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**

Direct Testimony and Exhibits of

James T. Selecky

On Behalf of

The Commercial Group

June 27, 2005
Project 8389

BAI

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

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Direct Testimony of James T. Selecky

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 potential 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.

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.

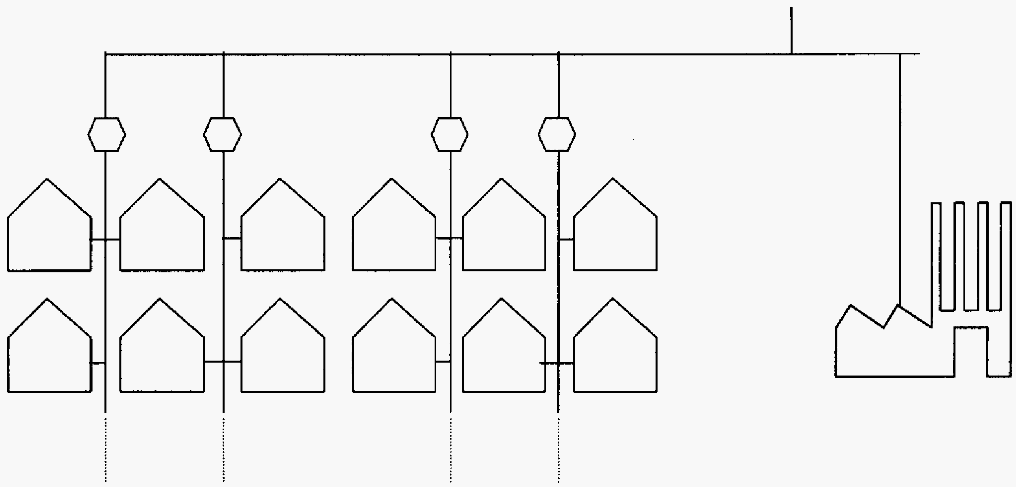
Q CAN YOU PROVIDE A SIMPLE ILLUSTRATION THAT SUPPORTS THE CLASSIFICATION OF A PORTION OF THE DISTRIBUTION SYSTEM AS CUSTOMER-RELATED?

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.

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.

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.

Qualifications of James T. Selecky

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A James T. Selecky. My business address is 1215 Fern Ridge Parkway, Suite 208, St. Louis, Missouri 63141.

Q PLEASE STATE YOUR OCCUPATION.

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

Q PLEASE STATE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EMPLOYMENT EXPERIENCE.

A I graduated from Oakland University in 1969 with a Bachelor of Science degree with a major in Engineering. In 1978, I received the degree of Master of Business Administration with a major in Finance from Wayne State University.

I was employed by The Detroit Edison Company (DECo) in April of 1969 in its Professional Development Program. My initial assignments were in the engineering and operations divisions where my responsibilities included evaluation of equipment for use on the distribution and transmission system; equipment performance testing under field and laboratory conditions; and troubleshooting and equipment testing at various power plants throughout the DECo system. I also worked on system design and planning for system expansion.

In May of 1975, I transferred to the Rate and Revenue Requirement area of DECo. From that time, and until my departure from DECo in June 1984, I held various positions which included economic analyst, senior financial analyst, supervisor of the Rate Research Division, supervisor of the Cost-of-Service Division and director of the Revenue Requirement Department. In these positions, I was responsible for overseeing and performing economic and financial studies and book depreciation studies; developing fixed charge rates and parameters and procedures used in economic studies; providing a financial analysis consulting service to all areas of DECo; developing and designing rate structure for electrical and steam service; analyzing profitability of various classes of service and recommending changes therein; determining fuel and purchased power adjustments; and all aspects of determining revenue requirements for ratemaking purposes.

In June of 1984, I joined the firm of Drazen-Brubaker & Associates, Inc. (DBA). In April 1995 the firm of Brubaker & Associates, Inc. (BAI) was formed. It includes most of the former DBA principals and staff. At DBA and BAI I have testified in electric, gas and water proceedings involving almost all aspects of regulation. I have also performed economic analyses for clients related to energy cost issues.

In addition to our main office in St. Louis, the firm also has branch offices in Phoenix, Arizona; Chicago, Illinois; Corpus Christi, Texas; and Plano, Texas.

Q **HAVE YOU PREVIOUSLY APPEARED BEFORE A REGULATORY COMMISSION?**

A Yes. I have testified on behalf of DECo in its steam heating and main electric cases. In these cases I have testified to rate base, income statement adjustments, changes in book depreciation rates, rate design, and interim and final revenue deficiencies.

In addition, I have testified before the regulatory commissions of the States of Colorado, Connecticut, Georgia, Illinois, Indiana, Iowa, Kansas, Louisiana, Maryland, Massachusetts, Missouri, New Hampshire, New Jersey, North Carolina, Ohio, Oklahoma, Tennessee, Texas, Utah, Washington, Wisconsin, and Wyoming, and the Provinces of Alberta and Saskatchewan. I also have testified before the Federal

Energy Regulatory Commission. In addition, I have filed testimony in proceedings before the regulatory commissions in the States of Florida, Montana, New York, and Pennsylvania and the Province of British Columbia. My testimony has addressed revenue requirement issues, cost of service, rate design, financial integrity, accounting-related issues, merger-related issues, and performance standards. The revenue requirement testimony has addressed book depreciation rates, decommissioning expense, O&M expense levels, and rate base adjustments for items such as plant held for future use, working capital, and post test year adjustments. In addition, I have testified on deregulation issues such as stranded cost estimates and rate design.

Q ARE YOU A REGISTERED PROFESSIONAL ENGINEER?

A Yes, I am a registered professional engineer in the State of Michigan.

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Regulatory Research Associates, Inc. REGULATORY FOCUS RRA

30 MONTGOMERY STREET JERSEY CITY, NEW JERSEY 07302 (201) 433-5507

Regulatory Study
January 14, 2005

MAJOR RATE CASE DECISIONS--JANUARY 2003-DECEMBER 2004 SUPPLEMENTAL STUDY

In conjunction with the preparation of the Regulatory Study entitled *Major Rate Case Decisions--January 1990-December 2004*, which will be distributed in the next few weeks, RRA has prepared chronological listings of all cases in that study for the years 2003 and 2004, by type of utility service. These listings, with key data concerning each case, appear on pages 7 through 12 of this Supplemental Study. Tables summarizing cases decided in the last 11 years appear on pages 2 and 3, and graphs summarizing the authorized equity returns in the last 14 years appear on pages 4 through 6. The average equity return authorized electric utilities in 2004 approximated 10.7%, down slightly from 11% in 2003. There were 19 electric equity return determinations in 2004 and 22 in 2003. The average return on equity (ROE) authorized gas utilities approximated 10.6% in 2004, down from 11% in 2003. There were 20 gas cases that included an ROE determination in 2004 and 25 in 2003. For the telecommunications industry, there was one ROE determination (10%) in 2004 and none in 2003.

Over the last several years there have been fewer equity return determinations relative to the 1980's and early 1990's. The reasons for this phenomenon include: industry restructuring/intensifying competition; more efficient utility operations; technological improvements; relatively low inflation and interest rates; accelerated depreciation/amortization programs; the increased utilization of settlements that do not specify return parameters; and, the growing use of performance or price-based regulation. As the number of equity return determinations has declined, the average authorized ROE has less of a relationship to the return that the typical electric, gas, or telecommunications company has an opportunity to earn from regulated operations. In addition, electric industry restructuring in many states has led to the unbundling of rates, with commissions authorizing revenue requirement and return parameters for transmission and/or distribution operations only (which we footnote in our chronology table), thus further complicating data comparability.

The individual electric, gas, and telecommunications cases listed on pages 7 through 12 are presented with the decision date shown first, followed by the company name, the abbreviation of the state issuing the decision, the authorized rate of return (ROR) and ROE, and the common equity component in the adopted capital structure. If the capital structure contained cost-free capital or investment tax credit balances at the overall rate of return, an asterisk (*) follows the number in this column. Next we show the month and year in which the adopted test year ended, whether the commission utilized an average or a year-end rate base, and the amount of the permanent rate change authorized. The dollar amount represents the permanent rate change ordered at the time a decision was issued. In a few cases, an interim rate change was previously ordered. Fuel adjustment clause rate changes are not reflected in this study.

(Text continued on page 6)

Average Equity Returns Authorized January 1994 - December 2004

(Return Percent - No. of Observations)

	Period	Electric Utilities	Gas Utilities	Telephone Utilities
1994	Full Year	11.34 (31)	11.35 (28)	11.81 (11)
1995	Full Year	11.55 (33)	11.43 (16)	12.08 (8)
1996	Full Year	11.39 (22)	11.19 (20)	11.74 (4)
1997	Full Year	11.40 (11)	11.29 (13)	11.56 (5)
1998	1st Quarter	11.31 (4)	--- (0)	11.30 (1)
	2nd Quarter	12.20 (1)	11.37 (3)	--- (0)
	3rd Quarter	11.80 (2)	11.41 (3)	--- (0)
	4th Quarter	11.83 (3)	11.69 (4)	--- (0)
1998	Full Year	11.66 (10)	11.51 (10)	11.30 (1)
1999	1st Quarter	10.58 (4)	10.82 (3)	13.00 (1)
	2nd Quarter	10.94 (4)	10.82 (3)	--- (0)
	3rd Quarter	10.63 (8)	--- (0)	--- (0)
	4th Quarter	11.08 (4)	10.33 (3)	--- (0)
1999	Full Year	10.77 (20)	10.66 (9)	13.00 (1)
2000	1st Quarter	11.06 (5)	10.71 (1)	11.50 (1)
	2nd Quarter	11.11 (2)	11.08 (4)	--- (0)
	3rd Quarter	11.68 (2)	11.33 (5)	11.25 (1)
	4th Quarter	12.08 (3)	12.50 (2)	--- (0)
2000	Full Year	11.43 (12)	11.39 (12)	11.38 (2)
2001	1st Quarter	11.38 (2)	11.16 (4)	--- (0)
	2nd Quarter	10.88 (2)	10.75 (1)	--- (0)
	3rd Quarter	10.78 (8)	--- (0)	--- (0)
	4th Quarter	11.50 (6)	10.65 (2)	--- (0)
2001	Full Year	11.09 (18)	10.95 (7)	--- (0)
2002	1st Quarter	10.87 (5)	10.67 (3)	--- (0)
	2nd Quarter	11.41 (6)	11.64 (4)	--- (0)
	3rd Quarter	11.06 (4)	11.50 (3)	--- (0)
	4th Quarter	11.20 (7)	10.78 (11)	--- (0)
2002	Full Year	11.16 (22)	11.03 (21)	--- (0)
2003	1st Quarter	11.47 (7)	11.38 (5)	--- (0)
	2nd Quarter	11.16 (4)	11.36 (4)	--- (0)
	3rd Quarter	9.95 (5)	10.61 (5)	--- (0)
	4th Quarter	11.09 (6)	10.84 (11)	--- (0)
2003	Full Year	10.97 (22)	10.99 (25)	--- (0)
2004	1st Quarter	11.00 (3)	11.10 (4)	10.00 (1)
	2nd Quarter	10.50 (6)	10.25 (2)	--- (0)
	3rd Quarter	10.33 (2)	10.37 (8)	--- (0)
	4th Quarter	10.91 (8)	10.66 (6)	--- (0)
2004	Full Year	10.73 (19)	10.59 (20)	10.00 (1)

Electric Utilities--Summary Table*

	Period	ROR %	ROE %	Eq. as % Cap. Struc.	Amt. $ Mil.
1994	Full Year	9.29 (30)	11.34 (31)	45.15 (30)	1,116.9 (40)
1995	Full Year	9.44 (30)	11.55 (33)	45.90 (30)	455.7 (43)
1996	Full Year	9.21 (20)	11.39 (22)	44.34 (20)	-5.6 (38)
1997	Full Year	9.16 (12)	11.40 (11)	48.79 (11)	-553.3 (33)
1998	Full Year	9.44 (9)	11.66 (10)	46.14 (8)	-429.3 (31)
1999	Full Year	8.81 (18)	10.77 (20)	45.08 (17)	-1,683.8 (30)
2000	Full Year	9.20 (12)	11.43 (12)	48.85 (12)	-291.4 (34)
2001	Full Year	8.93 (15)	11.09 (18)	47.20 (13)	14.2 (21)
2002	Full Year	8.72 (20)	11.16 (22)	46.27 (19)	-475.4 (24)
2003	1st Quarter	9.07 (6)	11.47 (7)	49.94 (5)	48.2 (7)
	2nd Quarter	9.07 (4)	11.16 (4)	49.46 (4)	116.2 (5)
	3rd Quarter	8.22 (5)	9.95 (5)	46.09 (5)	-61.0 (5)
	4th Quarter	9.07 (5)	11.09 (6)	52.17 (5)	210.4 (5)
2003	Full Year	8.86 (20)	10.97 (22)	49.41 (19)	313.8 (22)
2004	1st Quarter	8.94 (3)	11.00 (3)	44.94 (3)	-716.4 (4)
	2nd Quarter	7.88 (6)	10.50 (6)	45.59 (6)	641.4 (11)
	3rd Quarter	9.01 (2)	10.33 (2)	45.05 (2)	119.4 (4)
	4th Quarter	8.55 (7)	10.91 (8)	49.64 (6)	1,047.8 (11)
2004	Full Year	8.44 (18)	10.73 (19)	46.84 (17)	1,092.2 (30)

Gas Utilities--Summary Table*

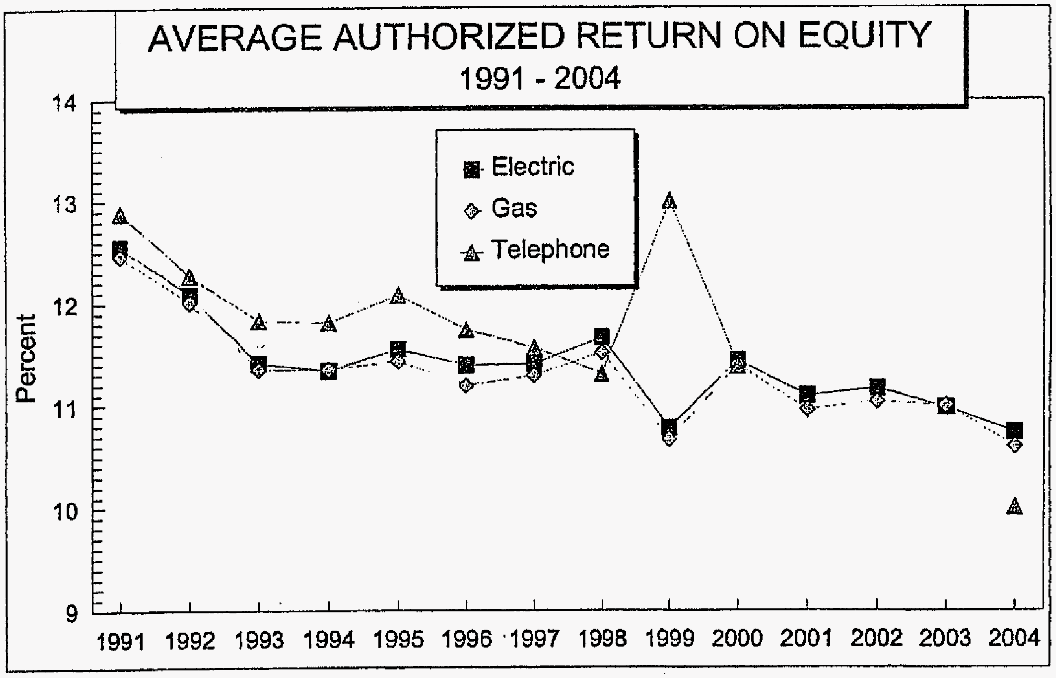
	Period	ROR %	ROE %	Eq. as % Cap. Struc.	Amt. $ Mil.
1994	Full Year	9.51 (32)	11.35 (28)	48.12 (27)	422.9 (42)
1995	Full Year	9.64 (16)	11.43 (16)	49.98 (15)	-61.5 (31)
1996	Full Year	9.25 (23)	11.19 (20)	47.69 (19)	193.4 (34)
1997	Full Year	9.13 (13)	11.29 (13)	47.78 (11)	-82.5 (21)
1998	Full Year	9.46 (10)	11.51 (10)	49.50 (10)	93.9 (20)
1999	Full Year	8.86 (9)	10.66 (9)	49.06 (9)	51.0 (14)
2000	Full Year	9.33 (13)	11.39 (12)	48.59 (12)	135.9 (20)
2001	Full Year	8.51 (6)	10.95 (7)	43.96 (5)	114.0 (11)
2002	Full Year	8.80 (20)	11.03 (21)	48.29 (18)	303.6 (26)
2003	1st Quarter	8.97 (4)	11.38 (5)	50.69 (4)	35.9 (6)
	2nd Quarter	9.09 (3)	11.36 (4)	50.32 (3)	14.2 (5)
	3rd Quarter	8.54 (4)	10.61 (5)	45.74 (4)	89.5 (6)
	4th Quarter	8.64 (11)	10.84 (11)	51.06 (11)	120.5 (13)
2003	Full Year	8.75 (22)	10.99 (25)	49.93 (22)	260.1 (30)
2004	1st Quarter	8.52 (4)	11.10 (4)	45.61 (4)	56.3 (6)
	2nd Quarter	8.21 (3)	10.25 (2)	46.90 (2)	121.7 (9)
	3rd Quarter	8.27 (8)	10.37 (8)	42.92 (8)	113.4 (8)
	4th Quarter	8.40 (6)	10.66 (6)	49.72 (6)	12.1 (8)
2004	Full Year	8.34 (21)	10.59 (20)	45.90 (20)	303.5 (31)

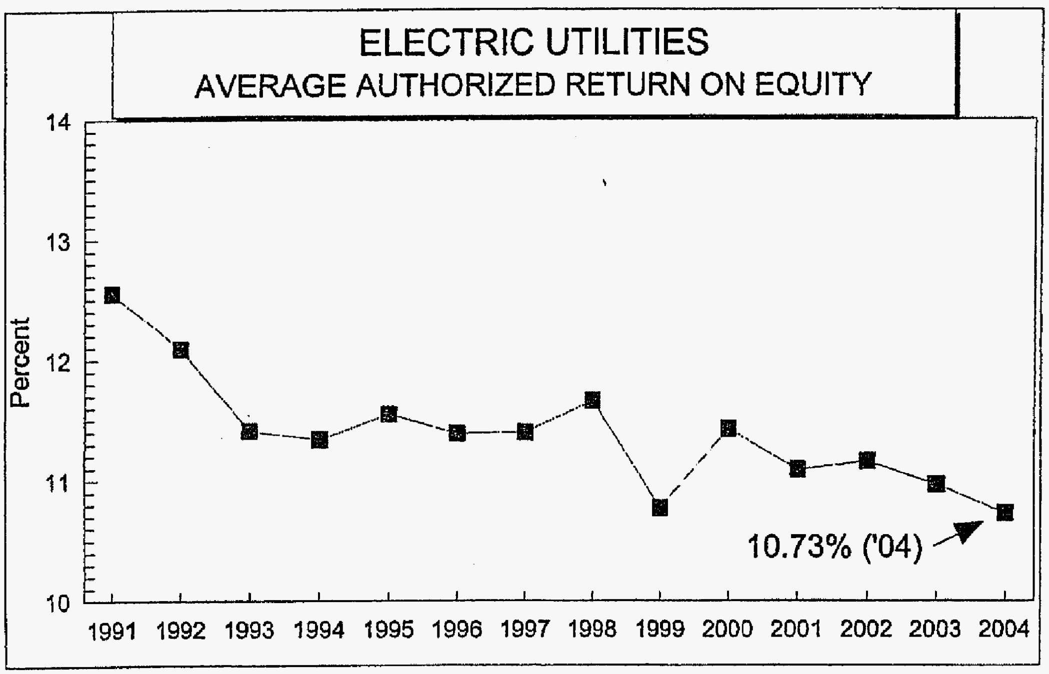
Telephone Utilities--Summary Table*

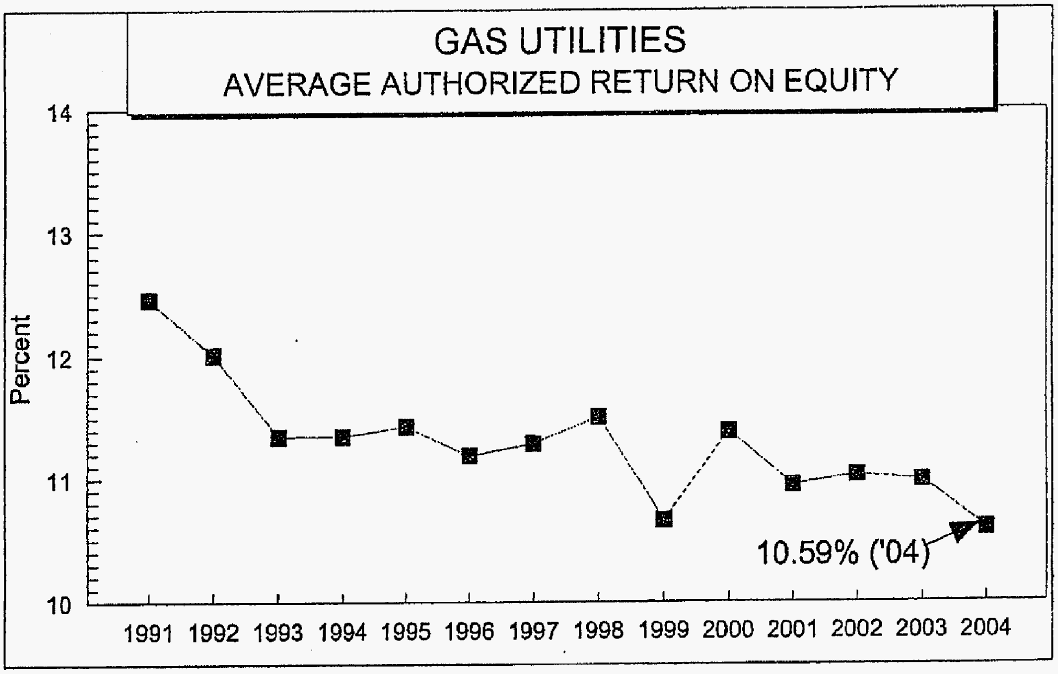
	Period	ROR %	ROE %	Eq. as % Cap. Struc.	Amt. $ Mil.
1994	Full Year	9.91 (12)	11.81 (11)	57.46 (11)	-236.6 (16)
1995	Full Year	9.81 (8)	12.08 (8)	55.02 (7)	-264.0 (14)
1996	Full Year	9.65 (2)	11.74 (4)	56.00 (2)	-348.2 (11)
1997	Full Year	9.57 (5)	11.56 (5)	55.84 (5)	-154.4 (7)
1998	Full Year	9.37 (1)	11.30 (1)	52.00 (1)	-323.3 (13)
1999	Full Year	11.34 (1)	13.00 (1)	66.90 (1)	-570.1 (19)
2000	Full Year	9.52 (2)	11.38 (2)	56.59 (2)	-390.4 (14)
2001	Full Year	9.61 (1)	--- (0)	--- (0)	-130.0 (8)
2002	Full Year	--- (0)	--- (0)	--- (0)	7.7 (4)
2003	1st Quarter	--- (0)	--- (0)	--- (0)	--- (0)
	2nd Quarter	--- (0)	--- (0)	--- (0)	-27.6 (1)
	3rd Quarter	--- (0)	--- (0)	--- (0)	-35.0 (1)
	4th Quarter	--- (0)	--- (0)	--- (0)	--- (0)
2003	Full Year	--- (0)	--- (0)	--- (0)	-62.6 (2)
2004	1st Quarter	8.02 (1)	10.00 (1)	44.18 (1)	3.1 (1)
	2nd Quarter	--- (0)	--- (0)	--- (0)	--- (0)
	3rd Quarter	--- (0)	--- (0)	--- (0)	--- (0)
	4th Quarter	--- (0)	--- (0)	--- (0)	--- (0)
2004	Full Year	8.02 (1)	10.00 (1)	44.18 (1)	3.1 (1)

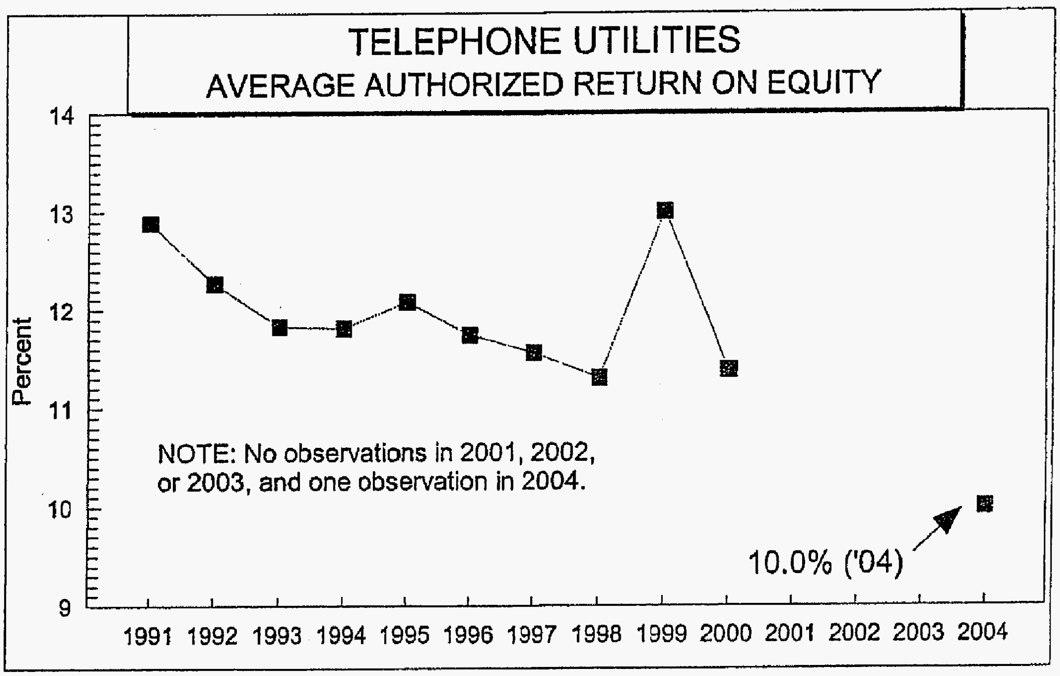
* Number of observations in each period indicated in parentheses.

4. RRA


AVERAGE AUTHORIZED RETURN ON EQUITY
1991 - 2004
Electric
Gas
Telephone
Percent
14
13
12
11
10
9
1991 1992 1993 1994 1995 1996 1997 1998 1999 2000 2001 2002 2003 2004


ELECTRIC UTILITIES
AVERAGE AUTHORIZED RETURN ON EQUITY
Percent
14
13
12
11
10
10.73% ('04)
1991 1992 1993 1994 1995 1996 1997 1998 1999 2000 2001 2002 2003 2004

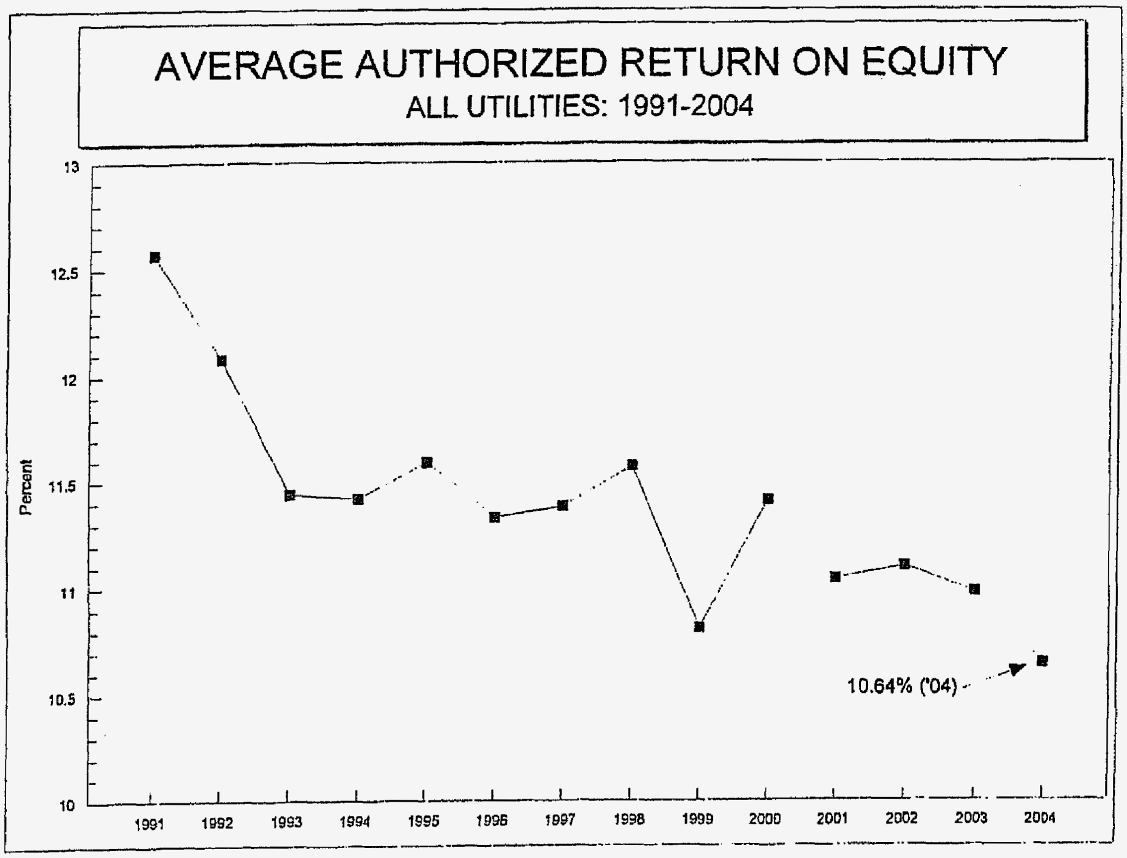

GAS UTILITIES
AVERAGE AUTHORIZED RETURN ON EQUITY
Percent
14
13
12
11
10
10.59% ('04)
1991 1992 1993 1994 1995 1996 1997 1998 1999 2000 2001 2002 2003 2004


TELEPHONE UTILITIES
AVERAGE AUTHORIZED RETURN ON EQUITY
Percent
14
13
12
11
10
9
NOTE: No observations in 2001, 2002,
or 2003, and one observation in 2004.
10.0% ('04)
1991 1992 1993 1994 1995 1996 1997 1998 1999 2000 2001 2002 2003 2004

The table on page 2 shows the average ROE authorized annually since 1994 and by quarter since 1998, in major electric, gas, and telecommunications rate decisions, followed by the number of observations in each period. The tables on page 3 show the composite electric, gas, and telecommunications industry data for all the cases included in the chronology of this and earlier reports, summarized annually since 1994 and by quarter for the past eight quarters. The graphs on pages 4 and 5 show the average authorized equity returns for the three industry groups.

The graph below tracks the average equity return authorized for all electric, gas, and telecommunications rate cases combined, by year, for the last 14 years. As the graph reveals, since 1991 authorized ROEs have generally trended downward, reflecting the significant decline in interest rates that has occurred since 1991. The combined average equity returns authorized for all utilities for the years 1991 though 2004, on an annual basis, and the number of observations for each year are as follows:

1991	12.57%	(96)	1998	11.57%	(21)
1992	12.08	(84)	1999	10.81	(30)
1993	11.44	(89)	2000	11.41	(26)
1994	11.42	(70)	2001	11.05	(25)
1995	11.59	(57)	2002	11.10	(43)
1996	11.33	(46)	2003	10.98	(47)
1997	11.38	(29)	2004	10.64	(40)



ELECTRIC UTILITY DECISIONS

Date	Company (State)	ROR %	ROE %	Common Eq. as % Cap. Str.	Test Year & Rate Base	Amt. $ Mil.
1/8/03	Entergy Gulf States (LA)	---	11.10	---	---	-22.1 (B)
1/28/03	Public Service Co. of New Mexico (NM)	---	---	---	---	-35.2 (B,Z,1)
1/31/03	South Carolina Electric & Gas (SC)	9.94	12.45	52.18	3/02-YE	70.7
2/28/03	Madison Gas and Electric (WI)	9.71 (G)	12.30	55.42	12/03-A	20.3
3/6/03	PacifiCorp (WY)	8.45	10.75	45.70	9/01-YE	8.7
3/7/03	Rochester Gas & Electric (NY)	8.11	9.96	41.40	6/03-A	-15.6 (2)
3/20/03	Wisconsin Public Service (WI)	9.24 (G)	12.00	55.00	12/03-A	21.4
3/28/03	Commonwealth Edison (IL)	8.99	11.72	---	12/02-YE	--- (I,B,3)
2003	***1ST QUARTER AVERAGES/TOTAL***	**9.07**	**11.47**	**49.94**		**48.2**
	OBSERVATIONS	**6**	**7**	**5**		**7**
4/3/03	Wisconsin Power & Light (WI)	9.04 (G)	12.00	51.72	12/03-A	77.1
4/15/03	Interstate Power & Light (IA)	9.08	11.15	47.20 (U)	12/01-A	25.8 (I,R)
5/15/03	Entergy New Orleans (LA)	---	---	---	---	18.4 (B)
6/25/03	Aquila (CO)	9.07	10.75	47.50	6/02-A	16.0 (B)
6/26/03	Public Service of Colorado (CO)	9.08	10.75	51.40	12/01-A	-21.1 (B)
2003	***2ND QUARTER AVERAGES/TOTAL***	**9.07**	**11.16**	**49.46**		**116.2**
	OBSERVATIONS	**4**	**4**	**4**		**5**
7/9/03	Public Service Electric & Gas (NJ)	8.18	9.75	41.45	12/02-YE	159.5 (B,Di)
7/16/03	Rockland Electric (NJ)	8.02	9.75	46.00	4/03-YE	-7.2 (Di)
8/1/03	Jersey Central Power & Light (NJ)	8.38	9.50	46.00	12/02-YE	-222.7 (Di)
8/26/03	PacifiCorp (OR)	8.28	10.50	46.00	3/04-A	8.5 (B)
9/3/03	Maine Public Service (ME)	8.25	10.25	51.00	12/02-A	0.9 (B,4)
2003	***3RD QUARTER AVERAGES/TOTAL***	**8.22**	**9.95**	**46.09**		**-61.0**
	OBSERVATIONS	**5**	**5**	**5**		**5**
12/17/03	Connecticut Light & Power (CT)	8.19	9.85	47.22	12/02-YE	70.5 (Z,TD)
12/17/03	PacifiCorp (UT)	8.43	10.70	47.04	3/03-A	65.0 (B)
12/18/03	Montana-Dakota Utilities (ND)	10.02	11.50	50.32	12/03-A	1.0 (B)
12/19/03	Wisconsin Power & Light (WI)	9.50 (G)	12.00	60.27	12/04-A	14.5
12/19/03	Wisconsin Public Service (WI)	9.20 (G)	12.00	56.00	12/04-A	59.4
12/22/03	Green Mountain Power (VT)	---	10.50	---	---	--- (B,5)
2003	***4TH QUARTER AVERAGES/TOTAL***	**9.07**	**11.09**	**52.17**		**210.4**
	OBSERVATIONS	**5**	**6**	**5**		**5**
2003	***FULL-YEAR AVERAGES/TOTAL***	**8.86**	**10.97**	**49.41**		**313.8**
	OBSERVATIONS	**20**	**22**	**19**		**22**

ELECTRIC UTILITY DECISIONS (continued)

Date	Company (State)	ROR %	ROE %	Common Eq. as % Cap. Str.	Test Year & Rate Base	Amt. $ Mil.
1/13/04	Madison Gas and Electric (WI)	9.37 (G)	12.00	55.91	12/04-A	11.7
2/26/04	Pacific Gas and Electric (CA)	---	---	---	---	-799.0 (B)
3/2/04	PacifiCorp (WY)	8.42	10.75	44.95	9/02-YE	22.9
3/26/04	Nevada Power (NV)	9.03	10.25	33.97	5/03-YE	48.0
2004	***1ST QUARTER AVERAGES/TOTAL***	**8.94**	**11.00**	**44.94**		**-716.4**
	OBSERVATIONS	**3**	**3**	**3**		**4**
4/5/04	Interstate Power and Light (MN)	9.05	11.00	47.15	12/02-A	0.2 (I)
4/13/04	Aquila-MPS (MO)	---	---	---	---	14.5 (B)
4/13/04	Aquila-L&P (MO)	---	---	---	---	3.3 (B)
5/5/04	Wisconsin Electric Power (WI)	---	---	---	12/04-A	59.0
5/18/04	PSI Energy (IN)	7.30	10.50	44.44 *	9/02-YE	107.3
5/20/04	Rochester Gas & Electric (NY)	---	---	---	4/05-A	7.4 (B,6)
5/25/04	Idaho Power (ID)	7.85	10.25	45.97	12/03-A	39.5 (R,B,Z)
5/27/04	Sierra Pacific Power (NV)	9.26	10.25	35.77	7/03-YE	46.7 (B)
6/2/04	Pacific Gas & Electric (CA)	---	---	---	12/03-A	274.0 (B)
6/30/04	Kentucky Utilities (KY)	7.00 (G)	10.50	51.58	9/03-YE	46.1 (B,7)
6/30/04	Louisville Gas and Electric (KY)	6.79 (G)	10.50	48.60	9/03-YE	43.4 (B,8)
2004	***2ND QUARTER AVERAGES/TOTAL***	**7.88**	**10.50**	**45.59**		**641.4**
	OBSERVATIONS	**6**	**6**	**6**		**11**
7/16/04	Southern California Edison (CA)	---	---	---	12/03-A	73.0
8/25/04	Aquila (CO)	8.76	10.25	47.50	8/03-A	8.2 (B)
9/2/04	Public Service New Hampshire (NH)	---	---	---	---	13.5 (B,Z,TD)
9/9/04	Avista Corp. (ID)	9.25	10.40	42.59	12/02-A	24.7
2004	***3RD QUARTER AVERAGES/TOTAL***	**9.01**	**10.33**	**45.05**		**119.4**
	OBSERVATIONS	**2**	**2**	**2**		**4**
10/27/04	PacifiCorp (WA)	8.39	---	---	---	15.0 (B)
11/9/04	Narragansett Electric (RI)	8.89 (E)	10.50	50.00	---	-10.2 (B,Di)
11/23/04	Cincinnati Gas & Electric (OH)	---	---	---	---	85.0 (R,Z)
11/23/04	Detroit Edison (MI)	7.24	11.00	38.08 *	12/02-A	373.7 (I)
12/8/04	San Diego Gas & Electric (CA)	---	---	---	12/04-A	-8.2 (B,Di)
12/14/04	Interstate Power & Light (IA)	8.83	10.97	47.89	12/03-A	106.7 (I,B)
12/21/04	Georgia Power (GA)	---	11.25	---	12/05-A	194.1 (B)
12/21/04	Wisconsin Public Service (WI)	8.89 (G)	11.50	57.35	12/05-A	61.0
12/22/04	PPL-Electric Utilities (PA)	8.43	10.70	46.87	12/04-YE	194.3 (TD)
12/22/04	Madison Gas and Electric (WI)	9.18 (G)	11.50	57.64	12/05-A	27.4
12/29/04	Western Massachusetts Electric (MA)	---	9.85	---	---	9.0 (B,Di,Z)
2004	***4TH QUARTER AVERAGES/TOTAL***	**8.55**	**10.91**	**49.64**		**1047.8**
	OBSERVATIONS	**7**	**8**	**6**		**11**
2004	***FULL-YEAR AVERAGES/TOTAL***	**8.44**	**10.73**	**46.84**		**1092.2**
	OBSERVATIONS	**18**	**19**	**17**		**30**

Date	Company (State)	ROR %	ROE %	Common Eq. as % Cap. Str.	Test Year & Rate Base	Amt. $ Mil.
1/6/03	Peoples Gas System (FL)	8.83	11.25	50.92 *	12/03-A	12.1 (I,B)
2/18/03	Aquila (IA)	---	---	---	12/01-A	4.3 (I,B)
2/28/03	Madison Gas and Electric (WI)	9.71 (G)	12.30	55.42	12/03-A	6.8
3/7/03	Rochester Gas & Electric (NY)	8.11	9.96	41.40	6/03-A	5.5
3/12/03	Aquila Networks-MGU (MI)	---	11.40	---	12/03	8.4 (I,B)
3/20/03	Wisconsin Public Service (WI)	9.24 (G)	12.00	55.00	12/03-A	-1.2
2003	***1ST QUARTER AVERAGES/TOTAL***	**8.97**	**11.38**	**50.69**		**35.9**
	OBSERVATIONS	**4**	**5**	**4**		**6**
4/3/03	Wisconsin Power & Light (WI)	9.04 (G)	12.00	51.72	12/03-A	3.6
5/2/03	SEMCO Energy Gas (MI)	---	11.40	---	12/03	3.3 (B)
5/15/03	Entergy New Orleans (LA)	---	---	---	---	11.8 (B)
5/15/03	Interstate Power and Light (IA)	9.03	11.05	47.84 (U)	12/01-A	13.3 (I)
6/26/03	Public Service of Colorado (CO)	9.20	11.00	51.40	12/01-A	-17.8 (B)
2003	***2ND QUARTER AVERAGES/TOTAL***	**9.09**	**11.36**	**50.32**		**14.2**
	OBSERVATIONS	**3**	**4**	**3**		**5**
7/1/03	Citizens Utilities (AZ)	---	11.00	---	12/01-YE	15.2 (B)
7/29/03	Peoples Natural Gas (MN)	9.93	11.71	49.99	12/00-A	5.0 (I,B)
8/22/03	Northwest Natural Gas (OR)	8.62	10.20	49.50	9/04-A	13.9 (B,Z)
9/17/03	Arkansas Western Gas (AR)	6.74	9.90	35.20 *	6/02-YE	4.1 (B)
9/17/03	ONEOK (KS)	---	---	---	---	45.0 (B)
9/25/03	Avista Corp. (OR)	8.88	10.25	48.25	12/02-A	6.3 (B)
2003	***3RD QUARTER AVERAGES/TOTAL***	**8.54**	**10.61**	**45.74**		**89.5**
	OBSERVATIONS	**4**	**5**	**4**		**6**
10/17/03	AmerenCILCO (IL)	8.16	10.54	48.54	12/01-YE	9.1
10/22/03	Orange & Rockland Utilities (NY)	---	---	---	10/04-A	23.6 (B,Z)
10/22/03	AmerenCIPS (IL)	8.33	10.71	44.44	6/02-YE	7.2
10/22/03	AmerenUE (IL)	8.24	10.46	52.70	6/02-YE	1.9
10/30/03	North Carolina Natural Gas (NC)	9.27	11.00	51.14	9/02-YE	21.0 (B)
10/31/03	Boston Gas (MA)	9.08	10.20	50.00	12/02-YE	19.7
10/31/03	Washington Gas (MD)	8.61	10.75	51.49	12/02-YE	2.9
11/10/03	Washington Gas (DC)	8.42	10.60	50.30	9/02-YE	5.4
12/9/03	Delmarva Power & Light (DE)	7.81	10.50	45.87	9/02	7.8 (I,B)
12/18/03	Washington Gas (VA)	8.44	10.50	50.96	12/01-YE	9.9 (I)
12/19/03	Wisconsin Power & Light (WI)	9.50 (G)	12.00	60.27	12/04-A	-0.4
12/19/03	Wisconsin Public Service (WI)	9.20 (G)	12.00	56.00	12/04-A	8.9
12/23/03	National Fuel Gas Distribution (PA)	---	---	---	9/03-YE	3.5 (B)
2003	***4TH QUARTER AVERAGES/TOTAL***	**8.64**	**10.84**	**51.06**		**120.5**
	OBSERVATIONS	**11**	**11**	**11**		**13**
2003	***FULL-YEAR AVERAGES/TOTAL***	**8.75**	**10.99**	**49.93**		**260.1**
	OBSERVATIONS	**22**	**25**	**22**		**30**

Date	Company (State)	ROR %	ROE %	Common Eq. as % Cap. Str.	Test Year & Rate Base	Amt. $ Mil.
1/13/04	Union Electric (MO)	---	---	---	---	13.0 (B)
1/13/04	Madison Gas and Electric (WI)	9.37 (G)	12.00	55.91	12/04-A	1.0
1/13/04	Public Service Co. of New Mexico (NM)	8.16	10.25	47.77	9/02-YE	22.0 (B,Z)
1/21/04	Aquila (NE)	---	---	---	---	6.2 (I,B)
2/9/04	City Gas Co. of Florida (FL)	7.36	11.25	36.77 *	9/04-A	6.7 (I)
3/16/04	Southwest Gas (CA)	9.17	10.90	42.00	12/03-A	7.4 (9)
2004	***1ST QUARTER AVERAGES/TOTAL OBSERVATIONS***	**8.52** **4**	**11.10** **4**	**45.61** **4**		**56.3** **6**
4/22/04	Aquila Networks-MPS (MO)	---	---	---	---	2.6 (B)
4/22/04	Aquila Networks-L&P (MO)	---	---	---	---	0.8 (B)
5/5/04	Wisconsin Gas (WI)	---	---	---	12/04-A	26.0 (I)
5/20/04	Rochester Gas & Electric (NY)	---	---	---	4/05-A	7.2 (B,6)
5/25/04	TXU-Gas (TX)	8.26	10.00	49.80	12/02-YE	12.0
6/2/04	Pacific Gas & Electric (CA)	---	---	---	12/03-A	52.0 (B)
6/23/04	Northwest Natural Gas (WA)	8.95	---	---	---	3.5 (B)
6/30/04	Southern Indiana Gas and Electric (IN)	7.41	10.50 (B)	44.00 *	9/03-YE	5.7 (B)
6/30/04	Louisville Gas and Electric (KY)	---	---	---	9/03-YE	11.9 (B)
2004	***2ND QUARTER AVERAGES/TOTAL OBSERVATIONS***	**8.21** **3**	**10.25** **2**	**46.90** **2**		**121.7** **9**
7/8/04	South Jersey Gas (NJ)	7.97	10.00	46.00	2/04-YE	20.0 (B)
7/22/04	CenterPoint Energy Arkla (LA)	8.09	10.25	45.80 (Hy)	6/03-A	7.1 (B)
8/26/04	Southwest Gas, Southern Division (NV)	7.45	10.50	40.00	9/03-YE	7.3
8/26/04	Southwest Gas, Northern Division (NV)	8.56	10.50	40.00	9/03-YE	6.4
9/9/04	Avista Corp. (ID)	9.25	10.40	42.59	12/02-A	3.3
9/21/04	Missouri Gas Energy (MO)	8.36	10.50	29.99	6/03-YE	22.5
9/27/04	Consolidated Edison of New York (NY)	8.06	10.30	48.00	9/05-A	46.8 (B)
9/27/04	Washington Gas (VA)	8.44	10.50	50.96	6/03-YE	0.0 (B)
2004	***3RD QUARTER AVERAGES/TOTAL OBSERVATIONS***	**8.27** **8**	**10.37** **8**	**42.92** **8**		**113.4** **8**
10/20/04	Chattanooga Gas (TN)	7.43	10.20	35.50	9/03-A	0.6
11/30/04	Indiana Gas (IN)	8.38	10.60	50.06	9/03-YE	24.0 (B)
12/8/04	San Diego Gas & Electric (CA)	---	---	---	12/04-A	1.6 (B,Di)
12/8/04	Southern California Gas (CA)	---	---	---	12/04-A	-33.0 (B,Di)
12/8/04	Yankee Gas Services (CT)	7.99	9.90	47.90	---	14.0 (B)
12/21/04	Wisconsin Public Service (WI)	8.89 (G)	11.50	57.35	12/05-A	5.6
12/22/04	Madison Gas and Electric (WI)	9.18 (G)	11.50	57.64	12/05-A	-4.2
12/28/04	CenterPoint Energy Arkla (OK)	8.51	10.25	49.86	3/04-YE	3.5 (B)
2004	***4TH QUARTER AVERAGES/TOTAL OBSERVATIONS***	**8.40** **6**	**10.66** **6**	**49.72** **6**		**12.1** **8**
2004	***FULL-YEAR AVERAGES/TOTAL OBSERVATIONS***	**8.34** **21**	**10.59** **20**	**45.90** **20**		**303.5** **31**

TELEPHONE UTILITY DECISIONS

Date	Company (State)	ROR %	ROE %	Common Eq. as % Cap. Str.	Test Year & Rate Base	Amt. $ Mil.
2003	***1ST QUARTER TOTAL***	---	---	---		---
	OBSERVATIONS	0	0	0		0
5/21/03	Verizon North/Verizon South (IL)	---	---	---	---	-27.6 (B,Z)
2003	***2ND QUARTER TOTAL***	---	---	---		-27.6
	OBSERVATIONS	0	0	0		1
8/12/03	Verizon Northwest (WA)	---	---	---	---	-35.0
2003	***3RD QUARTER TOTAL***	---	---	---		-35.0
	OBSERVATIONS	0	0	0		1
2003	***4TH QUARTER TOTAL***	---	---	---		---
	OBSERVATIONS	0	0	0		0
2003	***FULL-YEAR TOTAL***	---	---	---		-62.6
	OBSERVATIONS	0	0	0		2
1/29/04	CenturyTel of North West Arkansas (AR)	8.02	10.00	44.18 *	6/02-YE	3.1 (B)
2004	***1ST QUARTER AVERAGES/TOTAL***	8.02	10.00	44.18		3.1
	OBSERVATIONS	1	1	1		1
2004	***2ND QUARTER AVERAGES/TOTAL***	---	---	---		---
	OBSERVATIONS	0	0	0		0
2004	***3RD QUARTER AVERAGES/TOTAL***	---	---	---		---
	OBSERVATIONS	0	0	0		0
2004	***4TH QUARTER AVERAGES/TOTAL***	---	---	---		---
	OBSERVATIONS	0	0	0		0
2004	***FULL-YEAR AVERAGES/TOTAL***	8.02	10.00	44.18		3.1
	OBSERVATIONS	1	1	1		1

EEI Typical Bill Cost for Residential Users
Weighted Average Costs in ¢/kWh for Summer 2004 and Winter 2005*

Line	Company		Residential 750 kWh	Residential 1000 kWh
1	Conectiv	VA	10.31	9.97
2	Tampa Electric Company	FL	10.13	9.84
3	Entergy Mississippi, Inc.	MS	10.02	9.32
4	Progress Energy Florida	FL	9.54	9.27
5	Dominion North Carolina Power	NC	9.49	9.17
6	Entergy Gulf States, Inc.	LA	9.10	8.95
7	**Florida Power & Light Company**	**FL**	**8.82**	**8.88**
8	South Carolina Electric & Gas Company	SC	9.09	8.84
9	Entergy Louisiana, Inc.	LA	8.95	8.82
10	Mississippi Power Company	MS	9.50	8.79
11	Dominion Virginia Power	VA	9.13	8.72
12	Entergy Arkansas, Inc.	AR	8.85	8.62
13	Progress Energy Carolinas, Inc.	NC	8.83	8.61
14	Progress Energy Carolinas, Inc.	SC	8.77	8.42
15	CLECO Power LLC	LA	8.78	8.39
16	Gulf Power Company	FL	8.69	8.34
17	Duke Power Company	NC	8.20	8.02
18	Entergy New Orleans, Inc.	LA	8.08	7.93
19	Alabama Power Company	AL	8.34	7.85
20	OG&E Electric Services	AR	7.65	7.28
21	Georgia Power Company	GA	7.38	7.25
22	Duke Power Company	SC	7.37	7.17
23	Monongahela Power Company	WV	7.14	7.01
24	Potomac Edison Company	WV	7.14	7.01
25	Union Light, Heat and Power	KY	6.94	6.82
26	Potomac Edison Company	VA	6.99	6.81
27	Empire District Electric Company	AR	7.00	6.52
28	Louisville Gas & Electric Company	KY	6.67	6.50
29	Southwestern Electric Power Company	AR	6.69	6.46
30	Southwestern Electric Power Company	LA	6.29	6.11
31	AEP (Kentucky Power Rate Area)	KY	6.35	6.07
32	AEP (Wheeling Power Rate Area)	WV	6.22	5.88
33	AEP (Appalachian Power Rate Area)	VA	6.06	5.74
34	Old Dominion Power Company	VA	5.77	5.59
35	AEP (Appalachian Power Rate Area)	WV	5.85	5.53
36	Kentucky Utilities Company	KY	5.39	5.22
37	AEP (Kingsport Power Rate Area)	TN	5.37	5.13

* Data sorted by 1,000 kWh

EEI Typical Bill Cost for Commercial Users
Weighted Average Costs in ¢/kWh for Summer 2004 and Winter 2005*

			Commercial	
Line	Company		500 kW 150,000 kWh	500 kW 180,000 kWh
1	Progress Energy Florida	FL	9.52	9.32
2	Tampa Electric Company	FL	8.30	7.88
3	Entergy Mississippi, Inc.	MS	8.07	7.81
4	Entergy Gulf States, Inc.	LA	7.95	7.70
5	Entergy Louisiana, Inc.	LA	7.80	7.56
6	**Florida Power & Light Company**	**FL**	**8.02**	**7.55**
7	Conectiv	VA	7.79	7.41
8	Alabama Power Company	AL	7.93	7.40
9	South Carolina Electric & Gas Company	SC	7.82	6.96
10	Dominion North Carolina Power	NC	7.37	6.96
11	CLECO Power LLC	LA	7.34	6.92
12	Entergy New Orleans, Inc.	LA	7.05	6.68
13	Mississippi Power Company	MS	6.97	6.46
14	Gulf Power Company	FL	6.94	6.43
15	Georgia Power Company	GA	7.01	6.29
16	Duke Power Company	NC	6.27	6.07
17	Progress Energy Carolinas, Inc.	SC	6.45	5.98
18	Progress Energy Carolinas, Inc.	NC	6.33	5.86
19	Dominion Virginia Power	VA	6.57	5.85
20	Louisville Gas & Electric Company	KY	6.50	5.82
21	Duke Power Company	SC	5.89	5.65
22	Union Light, Heat and Power	KY	6.10	5.62
23	AEP (Kentucky Power Rate Area)	KY	5.75	5.53
24	Monongahela Power Company	WV	5.82	5.41
25	Potomac Edison Company	WV	5.82	5.41
26	Entergy Arkansas, Inc.	AR	5.73	5.29
27	Empire District Electric Company	AR	5.65	5.28
28	Old Dominion Power Company	VA	5.45	5.12
29	OG&E Electric Services	AR	5.42	5.10
30	AEP (Appalachian Power Rate Area)	WV	5.37	5.08
31	AEP (Wheeling Power Rate Area)	WV	5.28	5.06
32	Potomac Edison Company	VA	5.51	5.04
33	AEP (Kingsport Power Rate Area)	TN	4.97	4.72
34	Southwestern Electric Power Company	LA	4.89	4.60
35	AEP (Appalachian Power Rate Area)	VA	4.95	4.45
36	Kentucky Utilities Company	KY	4.84	4.43
37	Southwestern Electric Power Company	AR	4.43	4.17

* Data sorted by 500 kW @ 180,000 kWh

EEI Typical Bill Cost for Industrial Users
Weighted Average Costs in ¢/kWh for Summer 2004 and Winter 2005*

Line	Company		Industrial 1,000 kW 400,000 kWh	Industrial 1,000 kW 650,000 kWh	
1	Gulf Power Company	FL	6.13	7.91	**
2	Tampa Electric Company	FL	7.69	6.95	
3	Entergy Gulf States, Inc.	LA	7.38	6.92	
4	Progress Energy Florida	FL	9.19	6.72	
5	Entergy Louisiana, Inc.	LA	7.04	6.61	
6	Conectiv	VA	7.22	6.56	
7	**Florida Power & Light Company**	**FL**	**7.30**	**6.49**	
8	Entergy Mississippi, Inc.	MS	7.27	6.43	
9	CLECO Power LLC	LA	6.70	5.97	
10	Entergy New Orleans, Inc.	LA	6.42	5.67	
11	Dominion North Carolina Power	NC	6.57	5.52	
12	Progress Energy Carolinas, Inc.	NC	6.73	5.41	
13	Progress Energy Carolinas, Inc.	SC	6.25	5.08	
14	Mississippi Power Company	MS	5.98	5.07	
15	Georgia Power Company	GA	6.44	4.95	
16	Union Light, Heat and Power	KY	5.38	4.55	
17	South Carolina Electric & Gas Company	SC	5.72	4.51	
18	Empire District Electric Company	AR	5.05	4.28	
19	Dominion Virginia Power	VA	5.46	4.22	
20	Duke Power Company	NC	5.08	4.20	
21	Alabama Power Company	AL	5.05	4.20	
22	Old Dominion Power Company	VA	4.75	4.14	
23	Monongahela Power Company	WV	4.90	4.08	
24	Potomac Edison Company	WV	4.90	4.08	
25	OG&E Electric Services	AR	4.43	4.03	
26	Potomac Edison Company	VA	4.66	3.89	
27	Southwestern Electric Power Company	LA	4.45	3.85	
28	Entergy Arkansas, Inc.	AR	5.06	3.79	
29	Duke Power Company	SC	4.70	3.74	
30	Louisville Gas & Electric Company	KY	4.71	3.69	
31	AEP (Kingsport Power Rate Area)	TN	4.10	3.68	
32	Southwestern Electric Power Company	AR	4.03	3.58	
33	AEP (Wheeling Power Rate Area)	WV	4.47	3.53	
34	AEP (Kentucky Power Rate Area)	KY	4.50	3.50	
35	AEP (Appalachian Power Rate Area)	WV	4.28	3.25	
36	AEP (Appalachian Power Rate Area)	VA	3.87	3.01	
37	Kentucky Utilities Company	KY	4.11	2.93	

* Data sorted by 1,000 kW @ 650,000 kW
**Appears to be error in Gulf Power Company data for large user.

FLORIDA POWER & LIGHT COMPANY

Table 6-1
Classification of Distribution Plant[1]

FERC Uniform System of Accounts No.	Description	Demand Related	Customer Related
360	Land & Land Rights	X	X
361	Structures & Improvements	X	X
362	Station Equipment	X	--
363	Storage Battery Equipment	X	--
364	Poles, Towers, & Fixtures	X	X
365	Overhead Conductors & Devices	X	X
366	Underground Conduit	X	X
367	Underground Conductors & Devices	X	X
368	Line Transformers	X	X
369	Services	--	X
370	Meters	--	X
371	Installations on Customer Premises	--	X
372	Leased Property on Customer Premises	--	X
373	Street Lighting & Signal Systems[1]	--	--

[1]Assignment or "exclusive use" costs are assigned directly to the customer class or group which exclusively uses such facilities. The remaining costs are then classified to the respective cost components. The amounts between classification may vary considerably. A study of the minimum intercept method or other appropriate methods should be made to determine the relationships between the demand and customer components.

Source: Electric Utility Cost Allocation Manual, National Association of Regulatory Utility Commissioners, January 1992, Page 87.

FLORIDA POWER & LIGHT COMPANY

FPL Allocation of Proposed Base Rate Increase
Twelve Months Ending December 31, 2006

Line	Rate Class	Current Revenues (1)	Proposed Base Rate Increase Amount (2)	Proposed Base Rate Increase Percent (3)
1	CILC-1D	$45,594	$9,377	20.6%
2	CILC-1G	4,687	32	0.7%
3	CILC-1T	13,610	2,530	18.6%
4	CS1	5,238	1,171	22.4%
5	CS2	2,553	540	21.2%
6	GS1	274,229	(2,030)	-0.7%
7	GSD1	675,375	89,600	13.3%
8	GSLD1	241,942	42,229	17.5%
9	GSLD2	35,692	5,899	16.5%
10	GSLD3	3,012	370	12.3%
11	MET	2,684	568	21.2%
12	OL-1	11,629	2,935	25.2%
13	OS-2	1,139	294	25.8%
14	RS1	2,347,119	192,466	8.2%
15	SL-1	52,926	13,388	25.3%
16	SL-2	2,272	(4)	-0.2%
17	SST-TST	2,956	(17)	-0.6%
18	SST1-DST	8	2	25.0%
19	SST2-DST	96	14	14.6%
20	SST-3DST	236	17	7.2%
21	Total Retail	$3,722,997	$359,381	9.7%

FLORIDA POWER & LIGHT COMPANY

FPL Allocation of Proposed Base Rate Increase
As a Percent of Total System Average Increase
Twelve Months Ending December 31, 2006

Line	Rate Class	Current Revenues (1)	Proposed Base Rate Increase Amount (2)	Proposed Base Rate Increase Percent (3)	As a % of Total System Increase (4)
1	CILC-1D	$45,594	$9,377	20.6%	**213**
2	CILC-1G	4,687	32	0.7%	7
3	CILC-1T	13,610	2,530	18.6%	193
4	CS1	5,238	1,171	22.4%	**232**
5	CS2	2,553	540	21.2%	**219**
6	GS1	274,229	(2,030)	-0.7%	-8
7	GSD1	675,375	89,600	13.3%	137
8	GSLD1	241,942	42,229	17.5%	**181**
9	GSLD2	35,692	5,899	16.5%	**171**
10	GSLD3	3,012	370	12.3%	127
11	MET	2,684	568	21.2%	**219**
12	OL-1	11,629	2,935	25.2%	**261**
13	OS-2	1,139	294	25.8%	**267**
14	RS1	2,347,119	192,466	8.2%	85
15	SL-1	52,926	13,388	25.3%	**262**
16	SL-2	2,272	(4)	-0.2%	-2
17	SST-TST	2,956	(17)	-0.6%	-6
18	SST1-DST	8	2	25.0%	**259**
19	SST2-DST	96	14	14.6%	**151**
20	SST-3DST	236	17	7.2%	75
21	Total Retail	$3,722,997	$359,381	9.7%	100

FLORIDA POWER & LIGHT COMPANY

Comparison of Present and Proposed Rates CS-1, CS-2, GSD-1, GSLD-1 and GSLD-2
Twelve Months Ending December 31, 2006

Line	Description	Present Rates (1)	Proposed Rates (2)	Proposed Increase Amount (3)	Proposed Increase Percent (4)
	CS-1				
1	Customer	$ 102.27	$ 200.00	$ 97.73	96%
2	Non-Fuel Energy	$ 0.01083	$ 0.01502	$ 0.00419	39%
3	Demand	$ 5.81	$ 5.81	$ -	0%
	CS-2				
4	Customer	$ 158.05	$ 300.00	$ 141.95	90%
5	Non-Fuel Energy	$ 0.01080	$ 0.01502	$ 0.00422	39%
6	Demand	$ 5.81	$ 5.81	$ -	0%
	GSD-1				
7	Customer	$ 32.54	$ 25.00	$ (7.54)	-23%
8	Non-Fuel Energy	$ 0.01369	$ 0.01502	$ 0.00133	10%
9	Demand	$ 5.81	$ 5.81	$ -	0%
	GSLD-1				
10	Customer	$ 38.12	$ 150.00	$ 111.88	293%
11	Non-Fuel Energy	$ 0.01083	$ 0.01502	$ 0.00419	39%
12	Demand	$ 5.81	$ 5.81	$ -	0%
	GSLD-2				
13	Customer	$ 158.05	$ 350.00	$ 191.95	121%
14	Non-Fuel Energy	$ 0.01080	$ 0.01502	$ 0.00422	39%
15	Demand	$ 5.81	$ 5.81	$ -	0%

FLORIDA POWER & LIGHT COMPANY

Comparison of Unit Cost and Rates at Present & Proposed for Rates CS-1, CS-2, GSD-1, GSLD-1 and GSLD-2 Twelve Months Ending December 31, 2006

		Present Unit Cost and Rates			Proposed Unit Cost and Rates			Movement
Line	Description	Unit Cost at = ROR (1)	Present Rates (2)	Ratio Rate/Cost (3)	Unit Cost at = ROR (4)	Proposed Rates (5)	Ratio Rate/Cost (6)	Toward COS (7)
	CS-1							
1	Customer	$ 184.36	$ 102.27	55.5%	$ 200.02	$ 200.00	100.0%	Yes
2	Non-Fuel Energy	$ 0.00475	$ 0.01083	227.9%	$ 0.00495	$ 0.01502	303.6%	No
3	Demand	$ 8.22	$ 5.81	70.7%	$ 9.32	$ 5.81	62.3%	No
	CS-2							
4	Customer	$ 284.47	$ 158.05	55.6%	$ 311.34	$ 300.00	96.4%	Yes
5	Non-Fuel Energy	$ 0.00475	$ 0.01080	227.4%	$ 0.00494	$ 0.01502	303.9%	No
6	Demand	$ 8.24	$ 5.81	70.5%	$ 9.34	$ 5.81	62.2%	No
	GSD-1							
7	Customer	$ 35.50	$ 32.54	91.7%	$ 37.99	$ 25.00	65.8%	No
8	Non-Fuel Energy	$ 0.00484	$ 0.01369	282.7%	$ 0.00504	$ 0.01502	298.1%	No
9	Demand	$ 9.62	$ 5.81	60.4%	$ 10.76	$ 5.81	54.0%	No
	GSLD-1							
10	Customer	$ 119.21	$ 38.12	32.0%	$ 128.00	$ 150.00	117.2%	Yes
11	Non-Fuel Energy	$ 0.00483	$ 0.01083	224.1%	$ 0.00503	$ 0.01502	298.7%	No
12	Demand	$ 9.97	$ 5.81	58.3%	$ 11.15	$ 5.81	52.1%	No
	GSLD-2							
13	Customer	$ 316.87	$ 158.05	49.9%	$ 346.05	$ 350.00	101.1%	Yes
14	Non-Fuel Energy	$ 0.00481	$ 0.01080	224.7%	$ 0.00500	$ 0.01502	300.3%	No
15	Demand	$ 9.83	$ 5.81	59.1%	$ 10.99	$ 5.81	52.9%	No