc. In April 1995 the firm of Brubaker & Associates, Inc. (BAI) was formed. It includes most of the former DBA principals and Staff. Since 1990, I have performed various analyses and sponsored testimony on cost of capital, cost/benefits of utility mergers and acquisitions, utility reorganizations, level of operating expenses and rate base, cost of service studies, and analyses relating industrial jobs and economic development. I also participated in a study used to revise the financial policy for the municipal utility in Kansas City, Kansas.

At BAI, I also have extensive experience working with large energy users to distribute and critically evaluate responses to requests for proposals (RFPs) for electric, steam, and gas energy supply from competitive energy suppliers. These analyses include the evaluation of gas supply and delivery charges, cogeneration and/or combined cycle unit feasibility studies, and the evaluation of third-party asset/supply management agreements. I have also analyzed commodity pricing indices and forward pricing methods for third party supply agreements. Continuing, I have also conducted regional electric market price forecasts.

In addition to our main office in St. Louis, the firm also has branch offices in Asheville, NC; Kerrville, Texas; Plano, Texas; Denver, Colorado; and Chicago, Illinois.

Q HAVE YOU EVER TESTIFIED BEFORE A REGULATORY BODY?

A Yes. I have sponsored testimony on cost of capital, revenue requirements, cost of service and other issues before the regulatory commissions in Arizona, Delaware, Georgia, Illinois, Indiana, Michigan, Missouri, New Mexico, Oklahoma, Tennessee, Texas, Utah, Vermont, West Virginia, Wisconsin and Wyoming. I have also sponsored testimony before the Board of Public Utilities in Kansas City, Kansas; presented rate setting position reports to the regulatory board of the municipal utility in Austin, Texas, and Salt River Project, Arizona, on behalf of industrial customers; and negotiated rate disputes for industrial customers of the Municipal Electric Authority of Georgia in the LaGrange, Georgia district.

Q PLEASE DESCRIBE ANY PROFESSIONAL REGISTRATIONS OR ORGANIZATIONS TO WHICH YOU BELONG.

A I earned the designation of Chartered Financial Analyst (CFA) from the Association for Investment Management and Research (AIMR). The CFA charter was awarded after successfully completing three examinations which covered the subject areas of financial accounting, economics, fixed income and equity valuation and professional and ethical conduct. I am a member of AIMR's Financial Analyst Society.

MPG:cs/7718/26810

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that a true and correct copy of the foregoing Intervenor Testimony and Exhibits of Michael Gorman on Behalf of the Florida Industrial Power Users Group has been furnished by (*) hand delivery and U.S. Mail to the following this 18th day of January, 2002:

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