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June 24, 2005

VIA FEDEX

Blanca Bayo, Director
Division of the Commission Clerk and Administrative Services
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, Florida 32399-0850

Re: *Petition for Rate Increase by Florida Power & Light Company in Docket No. 050045-EI*

Dear Madame:

Please find enclosed an original plus twenty-five (25) copies of the Direct Testimony and Exhibits for each of the following witnesses on behalf of South Florida Hospital and Healthcare Association in Docket No. 050045-EI: Stephen J. Baron, Richard A. Baudino, and Lane Kollen. Also enclosed are a cd rom of the three sets of testimony and exhibits as well as a Certificate of Service.

In the event that you have any questions, please do not hesitate to call me.

Sincerely yours,

Gloria J. Halstead

Gloria J. Halstead

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CERTIFICATE OF SERVICE

I, Gloria J. Halstead, an attorney for South Florida Hospital and Healthcare Association ("SFHHA"), hereby certify that a true and correct copy of The Direct Testimony and Exhibits of each of the following SFHHA witnesses: Stephen J. Baron, Richard A. Baudino and Lane Kollen, was served on all parties of record in this proceeding on this 27th day of June, 2005 by Federal Express.

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Gloria J. Halstead

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

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

DIRECT TESTIMONY

AND EXHIBITS

OF

STEPHEN J. BARON

ON BEHALF OF THE

SOUTH FLORIDA HOSPITAL AND HEALTHCARE ASSOCIATION

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

June 2005

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

IN RE: PETITION FOR RATE INRCEASE BY FLORIDA POWER & LIGHT COMPANY	**) DOCKET NO. 050045-EI)**

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BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

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

DIRECT TESTIMONY OF STEPHEN J. BARON

I. QUALIFICATIONS AND SUMMARY

Q. Please state your name and business address.

A. My name is Stephen J. Baron. My business address is J. Kennedy and Associates, Inc. ("Kennedy and Associates"), 570 Colonial Park Drive, Suite 305, Roswell, Georgia 30075.

Q. What is your occupation and by whom are you employed?

A. I am the President and a Principal of Kennedy and Associates, a firm of utility rate, planning, and economic consultants in Atlanta, Georgia.

Q. Please describe briefly the nature of the consulting services provided by Kennedy and Associates.

A. Kennedy and Associates provides consulting services in the electric and gas utility industries. Our clients include state agencies and industrial electricity consumers. The firm provides expertise in system planning, load forecasting, financial analysis, cost-of-service, and rate design. Current clients include the Georgia and Louisiana Public Service Commissions, and industrial consumer groups throughout the United States.

Q. Please state your educational background.

A. I graduated from the University of Florida in 1972 with a B.A. degree with high honors in Political Science and significant coursework in Mathematics and Computer Science. In 1974, I received a Master of Arts Degree in Economics, also from the University of Florida. My areas of specialization were econometrics, statistics, and public utility economics. My thesis concerned the development of an econometric model to forecast electricity sales in the State of Florida, for which I received a grant from the Public Utility Research Center of the University of Florida. In addition, I have advanced study and coursework in time series analysis and dynamic model building.

Q. Please describe your professional experience.

A. I have more than thirty years of experience in the electric utility industry in the areas of cost and rate analysis, forecasting, planning, and economic analysis.

Following the completion of my graduate work in economics, I joined the staff of the Florida Public Service Commission in August of 1974 as a Rate Economist. My responsibilities included the analysis of rate cases for electric, telephone, and gas utilities, as well as the preparation of cross-examination material and the preparation of staff recommendations.

In December 1975, I joined the Utility Rate Consulting Division of Ebasco Services, Inc. as an Associate Consultant. In the seven years I worked for Ebasco, I received successive promotions, ultimately to the position of Vice President of Energy Management Services of Ebasco Business Consulting Company. My responsibilities included the management of a staff of consultants engaged in providing services in the areas of econometric modeling, load and energy forecasting, production cost modeling, planning, cost-of-service analysis, cogeneration, and load management.

I joined the public accounting firm of Coopers & Lybrand in 1982 as a Manager of the Atlanta Office of the Utility Regulatory and Advisory Services Group. In this capacity I was responsible for the operation and management of the Atlanta office. My duties included the technical and administrative supervision of the staff, budgeting, recruiting, and marketing as well as project management on client engagements. At Coopers & Lybrand, I specialized in utility cost analysis, forecasting, load analysis, economic analysis, and planning.

In January 1984, I joined the consulting firm of Kennedy and Associates as a Vice President and Principal. I became President of the firm in January 1991.

During the course of my career, I have provided consulting services to more than thirty utility, industrial, and Public Service Commission clients, including three international utility clients.

I have presented numerous papers and published an article entitled "How to Rate Load Management Programs" in the March 1979 edition of "Electrical World." My article on "Standby Electric Rates" was published in the November 8, 1984 issue of "Public Utilities Fortnightly." In February of

1984, I completed a detailed analysis entitled "Load Data Transfer Techniques" on behalf of the Electric Power Research Institute, which published the study.

I have presented testimony as an expert witness in Arizona, Arkansas, Colorado, Connecticut, Florida, Georgia, Indiana, Kentucky, Louisiana, Maine, Michigan, Minnesota, Maryland, Missouri, New Jersey, New Mexico, New York, North Carolina, Ohio, Pennsylvania, Texas, West Virginia, the Federal Energy Regulatory Commission and in United States Bankruptcy Court. A list of my specific regulatory appearances can be found in Baron Exhibit ____ (SJB-1)

Q. Do you have previous experience in FPL regulatory proceedings?

A. Yes. I have been involved in a number of FPL rate proceedings during my career. This includes participation as a Florida Public Service Commission Staff member in a 1975 FPL rate case, a generic DSM proceeding in 1993 and an FPL rate case in 2002.

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

A. I am testifying on behalf of the South Florida Hospital and Healthcare Association, Inc. ("SFHHA" or the "hospitals"). SFHHA members take service on FPL general service and CILC rate schedules throughout the Company's service area.

Q. What is the purpose of your testimony?

A. I will address issues associated with FPL's proposed allocation of its requested base rate revenue increase of $385 million to rate schedules. FPL witness Rosemary Morley provides testimony on these issues, including the Company's proposed methodology to utilize the results of its class cost of service study ("parity study") to assign increases to each rate schedule. I will discuss the Company's approach and recommend an improved allocation based on alternative cost of service analyses, as well as the application of a "1.5 times average increase cap" approach.

With regard to the class cost of service study, I will address the Company's filed 12 CP and 1/13th average demand methodology and offer an alternative approach that focuses on the key summer and winter peaks that drive the

Company's generation resource decisions. As I will discuss, it is growth in the summer and winter peak demands that will require the Company to obtain almost 6000 mW of additional generating capacity over the next ten years. Customers should, through the cost of service and rate design process, be provided price signals reflecting the "cost" of their decisions to use and cause the construction of additional scarce generation resources during the summer and winter peak periods. The Company's use of a 12 CP cost allocation methodology does not adequately reflect the Company's planning decisions. As a result, FPL will overbuild capacity, customers will receive the wrong message about the actual cost of their consumption patterns, resources will be misallocated, and pollution may be increased by virtue of running additional generation.

Finally, I will address the proposal by the Company to recover the fixed costs associated with Turkey Point 5 on a kWh basis, within rate schedules. Since these costs are demand related, they should be recovered by increasing the kW billing demand charge (or charges) of rate schedules that include a demand charge as part of the rate.

Q. Would you summarize your conclusions and recommendations?

A. Yes.

- **FPL has proposed increases to some rate schedules that are substantially in excess of 1.5 times the average retail base rate increase requested by the Company. Some rate schedules will receive increases of as much as 21% under the Company's proposals in this case. In consideration of the impact and the potential for "rate shock" with such large increases, no rate schedule should receive an increase greater than the "1.5 times" cap applied to the average base rate increase, excluding adjustment clauses.**

- **FPL has based its proposed rate schedule increases on the results of its 12 CP and 1/13th average demand cost of service study and an objective to bring each rate schedule to within +/- 10% of the system average rate of return. A more efficient cost of service study for FPL is a method based on a summer/winter average CP methodology, coupled with consideration of a "minimum distribution system" approach to the classification of secondary distribution facilities. The parity results using this corrected cost of service study supports an equal percentage increase to rate schedules in this case, which should be adopted by the Commission.**

- **The Company's proposal to offer a high load factor time of use rate (HLFT) should be adopted by the Commission. The methodology used by the Company to develop this rate, which is directly tied to the underlying costs for serving general service customers, is reasonable. In the event that the Commission adjusts the revenue increases proposed by FPL for general service rates, either because of a reduction in the overall FPL revenue requirement increase or an alternative allocation of the approved increase, the proposed HLFT rate should be adjusted accordingly (as described subsequently in this testimony).**

- **If the Commission approves the Company's proposed 2007 Turkey Point Unit 5 recovery in this case, the allocated revenue to demand metered rate schedules should be recovered on a kW demand basis, rather than on a kWh basis as proposed by FPL. These are demand related costs and, to the extent that a rate schedule incorporates a demand charge in the rate, the Turkey Point Unit 5 charges should be recovered from the kW demand charge.**

II. ALLOCATION OF THE AUTHORIZED REVENUE INCREASE

Q. Would you please briefly describe the methodology that FPL is proposing to use to allocate its requested $385 million increase to rate schedules?

A. FPL has used the results of its cost of service "parity" study to assign the increase to rate schedules such that each rate schedule produces a rate of return on rate base (premised upon the Company's recommended cost allocation study) within a "+/- 10%" band. Essentially, FPL claims it is adjusting its rates in this case to bring each of its rates schedules to within 10% of the system rate of return. The Company is not proposing to limit the increases to any specific rate schedule to "1.5 times" the average increase. In fact, FPL is proposing increases to some rate schedules at a much higher percentage than the level that would be produced had the Company adhered to a "1.5 times" constraint.

Q. What are the specific increases recommended by FPL, assuming that it is authorized its full $385 million rate increase in this case?

A. Table 1 below summarizes the increases recommended by the Company for most of the general service and CILC rate schedules. These rate schedules, as can be

Table 1
FPL Proposed Revenue Increases

Rate		Base Rev (Present)	Base Rev (Proposed)	Percent	Excess Over "1.5 x Avg."
CILC-1D		45,594,194	54,970,753	20.6%	**6.09%**
CILC-1T		13,609,695	16,140,110	18.6%	**4.11%**
CS1		3,479,708	4,272,915	22.8%	**8.32%**
CST1		1,758,579	2,136,289	21.5%	**7.00%**
CS2		1,273,351	1,542,219	21.1%	**6.64%**
CST2		1,279,726	1,550,869	21.2%	**6.71%**
GSD1	Non-Migrate	554,457,645	637,058,916	14.9%	**0.42%**
GSLD1	Non-Migrate	120,481,295	144,231,946	19.7%	**5.23%**
GSLDT1	Non-Migrate	17,325,850	20,308,479	17.2%	**2.74%**
GSLDT1	Migr-HLFT	65,347,245	76,061,539	16.4%	**1.92%**
GSLD2	Non-Migrate	10,152,158	12,120,591	19.4%	**4.91%**
GSLDT2	Non-Migrate	6,617,515	7,780,602	17.6%	**3.10%**
GSLDT2	Migr-HLFT	14,052,762	16,250,410	15.6%	**1.16%**
GSLD3		450,776	523,553	16.1%	**1.67%**
GSLDT3		2,561,176	2,857,992	11.6%	
Total Retail				**9.7%**	
"1.5 Times Cap"				**14.5%**	

seen in the table, reflect general service classes (on which the hospitals are served) that will receive substantially greater increases than "1.5 times the average 9.7% retail increase" in base rates being proposed by FPL. In particular, customers taking service on rate schedule CILC-1D, and the non-migrating customers on schedules GSLD-1 and GSLDT-1 will receive base rate increases of 20.6%, 19.7% and 17.2% respectively. CILC-1D customers will receive an increase of 212% of the system average (2.12 times the average increase of 9.7%).

Q. Has FPL provided sufficient support to justify an increase to these (and other) rate schedules of such magnitude?

A. No. Even if one were to agree with the Company's cost of service results without exception, which I do not, it is unreasonable to increase some customer rates by more than a "1.5 times" system average base rate cap. Given the magnitude of the increase requested by the Company in this case and its impact on ratepayers, including general service customers, such a limitation by rate schedule is appropriate. This is further warranted by the additional proposed increases requested by FPL in 2007. The Commission should limit the increase in base rates to 1.5 times the system average for each rate schedule.

Q. Why do you believe that the "1.5 times" cap should apply to the system average base rate increase?

A. This proceeding involves a substantial increase to base rates. The appropriate metric to measure the impact and assess "rate shock" is the impact on the base rates at issue. Because the base rate represents less than half the overall bill for most, if not all of FPL's customers, the reasonableness of a proposed base rate increase should not be obscured and clouded by including fuel costs and other adjustment clause revenues in the evaluation of rate shock. The component of the rate here at issue and which can be adjusted is the base rate.

This is particularly problematic for higher load factor general service rate schedule customers who have a relatively greater proportion of fuel revenues included in their total costs. If the rate shock "test" is applied to the impact of a proposed base rate increase on total revenues, including fuel, higher load factor rate schedules are penalized, all else being equal. If all rate schedules had the same proportion of adjustment clause revenues, then it would not matter whether the "1.5 times" cap was applied to assess the impact of an increase in base rates or whether it is applied to as a cap on the percentage increase in total revenues, including adjustment clauses. However, this is not the case and it is more reasonable and fair to cap the increases using a "1.5 times" cap applied to base rates.

Q. **You indicated in a previous answer that you did not agree with FPL's cost of service results. Would you please address your concerns with the Company's study?**

A. Yes. As I will discuss in more detail later in my testimony, the Company's cost of service study and the related "parity" results on which FPL has relied to establish its proposed increases to each rate schedule are not reasonable and should not be used to set rates in this case. The cost of service methodology is of particular significance in this case because of the extent of the reliance being placed on the results to establish rate schedule revenue targets. Though I support the use of a cost of service study to set rates (subject to some type of limitation to address potential rate shock concerns, such as the "cap" limitation that I discussed above to limit the increase to any rate schedule to 1.5 times the system average increase), the necessary pre-condition to such an analysis is to utilize a reasonable cost of service study that allocates costs in a manner that reflects cost causation. Though the Company has used a methodology that has been previously found by the Commission to be appropriate for FPL and other Florida electric utilities, I am recommending that the Commission consider an alternative approach in this case to assign cost responsibility. Specifically, as I will discuss, I am recommending that the Commission adopt a summer/winter average production demand methodology. I will discuss the support for such a study in the next section of my testimony. I am also recommending that the Commission consider an alternative approach to the classification of distribution plant. I present the basis for such an approach and the cost of service and parity implications of classifying a portion of the Company's secondary distribution facilities using a customer component, in addition to a demand component. As I will discuss, FPL has classified 100% of secondary lines (underground and overhead), secondary poles and secondary line transformers as demand related. I believe that there is strong support to classify a portion of these costs as both customer and demand related. I will present an alternative cost of service study that illustrates the potential impact on class parity results from such a change in the Company's study.

Q. What are the parity results using your alternative cost of service studies?

A. Table 2 below presents the results of the parity analyses using the two alternative cost of service studies that I discuss later in my testimony. These studies show that general service and CILC-1D customers should receive revenue increases much closer to the system average increase than recommended by FPL. The rate schedule increases approved by the Commission may be in place for many years, if history is a guide. Given the large disparity between the parity results presented by FPL in this case (see Table 3) and the parity results shown in Table 2, using what I believe are more reasonable assumptions, I recommend that the Commission apply an equal percentage increase to all rate schedules in this case. For general service rate schedules, GSD, GSDT, GSLD-1, GSLD-2, GSLDT-1 and GSLDT-2 that include both non-migrating and migrating (to HLF and SDTR) customers, the equal percentage increase should be applied to all of the customers on the rate (e.g., GSLDT-1) in a first step. As I discuss subsequently, the second step would then develop the individual increases to the non-migrating and migrating customers within the rate schedule such that the same relative relationships among the general service rates and the HLF and SDTR rates are preserved.

Table 2
Comparison of Parity Index Results

Rate Class	Sum/Win CP	S/W CP w/Min Dist
CILC-1D	108%	114%
CILC-1G	175%	187%
CILC-1T	108%	108%
CS1	89%	96%
CS2	84%	91%
GS1	179%	171%
GSD1	115%	124%
GSLD1	81%	89%
GSLD2	86%	93%
GSLD3	127%	127%
MET	66%	66%
OL-1	-16%	-15%
OS-2	68%	77%
RS1	93%	90%
SL-1	33%	35%
SL-2	290%	305%
SST-TST	618%	618%
SST1-DST	-54%	-54%
SST2-DST	86%	98%
SST3-DST	143%	143%

Q. Does your recommendation for the Commission to adopt an alternative cost of service study and use these results to allocate the revenue increases in this case result in "cost shifting"?

A. No. As I will more fully discuss subsequently in my testimony, the Company's 12 CP & 1/13th average demand cost of service methodology does not adequately reflect cost responsibility. FPL is proposing substantial increases in this proceeding based on the assumption that certain rate classes have under-contributed to their share of the system's costs (e.g., rate schedule CILC-1D). However, using a more reasonable measure of cost responsibility, these same classes are actually over-contributing to their share of costs. Likewise, some rate schedules (RS-1, for example) are shown to be over-contributing to their share of costs under FPL's cost study, while under a more reasonable measure, these same classes are under-contributing to their share of costs (i.e., producing a parity less than 100%). As a result, when the contribution to costs by the various rate classes is analyzed in a more appropriate and logical basis than is reflected in the Company's cost of service study, it is apparent that an equal percentage increase is reasonable and would not unduly burden the residential class or general service schedules.

Q. The Company is proposing to a new tariff, HLF (high load factor), for some general service customers who are able to migrate to the new rate. How should the proposed target revenue level for rate HLF be adjusted,

if the Commission adopts your recommendations to change the allocation of the increase to general service rates?

A. First, as I will discuss later in my testimony, the Hospitals support the Company's proposal to introduce rate schedule HLF. If the Commission adjusts the allocation of the increase to general service schedules, as I am recommending, there should be a corresponding decrease to proposed rate schedule HLF so that the relationships established among the general service feeder rates to HLF and HLF remain essentially the same. I recognize that because customers from a number of general service rate schedules will migrate to rate HLF, the process of adjusting rate HLF, following a change in one or more general service schedules, will require an iterative approach in compliance filings with the Commission. The objective, however, should be that the relative relationship between the various general service rates and rate HLF should remain the same (within a reasonable bound) as exists under the Company's proposed tariffs.

Q. Are there any additional issues that you would like to address regarding the allocation of any authorized revenue increase to rate schedules?

A. Yes. In presenting summary proposed increases by rate schedule in Schedule E-8 of the MFR, the Company included "other operating revenue", which includes not only connection and reconnection fees and other retail customer miscellaneous revenues, but also the allocated share of other revenue credits (for example, transmission) that are not even at issue in this case. These other revenues should be excluded from the presentation of the proposed increases at issue in this case since they are not tied to the sale of electricity governed by the tariffs being adjusted in this case. Though it is reasonable to consider the proposed changes, if any, in connection fees (for example), it is not appropriate to include any such amounts in the calculation of the proposed increases to rate schedule. In sum, this presentation obscures and conceals the full effects of FPL's proposals.

More significantly, FPL has included "imputed" CILC incentives in the computation of the rate increase proposed for the three CILC rate schedules. It is appropriate to include these incentives in the cost of service study, as FPL has done. However, it is completely inappropriate to include the imputed incentives in the "presentation" of FPL's proposed increase to these rates. The CILC rates do not include these incentive revenues in customer charges and it is thus incorrect to calculate a rate impact using an "imputed" amount of additional revenues that are not actually part of a customer's bill.

III. COST ALLOCATION ISSUES

Q. Would you please discuss the issue of the allocation of demand related production costs?

A. Yes. As required by the MFR, FPL has filed a 12 CP and 1/13th average demand based cost of service study in this case. The Company has not filed any alternative studies and supports the 12 CP and 1/13th method in this case.

In the past, based upon circumstances then in effect, FPL used and the Commission accepted this methodology. However, circumstances now in effect and compelling public policy reasons suggest alternative methodologies for FPL cost allocation. This issue is not an academic exercise in this case, since FPL is proposing to assign its requested $385 million base rate increase to rate schedules on the basis of the class cost of service study ("parity" results).

Q. What is your understanding of the underpinning for the use of the 12 CP and 1/13th average demand method?

A. This methodology, which is primarily a 12 CP method, allocates production demand costs under the assumption that customer (and ultimately rate schedule) kW demand contributions to each of the 12 monthly coincident peaks have equal "cost responsibility" for the Company's generating units and power purchases (the capacity portion thereof). Thus, for example, the 12 CP method presumes that a residential or general service customer's incremental demand at the time of the August or January system coincident peak is no more "costly" to the system than the same amount of incremental demand at the time of the October or April FPL peak. This method sends price signals to customers that adding demand during any of the monthly peaks throughout the year costs the same to the Company. Correspondingly, if residential loads are being added more rapidly in the summer and winter peak months than in the off-peak months, the impact on class revenue requirements is much less (under FPL's cost methodology) than if a group of general service customers added the identical load during the summer and winter peaks, but also added a like amount of load in the off-peak months. In that case, general service class cost responsibility would increase much more under the Company's cost of service study allocation approach, even though such responsibility was spread throughout the year and not concentrated during the summer and winter peak months.

A numerical example will help illustrate this point. Assume that both the residential and general service class peak demands increased by 1000 mW during July, August, January and February. Further assume that during the other eight months of the year, the residential class coincident peak demand increased by only 500 mW, while the general service peaks increased by 800 mW, reflecting the higher load factor for this class. The 12 CP demands for each of the two classes would increase by 8000 mW and 10,400 mW respectively for the residential and general service classes. Despite the fact that both rate classes contributed identical amounts to the summer and winter peaks that drive the capacity needs of the FPL system, the general service class would be assigned 30% more cost responsibility for this incremental demand than the residential class. Since rates ultimately will be impacted from the results of the cost of service study, residential customers will receive a "discounted" price signal on the cost associated with its behavior. The opposite will occur for general service customers.

Q. Have you prepared any analyses that show the changes in residential and general service customer coincident peak demands during the past six years, compared to the expectations of FPL for the test year?

A. Yes. Figures 1 and 2 that follow contain charts for the RS-1 and GSLDT-1 rate schedules comparing each the 12 CP demands and the average of the summer and winter CP demands for the period 1998 through 2003, together with the Company's test year 2006 estimate.

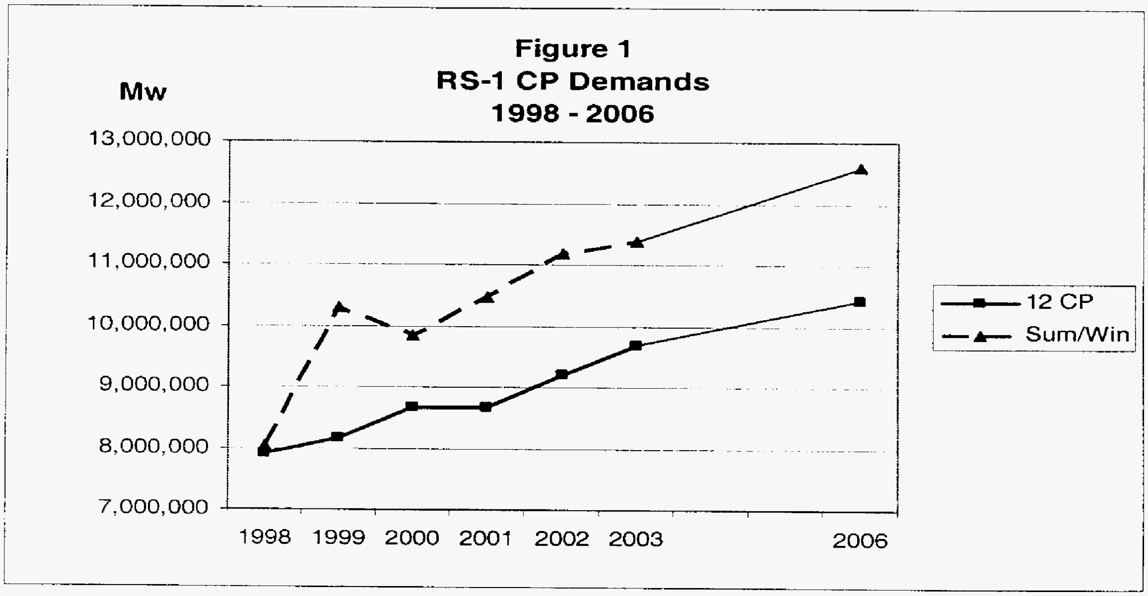
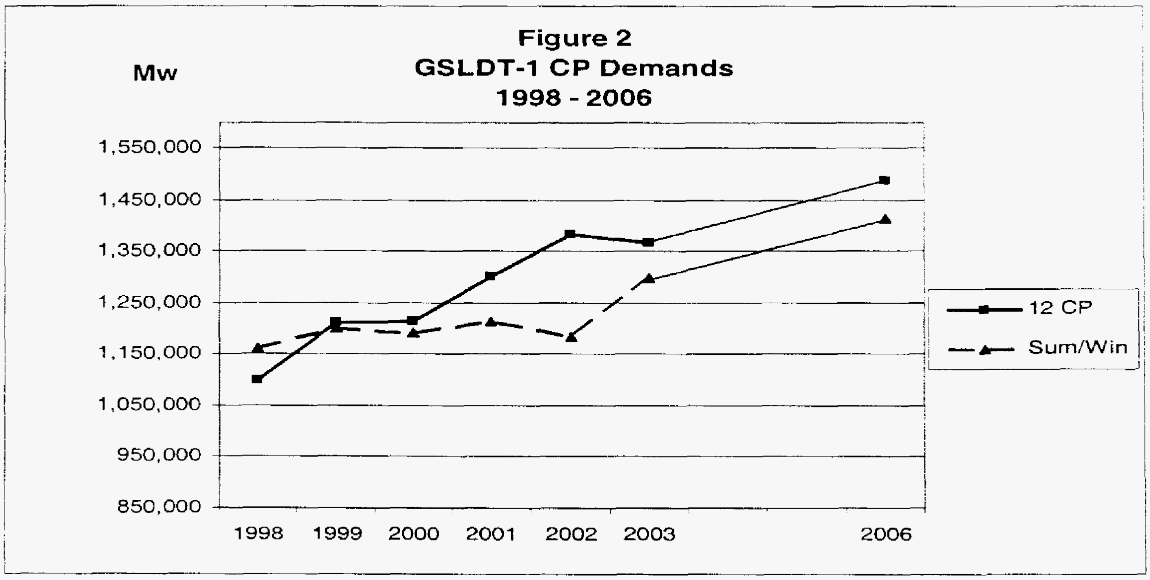


Figure 1
RS-1 CP Demands
1998 - 2006



The charts show that the growth in the residential contribution to the summer/winter average has been growing much faster than its 12 CP contribution. For the GSLDT-1 rate, the two measures of coincident peak have been growing at a much closer rate. More significantly, for the RS class, the summer/winter average CP demand is substantially above the 12 CP level, while for the GSLDT-1 class, the two measure of CP are similar, with the 12 CP level being the higher value. Because the FPL cost allocation study is driven in large part by a rate schedule's contribution to 12 CP demand, rather than the important summer and winter peak contributions that are driving capacity additions on the FPL system, GSLDT-1 customers are being assigned a relatively larger share of the system's fixed production costs. All else being equal, this results in higher rates to these customers simply because they have relatively higher demands in the off-peak months.

This is also problematic because these higher load factor general service customers contribute a relatively greater amount of revenues during the off-peak (non-summer and winter peak periods), which helps defray the capital costs of capacity additions, while classes that have more concentrated demands during the summer and winter peak periods provide proportionately less contribution to these capacity costs because of their lower non-summer/winter consumption.

Q. Does FPL's current 10 year site plan support the general assumptions in your illustration that the growth in summer and winter peak demands is driving the need for capacity additions on the system?

A. Yes, I believe that it does. Baron Exhibit__(SJB-2), schedules 1 and 2 contain copies of FPL's projected summer and winter peak capacity, load and reserves. These schedules are copies of Schedules 7.1 and 7.2 from FPL's 2004 Ten Year Power Plant Site Plan. As can be seen, the Company is projecting substantial capacity additions over the next ten years to meet growing summer and winter peak demand and to maintain a 20% reserve margin during the summer. It is clear that the requirement to meet the summer and winter peak demand is driving the capacity resource addition on the system.

Q. Don't the generation resources also meet the demands during the other months of the year?

A. Yes. Clearly, all of FPL's generating resources (except seasonal purchases, if any) are designed to meet the loads of the Company's customers, regardless of when they occur. However, these loads in other months do not drive the incurrence of generation resource costs on the system. This is true, even if planned maintenance is considered. Because, by its very nature, planned maintenance is "planned", it is not the driver of the need to obtain additional generation resources. This need is driven by the summer and winter peaks projected in the ten year site plan.[1] This is further confirmed in a December 2004 report by The Division of Economic Regulation of the Florida Public Service Commission at page 13, which states:

> **FRCC studies currently show that a 15% reserve margin correlates to LOLP values that are well below 0.1 days per year. These low LOLP values are the result of two factors: high unit availabilities and low forced outage rates typical of new, efficient generating units; and, enhanced maintenance practices on older generating units. <u>As a result, reserve margin continues to be the primary criterion driving a utility's capacity needs</u>. In the late 1990's, the Commission was increasingly concerned with the declining reserve margins forecasted by Florida's utilities and the impact of such declines on reliability. In response to these concerns, PEF, FPL and TECO agreed to adopt a 20% reserve margin planning criterion starting in Summer 2004.** (emphasis added).

Q. How do the monthly peak loads compare to the summer and winter peaks on the FPL system?

A. The following graph (figure 3) shows the actual 2003 and projected 2005 monthly peak loads on the FPL system. As can be seen from the graph, there is a significant system peak in the summer and the winter period. Since the 2005 data is projected, it reflects a weather normalized result and it is clear that <u>two seasonal peaks</u> rise above the coincident peaks in the remaining months.

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[1] FPL also employs a maximum loss-of-load probability ("LOLP") criterion of "0.1 day per year" in its planning. However, based on the Company's resource plan, FPL is generally adding capacity that maintains a 20% reserve margin in the summer.

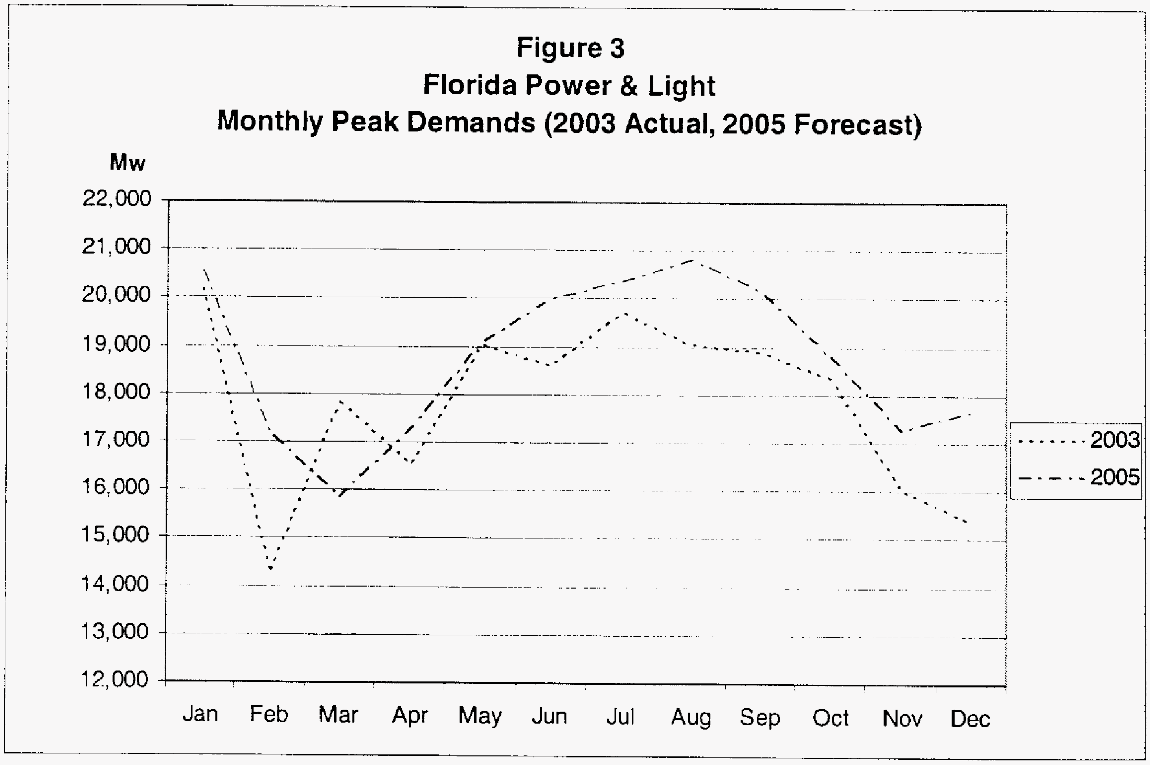
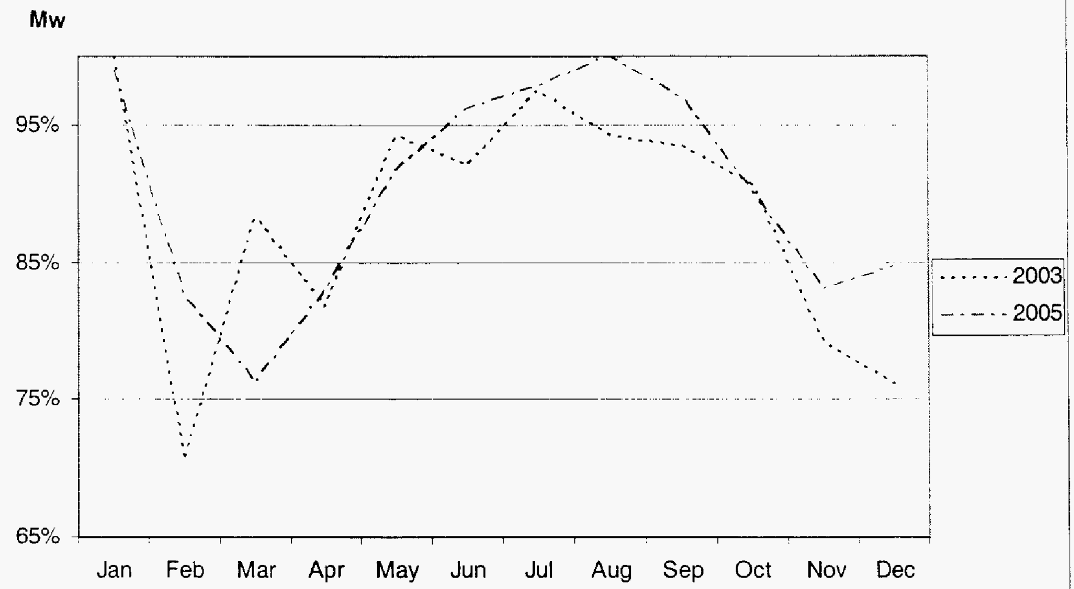


Figure 3
Florida Power & Light
Monthly Peak Demands (2003 Actual, 2005 Forecast)

Figure 4, below, shows the same data in terms of the percentage of each month's peak to the annual peak. As can be seen, coincident peak demands in most months fall far short of the load during the key summer and winter peak months. In half the months, the peak demand falls below 90% of the annual system peak. This represents more than a 2000 mW difference from the peak month demand.

Figure 4
Florida Power & Light
Monthly "% to Peak" Demands (2003 Actual, 2005 Forecast)



Q. What are the implications of this for pricing using the Company's proposed 12 CP and 1/13th average demand methodology?

A. The main implication is that customers are being provided price signals through rates that FPL is indifferent as to whether customers use demand in say March or in August or January. According to FPL's 2004 Ten Year Power Plant Site Plan, the Company will be acquiring almost 6000 mW of new generating capacity over the next 10 years to meet additional summer and winter customer peak loads on the system. Baron Exhibit__(SJB-3), page 1 of 2 presents a copy of "Schedule III.B.1" from the Site Plan. This capacity is expected to cost the Company and its ratepayers in the range of $500 to $600 per kW (see "Schedule 9, Page 5 of 7 of the Site Plan", a copy of which is included on page 2 of 2 of Exhibit__(SJB-3)). That amounts to additional investment (or purchase equivalent) in new generation facilities in the range of $3 billion over the next ten years. Yet, despite this expectation, FPL continues to argue in its rate filing that customer behavior during any of the 12 months during the year is equally responsible for the Company's need to acquire new generating facilities to meet demand.

Q. What about the argument that the fuel savings associated with base load generating units support an allocation method that recognizes customer usage in non-peak months or even in the off-peak period?

A. Though it is certainly true that a base load nuclear unit produces energy at a lower fuel cost than a gas fired combined cycle unit, this does not change the fact that the Company is adding thousands of mW of additional generating capacity to meet its summer and winter peak demand. At the same time, FPL is "telegraphing" its customers through cost allocation and rate design that the "cost" of customer decisions associated with the next unit of consumption during March or October is equally responsible for this new capacity cost as the next unit of consumption during August or January at the time of the system peak.

Q. What conclusions do you draw from this analysis?

A. I believe that it is now appropriate for the Commission to consider an alternative cost allocation method in this case and I recommend a summer/winter coincident peak method using class coincident demand contributions to the August and January test year peaks to allocate production demand costs. Baron Exhibit__(SJB-4) presents summary schedules of the results of such a cost of service study.

Table 3 below shows a comparison of the parity results using the filed 12 CP and 1/13th average demand method and the summer/winter CP method. As can be seen, there are significant differences in the reported parity results using the two methodologies.

Table 3
Comparison of Parity Index Results

Rate Class	12 CP & 1/13th As Filed	Sum/Win CP
CILC-1D	77%	108%
CILC-1G	141%	175%
CILC-1T	82%	108%
CS1	72%	89%
CS2	69%	84%
GS1	151%	179%
GSD1	93%	115%
GSLD1	60%	81%
GSLD2	65%	86%
GSLD3	85%	127%
MET	64%	66%
OL-1	-21%	-16%
OS-2	42%	68%
RS1	106%	93%
SL-1	25%	33%
SL-2	252%	290%
SST-TST	279%	618%
SST1-DST	-53%	-54%
SST2-DST	91%	86%
SST3-DST	112%	143%

Q. Would you please discuss the methodology used by FPL to allocate distribution plant investment and expenses to retail rate classes?

A. Yes. As discussed in Ms. Morley's testimony, the Company has classified all distribution plant as demand related except account 369 Services and account 370 meters, which are classified as customer related. The Company's approach does not give any recognition to a customer component of any primary or secondary line, pole or transformer. All of these costs are assigned on the basis of relative class kW demand. FPL, in its response to Commercial Group's interrogatory No. 3 cites a number of prior Commission orders as precedent for its treatment of these costs.

Q. Do you agree with the Company's classification of these distribution costs?

A. No. Despite the Commission's prior decision's rejection of a customer component for these distribution facilities, I believe that there is credible evidence to support a classification of some portion of these facilities as customer related. Given the significant reliance that the Company has placed on the results of its cost of service study in assigning its requested revenue increase to rate schedules in this case, it is reasonable for the Commission to consider evidence on alternative methods of classifying distribution costs in this case. FPL has, to a very significant degree, relied on the "parity" results from its cost of service study to assign increases to rate schedules. In particular, the proposed increases to general service (GSD, GSLD, GSLDT-1, GSLDT-2) and CILC rate schedules are substantially higher than the system average increase due to the parity results. These parity results are driven to a large extent by the methodology used by FPL to classify and allocate costs to rate schedules. This is not purely an argument of academic interest. The impact of this issue for commercial and industrial rate schedules is $30 million, based on a comparison of allocated distribution costs under the FPL methodology and the cost of service results using the minimum secondary distribution system analysis that I have developed and present subsequently.

Q. What is the central argument underlying a classification of some portion of distribution costs (other than services, meters and "primary pull-offs") as customer related?

A. As described in the NARUC Electric Utility Cost Allocation Manual, the underlying argument in support of a customer component is that there is a minimal level of distribution investment necessary to connect a customer to the distribution system (lines, poles, transformers) that is independent of the level of demand of the customer. To the extent that this component of distribution cost is a function of the requirement to interconnect the customer, regardless of the customer's size, it is appropriate to assign the cost of these facilities to rate schedules on the basis of the number of customers, rather than on the kW demand of the class. As stated on page 90 of the NARUC cost allocation manual:

> **When the utility installs distribution plant to provide service to a customer and to meet the individual customer's peak demand requirements, the utility must classify distribution plant data separately into demand- and customer-related costs.**

Q. In the recent Gulf Power rate case, the Commission considered and rejected a customer component methodology to classify distribution related costs. Have you reviewed the Commission's decision in that case (Docket No. 010949-EI, Order No. PSC-02-0787-FOF-EI)?

A. Yes. I have reviewed the portion of the Order that addresses the allocation and classification of distribution costs. Though the Order speaks for itself, the Commission rejected the conceptual basis of a "zero load cost" that underlies the two methodologies ("zero-intercept" and "minimum size") that have been used to estimate the customer component of various distribution plant accounts (e.g., poles, primary lines, secondary lines, line transformers, etc.). Each of the two methods (the zero-intercept method, for example) is designed to estimate the component of distribution plant cost that is incurred by a utility to effectively interconnect a customer to the system, as opposed to providing a specific level of power (kW demand) to the customer. Though arithmetically, the zero-intercept method does produce the cost of say "line transformers" associated with "0" kW demand, the more appropriate interpretation of the zero-intercept is that it represents the portion of cost that does not vary with a change in size or kW demand and thus should not be allocated on NCP demand (as FPL has done). Essentially, the "zero-intercept" represents the cost that would be incurred, irrespective of differences in the kW demand of a distribution customer. It is this cost-invariant component that is used in the zero-intercept method to identify the portion of distribution costs that should be allocated to rate classes based on the number of primary and secondary distribution customers taking service in the class.

Conceptually, this analysis is designed to estimate the behavior of costs statistically, as the Company meets growth in both the number of distribution customers and the loads of these customers. This is in contrast to FPL's analysis that is premised on an assumption that all distribution costs (except services and meters) vary directly with kW demand, without any fixed component that should be allocated on the basis of the number of customers in each class

Q. Do you have any specific examples that could illustrate this point?

A. Yes. In this rate case, FPL has classified all costs in account No. 368, line transformers, as demand related and allocated these costs to rate schedules on the basis of rate class NCP demand. This account would include equipment ranging from residential pole and pad mounted transformers rated at say 20 kVa to 160 kVa that might serve one or two residential customers (in the case of the smaller size units, to a larger group of residential customers (in the case of a larger pad mounted single phase transformer). For commercial customers, both pole and pad mounted transformers would also be used, including larger sizes rated at say 300 kVa to 500 kVa or greater that might serve a food market, hospital facility or retail store.

To explain why it is inappropriate to allocate the costs of all of these line transformers on the basis of relative class kW demand, it is necessary to examine the cost of this equipment. An analysis of FPL data indicates that the cost per kVa for line transformers decreases as the size of the transformer increases. Table 4 below summarizes some of the line transformer cost data in Account No. 368 on a per kVa basis.

Table 4
Account No. 368 Line Transformer Data

kVa Block	Units	Cost	Avg. Cost	Unit @ Midpoint
< 37	405,131	284,704,516	$ 702.75	$ 37.99
50 - 75	137,779	154,349,814	$1,120.27	$ 17.92
100 - 167	19,153	35,914,215	$1,875.12	$ 14.05
< 75	172,844	272,479,653	$1,576.45	$ 42.04
100 - 300	43,463	168,710,966	$3,881.71	$ 19.41

Based on my experience, this is consistent with industry data. It simply reflects the economies of scales of this type of equipment. Also, the labor associated with the installation of line transformers is a much larger percentage of the cost per kVa for smaller size units, than for larger size units. Again, this represents the economies of scales associated with this investment.

Q. Does FPL's cost allocation study give any recognition to this cost/size relationship?

A. No. Baron Exhibit__(SJB-5) shows the average cost per customer maximum kW demand for line transformer plant in service (the line transformer portion of FERC account No. 368) for both residential and GSLDT-1 customers. This summary is based directly from the Company's cost of service study, as filed in this case. As can be seen, thought the average size of a residential (RS-1) customer is 9.5 kW compared to the average size GSLDT-1 customer of 730 kW, the allocated cost of line transformers to these two rate schedules, on a per kW basis, is identical ($28.90 per kW). The Company's cost allocation study, because it does not recognize a customer component in the allocation of Account No. 368 costs, over-assigns costs to the GSLDT-1 customers.

In FPL's cost of service study, which assigns line transformer costs to rate schedules on the sole basis of kW demand, the underlying assumption is that if a secondary customer on rate schedule GSLD has an average NCP demand of 730 kW and a residential class customer has an average NCP demand of 10 kW, then the cost responsibility of the GSLD customer for line transformer costs is 73 times greater than for an RS-1 customer. This is contrary to the costs of line transformers serving these customers. If a portion of the cost had been classified as customer related so that line transformer costs would be allocated on a demand and a customer basis, the resulting allocation to rate schedules would more reasonably reflect that cost to serve these classes. Again, because the Company is proposing to set rates in this case on the basis of the cost of service study and the resulting parities, it is critical to develop a cost study that accurately reflects the cost to serve each rate schedule. The current method means that commercial class customers pay a distinct subsidy through their rates.

Q. Can similar arguments be made for other distribution facilities?

A. Yes. As I noted previously, the Commission has previously rejected this "no-load" conceptual argument. However, as I discussed earlier, the rationale for assigning some distribution facilities on the basis of both a customer and demand component can be supported by examining the nature of the cost for these facilities, rather than a strict reliance on a "no-load" hypothetical construct. I showed this to be the case for line transformers and it can also be logically argued for distribution poles (Account 364). If, for example, the minimum size pole that FPL might install is a 25/30 foot wood pole (which appears to be the FPL minimum), then this "cost" (or at least some portion of it) is incurred to simply interconnect the customer to the system and is not influenced by the level of the customer's demand. Essentially, there is a fixed component of the cost related to the requirement to connect the customer to the system and a variable component related to the size of the customer's load. Sending an FPL customer a "price signal" that relates the incurrence of this cost by FPL to only the level of the customer's kW demand is simply not realistic. Yet, that is the message being sent by way of FPL's cost of service study.

Q. Can you illustrate why the Company's allocation of poles is unreasonable?

A. Yes. FPL's cost of service study classifies all "25/30 foot" wooden poles and all "30 foot" concrete poles as secondary and allocates these facilities to rate schedules on the basis of "secondary group coincident peak demand" (allocation factor FPL105). Based on the Company's workpapers that support the primary/secondary split of account 364 (poles, towers and fixtures), there were 172,403 "25/30 foot" wooden poles in 2003 and 2,719 "30 foot" concrete poles. FPL's allocation of these 175,122 secondary poles to rate schedules is shown in Table 5. Also shown, is the average number of secondary poles assigned per customer for each of these rate schedules.[2]

Table 5
FPL's Assignment of Secondary Poles Per Customer

Total Secondary Poles: 175,122

Rate Class	Allocation Factor*	Poles Allocated to Rate	Poles Per Customer	**Poles Per Every 50 Customers**
CILC-1D	1.302%	2,281	7.84	**391.9**
CILC-1G	0.159%	278	2.28	**113.8**
GS1	6.151%	10,771	0.03	**1.4**
GSD1	19.215%	33,650	0.35	**17.5**
GSLD1	8.233%	14,417	4.95	**247.6**
GSLD2	0.920%	1,610	20.65	**1,032.4**
RS1	63.063%	110,436	0.03	**1.4**

* FPL105

As can be seen from the analysis, the results show that the average number of secondary poles assigned by FPL to CILC-1D customers is 7.84, while for residential customers, it is 0.03. To help place this in perspective, the last column of the table shows the average number of poles for every 50 customers on the rate schedule. For the residential class, the Company's

[2] To illustrate this point, only residential, general service and CILC rates have been included.

study assumes that there are 1.4 secondary poles for every 50 residential customers. These results speak for themselves as regards the reasonableness of the Company's distribution plant analysis. The presumption that the average GSLD-2 customer relies on over 20 ("secondary voltage") poles would appear to be unsupportable.

Q. What about other distribution plant accounts?

A. A traditional distribution plant classification analysis would normally perform a classification analysis on most distribution plant accounts, including Account 364 (poles, towers, fixtures), Account 365 (overhead conductors), Account 366 (underground conduit), Account 367 (underground conductors) and Account 368 (line transformers). Accounts 369 and 370 (services and meters) are usually always classified as customer related, as FPL has done in this case. The result of such a study would be a classification of each of these accounts into both customer and demand components, using either a minimum system or, more commonly, a "zero-intercept" method.

The conceptual basis for the zero-intercept method is that it reflects a classification of the distribution facilities that would be required to simply interconnect a customer to the system, irrespective of the kW load of the customer. From a cost causation standpoint, the argument supporting this approach is that all of these minimal facilities would be required simply due to the requirement to interconnect the customer, including meeting minimum safety standards set forth in the National Electric Safety Code ("NESC"), which the FPSC requires be adhered to for all Florida electric utilities.

Q. Are there other reasons why a customer classification of some portion of distribution plant is appropriate for FPL's system?

A. Yes. There are a significant number of "second homes" or vacation homes on the FPL system. Consider a residential single family home that is used for say 50 days per year as a vacation home. FPL, in connecting this dwelling to its system, does not know that this customer's contribution to the residential class "secondary group coincident peak demand" is likely to be very low, given the probability that the customer will not occupy the dwelling on the day and hour of the group peak. Because the Company does not know this, and to meet standard reliability requirements for distribution facilities, FPL will install secondary conductors to meet or exceed the expected maximum load of this customer and the other customers than may be served from the secondary line segment. In its cost of service study, FPL classifies secondary lines (the secondary component of accounts 365 and 367) as demand related and allocates the cost to rate schedules on allocation factor "FPL105" (secondary group coincident peak demand). The obvious problem with FPL's approach is that very little of the cost of this distribution line will be assigned to the residential class, even though it is in place to serve the customer. Only in the low probability event that the vacation home is being occupied on the day and hour of the residential class peak would the cost of this secondary line be assigned to the customer and the residential class. By failing to recognize that a fixed "customer related" component of this cost exists, the Company's study is understating the cost of service to residential customers and, by definition, overstating the cost of service to general service customers.

Q. Have you develop any estimate of the potential impact of this distribution classification issue on the rate schedule cost of service parity results presented by FPL in this case?

A. Yes. To illustrate the impact of this distribution plant classification issue in this case, I have developed two alternative cost of service analyses using the cost classification percentages presented by Gulf Power Company in its cost study. I have only applied these customer/demand classification to the <u>secondary portion</u> distribution accounts 364, 368 (poles and line transformers) and the <u>secondary portion</u> of accounts 365, 366 and 367 (overhead and underground lines and underground conduit). Though I believe that the primary portion of all of these facilities should also reflect a "customer component", I have not reclassified FPL's costs for these primary facilities. The purpose of this analysis is to illustrate the impact of this issue on the parity results presented by the Company and used to establish the rate schedule revenue increases in this case.

The first analysis, shown in Baron Exhibit__(SJB-6) is a modification of the FPL 12 CP and 1/13th average demand methodology cost study presented in the Company's filing. The modification made to this study is to classify the secondary portions of accounts 364, 365, 366, 367 and 368 using the customer/demand ratios for these accounts developed in the Gulf Power cost study. Though I acknowledge that an FPL specific analysis of these two plant accounts would likely produce different classification ratios, since the equipment used by Gulf Power (for example, line transformers, poles) would be similar in nature and cost, the use of the Gulf Power classification data should provide indicative impacts to illustrate the significance of this issue on parity results.

The second analysis that I developed (Baron Exhibit__(SJB-7) uses the summer/winter CP allocation methodology from production demand related costs, together with the modified classification for the secondary portion of accounts 364, 365, 366, 367 and 368.

Q. What are the results of the alternative analyses?

A. Table 6 below shows the rate schedule parity results of the two alternative cost of service studies, compared to FPL's filed results.

Table 6
Comparison of Parity Index Results

Rate Class	12 CP & 1/13th w/Min Dist	S/W CP w/Min Dist
CILC-1D	82%	114%
CILC-1G	152%	187%
CILC-1T	82%	108%
CS1	79%	96%
CS2	74%	91%
GS1	145%	171%
GSD1	101%	124%
GSLD1	67%	89%
GSLD2	70%	93%
GSLD3	85%	127%
MET	64%	66%
OL-1	-21%	-15%
OS-2	48%	77%
RS1	103%	90%
SL-1	26%	35%
SL-2	266%	305%
SST-TST	281%	618%
SST1-DST	-54%	-54%
SST2-DST	104%	98%
SST3-DST	112%	143%

As can be seen, the parity results for the general service and CILC rate schedules based on my recommended study (summer/winter CP, minimum distribution system for secondary facilities) are significantly closer to 1.00 than under the Company's filed study for the major rate classes. These results support the allocation of approved revenue increases on an equal percentage increase for all rate schedules.

Q. Are there any additional issues that you would like to address?

A. Yes. The Company is proposing to recover the fixed costs associated with Turkey Point Unit 5 on a kWh basis, within rate schedules. If the Commission approves the Company's proposed 2007 Turkey Point Unit 5 recovery in this case, the allocated revenue to demand metered rate schedules should be recovered on a kW demand basis, rather than on a kWh basis as proposed by FPL. These are demand related costs and, to the extent that a rate schedule incorporates a demand charge in the rate, the Turkey Point Unit 5 charges should be recovered from the kW demand charge.

Q. Does that complete your testimony at this time?

A. Yes.

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

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

EXHIBITS

OF

STEPHEN J. BARON

ON BEHALF OF THE

SOUTH FLORIDA HOSPITAL AND HEALTHCARE ASSOCIATION

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

June 2005

Expert Testimony Appearances
of
Stephen J. Baron
As June 2005

Date	Case	Jurisdict.	Party	Utility	Subject
4/81	203(B)	KY	Louisville Gas & Electric Co.	Louisville Gas & Electric Co.	Cost-of-service.
4/81	ER-81-42	MO	Kansas City Power & Light Co.	Kansas City Power & Light Co.	Forecasting.
6/81	U-1933	AZ	Arizona Corporation Commission	Tucson Electric Co.	Forecasting planning.
2/84	8924	KY	Airco Carbide	Louisville Gas & Electric Co.	Revenue requirements, cost-of-service, forecasting, weather normalization.
3/84	84-038-U	AR	Arkansas Electric Energy Consumers	Arkansas Power & Light Co.	Excess capacity, cost-of-service, rate design.
5/84	830470-EI	FL	Florida Industrial Power Users' Group	Florida Power Corp.	Allocation of fixed costs, load and capacity balance, and reserve margin. Diversification of utility.
10/84	84-199-U	AR	Arkansas Electric Energy Consumers	Arkansas Power and Light Co.	Cost allocation and rate design.
11/84	R-842651	PA	Lehigh Valley Power Committee	Pennsylvania Power & Light Co.	Interruptible rates, excess capacity, and phase-in.
1/85	85-65	ME	Airco Industrial Gases	Central Maine Power Co.	Interruptible rate design.
2/85	I-840381	PA	Philadelphia Area Industrial Energy Users' Group	Philadelphia Electric Co.	Load and energy forecast.
3/85	9243	KY	Alcan Aluminum Corp., et al.	Louisville Gas & Electric Co.	Economics of completing fossil generating unit.
3/85	3498-U	GA	Attorney General	Georgia Power Co.	Load and energy forecasting, generation planning economics.
3/85	R-842632	PA	West Penn Power Industrial Intervenors	West Penn Power Co.	Generation planning economics, prudence of a pumped storage hydro unit.
5/85	84-249	AR	Arkansas Electric Energy Consumers	Arkansas Power & Light Co.	Cost-of-service, rate design return multipliers.
5/85		City of Santa	Chamber of Commerce	Santa Clara Municipal	Cost-of-service, rate design.

Expert Testimony Appearances
of
Stephen J. Baron
As June 2005

Date	Case	Jurisdict.	Party	Utility	Subject
6/85	84-768-E-42T	Clara WV	West Virginia Industrial Intervenors	Monongahela Power Co.	Generation planning economics, prudence of a pumped storage hydro unit.
6/85	E-7 Sub 391	NC	Carolina Industrials (CIGFUR III)	Duke Power Co.	Cost-of-service, rate design, interruptible rate design.
7/85	29046	NY	Industrial Energy Users Association	Orange and Rockland Utilities	Cost-of-service, rate design.
10/85	85-043-U	AR	Arkansas Gas Consumers	Arkla, Inc.	Regulatory policy, gas cost-of-service, rate design.
10/85	85-63	ME	Airco Industrial Gases	Central Maine Power Co.	Feasibility of interruptible rates, avoided cost.
2/85	ER-8507698	NJ	Air Products and Chemicals	Jersey Central Power & Light Co.	Rate design.
3/85	R-850220	PA	West Penn Power Industrial Intervenors	West Penn Power Co.	Optimal reserve, prudence, off-system sales guarantee plan.
2/86	R-850220	PA	West Penn Power Industrial Intervenors	West Penn Power Co.	Optimal reserve margins, prudence, off-system sales guarantee plan.
3/86	85-299U	AR	Arkansas Electric Energy Consumers	Arkansas Power & Light Co.	Cost-of-service, rate design, revenue distribution.
3/86	85-726-EL-AIR	OH	Industrial Electric Consumers Group	Ohio Power Co.	Cost-of-service, rate design, interruptible rates.
5/86	86-081-E-GI	WV	West Virginia Energy Users Group	Monongahela Power Co.	Generation planning economics, prudence of a pumped storage hydro unit.
8/86	E-7 Sub 408	NC	Carolina Industrial Energy Consumers	Duke Power Co.	Cost-of-service, rate design, interruptible rates.
10/86	U-17378	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Excess capacity, economic analysis of purchased power.
12/86	38063	IN	Industrial Energy Consumers	Indiana & Michigan Power Co.	Interruptible rates.

Expert Testimony Appearances
of
Stephen J. Baron
As June 2005

Date	Case	Jurisdict.	Party	Utility	Subject
3/87	EL-86-53-001 EL-86-57-001	Federal Energy Regulatory Commission (FERC)	Louisiana Public Service Commission Staff	Gulf States Utilities, Southern Co.	Cost/benefit analysis of unit power sales contract.
4/87	U-17282	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Load forecasting and imprudence damages, River Bend Nuclear unit.
5/87	87-023-E-C	WV	Airco Industrial Gases	Monongahela Power Co.	Interruptible rates.
5/87	87-072-E-G1	WV	West Virginia Energy Users' Group	Monongahela Power Co.	Analyze Mon Power's fuel filing and examine the reasonableness of MP's claims.
5/87	86-524-E-SC	WV	West Virginia Energy Users' Group	Monongahela Power Co.	Economic dispatching of pumped storage hydro unit.
5/87	9781	KY	Kentucky Industrial Energy Consumers	Louisville Gas & Electric Co.	Analysis of impact of 1986 Tax Reform Act.
6/87	3673-U	GA	Georgia Public Service Commission	Georgia Power Co.	Economic prudence, evaluation of Vogtle nuclear unit - load forecasting, planning.
6/87	U-17282	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Phase-in plan for River Bend Nuclear unit.
7/87	85-10-22	CT	Connecticut Industrial Energy Consumers	Connecticut Light & Power Co.	Methodology for refunding rate moderation fund.
8/87	3673-U	GA	Georgia Public Service Commission	Georgia Power Co.	Test year sales and revenue forecast.
9/87	R-850220	PA	West Penn Power Industrial Intervenors	West Penn Power Co.	Excess capacity, reliability of generating system.
10/87	R-870651	PA	Duquesne Industrial Intervenors	Duquesne Light Co.	Interruptible rate, cost-of-service, revenue allocation, rate design.
10/87	I-860025	PA	Pennsylvania Industrial Intervenors		Proposed rules for cogeneration, avoided cost, rate recovery.

Expert Testimony Appearances
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Date	Case	Jurisdict.	Party	Utility	Subject
10/87	E-015/ GR-87-223	MN	Taconite Intervenors	Minnesota Power & Light Co.	Excess capacity, power and cost-of-service, rate design.
10/87	8702-EI	FL	Occidental Chemical Corp.	Florida Power Corp.	Revenue forecasting, weather normalization.
12/87	87-07-01	CT	Connecticut Industrial Energy Consumers	Connecticut Light Power Co.	Excess capacity, nuclear plant phase-in.
3/88	10064	KY	Kentucky Industrial Energy Consumers	Louisville Gas & Electric Co.	Revenue forecast, weather normalization rate treatment of cancelled plant.
3/88	87-183-TF	AR	Arkansas Electric Consumers	Arkansas Power & Light Co.	Standby/backup electric rates.
5/88	870171C001	PA	GPU Industrial Intervenors	Metropolitan Edison Co.	Cogeneration deferral mechanism, modification of energy cost recovery (ECR).
6/88	870172C005	PA	GPU Industrial Intervenors	Pennsylvania Electric Co.	Cogeneration deferral mechanism, modification of energy cost recovery (ECR).
7/88	88-171-EL-AIR 88-170-EL-AIR Interim Rate Case	OH	Industrial Energy Consumers	Cleveland Electric/ Toledo Edison	Financial analysis/need for interim rate relief.
7/88	Appeal of PSC	19th Judicial Docket U-17282	Louisiana Public Service Commission Circuit Court of Louisiana	Gulf States Utilities	Load forecasting, imprudence damages.
11/88	R-880989	PA	United States Steel	Carnegie Gas	Gas cost-of-service, rate design.
11/88	88-171-EL-AIR 88-170-EL-AIR	OH	Industrial Energy Consumers	Cleveland Electric/ Toledo Edison. General Rate Case.	Weather normalization of peak loads, excess capacity, regulatory policy.
3/89	870216/283 284/286	PA	Armco Advanced Materials Corp., Allegheny Ludlum Corp.	West Penn Power Co.	Calculated avoided capacity, recovery of capacity payments.

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Date	Case	Jurisdict.	Party	Utility	Subject
8/89	8555	TX	Occidental Chemical Corp.	Houston Lighting & Power Co.	Cost-of-service, rate design.
8/89	3840-U	GA	Georgia Public Service Commission	Georgia Power Co.	Revenue forecasting, weather normalization.
9/89	2087	NM	Attorney General of New Mexico	Public Service Co. of New Mexico	Prudence - Palo Verde Nuclear Units 1, 2 and 3, load fore-casting.
10/89	2262	NM	New Mexico Industrial Energy Consumers	Public Service Co. of New Mexico	Fuel adjustment clause, off-system sales, cost-of-service, rate design, marginal cost.
11/89	38728	IN	Industrial Consumers for Fair Utility Rates	Indiana Michigan Power Co.	Excess capacity, capacity equalization, jurisdictional cost allocation, rate design, interruptible rates.
1/90	U-17282	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Jurisdictional cost allocation, O&M expense analysis.
5/90	890366	PA	GPU Industrial Intervenors	Metropolitan Edison Co.	Non-utility generator cost recovery.
6/90	R-901609	PA	Armco Advanced Materials Corp., Allegheny Ludlum Corp.	West Penn Power Co.	Allocation of QF demand charges in the fuel cost, cost-of-service, rate design.
9/90	8278	MD	Maryland Industrial Group	Baltimore Gas & Electric Co.	Cost-of-service, rate design, revenue allocation.
12/90	U-9346 Rebuttal	MI	Association of Businesses Advocating Tariff Equity	Consumers Power Co.	Demand-side management, environmental externalities.
12/90	U-17282 Phase IV	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Revenue requirements, jurisdictional allocation.
12/90	90-205	ME	Airco Industrial Gases	Central Maine Power Co.	Investigation into interruptible service and rates.
1/91	90-12-03 Interim	CT	Connecticut Industrial Energy Consumers	Connecticut Light & Power Co.	Interim rate relief, financial analysis, class revenue allocation.

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Date	Case	Jurisdict.	Party	Utility	Subject
5/91	90-12-03 Phase II	CT	Connecticut Industrial Energy Consumers	Connecticut Light & Power Co.	Revenue requirements, cost-of-service, rate design, demand-side management.
8/91	E-7, SUB SUB 487	NC	North Carolina Industrial Energy Consumers	Duke Power Co.	Revenue requirements, cost allocation, rate design, demand-side management.
8/91	8341 Phase I	MD	Westvaco Corp.	Potomac Edison Co.	Cost allocation, rate design, 1990 Clean Air Act Amendments.
8/91	91-372 EL-UNC	OH	Armco Steel Co., L.P.	Cincinnati Gas & Electric Co.	Economic analysis of cogeneration, avoid cost rate.
9/91	P-910511 P-910512	PA	Allegheny Ludlum Corp., Armco Advanced Materials Co., The West Penn Power Industrial Users' Group	West Penn Power Co.	Economic analysis of proposed CWIP Rider for 1990 Clean Air Act Amendments expenditures.
9/91	91-231 -E-NC	WV	West Virginia Energy Users' Group	Monongahela Power Co.	Economic analysis of proposed CWIP Rider for 1990 Clean Air Act Amendments expenditures.
10/91	8341 - Phase II	MD	Westvaco Corp.	Potomac Edison Co.	Economic analysis of proposed CWIP Rider for 1990 Clean Air Act Amendments expenditures.
10/91	U-17282	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Results of comprehensive management audit.
Note: No testimony was prefiled on this.					
11/91	U-17949 Subdocket A	LA	Louisiana Public Service Commission Staff	South Central Bell Telephone Co. and proposed merger with Southern Bell Telephone Co.	Analysis of South Central Bell's restructuring and
12/91	91-410-EL-AIR	OH	Armco Steel Co., Air Products & Chemicals, Inc.	Cincinnati Gas & Electric Co.	Rate design, interruptible rates.
12/91	P-880286	PA	Armco Advanced Materials Corp., Allegheny Ludlum Corp.	West Penn Power Co.	Evaluation of appropriate avoided capacity costs - QF projects.

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Date	Case	Jurisdict.	Party	Utility	Subject
1/92	C-913424	PA	Duquesne Interruptible Complainants	Duquesne Light Co.	Industrial interruptible rate.
6/92	92-02-19	CT	Connecticut Industrial Energy Consumers	Yankee Gas Co.	Rate design.
8/92	2437	NM	New Mexico Industrial Intervenors	Public Service Co. of New Mexico	Cost-of-service.
8/92	R-00922314	PA	GPU Industrial Intervenors	Metropolitan Edison Co.	Cost-of-service, rate design, energy cost rate.
9/92	39314	ID	Industrial Consumers for Fair Utility Rates	Indiana Michigan Power Co.	Cost-of-service, rate design, energy cost rate, rate treatment.
10/92	M-00920312 C-007	PA	The GPU Industrial Intervenors	Pennsylvania Electric Co.	Cost-of-service, rate design, energy cost rate, rate treatment.
12/92	U-17949	LA	Louisiana Public Service Commission Staff	South Central Bell Co.	Management audit.
12/92	R-00922378	PA	Armco Advanced Materials Co. The WPP Industrial Intervenors	West Penn Power Co.	Cost-of-service, rate design, energy cost rate, SO_2 allowance rate treatment.
1/93	8487	MD	The Maryland Industrial Group	Baltimore Gas & Electric Co.	Electric cost-of-service and rate design, gas rate design (flexible rates).
2/93	E002/GR-92-1185	MN	North Star Steel Co. Praxair, Inc.	Northern States Power Co.	Interruptible rates.
4/93	EC92 21000 ER92-806-000 (Rebuttal)	Federal Energy Regulatory Commission	Louisiana Public Service Commission Staff	Gulf States Utilities/Entergy agreement.	Merger of GSU into Entergy System; impact on system
7/93	93-0114-E-C	WV	Airco Gases	Monongahela Power Co.	Interruptible rates.
8/93	930759-EG	FL	Florida Industrial Power Users' Group	Generic - Electric Utilities	Cost recovery and allocation of DSM costs.
9/93	M-009 30406	PA	Lehigh Valley Power Committee	Pennsylvania Power & Light Co.	Ratemaking treatment of off-system sales revenues.

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Date	Case	Jurisdict.	Party	Utility	Subject
11/93	346	KY	Kentucky Industrial Utility Customers	Generic - Gas Utilities	Allocation of gas pipeline transition costs - FERC Order 636.
12/93	U-17735	LA	Louisiana Public Service Commission Staff	Cajun Electric Power Cooperative	Nuclear plant prudence, forecasting, excess capacity.
4/94	E-015/ GR-94-001	MN	Large Power Intervenors	Minnesota Power Co.	Cost allocation, rate design, rate phase-in plan.
5/94	U-20178	LA	Louisiana Public Service Commission	Louisiana Power & Light Co.	Analysis of least cost integrated resource plan and demand-side management program.
7/94	R-00942986	PA	Armco, Inc.; West Penn Power Industrial Intervenors	West Penn Power Co.	Cost-of-service, allocation of rate increase, rate design, emission allowance sales, and operations and maintenance expense.
7/94	94-0035-E-42T	WV	West Virginia Energy Users Group	Monongahela Power Co.	Cost-of-service, allocation of rate increase, and rate design.
8/94	EC94 13-000	Federal Energy Regulatory Commission	Louisiana Public Service Commission	Gulf States Utilities/Entergy	Analysis of extended reserve shutdown units and violation of system agreement by Entergy.
9/94	R-00943 081 R-00943 081C0001	PA	Lehigh Valley Power Committee	Pennsylvania Public Utility Commission	Analysis of interruptible rate terms and conditions, availability.
9/94	U-17735	LA	Louisiana Public Service Commission	Cajun Electric Power Cooperative	Evaluation of appropriate avoided cost rate.
9/94	U-19904	LA	Louisiana Public Service Commission	Gulf States Utilities	Revenue requirements.
10/94	5258-U	GA	Georgia Public Service Commission	Southern Bell Telephone & Telegraph Co.	Proposals to address competition in telecommunication markets.
11/94	EC94-7-000 ER94-898-000	FERC	Louisiana Public Service Commission	El Paso Electric and Central and Southwest	Merger economics, transmission equalization hold harmless proposals.
2/95	941-430EG	CO	CF&I Steel, L.P.	Public Service Company of Colorado	Interruptible rates, cost-of-service.

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Date	Case	Jurisdict.	Party	Utility	Subject
4/95	R-00943271	PA	PP&L Industrial Customer Alliance	Pennsylvania Power & Light Co.	Cost-of-service, allocation of rate increase, rate design, interruptible rates.
6/95	C-00913424 C-00946104	PA	Duquesne Interruptible Complainants	Duquesne Light Co.	Interruptible rates.
8/95	ER95-112 -000	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Open Access Transmission Tariffs - Wholesale.
10/95	U-21485	LA	Louisiana Public Service Commission	Gulf States Utilities Company	Nuclear decommissioning, revenue requirements, capital structure.
10/95	ER95-1042 -000	FERC	Louisiana Public Service Commission	System Energy Resources, Inc.	Nuclear decommissioning, revenue requirements.
10/95	U-21485	LA	Louisiana Public Service Commission	Gulf States Utilities Co.	Nuclear decommissioning and cost of debt capital, capital structure.
11/95	I-940032	PA	Industrial Energy Consumers of Pennsylvania	State-wide - all utilities	Retail competition issues.
7/96	U-21496	LA	Louisiana Public Service Commission	Central Louisiana Electric Co.	Revenue requirement analysis.
7/96	8725	MD	Maryland Industrial Group	Baltimore Gas & Elec. Co., Potomac Elec. Power Co., Constellation Energy Co.	Ratemaking issues associated with a Merger.
8/96	U-17735	LA	Louisiana Public Service Commission	Cajun Electric Power Cooperative	Revenue requirements.
9/96	U-22092	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Decommissioning, weather normalization, capital structure.
2/97	R-973877	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy Co.	Competitive restructuring policy issues, stranded cost, transition charges.
6/97	Civil Action No. 94-11474	US Bank-ruptcy Court Middle District of Louisiana	Louisiana Public Service Commission	Cajun Electric Power Cooperative	Confirmation of reorganization plan; analysis of rate paths produced by competing plans.

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Date	Case	Jurisdict.	Party	Utility	Subject
6/97	R-973953	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy Co.	Retail competition issues, rate unbundling, stranded cost analysis.
6/97	8738	MD	Maryland Industrial Group	Generic	Retail competition issues
7/97	R-973954	PA	PP&L Industrial Customer Alliance	Pennsylvania Power & Light Co.	Retail competition issues, rate unbundling, stranded cost analysis.
10/97	97-204	KY	Alcan Aluminum Corp. Southwire Co.	Big River Electric Corp.	Analysis of cost of service issues - Big Rivers Restructuring Plan
10/97	R-974008	PA	Metropolitan Edison Industrial Users	Metropolitan Edison Co.	Retail competition issues, rate unbundling, stranded cost analysis.
10/97	R-974009	PA	Pennsylvania Electric Industrial Customer	Pennsylvania Electric Co.	Retail competition issues, rate unbundling, stranded cost analysis.
11/97	U-22491	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Decommissioning, weather normalization, capital structure.
11/97	P-971265	PA	Philadelphia Area Industrial Energy Users Group	Enron Energy Services Power, Inc./ PECO Energy	Analysis of Retail Restructuring Proposal.
12/97	R-973981	PA	West Penn Power Industrial Intervenors	West Penn Power Co.	Retail competition issues, rate unbundling, stranded cost analysis.
12/97	R-974104	PA	Duquesne Industrial Intervenors	Duquesne Light Co.	Retail competition issues, rate unbundling, stranded cost analysis.
3/98 (Allocated Stranded Cost Issues)	U-22092	LA	Louisiana Public Service Comission	Gulf States Utilities Co.	Retail competition, stranded cost quantification.
3/98	U-22092		Louisiana Public Service Commission	Gulf States Utilities, Inc.	Stranded cost quantification, restructuring issues.
9/98	U-17735		Louisiana Public Service Commission	Cajun Electric Power Cooperative, Inc.	Revenue requirements analysis, weather normalization.
12/98	8794	MD	Maryland Industrial Group and	Baltimore Gas and Electric Co.	Electric utility restructuring, stranded cost recovery, rate

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Date	Case	Jurisdict.	Party	Utility	Subject
			Millennium Inorganic Chemicals Inc.		unbundling.
12/98	U-23358	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Nuclear decommissioning, weather normalization, Entergy System Agreement.
5/99 (Cross-Answering Testimony)	EC-98-40-000	FERC	Louisiana Public Service Commission	American Electric Power Co. & Central South West Corp.	Merger issues related to market power mitigation proposals.
5/99 (Response Testimony)	98-426	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas & Electric Co.	Performance based regulation, settlement proposal issues, cross-subsidies between electric. gas services.
6/99	98-0452	WV	West Virginia Energy Users Group	Appalachian Power, Monongahela Power, & Potomac Edison Companies	Electric utility restructuring, stranded cost recovery, rate unbundling.
7/99	99-03-35	CT	Connecticut Industrial \Energy Consumers	United Illuminating Company	Electric utility restructuring, stranded cost recovery, rate unbundling.
7/99	Adversary Proceeding No. 98-1065	U.S. Bankruptcy Court	Louisiana Public Service Commission	Cajun Electric Power Cooperative	Motion to dissolve preliminary injunction.
7/99	99-03-06	CT	Connecticut Industrial Energy Consumers	Connecticut Light & Power Co.	Electric utility restructuring, stranded cost recovery, rate unbundling.
10/99	U-24182	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Nuclear decommissioning, weather normalization, Entergy System Agreement.
12/99	U-17735	LA	Louisiana Public Service Commission	Cajun Electric Power Cooperative, Inc.	Ananlysi of Proposed Contract Rates, Market Rates.
03/00	U-17735	LA	Louisiana Public Service Commission	Cajun Electric Power Cooperative, Inc.	Evaluation of Cooperative Power Contract Elections
03/00	99-1658-EL-ETP	OH	AK Steel Corporation	Cincinnati Gas & Electric Co.	Electric utility restructuring, stranded cost recovery, rate Unbundling.

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Date	Case	Jurisdict.	Party	Utility	Subject
08/00	98-0452 E-GI 98-0452 E-GI	WVA	West Virginia Energy Users Group	Appalachian Power Co. American Electric Co.	Electric utility restructuring rate unbundling.
08/00	00-1050 E-T 00-1051-E-T	WVA	West Virginia Energy Users Group	Mon Power Co. Potomac Edison Co.	Electric utility restructuring rate unbundling.
10/00	SOAH 473-00-1020 PUC 2234	TX	The Dallas-Fort Worth Hospital Council and The Coalition of Independent Colleges And Universities	TXU, Inc.	Electric utility restructuring rate unbundling.
12/00	U-24993	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Nuclear decommissioning, revenue requirements.
12/00	EL00-66-000 & ER-2854-000 EL95-33-002	LA	Louisiana Public Service Commission	Entergy Services Inc.	Inter-Company System Agreement: Modifications for retail competition, interruptible load.
04/01	U-21453, U-20925, U-22092 (Subdocket B) Addressing Contested Issues	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Jurisdictional Business Separation - Texas Restructuring Plan
10/01	14000-U	GA	Georgia Public Service Commission Adversary Staff	Georgia Power Co.	Test year revenue forecast.
11/01	U-25687	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Nuclear decommissioning requirements transmission revenues.
11/01	U-25965	LA	Louisiana Public Service Commission	Generic .	Independent Transmission Company ("Transco"). RTO rate design.
03/02	001148-EI	FL	South Florida Hospital and Healthcare Assoc.	Florida Power & Light Company	Retail cost of service, rate design, resource planning and demand side management.
06/02	U-25965	LA	Louisiana Public Service Commission	Entergy Gulf States Entergy Louisiana	RTO Issues
07/02	U-21453	LA	Louisiana Public Service Commission	SWEPCO, AEP	Jurisdictional Business Sep. - Texas Restructuring Plan.

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Date	Case	Jurisdict.	Party	Utility	Subject
08/02	U-25888	LA	Louisiana Public Service Commission	Entergy Louisiana, Inc. Entergy Gulf States, Inc.	Modifications to the Inter-Company System Agreement, Production Cost Equalization.
08/02	EL01-88-000	FERC	Louisiana Public Service Commission	Entergy Services Inc. and The Entergy Operating Companies	Modifications to the Inter-Company System Agreement, Production Cost Equalization.
11/02	02S-315EG	CO	CF&I Steel & Climax Molybdenum Co.	Public Service Co. of Colorado	Fuel Adjustment Clause
01/03	U-17735	LA	Louisiana Public Service Commission	Louisiana Coops	Contract Issues
02/03	02S-594E	CO	Cripple Creek and Victor Gold Mining Co.	Aquila, Inc.	Revenue requirements, purchased power.
04/03	U-26527	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Weather normalization, power purchase expenses, System Agreement expenses.
11/03	ER03-753-000	FERC	Louisiana Public Service Commission Staff	Entergy Services, Inc. and the Entergy Operating Companies	Proposed modifications to System Agreement Tariff MSS-4.
11/03	ER03-583-000, ER03-583-001, and ER03-583-002 ER03-681-000, ER03-681-001 ER03-682-000, ER03-682-001, and ER03-682-002	FERC	Louisiana Public Service Commission	Entergy Services, Inc., the Entergy Operating Companies, EWO Market-Ing, L.P, and Entergy Power, Inc.	Evaluation of Wholesale Purchased Power Contracts.
12/03	U-27136	LA	Louisiana Public Service Commission	Entergy Louisiana, Inc.	Evaluation of Wholesale Purchased Power Contracts.
01/04	E-01345-03-0437	AZ	Kroger Company	Arizona Public Service Co.	Revenue allocation rate design.
02/04	00032071	PA	Duquesne Industrial Intervenors	Duquesne Light Company	Provider of last resort issues.
03/04	03A-436E	CO	CF&I Steel, LP and Climax Molybedenum	Public Service Company of Colorado	Purchased Power Adjustment Clause.

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Date	Case	Jurisdict.	Party	Utility	Subject
04/04	2003-00433 2003-00434	PA	Kentucky Industrial Utility Customers, Inc.	Louisville Gas & Electric Co. Kentucky Utilities Co.	Cost of Service Rate Design
0-6/04	03S-539E	CO	Cripple Creek, Victor Gold Mining Co., Goodrich Corp., Holcim (U.S.,), Inc., and The Trane Co.	Aquila, Inc.	Cost of Service, Rate Design Interruptible Rates
06/04	R-00049255	PA	PP&L Industrial Customer Alliance PPLICA	PPL Electric Utilities Corp.	Cost of service, rate design, tariff issues and transmission service charge.
10/04	04S-164E	CO	CF&I Steel Company, Climax Mines	Public Service Company of Colorado	Cost of service, rate design, Interruptible Rates.
03/05	Case No. 2004-00426 Case No. 2004-00421	KY	Kentucky Utilities Co. Louisville Gas & Electric Co.	Kentucky Industrial Utility Customers, Inc.	Environmental cost recovery.

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

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

EXHIBIT__(SJB-2)

Schedule 1

Schedule 7.1
Forecast of Capacity, Demand, and Scheduled Maintenance At Time Of Summer Peak

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Year	Total Installed 1/ Capacity MW	Firm Capacity Import MW	Firm Capacity Export MW	Firm QF MW	Total Capacity Available 2/ MW	Total Peak 3/ Demand MW	DSM 4/ MW	Firm Summer Peak Demand MW	Reserve Margin Before Maintenance 5/ MW	% of Peak	Scheduled Maintenance MW	Reserve Margin After Maintenance 6/ MW	% of Peak
2004	19,130	2,667	0	880	22,677	20,297	1,510	18,787	3,890	20.7	0	3,890	20.7
2005	21,021	2,257	0	870	24,148	20,799	1,589	19,210	4,938	25.7	0	4,938	25.7
2006	21,020	2,257	0	734	24,011	21,331	1,667	19,664	4,347	22.1	0	4,347	22.1
2007	22,162	1,312	0	734	24,208	21,851	1,744	20,107	4,101	20.4	0	4,101	20.4
2008	22,486	1,312	0	734	24,532	22,289	1,822	20,467	4,065	19.9	0	4,065	19.9
2009	23,630	1,312	0	683	25,625	22,784	1,897	20,887	4,738	22.7	0	4,738	22.7
2010	23,630	1,312	0	640	25,582	23,294	1,922	21,372	4,210	19.7	0	4,210	19.7
2011	24,774	1,312	0	595	26,681	23,783	1,922	21,861	4,820	22.0	0	4,820	22.0
2012	25,918	1,312	0	595	27,825	24,279	1,922	22,357	5,468	24.5	0	5,468	24.5
2013	25,918	1,312	0	595	27,825	24,784	1,922	22,862	4,963	21.7	0	4,963	21.7

1/ Capacity additions and changes projected to be in-service by June 1st are considered to be available to meet Summer peak loads which are forecasted to occur during August of the year indicated. All values are Summer net MW.

2/ Total Capacity Available = Col (2) + Col (3) - Col (4) + Col (5)

3/ These forecasted values reflect the Most Likely forecast without DSM

4/ The MW shown represent cumulative load management capability plus incremental conservation. They are not included in total additional resources but reduce the peak load upon which Reserve Margin calculations are based.

5/ Margin (%) Before Maintenance = Col (10) / Col (9)

6/ Margin (%) After Maintenance = Col (13) / Col (9)

Schedule 2

Schedule 7.2
Forecast of Capacity , Demand, and Scheduled Maintenance At Time of Winter Peak

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Year	Total Installed 1/ Capability MW	Firm Capacity Import MW	Firm Capacity Export MW	Firm QF MW	Total Capacity Available 2/ MW	Total Peak 3/ Demand MW	DSM 4/ MW	Firm Winter Peak Demand MW	Reserve Margin Before Maintenance 5/ MW	% of Peak	Scheduled Maintenance MW	Reserve Margin After Maintenance 6/ MW	% of Peak
2003/04	20,356	2,345	0	880	23,581	20,081	1,561	18,520	5,061	27.3	0	5,061	27.3
2004/05	19,993	2,339	0	870	23,202	20,583	1,615	18,968	4,234	22.3	0	4,234	22.3
2005/06	22,390	2,339	0	734	25,463	21,100	1,670	19,430	6,033	31.0	0	6,033	31.0
2006/07	22,389	2,339	0	734	25,462	21,605	1,723	19,882	5,580	28.1	0	5,580	28.1
2007/08	23,569	1,321	0	734	25,624	22,046	1776	20,270	5,354	26.4	0	5,354	26.4
2008/09	23,931	1,321	0	734	25,986	22,539	1,828	20,711	5,275	25.5	0	5,275	25.5
2009/10	25,112	1,321	0	683	27,116	23,026	1,873	21,153	5,963	28.2	0	5,963	28.2
2010/11	25,112	1,321	0	595	27,028	23,522	1,873	21,649	5,379	24.8	0	5,379	24.8
2011/12	26,293	1,321	0	595	28,209	24,024	1,873	22,151	6,058	27.3	0	6,058	27.3
2012/13	27,474	1,321	0	595	29,390	24,535	1,873	22,662	6,728	29.7	0	6,728	29.7

1/ Capacity additions and changes projected to be in-service by January 1st are considered to be available to meet Winter peak loads which are forecast to occur during January of the "second" year indicated. All values are Winter net MW.

2/ Total Capacity Available = Col (2) + Col (3) - Col (4) + Col (5)

3/ These forecasted values reflect the Most Likely forecast without DSM

4/ The MW shown represent cumulative load management capability plus incremental conservation. They are not included in total additional resources but reduce the peak load upon which Reserve Margin calculations are based.

5/ Margin (%) Before Maintenance = Col (10) / Col (9)

6/ Margin (%) After Maintenance = Col (13) / Col (9)

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

IN RE:	**PETITION FOR RATE INCREASE BY**	**)**	**DOCKET NO. 050045-EI**
	FLORIDA POWER & LIGHT COMPANY	**)**	

EXHIBIT__(SJB-3)

Projected Capacity Changes and Reserve Margins for FPL [1]		Net Capacity Changes (MW)		FPL Reserve Margin (%)	
		Winter [2]	Summer [3]	Winter	Summer
2004	Purchases [4]	(127)	44	27%	21%
	New Short-Term Purchase [5]	---	360		
	Changes to existing Units	21	74		
2005	Purchases [4]	(16)	(60)	22%	26%
	Manatee Unit #3 Combined Cycle [6]	---	1,107		
	New Short-Term Purchase [5]	---	(360)		
	Conversion of MR #8 CT's to CC [6]	(363)	785		
2006	Manatee Unit #3 Combined Cycle [6]	1,201	---	31%	22%
	Conversion of MR #8 CT's to CC [6]	1,198	---		
	Purchases [4]	(136)	(136)		
	Changes to existing Units	(2)	(1)		
2007	Purchases [4]	---	(945)	28%	20%
	Turkey Point Combined Cycle #5 [5]	---	1,144		
	Changes to existing Units	(1)	(2)		
2008	Purchases [4]	(1,018)	---	26%	20%
	Turkey Point Combined Cycle #5 [5]	1,181	---		
	Combustion Turbines at Midway	---	324		
	Changes to existing Units	(1)	---		
2009	Combustion Turbines at Midway	362	---	26%	23%
	Purchases [4]	---	(51)		
	Combined Cycle at Corbett [6]	---	1,144		
2010	Combined Cycle at Corbett [6]	1,181	---	28%	20%
	Purchases [4]	(51)	(975)		
	New Purchase(s)	---	931		
2011	Unsited Combined Cycle # 1 [6]	---	1,144	25%	22%
	Purchases [4]	(1,020)	(45)		
	New Purchase(s)	931	---		
2012	Unsited Combined Cycle # 1 [6]	1,181	---		
	Unsited Combined Cycle # 2 [6]	---	1,144	27%	25%
2013	Unsited Combined Cycle # 2 [6]	1,181	---	30%	22%
	TOTALS =	5,702	5,627		

(1) Additional information about these resulting reserve margins and capacity changes are found on Schedules 7 & 8 respectively.

(2) Winter values are values for January of year shown.

(3) Summer values are values for August of year shown.

(4) These are firm capacity purchases. See Section I.D and III.A. for more details.

(5) Negotiations are currently underway between FPL and several parties to secure this short - term capacity.

(6) All new combined cycle units are scheduled to be in-service in June of the year shown. Consequently, they are included in the Summer reserve margin calculation for the in-service year and in both the Summer and Winter reserve margin calculations for subsequent years.

Table III.B.1

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1)	**Plant Name and Unit Number:**		Corbett Combined Cycle No. 1
(2)	**Capacity**		
	a. Summer	1,144 MW	
	b. Winter	1,181 MW	
(3)	**Technology Type:**	Combined Cycle	
(4)	**Anticipated Construction Timing**		
	a. Field construction start-date:	2007	
	b. Commercial In-service date:	2009	
(5)	**Fuel**		
	a. Primary Fuel		Natural Gas
	b. Alternate Fuel		Distillate
(6)	**Air Pollution and Control Strategy:**		Natural Gas, Dry Low No_x Combustors, SCR 0.0015% S. Distillate, & Water Injection on Distillate
(7)	**Cooling Method:**		Cooling Tower
(8)	**Total Site Area:**	220	Acres
(9)	**Construction Status:**	P	(Planned)
(10)	**Certification Status:**	P	(Planned)
(11)	**Status with Federal Agencies:**	P	(Planned)
(12)	**Projected Unit Performance Data:**		
	Planned Outage Factor (POF):		2%
	Forced Outage Factor (FOF):		1%
	Equivalent Availability Factor (EAF):		97% (Base & Duct Firing Operation)
	Resulting Capacity Factor (%):		Approx. 70% (First Year Base Operation)
	Average Net Operating Heat Rate (ANOHR):		6,835 Btu/kWh (Base Operation)
	Base Operation 75F,100%		
(13)	**Projected Unit Financial Data *,****		
	Book Life (Years):		25 years
	Total Installed Cost (In-Service Year $/kW):		538
	Direct Construction Cost ($/kW):		
	AFUDC Amount ($/kW):		
	Escalation ($/kW):		
	Fixed O&M ($/kW -Yr.): (2009 $kW-Yr)		13.44
	Variable O&M ($/MWH): (2009 $/MWH)		0.20
	K Factor:		Approx. 1.6

* $/kW values are based on Summer capacity.
** Fixed O&M cost includes capital replacement, but not firm gas transportation costs.

NOTE: Total installed cost includes escalation and AFUDC only.
Transmission interconnection, transmission integration and gas expansion costs are not included.

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

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

EXHIBIT__(SJB-4)

Cost of Service Summary: Summer/Winter CP

Description	Total	CILC-1D	CILC-1G	CILC-1T	CS1	CS2	GS1	GSD1	GSLD1	GSLD2	GSLD3	MET
RATE BASE												
Electric Plant in Service	23,394,793	386,161	32,025	126,774	38,016	18,848	1,288,974	3,987,772	1,625,686	236,458	17,086	19,825
Accumulated Depreciation and Amortization	(11,700,179)	(194,646)	(15,997)	(72,635)	(18,999)	(9,268)	(627,385)	(1,993,313)	(812,056)	(118,671)	(9,735)	(10,076)
Net Plant In Service	11,694,614	191,516	16,028	54,139	19,017	9,580	661,589	1,994,459	813,630	117,787	7,351	9,748
Plant Held for Future Use	135,593	2,527	201	702	248	128	7,409	24,711	10,570	1,558	97	134
Construction Work In Progress	522,642	9,061	728	3,478	877	430	28,124	89,978	37,440	5,512	472	470
Total Utility Plant	12,352,849	203,103	16,956	58,319	20,141	10,138	697,122	2,109,148	861,639	124,857	7,920	10,352
Working Capital - Assets	2,252,159	40,145	3,341	15,183	3,740	1,811	137,928	391,496	157,849	23,355	1,961	1,788
Working Capital - Liabilities	(2,194,486)	(38,015)	(3,158)	(14,308)	(3,565)	(1,730)	(133,499)	(375,612)	(151,001)	(22,289)	(1,855)	(1,734)
Working Capital - Net	57,673	2,130	183	875	174	81	4,429	15,885	6,848	1,066	105	54
Total Rate Base	**12,410,522**	**205,233**	**17,140**	**59,194**	**20,316**	**10,219**	**701,551**	**2,125,033**	**868,488**	**125,923**	**8,025**	**10,406**
REVENUES												
Sales of Electricity	3,757,025	64,883	6,582	21,631	5,243	2,555	274,458	676,024	243,325	36,217	3,014	2,686
Other Operating Revenues	131,208	1,497	122	468	146	73	8,912	15,855	6,201	906	62	77
Total Operating Revenues	3,888,233	66,380	6,704	22,099	5,389	2,628	283,370	691,879	249,526	37,123	3,076	2,763
EXPENSES												
Operating & Maintenance	(1,591,191)	(27,416)	(2,274)	(10,237)	(2,568)	(1,248)	(97,501)	(270,432)	(108,816)	(16,065)	(1,326)	(1,241)
Depreciation & Amortization	(861,940)	(13,728)	(1,155)	(4,476)	(1,352)	(667)	(47,689)	(143,666)	(57,783)	(8,374)	(598)	(692)
Taxes Other Than Income	(299,798)	(4,884)	(412)	(1,432)	(482)	(241)	(17,339)	(50,973)	(20,600)	(2,987)	(194)	(246)
Income Taxes	(291,326)	(5,431)	(891)	(1,577)	(151)	(67)	(37,647)	(62,274)	(14,094)	(2,291)	(272)	(109)
Amortization of Property Losses	(62,383)	(994)	(87)	(340)	(94)	(45)	(4,083)	(10,317)	(3,949)	(577)	(44)	(45)
Gain or Loss on Sale of Plant	967	19	2	0	2	1	59	183	81	12	0	1
Total Operating Expense	(3,105,671)	(52,434)	(4,817)	(18,063)	(4,645)	(2,268)	(204,201)	(537,479)	(205,161)	(30,282)	(2,433)	(2,331)
NOI Before Curtailment Adjustment	782,562	13,946	1,887	4,036	744	360	79,169	154,400	44,365	6,841	643	432
Curtailment Credit Revenue	932				638	294						
Reassign Curtailment Credit Revenue	(932)	(17)	(1)	(8)	(2)	(1)	(47)	(165)	(68)	(10)	(1)	(1)
Net Curtailment Credit Revenue	0	(17)	(1)	(8)	637	293	(47)	(165)	(68)	(10)	(1)	(1)
Net Curtailment NOI Adjustment	0	(10)	(1)	(5)	391	180	(29)	(101)	(42)	(6)	(1)	(1)
Net Operating Income	**782,562**	**13,935**	**1,886**	**4,031**	**1,135**	**540**	**79,140**	**154,299**	**44,323**	**6,834**	**642**	**432**
Rate of Return	**6.31%**	**6.79%**	**11.00%**	**6.81%**	**5.59%**	**5.28%**	**11.28%**	**7.26%**	**5.10%**	**5.43%**	**8.00%**	**4.15%**
Parity	**1.00**	**1.08**	**1.75**	**1.08**	**0.89**	**0.84**	**1.79**	**1.15**	**0.81**	**0.86**	**1.27**	**0.66**

Cost of Service Summary: Summer/Winter CP

Description	OL-1	OS-2	RS1	SL-1	SL-2	SST-TST	SST1-DST	SST2-DST	SST3-DST
RATE BASE									
Electric Plant in Service	95,570	7,661	15,112,556	384,289	8,497	6,554	151	646	1,243
Accumulated Depreciation and Amortization	(54,430)	(3,227)	(7,522,866)	(228,249)	(4,320)	(3,404)	(55)	(305)	(543)
Net Plant In Service	41,140	4,434	7,589,691	156,040	4,177	3,150	96	342	700
Plant Held for Future Use	76	45	86,772	299	54	46	1	4	10
Construction Work In Progress	1,758	126	336,610	7,139	201	196	3	14	26
Total Utility Plant	42,975	4,604	8,013,073	163,479	4,433	3,392	100	360	737
Working Capital - Assets	8,509	738	1,427,483	34,913	916	817	11	57	117
Working Capital - Liabilities	(7,843)	(680)	(1,407,215)	(30,198)	(868)	(741)	(10)	(55)	(110)
Working Capital - Net	666	58	20,268	4,715	49	76	0	2	6
Total Rate Base	**43,641**	**4,662**	**8,033,341**	**168,193**	**4,482**	**3,469**	**100**	**362**	**743**
REVENUES									
Sales of Electricity	11,639	1,140	2,349,084	52,970	2,274	2,959	8	96	236
Other Operating Revenues	260	39	95,729	792	40	21	1	2	5
Total Operating Revenues	11,899	1,179	2,444,813	53,762	2,314	2,980	9	99	241
EXPENSES									
Operating & Maintenance	(5,869)	(489)	(1,022,912)	(21,506)	(628)	(534)	(8)	(40)	(81)
Depreciation & Amortization	(5,975)	(297)	(551,421)	(23,468)	(306)	(221)	(5)	(23)	(43)
Taxes Other Than Income	(1,104)	(114)	(194,253)	(4,318)	(108)	(84)	(2)	(9)	(17)
Income Taxes	917	(53)	(166,527)	376	(430)	(769)	4	(7)	(30)
Amortization of Property Losses	(319)	(26)	(40,031)	(1,386)	(23)	(19)	(0)	(1)	(3)
Gain or Loss on Sale of Plant	1	1	600	5	0	0	0	0	0
Total Operating Expense	(12,349)	(978)	(1,974,543)	(50,297)	(1,495)	(1,627)	(12)	(79)	(174)
NOI Before Curtailment Adjustment	(450)	201	470,270	3,464	819	1,352	(3)	20	67
Curtailment Credit Revenue									
Reassign Curtailment Credit Revenue	0	(0)	(611)	0	(0)	(0)	0	(0)	(0)
Net Curtailment Credit Revenue	0	(0)	(611)	0	(0)	(0)	0	(0)	(0)
Net Curtailment NOI Adjustment	0	(0)	(375)	0	(0)	(0)	0	(0)	(0)
Net Operating Income	**(450)**	**201**	**469,895**	**3,464**	**818**	**1,352**	**(3)**	**20**	**67**
Rate of Return	**-1.03%**	**4.31%**	**5.85%**	**2.06%**	**18.26%**	**38.99%**	**-3.41%**	**5.43%**	**9.01%**
Parity	**(0.16)**	**0.68**	**0.93**	**0.33**	**2.90**	**6.18**	**(0.54)**	**0.86**	**1.43**

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

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

EXHIBIT__(SJB-5)

Total Acct 368 Line Transformers

	Allocator	Total PIS (FPL)	RS		GSLDT		Total Retail
Sec	FP109	$ 1,412,147,268	36,936,568	75.601%	2,125,864	4.351%	48,857,060
PRI	FP104	$ 172,131,054	14,938,106	62.059%	2,027,302	8.422%	24,070,852
Total Account 368		$ 1,584,278,322					
Line Transformers only			$ 1,067,601,562		$ 61,445,225		
Primary			$ 106,822,639		$ 14,497,270		
Total Allocated Acct. 368			$ 1,174,424,201		$ 75,942,494		
No. Secondary Customers			3,870,857		2,911		
$Cost/customer			**$ 275.80**		**$ 21,107.94**		
Avg kW Max Demand (FP109)			**9.5**		**730.3**		
$Cost/kVa			**$ 28.90**		**$ 28.90**		

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

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

EXHIBIT__(SJB-6)

Cost of Service Summary: 12 CP & 1/13th Average Demand, Minimum Distribution System on Secondary Facilities

Description	Total	CILC-1D	CILC-1G	CILC-1T	CS1	CS2	GS1	GSD1	GSLD1	GSLD2	GSLD3	MET
RATE BASE												
Electric Plant in Service	23,394,793	434,919	35,016	141,202	40,097	19,874	1,448,304	4,262,389	1,753,710	256,244	20,038	20,013
Accumulated Depreciation and Amortization	(11,700,179)	(224,686)	(17,940)	(81,030)	(20,416)	(9,964)	(714,078)	(2,176,309)	(896,739)	(131,360)	(11,451)	(10,186)
Net Plant In Service	11,694,614	210,232	17,076	60,172	19,682	9,910	734,225	2,086,080	856,970	124,885	8,587	9,827
Plant Held for Future Use	135,593	2,848	223	783	266	136	8,128	26,912	11,577	1,703	113	135
Construction Work In Progress	522,642	10,510	825	3,862	950	466	31,764	99,427	41,733	6,142	551	475
Total Utility Plant	12,352,849	223,590	18,124	64,816	20,897	10,512	774,117	2,212,420	910,281	132,730	9,251	10,437
Working Capital - Assets	2,252,159	42,830	3,506	15,900	3,849	1,865	147,103	407,910	165,125	24,442	2,125	1,798
Working Capital - Liabilities	(2,194,486)	(41,030)	(3,347)	(15,107)	(3,694)	(1,793)	(143,285)	(394,374)	(159,349)	(23,528)	(2,036)	(1,745)
Working Capital - Net	57,673	1,800	159	793	155	72	3,818	13,535	5,776	914	89	53
Total Rate Base	**12,410,522**	**225,391**	**18,284**	**65,609**	**21,052**	**10,584**	**777,935**	**2,225,955**	**916,057**	**133,644**	**9,341**	**10,490**
REVENUES												
Sales of Electricity	3,757,025	64,883	6,582	21,631	5,243	2,555	274,458	676,024	243,325	36,217	3,014	2,686
Other Operating Revenues	131,208	1,656	132	513	153	76	9,393	16,808	6,633	972	71	77
Total Operating Revenues	3,888,233	66,540	6,714	22,144	5,396	2,631	283,852	692,832	249,957	37,189	3,086	2,764
EXPENSES												
Operating & Maintenance	(1,591,191)	(29,440)	(2,399)	(10,771)	(2,652)	(1,289)	(104,272)	(282,995)	(114,361)	(16,890)	(1,448)	(1,248)
Depreciation & Amortization	(861,940)	(15,294)	(1,247)	(4,957)	(1,413)	(697)	(53,414)	(151,903)	(61,677)	(8,989)	(698)	(699)
Taxes Other Than Income	(299,798)	(5,333)	(437)	(1,574)	(498)	(249)	(19,080)	(53,226)	(21,655)	(3,158)	(223)	(247)
Income Taxes	(291,326)	(3,766)	(792)	(1,095)	(86)	(35)	(31,675)	(52,921)	(9,824)	(1,632)	(167)	(102)
Amortization of Property Losses	(62,383)	(1,037)	(89)	(351)	(95)	(46)	(4,287)	(10,555)	(4,048)	(592)	(47)	(45)
Gain or Loss on Sale of Plant	967	19	2	0	2	1	59	183	81	12	0	1
Total Operating Expense	(3,105,671)	(54,851)	(4,963)	(18,749)	(4,742)	(2,316)	(212,670)	(551,417)	(211,484)	(31,248)	(2,583)	(2,340)
NOI Before Curtailment Adjustment	782,562	11,689	1,751	3,396	654	316	71,182	141,415	38,474	5,940	502	424
Curtailment Credit Revenue	932				638	294						
Reassign Curtailment Credit Revenue	(932)	(20)	(2)	(9)	(2)	(1)	(56)	(190)	(80)	(12)	(1)	(1)
Net Curtailment Credit Revenue	0	(20)	(2)	(9)	637	293	(56)	(190)	(80)	(12)	(1)	(1)
Net Curtailment NOI Adjustment	0	(12)	(1)	(5)	391	180	(34)	(117)	(49)	(7)	(1)	(1)
Net Operating Income	**782,562**	**11,676**	**1,750**	**3,390**	**1,045**	**496**	**71,148**	**141,298**	**38,425**	**5,933**	**502**	**423**
Rate of Return	**6.31%**	**5.18%**	**9.57%**	**5.17%**	**4.96%**	**4.68%**	**9.15%**	**6.35%**	**4.19%**	**4.44%**	**5.37%**	**4.03%**
Parity	**1.00**	**0.82**	**1.52**	**0.82**	**0.79**	**0.74**	**1.45**	**1.01**	**0.67**	**0.70**	**0.85**	**0.64**

Cost of Service Summary: 12 CP & 1/13th Average Demand, Minimum Distribution System on Secondary Facilities

Description	OL-1	OS-2	RS1	SL-1	SL-2	SST-TST	SST1-DST	SST2-DST	SST3-DST
RATE BASE									
Electric Plant in Service	98,983	8,630	14,433,735	398,026	9,127	12,303	151	603	1,429
Accumulated Depreciation and Amortization	(56,573)	(3,847)	(7,096,275)	(236,855)	(4,735)	(6,743)	(55)	(286)	(651)
Net Plant In Service	42,411	4,783	7,337,460	161,171	4,392	5,560	96	318	778
Plant Held for Future Use	100	52	82,069	394	59	78	1	4	12
Construction Work In Progress	1,862	157	315,742	7,556	222	350	3	13	31
Total Utility Plant	44,373	4,991	7,735,271	169,121	4,673	5,988	100	335	821
Working Capital - Assets	8,685	797	1,388,302	35,627	947	1,157	11	54	127
Working Capital - Liabilities	(8,044)	(746)	(1,363,199)	(31,012)	(904)	(1,111)	(10)	(52)	(121)
Working Capital - Net	641	51	25,104	4,615	43	46	0	2	5
Total Rate Base	**45,014**	**5,042**	**7,760,374**	**173,736**	**4,716**	**6,033**	**100**	**337**	**826**
REVENUES									
Sales of Electricity	11,639	1,140	2,349,084	52,970	2,274	2,959	8	96	236
Other Operating Revenues	271	42	93,482	836	42	39	1	2	6
Total Operating Revenues	11,910	1,182	2,442,566	53,806	2,316	2,998	9	99	242
EXPENSES									
Operating & Maintenance	(6,003)	(534)	(993,271)	(22,044)	(652)	(789)	(8)	(38)	(88)
Depreciation & Amortization	(6,083)	(327)	(529,824)	(23,904)	(325)	(415)	(5)	(21)	(49)
Taxes Other Than Income	(1,134)	(122)	(188,134)	(4,440)	(113)	(142)	(2)	(8)	(19)
Income Taxes	1,028	(19)	(190,069)	827	(411)	(559)	4	(8)	(23)
Amortization of Property Losses	(321)	(27)	(39,394)	(1,396)	(23)	(26)	(0)	(1)	(3)
Gain or Loss on Sale of Plant	1	1	600	5	0	0	0	0	0
Total Operating Expense	(12,511)	(1,028)	(1,940,092)	(50,952)	(1,524)	(1,930)	(12)	(77)	(183)
NOI Before Curtailment Adjustment	(601)	154	502,474	2,854	792	1,068	(3)	22	58
Curtailment Credit Revenue									
Reassign Curtailment Credit Revenue	(0)	(0)	(558)	(1)	(0)	(1)	0	(0)	(0)
Net Curtailment Credit Revenue	(0)	(0)	(558)	(1)	(0)	(1)	0	(0)	(0)
Net Curtailment NOI Adjustment	(0)	(0)	(343)	(1)	(0)	(0)	0	(0)	(0)
Net Operating Income	**(601)**	**154**	**502,131**	**2,854**	**792**	**1,067**	**(3)**	**22**	**58**
Rate of Return	**-1.33%**	**3.05%**	**6.47%**	**1.64%**	**16.79%**	**17.69%**	**-3.38%**	**6.54%**	**7.07%**
Parity	**(0.21)**	**0.48**	**1.03**	**0.26**	**2.66**	**2.81**	**(0.54)**	**1.04**	**1.12**

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

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

EXHIBIT__(SJB-7)

Cost of Service Summary: Summer/Winter CP, Minimum Distribution System on Secondary Facilities

Description	Total	CILC-1D	CILC-1G	CILC-1T	CS1	CS2	GS1	GSD1	GSLD1	GSLD2	GSLD3	MET
RATE BASE												
Electric Plant in Service	23,394,793	377,502	30,985	126,774	36,965	18,341	1,319,467	3,867,802	1,573,360	230,411	17,086	19,823
Accumulated Depreciation and Amortization	(11,700,179)	(191,311)	(15,597)	(72,635)	(18,594)	(9,073)	(639,252)	(1,947,054)	(791,930)	(116,343)	(9,735)	(10,076)
Net Plant In Service	11,694,614	186,191	15,388	54,139	18,371	9,268	680,215	1,920,748	781,430	114,068	7,351	9,748
Plant Held for Future Use	135,593	2,527	201	702	248	128	7,410	24,709	10,569	1,558	97	134
Construction Work In Progress	522,642	8,976	717	3,478	866	425	28,312	88,868	36,911	5,452	472	470
Total Utility Plant	12,352,849	197,694	16,306	58,319	19,485	9,821	715,936	2,034,325	828,910	121,078	7,920	10,351
Working Capital - Assets	2,252,159	39,652	3,283	15,183	3,681	1,783	139,354	384,992	154,899	23,012	1,961	1,786
Working Capital - Liabilities	(2,194,486)	(37,537)	(3,102)	(14,308)	(3,509)	(1,702)	(134,855)	(369,338)	(148,145)	(21,957)	(1,855)	(1,732)
Working Capital - Net	57,673	2,115	182	875	172	80	4,500	15,655	6,754	1,055	105	54
Total Rate Base	**12,410,522**	**199,809**	**16,488**	**59,194**	**19,657**	**9,902**	**720,436**	**2,049,980**	**835,664**	**122,134**	**8,025**	**10,405**
REVENUES												
Sales of Electricity	3,757,025	64,883	6,582	21,631	5,243	2,555	274,458	676,024	243,325	36,217	3,014	2,686
Other Operating Revenues	131,208	1,473	120	468	143	71	8,975	15,535	6,054	889	62	77
Total Operating Revenues	3,888,233	66,356	6,701	22,099	5,386	2,627	283,434	691,559	249,378	37,106	3,076	2,763
EXPENSES												
Operating & Maintenance	(1,591,191)	(27,064)	(2,233)	(10,237)	(2,526)	(1,228)	(98,467)	(265,840)	(106,712)	(15,820)	(1,326)	(1,239)
Depreciation & Amortization	(861,940)	(13,364)	(1,111)	(4,476)	(1,308)	(646)	(49,055)	(138,591)	(55,604)	(8,121)	(598)	(692)
Taxes Other Than Income	(299,798)	(4,758)	(396)	(1,432)	(467)	(234)	(17,772)	(49,242)	(19,842)	(2,899)	(194)	(245)
Income Taxes	(291,326)	(5,796)	(935)	(1,577)	(195)	(89)	(36,436)	(67,230)	(16,281)	(2,546)	(272)	(109)
Amortization of Property Losses	(62,383)	(978)	(85)	(340)	(92)	(44)	(4,128)	(10,105)	(3,853)	(565)	(44)	(45)
Gain or Loss on Sale of Plant	967	19	2	0	2	1	59	183	81	12	0	1
Total Operating Expense	(3,105,671)	(51,942)	(4,759)	(18,063)	(4,586)	(2,240)	(205,799)	(530,826)	(202,211)	(29,939)	(2,433)	(2,330)
NOI Before Curtailment Adjustment	782,562	14,414	1,942	4,036	800	387	77,635	160,734	47,168	7,167	643	434
Curtailment Credit Revenue	932				638	294						
Reassign Curtailment Credit Revenue	(932)	(17)	(1)	(8)	(2)	(1)	(47)	(165)	(68)	(10)	(1)	(1)
Net Curtailment Credit Revenue	0	(17)	(1)	(8)	637	293	(47)	(165)	(68)	(10)	(1)	(1)
Net Curtailment NOI Adjustment	0	(10)	(1)	(5)	391	180	(29)	(101)	(42)	(6)	(1)	(1)
Net Operating Income	**782,562**	**14,404**	**1,942**	**4,031**	**1,191**	**567**	**77,606**	**160,632**	**47,125**	**7,161**	**642**	**433**
Rate of Return	**6.31%**	**7.21%**	**11.78%**	**6.81%**	**6.06%**	**5.73%**	**10.77%**	**7.84%**	**5.64%**	**5.86%**	**8.00%**	**4.16%**
Parity	**1.00**	**1.14**	**1.87**	**1.08**	**0.96**	**0.91**	**1.71**	**1.24**	**0.89**	**0.93**	**1.27**	**0.66**

Cost of Service Summary: Summer/Winter CP, Minimum Distribution System on Secondary Facilities

Description	OL-1	OS-2	RS1	SL-1	SL-2	SST-TST	SST1-DST	SST2-DST	SST3-DST
RATE BASE									
Electric Plant in Service	94,771	7,368	15,276,164	381,160	8,248	6,554	151	617	1,243
Accumulated Depreciation and Amortization	(54,123)	(3,114)	(7,585,776)	(227,047)	(4,224)	(3,404)	(55)	(294)	(543)
Net Plant In Service	40,648	4,254	7,690,388	154,113	4,024	3,150	96	323	700
Plant Held for Future Use	76	45	86,775	299	54	46	1	4	10
Construction Work In Progress	1,750	123	338,277	7,107	199	196	3	14	26
Total Utility Plant	42,474	4,422	8,115,440	161,519	4,277	3,392	100	341	737
Working Capital - Assets	8,463	722	1,436,751	34,735	902	817	11	55	116
Working Capital - Liabilities	(7,798)	(664)	(1,416,190)	(30,025)	(854)	(741)	(10)	(53)	(110)
Working Capital - Net	665	58	20,561	4,709	48	76	0	2	6
Total Rate Base	**43,139**	**4,479**	**8,136,001**	**166,228**	**4,325**	**3,469**	**100**	**344**	**743**
REVENUES									
Sales of Electricity	11,639	1,140	2,349,084	52,970	2,274	2,959	8	96	236
Other Operating Revenues	258	38	96,194	783	39	21	1	2	5
Total Operating Revenues	11,897	1,178	2,445,278	53,753	2,313	2,980	9	99	241
EXPENSES									
Operating & Maintenance	(5,837)	(477)	(1,029,529)	(21,378)	(618)	(534)	(8)	(39)	(80)
Depreciation & Amortization	(5,941)	(284)	(558,221)	(23,339)	(296)	(221)	(5)	(22)	(43)
Taxes Other Than Income	(1,093)	(110)	(196,626)	(4,272)	(105)	(84)	(2)	(8)	(17)
Income Taxes	883	(65)	(159,679)	244	(441)	(769)	4	(8)	(30)
Amortization of Property Losses	(317)	(25)	(40,333)	(1,380)	(22)	(19)	(0)	(1)	(3)
Gain or Loss on Sale of Plant	1	1	600	5	0	0	0	0	0
Total Operating Expense	(12,304)	(961)	(1,983,788)	(50,120)	(1,481)	(1,627)	(12)	(78)	(174)
NOI Before Curtailment Adjustment	(407)	217	461,491	3,632	832	1,352	(3)	21	67
Curtailment Credit Revenue									
Reassign Curtailment Credit Revenue	0	(0)	(611)	0	(0)	(0)	0	(0)	(0)
Net Curtailment Credit Revenue	0	(0)	(611)	0	(0)	(0)	0	(0)	(0)
Net Curtailment NOI Adjustment	0	(0)	(375)	0	(0)	(0)	0	(0)	(0)
Net Operating Income	**(407)**	**217**	**461,116**	**3,632**	**832**	**1,352**	**(3)**	**21**	**67**
Rate of Return	**-0.94%**	**4.84%**	**5.67%**	**2.19%**	**19.23%**	**38.99%**	**-3.38%**	**6.18%**	**9.04%**
Parity	**(0.15)**	**0.77**	**0.90**	**0.35**	**3.05**	**6.18**	**(0.54)**	**0.98**	**1.43**