ORIGINAL

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Review of Florida Power Corporation's Earnings, Including Effects of Proposed Acquisition of Florida Power Corporation by Carolina Power & Light

DOCKET NO. 000824-EI

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DIRECT TESTIMONY
OF
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ON BEHALF OF
FLORIDA POWER CORPORATION

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DIRECT TESTIMONY OF
WILLIAM C. SLUSSER, JR.

I. <u>Introduction and Summary</u>.

Q. Would you please state your name and business address?

A. My name is William C. Slusser, Jr. My business address is 16550 Gulf Boulevard, N. Redington Beach, Florida 33708.

Q. What is your occupation?

A. I am an electric utility rate consultant.

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

A. I am testifying on behalf of Florida Power Corporation on allocated cost of service and rate design issues.

Q. Please describe your educational background and professional experience.

A. I graduated in 1967 from the University of Florida with a Bachelor of Science Degree in Electrical Engineering and in 1970 from the University of South Florida with a Master's Degree in Engineering Administration. I am a registered Professional Engineer in the state of Florida. I retired from Florida Power Corporation in January, 2001 after 36 years of service where I devoted most of my career to allocated cost of service and rate design matters. I have been retained by Florida Power Corporation exclusively since my retirement as a consultant on pricing issues related to the Company's participation in an RTO and allocated cost of service and rate design matters in this proceeding.

II. Purpose and Summary of Testimony.

Q. Mr. Slusser, what is the purpose of your testimony?

A. My testimony serves three main purposes. First, I present a Jurisdictional Separation Study for the projected 2002 test period. This study provides the basis for determining the Company's total revenue requirements subject to the jurisdiction of this Commission. Second, I present three retail Allocated Class Cost of Service and Rate of Return studies for the test period, each study differing as to the production capacity allocation method employed. I am recommending that the method called 12 CP and 25% AD be the production cost allocation method relied upon in this proceeding for setting the amount of revenues each rate class should produce. Third, I present the Company's proposed rate schedules and rate charges which, when applied to test period billing determinants, produce the Company's total retail revenue requirements.

Q. What Minimum Filing Requirement (MFR) Schedules do you sponsor?

A. I sponsor all or portions of the MFR Schedules listed in Exhibit No. _____(WCS-1). These schedules are true and correct, subject to their being updated in the course of this proceeding.

Q. Are the Company's Jurisdictional Separation Study, Allocated Class Cost of Service Studies, and proposed rate schedules provided as a part of the Company's Minimum Filing Requirements?

A. Yes. It should be noted due to the volume of output reports, the Jurisdictional Separation Study and three Allocated Class Cost of Service studies are each provided as a separate volume which are included as part of the "Minimum Filing Requirements – Section E – Rate Schedules."

Q. Please provide a summary of your testimony.

A. My role in this proceeding is to develop the rate charges of the Company's retail Tariff that produce sufficient revenues to recover the Company's total retail jurisdictional cost of service. In so doing, I have prepared and sponsor two types of cost studies.

The first type of cost study I present is entitled "Jurisdictional Separation Study". This study allocates the various items comprising the Company's total system costs to the businesses representing the Company's wholesale business and the Company's retail business. This separation of costs between the businesses is based on accepted mathematical factors representing appropriate customer, capacity, or energy responsibilities. The resultant allocation of costs to the retail business is the basis for determining the Company's revenue requirements subject to the jurisdiction of this Commission.

The second type of cost study is called an "Allocated Class Cost of Service and Rate of Return Study". This study is simply a further allocation to retail rate classes of the total retail jurisdictional cost resulting from the Jurisdictional Separation Study. This allocation forms the cost basis for establishing revenue requirements for each rate class. The resultant costs allocated to each rate class are most dependent upon the method of production capacity cost allocation employed in the study. Of three allocation methods employed, Florida Power Corporation is recommending reliance on the production capacity cost allocation method called the "12CP and 25% AD". This method provides a greater recognition to energy responsibility, that being 25%, as a determinant of production costs. This compares to the method previously most relied upon by the Commission called the "12CP and 1/13 AD" method, which recognizes only 8% of production capacity costs as having energy responsibility.

Finally, proposed rate charges are developed for each rate schedule, that to the extent practical, have been designed to produce the revenues required to recover their respective class cost of service based on the "12CP and 25% AD" class cost of service study.

The Company is including in its proposed rate development the following significant changes:

1. The Company is proposing a two block, inverted rate for residential service in order to promote energy efficiency and conservation.
2. Service charges for connecting electric service are proposed to be increased to reflect current costs or what the Company believes is reasonable to assess.
3. As a result of a prior rate stipulation, the Company is reviewing in this proceeding the level of credits paid to interruptible and curtailable general service customers and is proposing that they be set at a cost-effective level.

III. <u>Jurisdictional Separation Study</u>

Q. What is a Jurisdictional Separation Study?

A. Most of the costs incurred by an electric utility to serve its customers are of a "joint" or "common use" nature. For example, a generating plant is ordinarily not constructed to serve any one customer or even one class of customers, but is part of a total generating system designed to serve the aggregate load requirements of all customers on the system. The investment in this plant is recorded on the Company's books and records as a joint cost for which all customers receiving electric service should share. A Jurisdictional Separation Study is an allocation of the Company's joint costs between those customers served under the jurisdiction of the Federal Energy Regulatory Commission (FERC) and those customers served under the jurisdiction of the Florida Public Service Commission (FPSC). The study consists of allocations for all rate base and operating expense items comprising the Company's total system cost of service for the test period. Allocations are performed using mathematical formulas that best represent each jurisdiction's cost responsibility.

Q. What sources of information have been used to prepare the Company's Jurisdictional Separation Study?

A. The accounting data, particularly data provided in MFR Schedules B, C, and D, sponsored by Company witness Mark Myers, provide the basic system cost of service information. This data is organized by primary FERC accounts and is classified or assigned into functional groupings for allocation purposes. The data represents the fully adjusted data for the test period. Factors developed for allocating the system costs are predominately based on load data at the time of the Company's projected system monthly peaks. This load data, which is sponsored by Company witness Ben Crisp, is projected for each individual wholesale customer and the total retail load.

Q. Are the procedures and methodologies employed in the preparation of the Jurisdictional Separation Study in this proceeding consistent with those used in separation studies submitted in prior regulatory filings before both the FPSC and the FERC?

A. Yes. I consider it extremely important to utilize procedures and methodologies that are both consistent and acceptable to both the FPSC and the FERC and have endeavored to do so for the many years I prepared such studies for FPC. The use or adoption of different costing procedures by either commission can result in an under- or over-recovery of costs by the Company on a total system basis. Both commissions employ similar embedded cost ratemaking practices and establish rate base and return developments for a test period to determine revenue requirements. The most significant allocation factor is that related to power supply costs, for which both commissions have relied upon the use of the "Average of the 12 Monthly Coincident Peak Demands" methodology for jurisdictional separation.

The FERC staff provides a computerized cost allocation model which is intended to be utilized for rate filings before the FERC. The Company has elected to use this same model in this proceeding. The FERC model is somewhat limited in the number of line items it can accommodate, and therefore it was necessary to group certain FERC accounts for input into the model. This grouping process is referred to as "Cost Assignments to Allocation Categories" and is fully included in the volume containing the Jurisdictional Separation Study.

Q. What type customers comprise the Company's separated wholesale sales business?

A. The Company provides full requirements service to the Cities of Bartow, Havana, Mt. Dora, Quincy, Chattahoochee, Newberry, and Williston. Partial requirements sales are made to the Florida Municipal Power Agency, New Smyrna Beach Utilities Comission, and the City of Tallahassee. The Company has a number of sales agreements with Seminole Electric Cooperative, Inc. for stratified power. A stratified power sale is a sale specifically from a type of production resource, i.e. base, intermediate, or peaking. Seminole Electric Cooperative Inc. purchases significant amounts of intermediate and peaking service. The Company also has agreements to sell stratified base power to the City of Homestead and Florida Power and Light Company.

Q. Would you describe the treatment for assigning production costs to wholesale customers purchasing stratified production services?

A. Yes. The costing treatment for production non-fuel costs is similar to that employed in the development of the Company's fuel charges. Costs are first determined for the stratified rate customers. These costs are then subtracted from the Company's total costs for recovery from the average rate customers.

In developing the capacity portion of production costs to be assigned to the stratified rate customers, ratios for each stratification are calculated by dividing (a) the average 12 CP load of stratified customers by (b) the total average monthly system stratified resource capability adjusted for reserves. These ratios result in a specific capacity cost responsibility, expressed as a percentage for the type of generation resources required by each of the stratified customers. The remaining cost responsibility of the stratified resources is allocated to the average rate customer classes based on their 12 monthly coincident peak demands. This development is contained in the "Development of Input Allocation Factors" section of the separate MFR volume entitled "Jurisdictional Separation Study."

In developing the energy portion of production non-fuel costs to be assigned to stratified customers, direct assignments are calculated for stratified customers by applying per unit resource energy costs to stratified customer sales. These assignments are contained in the production O&M cost assignments section of the Jurisdictional Separation Study.

It should be noted that all the various system production costs (plant-in-service, accumulated depreciation, fuel inventories, operation and maintenance expenses, and depreciation expenses) have been stratified within the separation study in order to apply the appropriate allocation factors reflecting the stratified customer assignments.

Q. Are there any other different costing treatments afforded the wholesale jurisdiction?

A. Yes. In accordance with FPSC Order PSC-99-1741-PPA-EI in Docket No. 990771-EI, specific amounts of plant and expense have been assigned to the wholesale business related to a sale to the City of Tallahassee. This cost, of course, is not included in the balance of production costs assigned or allocated to any other customers.

Q. Would you summarize the wholesale customers' proportional requirements of the Company's investment in production, transmission, distribution, and general plant that result from the Jurisdictional Separation Study?

A. Yes. The wholesale customers require 8.7% of the production, 27.4% of the transmission, 0.3% of the distribution, and 4.7% of the general plant investment of the Company. The wholesale customers require a proportionally higher investment in transmission relative to production due to the fact that some wholesale customers have acquired production resources from other than Florida Power which are delivered to them utilizing the Company's transmission system. Wholesale customers require very little distribution investment since most wholesale power is delivered at points connected to the Company's transmission system.

IV. <u>Class Allocated Cost of Service and Rate of Return Study</u>

Q. What is a retail Allocated Class Cost of Service and Rate of Return Study?

A. This study is simply an extension of the Jurisdictional Separation Study in which the retail jurisdictional costs are further allocated to rate classes within the retail jurisdiction. This type study provides: (1) class realized rates of return at present and proposed rates, (2) class revenue surplus or deficiencies from full cost of service, and (3) functional unit cost information for rate design consideration. Factors for allocating the jurisdictional costs to rate classes are based on billing determinants and class load characteristics derived from the Company's sales forecast and most current load research study.

Again, the FERC cost model was utilized to perform the cost allocations to rate classes. To obtain the functional cost information required by the Commission MFRs, additional model runs were made utilizing each class's cost results and allocating this data to functional categories.

Q. What customer rate classes or rate groups were established as costing entities for the Allocated Class Cost of Service Studies?

A. Each regular rate schedule in the Company's present tariff has been established as a rate group in the cost of service studies. Rate schedules serving either, (i) optional time of use, (ii) load management service, or (iii) standby service, have been combined with its corresponding or related rate schedule. The resultant rate groups are described as:

(1) Residential Service (RS)

(2) General Service Non-Demand (GS-1)

(3) General Service 100% Load Factor (GS-2)

(4) General Service Demand (GSD)

(5) Curtailable General Service (CS)

(6) Interruptible General Service (IS)

and

(7) Lighting (LS)

(a) Energy Service

(b) Fixture and Maintenance Service

(c) Poles Service

Q. What is the Company's costing treatment for interruptible and curtailable general service customers in the class cost of service studies?

A. Consistent with the Company's rate treatment for such service, the development of costs for these classes of customers is based on their usage characteristics as if their requirements are firm. The value for their load being interruptible or curtailable is recognized separately by payment of credits as a demand side management (DSM) program. In this regard, the costing and rate treatment afforded curtailable and interruptible general service is the same treatment afforded residential and general service customers receiving non-firm service under the Company's load management rate schedules.

Q. Mr. Slusser, you indicated you prepared three allocated class cost of service studies for this proceeding which differ as to the production capacity cost allocation method employed. What three different production capacity cost allocation methods did you employ?

A. The Commission MFRs require at a minimum that one cost of service study be provided utilizing the average of the twelve monthly coincident peaks and 1/13 weighted average demand, which is called the 12 CP and 1/13 AD method. This has been the method most often relied upon previously by the Commission in rate cases involving all four investor owned electric utilities in Florida. This method allocates 12/13, or 92%, of production capacity costs on the basis of class average choose to install a unit of higher capital cost if the unit was intended to provide fuel or other operating savings that would offset the higher capital costs, in addition to providing peak load capacity. An equivalent peaker system investment can be derived by estimating the utility's installed cost had only peaking capacity been built to meet peak loads. The additional production capacity investment on the utility's books (the amount of plant investment in excess of the estimated equivalent peaker investment) is assumed to have been economically justified in order to achieve lower fuel or other operating costs. Under the Equivalent Peaker Allocation Method, the portion of production capacity costs representing an equivalent peaker system is allocated on the basis of class monthly peak loads and the portion representing the excess or remaining investment on the utility's books is allocated on the basis of class average demands.

When the equivalent peaker method was analyzed by the Company in Docket No. 870220-EI, the equivalent peaker investment was estimated at 49% of the Company's total production plant investment. This is the same as preparing a 12 CP and 51% AD production capacity cost allocation study. When this same analysis was performed in Docket No. 910890-EI, the equivalent peaker investment was estimated at 55% of the Company's total production plant investment. This is the same as preparing a 12 CP and 45% AD production capacity cost allocation method. Thus, the presentation of the 12 CP and 50% AD method is believed to be representative of the cost allocation results had the

Equivalent Peaker Method been employed for Florida Power Corporation in this proceeding.

Q. **If you believe that the Equivalent Peaker Method has merit, is Florida Power Corporation recommending reliance on it to establish class revenue requirements in this proceeding?**

A. I do believe that the economic theory underlying the Equivalent Peaker Method is sound. There are many consumer examples of employing this same theory, from purchasing an air conditioner to building a house, where the consumer justifiably expends greater capital costs for the purchase with the expectation that there will be more than off-setting lower operating costs. There is no doubt, in Florida Power's generation expansion planning, that the extent generation resources operate (energy utilization) is and has been a major consideration in the type of plant considered to be built. Thus the Company believes a much greater weighting of energy responsibility is warranted.

However, Florida Power is not recommending that the Commission move fully to reliance in this proceeding on the Equivalent Peaker Method or its equivalent 12 CP and 50% AD cost study method which has been presented in this proceeding. The Company is concerned that such reliance would certainly have significant cost shifting consequences on those rate classes, such as Lighting and Firm and Non-Firm General Service Demand rate classes, which have greater energy responsibilities than peak load responsibilities.

Q. What is the significance of preparing the allocated cost of service study based on the 12 CP and 25% AD method?

A. The 12 CP and 25% AD production capacity cost allocation method is the study method for which Florida Power proposes to rely on for establishing class revenue requirements in this proceeding. It allocates 75% of production capacity costs on the basis of class monthly coincident peak loads and 25% of production capacity costs on the basis of class average demands. This study method is viewed as a compromise between what has been most often relied upon previously by the Commission as the 12 CP and 1/13 AD method and the Equivalent Peaker Method or its counter part 12 CP and 50% AD method. It accomplishes what Florida Power believes is a more appropriate recognition of energy utilization, i.e. 25% vs. 8%, as a cost causation of the Company's production capacity costs.

Q. Are there other factors in addition to operating cost considerations that support a greater portion than 8% of costs being allocated on an average demand basis?

A. Yes, I believe that there are significant amounts of production plant costs which relate to environmental concerns including siting, fuel storage and handling, air quality, water quality, water cooling etc. which are more a consideration of energy utilization of a production facility than its peak capability. The Company has over $500 Million of plant investment in Air and Water Pollution Control

Facilities as reported in the Company's FERC Form No. 1 for year 2000. This investment alone represents over 14% of the Company's total production plant investment that should be allocated on an average demand basis.

Q. Do you have an exhibit that compares the results of the three allocated class cost of service studies which you have prepared?

A. Yes. My Exhibit No. __________(WCS-2) provides such a comparison. It shows the allocated class cost of service resulting from each of the three production capacity cost allocation methods. A comparison is also made of the differences in class cost of service allocation of the 25% and 50% average demand weighted methods to the MFR required 1/13 average demand study method.

Q. Has the Commission ever deviated from reliance on the 12 CP and 1/13 AD method for establishing class revenue requirements in a rate proceeding?

A. Yes. I already mentioned that the Commission relied upon the Equivalent Peaker Method in a Tampa Electric Company rate proceeding in Docket No. 850246-EI. In addition, I recall the Commission in Docket Numbers 770316-EU (FPC rate case) and 830465-EI (FP&L rate case) apportioning all or a portion of the fixed costs of a nuclear unit to rate classes on an energy basis to give recognition to the substantial fuel savings afforded from such type units. Since the fuel cost savings of a nuclear unit flow through to customers on an energy basis through the fuel clause, they found that at least that amount of fixed costs equal to fuel savings should be recovered in base rates in a similar manner--- that being on an energy basis.

Q. Will the method of production cost allocation that the Commission relies on for base ratemaking in this proceeding affect the class allocations of costs other than base recoverable costs?

A. Yes. The Commission has previously required that the cost of service methodology approved in the utility's last rate case be the same methodology for allocating capacity costs in both the Capacity Cost Recovery Clause and the Energy Conservation Cost Recovery Clause. Currently, the charges of those recovery clauses reflect the 12 CP and 1/13 AD methodology for Florida Power Corporation. If the Commission chooses to rely on the Company's proposed methodology or any other different methodology in this proceeding, the charges in these clauses should reflect such new allocation methodology when they are next revised.

Q. You indicated that an Allocated Class Cost of Service Study provides functional cost information for rate design purposes. What functional components are provided in the cost of service studies?

A. A class's cost of service or revenue requirements resulting from the Company's allocated cost of service studies consist of the following cost components:

1. Production Capacity
2. Production Energy

3. Transmission Capacity

4. Distribution Capacity - Primary

5. Distribution Capacity - Secondary

6. Distribution Services

7. Metering

8. Interruptible General Service Equipment

9. Lighting Facilities (Fixtures & Poles)

10. Customer Billing, Info., etc.

Unit costs are developed in the allocated cost of service studies by dividing the class's component cost of service by the appropriate billing units, either number of customer bills, energy sales, or billing demands. This type of information can be used as a consideration in rate design when establishing the level of customer charges, demand charges, energy charges, etc. I provide a summary of the functional cost of service by rate class and the development of their respective unit costs in Exhibit No. __________(WCS-3). The production capacity costs in this exhibit are based on the 12 CP and 25% AD allocation method. All cost of service amounts shown have been reduced by an allocation of revenue credits from other operating revenues. The Company has included in the revenue credits an increase in service charge revenue which the Company is proposing.

V. Development of Class Revenues

Q. How did the Company derive the billing determinants for purposes of simulating the amount of present and proposed revenues by rate class?

A. As sponsored by Company witness Ben Crisp, a retail kwh sales forecast by major rate class was prepared for the projected test period, calendar year 2002. Utilizing actual calendar year 2000 billing determinants, kwh and load factor relationships were established for each rate schedule and applied to the kwh sales forecast to derive the individual rate class billing determinants. The MFR Schedule E-16c shows the development of revenues by the application of present and proposed rate charges to these billing determinants.

Q. Has the Company proposed to increase its service charges?

A. Yes. The various service charges imposed by the Company for connecting electric service are proposed to be increased to reflect current costs or what the Company believes is reasonable to assess. As noted previously, revenues from service charges are treated as an allocated revenue credit in the cost of service determination. Thus, any increase in these charges reduces the amount of cost which must be recovered in base rate charges.

Q. How did the Company establish its proposed revenue requirements for each rate class?

A. The Company first relied on the classes' allocated cost of service resulting from the 12 CP and 25% AD production capacity cost study as a target amount of revenue to obtain from each rate class. Additional allocated revenue credits from proposed service charges were taken into account to obtain revised target amounts of class revenue requirements. Rate charges were established that achieved the revised target class revenues for the GS-2, GSD, CS, IS, and LS (energy sales) rate classes. Due to capping the amount of increase required for certain lighting fixtures and poles, full revenue requirement recovery was not achievable for these facilities. This deficiency was then included with the target revenue requirements of RS and GS-1 to derive the amount of revenue to be produced from the RS and GS-1 rate classes. The Company is desirous of continuing a practice, for rate administration reasons, of setting the GS-1 base energy charges at the rate level of the average RS base energy charges. Therefore, these rate classes were combined to recover the balance of the total retail revenue requirements.

Q. Is the Company proposing any major rate design changes to any of its rate schedules?

A. Yes. One major rate design change is proposed affecting the standard residential rate service offering. To encourage energy efficiency and conservation, the Company is proposing a two block energy charge whereby the charge for a customer's monthly usage in excess of 1,000 kwh (second block) is priced one cent per kwh more than the charge for the customer's usage up to 1,000 kwh (first block). This type rate design is often referred to as an inverted rate design. The Company believes that the 1,000 kwh price change breakpoint is reasonable in that approximately 2/3 of all residential energy is consumed in the first block and 1/3 of all energy is consumed in the second block. The Company believes a one cent higher per unit price, targeted at 1/3 of the residential class's energy consumption, is a worthwhile attempt to promote energy efficiency and conservation.

Q. Are you aware of other utilities that administer an inverted rate design for residential service of a utility product?

A. Yes. Also for reasons of encouraging energy efficiency and conservation, I am aware that both the City of St. Petersburg and the City of Tampa impose an inverted rate structure for residential water usage. Florida Power and Light has had for a number of years a two block, inverted rate design applicable to residential electric service. I have read that at least one electric utility in the West, Nevada Power & Light, has recently enacted a three block, inverted residential rate due to concerns regarding rapidly growing power needs in that part of the country.

Q. **Has the Company proposed any other significant base rate design changes**?

A. Although I would not necessarily characterize the changes as significant, the following changes are also incorporated in the proposed base rates for sales of electricity: (1) correct certain demand charges in demand-billed rates to that which the Company believes was previously intended, (2) update the cost-based Standby Rate Charges, (3) update delivery voltage credits in the general service demand rates, (4) institute a minimum billing demand of 500 kw in the Interruptible and Curtailable General Service rate schedules, and (5) revise the energy charges in all rate schedules to produce the target class revenues. The

Company has not proposed to change the level of customer charges, time-of-use period energy charge weightings, power factor clauses, or metering voltage adjustments in this proceeding.

Q. Will the Company's proposed rate changes cause any general service customers to seek to be transferred or obligate the Company to transfer them from one rate schedule to another to obtain a more economical billing?

A. This phenomenon, which we call rate migration, is always a possible outcome when general service rates are revised. Migration could occur between non-demand rate schedules and demand rate schedules or between standard rates and time-of-use rates. The Company does not believe its proposed changes will create any significant migration.

Obviously, if migration does occur, the Company will not realize the full revenues it expects from the general service customers. The Company should be allowed to test for migration if any further revisions are made to the general service rate charges. Where migration would occur, the billing determinants for each rate schedule should be revised to reflect the post migration effect. This may be an iterative process, but one that must be undertaken before final rate charges are established.

Q. It appears that the Company is withdrawing its interruptible and curtailable general service rate schedules IS-1, IST-1, CS-1, and CST-1. In addition, it is

modifying the remaining interruptible and curtailable rate schedules IS-2, IST-2, SS-2, CS-2, CST-2 , and SS-3 to, in particular, revise the level of the interruptible and curtailable credits. Why is the Company doing this?

A. In Docket No. 910890-EI, interruptible and curtailable credits were established for the interruptible and curtailable general service rate schedules in effect at that time, which were the IS-1, IST-1, CS-1, and CST-1 rate schedules. In accordance with a rate stipulation in this rate case proceeding, the credits would remain in effect until the next rate case.

Subsequently, in Docket No. 950645-EI, the IS-1, IST-1, CS-1, and CST-1 rate schedules were closed to new customers, and new rate schedules IS-2, IST-2, CS-2, and CST-2 with lower, cost-effective credits were approved for new customers.

The Company believes that the current proceeding represents the next rate case as was intended by the rate stipulation in Docket No. 910890-EI. Therefore, the Company believes the credits should be reviewed and adjusted as necessary to a cost-effective level. If the credits are revised to a cost-effective level for all interruptible and curtailable customers, it is no longer necessary to maintain the IS-1, IST-1, CS-1, and CST-1 rate schedules which were closed to new customers as of April 16, 1996. Therefore, the Company proposes these schedules be withdrawn from its Tariff, and that all interruptible and curtailable customers take service under the applicable IS-2, IST-2, CS-2, or CST-2 rate schedule whereby the credits contained therein are proposed to be revised to a cost-effective level.

Q. How does the Company propose that the interruptible and curtailable credits be established in order to be considered cost-effective?

A. Since the interruptible and curtailable service offerings are a demand-side management program and the Company seeks to continue recovery of the credits as a recoverable conservation program cost, the credits should reflect the same type evaluation as other conservation programs with a benefit to cost ratio of 1.2. This evaluation was performed and included in Supplement F to MFR Schedule E-17. The evaluation indicates a credit of $2.82 per monthly coincident peak kw is justified. This is the level of credit the Company proposes for interruptible load. Curtailable load is considered to have lesser value than interruptible load since actual curtailment remains at the option of the customer and the load reduction cannot be instantaneously realized. Therefore, the Company proposes a credit of $2.12 per monthly coincident peak kw, for curtailable load, which is 75% of the proposed interruptible credit to recognize such lesser value.

Q. How do the proposed interruptible and curtailable credits compare with those that customers have been realizing under present rate credits?

A. The proposed credits compare very closely with the IS-2 and IST-2 rate schedules, i.e. $2.82 vs. $2.86 per coincident kw. The proposed credits are actually more favorable for the CS-2 and CST-2 rate schedules, i.e. $2.12 vs. $1.50 per coincident kw. However, the proposed credits are significantly lower than that provided to customers under the IS-1 and IST-1 rate schedules, i.e. $2.82

per coincident kw of load vs. $3.37 per maximum kw of load. Likewise, the proposed credits are significantly lower than that provided under the CS-1 and CST-1 rate schedules, i.e. $2.12 per coincident kw of curtailable load vs. $2.33 per kw of maximum curtailable load. Where credits are provided on a coincident kw basis, billing load factor is considered a suitable proxy for coincidence factor. Therefore, the customer's maximum demand is multiplied by his billing load factor to derive an estimate of the coincident load for which the proposed credit applies.

Q. **It also appears that the Company is instituting a minimum billing demand of 500 kw under its proposed Interruptible and Curtailable rate schedules. Why does the Company believe this is necessary?**

A. When the new rate schedules IS-2, IST-2, CS-2, and CST-2 were approved in Docket No. 950645-EI for new interruptible and curtailable customers, the rate schedules were approved for application to customers whose average billing demand is 500 kw or more. The Company had found that loads less than 500 kw posed administrative problems and required customized interruptible equipment and metering installations which were not cost effective.

However, even though an interruptible or curtailable general service customer may initially satisfy the 500 kw application criteria, there is no further enforcement mechanism or incentive for the customer to maintain this level of billing demand. Therefore, the Company is proposing that any customer, who elects service under an interruptible or curtailable rate schedule, be subject to a minimum billing demand of 500 kw.

The Company finds that there are at least 35 interruptible or curtailable customers who currently may have a monthly billing demand of less than 500 kw. The Company proposes that those customers, who have a billing demand of less than 500 kw for the billing month preceding the effective date of the revised rate schedules, be exempt from application of the proposed minimum monthly billing demand.

Q. **Mr. Slusser, you indicated earlier in your testimony that proposed increases for certain lighting fixtures or poles were capped at a level below what charges could be cost justified. Why did the Company choose to do this?**

A. Several of the Company's charges for street light facilities appear to be substantially below what we believe to be their appropriate unit cost. Other than the addition of decorative lighting facilities and poles in recent years, individual lighting charges have not been established specifically since the rate cases in the early 1980's. For example, charges for poles and fixtures were reduced pro rata in the last full rate case of Docket 910890-EI to achieve the overall lighting class revenue target in that case. Instead, however, certain fixture or pole charges should have been increased in that proceeding while other charges should have been decreased. The average embedded cost of certain commonly utilized lights and poles has changed significantly since their original inclusion in the tariff due to the fact that many of these facilities have been replaced in recent years at much higher installed costs.

The Company would like to have individual lighting charges reflect their current embedded cost. However, this would require that certain fixture charges be increased as much as 48% and certain pole charges be increased as much as 116%. The Company in this proceeding proposes to take a significant step toward correcting these deficiencies and is proposing to set the fixture and pole charges to reflect their current embedded cost, but limiting any particular fixture charge to a maximum of a 15% increase and limiting any particular pole charge to a maximum of a 20% increase at this time.

Q. What other changes is the Company proposing to make to its rate schedule for lighting services, Rate Schedule LS-1?

A. The Company is proposing a number of revisions to its lighting fixture and pole offerings. These revisions include:

(1) Certain fixture and pole types are being restricted to existing installations. The Company has little demand for some of these facilities, or the Company has experienced poor field performance with these facilities.

(2) Certain existing fixture and pole types and certain new fixture and pole types are being specified as applicable only for overhead service or only for underground service. This specification is being made to

comply with the Company's construction standards for utilizing the most appropriate facility for the type of electric service available.

(3) The Company is proposing to include metal halide fixtures in its lighting service offerings. The Company has concluded its metal halide pilot lighting program and finds these facilities can be offered under its regular lighting service schedule to any customer desiring such facilities.

(4) At the request of a number of governmental customers, the Company is proposing to offer a decorative electrical receptacle available on certain decorative poles. Such receptacle use is limited to electric use from October through January whereby electrical usage will be billed separately.

Q. Do you have an exhibit that summarizes the amount and change in class revenues as a result of the Company's proposed rates and the class rates of return which would be realized?

A. Yes. My Exhibit No. ________(WCS-4) shows that the class revenues resulting from the proposed rates closely match their allocated cost of service based on the 12 CP and 25% AD method, with the exception of the Lighting Facilities grouping for which certain proposed charges were limited as I had discussed in my testimony. Also, this statement is only true when viewing the RS and GS-1 rate classes as being combined, which I believe should be done since both classes are subject to the same proposed rate level.

Q. Does this conclude your testimony?

A. Yes, it does.

monthly coincident peak loads, and 1/13, or 8%, of production capacity costs on the basis of class average hourly demands, which is mathematically equivalent to class annual energy consumption. Florida Power believes that this method gives too little recognition to energy responsibility, only 8%, as a determinant of production costs, and, therefore, two additional studies have been prepared to recognize a greater extent that energy responsibility should bear for sharing in the Company's total production capacity costs.

The two additional studies that have been prepared increase the proportion of production costs that are allocated on average demand to 25% and 50% respectively. I will refer to theses two additional studies as the 12 CP and 25% AD method and the 12 CP and 50% AD method.

Q. What is the rationale for preparing the 12 CP and 50% AD study which allocates 50% of production capacity costs on an average demand basis?

This method for which 50% of production capacity costs are allocated on an average demand basis is indicative of the type study that would result if an Equivalent Peaker Method was prepared for Florida Power Corporation. The Equivalent Peaker Method was introduced by the FPSC Staff in a 1985 Tampa Electric Company rate case, Docket No. 850050-EI. It is predicated on the theory that if a utility installed new capacity simply to serve peak loads, it would choose a unit requiring the least capital investment, typically a combustion turbine unit (peaker). Under this theory, which I believe has merit, a utility would only

MINIMUM FILING REQUIREMENTS SCHEDULES
Sponsored, All or in Part, by William C. Slusser, Jr.

Schedule	*Title*
A-4a	Full Revenue Requirements Bill Comparisons - Typical Monthly Bills
A-5	Summary of Tariffs
B-1	Balance Sheet - Jurisdictional
B-2a	Balance Sheet - Jurisdictional Assets Calculation
B-2b	Balance Sheet - Jurisdictional Liabilities Calculation
B-3	Adjusted Rate Base
B-4	Rate Base Adjustments
B-7	Jurisdictional Separation Factors - Rate Base
B-14	Working Capital - 13 Month Average
C-1	Jurisdictional Net Operating Income
C-2	Adjusted Jurisdictional Net Operating Income
C-3	Net Operating Income and Adjustments
C-3b	Commission Net Operating Income Adjustments
C-3c	Company Net Operating Income Adjustments
C-9	Jurisdictional Separation Factors - Net Operating Income
C-26	Advertising Expenses
C-27	Industry Association Dues
C-31	Administrative Expenses
C-32	Miscellaneous General Expenses
C-38a	Taxes Other than Income Taxes
C-38b	Revenue Taxes
C-39	State Deferred Income Taxes
C-40	Federal Deferred Income Taxes
C-42	State and Federal Income Taxes
E-1	Cost of Service Studies
E-2	Explanation of Variations From Cost of Service Study Approved in Company's Last Rate Case
E-3a	Cost of Service Study-Rates of Return by Rate Schedule - Present Rates
E-3b	Cost of Service Study-Rates of Return by Rate Schedule - Proposed Rates
E-5a	Cost of Service Study-Allocation of Rate Base Components to Rate Schedule
E-5b	Cost of Service Study-Allocation of Expense Components to Rate Schedule
E-6a	Cost of Service Study-Functionalization and Classification of Rate Base
E-6b	Cost of Service Study-Functionalization and Classification of Expenses
E-7	Source and Amount of Revenues-at Present Rates

MINIMUM FILING REQUIREMENTS SCHEDULES
Sponsored, All or in Part, by William C. Slusser, Jr.

Schedule	***Title***
E-8a	Cost of Service Study-Unit Costs, Present Rates
E-8b	Cost of Service Study-Unit Costs, Proposed Rates
E-9	Detailed Breakdown of Customer Unit Costs
E-10	Development of Service Charges
E-11	Company Proposed Allocation of the Rate Increase/(Decrease) by Rate Class
E-12	Cost of Service-Load Data
E-13	Cost of Service Study-Development of Allocation Factors
E-14	Development of Coincident and Noncoincident Demands for Cost Study
E-15	Adjustment to Test Year Unbilled Revenue
E-16a	Revenue from Sale of Electricity by Rate Schedule
E-16b	Revenues by Rate Schedule-Service Charges
E-16c	Base Revenue by Rate Schedule-Calculations
E-16d	Revenue by Rate Schedule-Lighting Schedule Calculation
E-17	Proposed Tariff Sheets and Support for Charges
E-18a	Billing Determinants-Number of Bills
E-18b	Billing Determinants-KW Demand
E-18c	Billing Determinants-MWH Sales
E-18d	Projected Billing Determinants-Derivation
E-19	Customers by Voltage Level
E-20	Load Research Data
E-26	Monthly Peaks
E-27a-c	Demand and Energy Losses
E-28a	Interruptible Rates Policy
E-28b	Curtailable Rates Policy

FLORIDA POWER CORPORATION
ALLOCATED CLASS COST OF SERVICE
COMPARISON OF PRODUCTION CAPACITY COST ALLOCATION METHODS
TEST PERIOD: PROJECTED CALENDAR YEAR 2002
$000's

Line	Rate Class	Rate Schedules	(A) Cost of Service 12 CP & 1/13th AD	(B) 12 CP and 25% Cost of Service	(C) 12 CP and 25% Difference to 12 CP & 1/13th AD (B) - (A)	(D) 12 CP and 25% % Diff to 12 CP & 1/13th AD (C) / (A)	(E) 12 CP and 50% Cost of Service	(F) 12 CP and 50% Difference to 12 CP & 1/13th AD (E) - (A)	(G) 12 CP and 50% % Diff to 12 CP & 1/13th AD (F) / (A)
1	Residential	RS-1, RSL-1, RST-1	$ 896,616	$ 884,863	$ (11,753)	-1.31%	$ 867,908	$ (28,708)	-3.20%
2									
3	General Service	GS-1, GST-1, GSLM-1	52,653	52,949	296	0.56%	53,354	701	1.33%
4	Non-Demand								
5									
6	General Service	GS-2, GSLM-2	2,775	2,845	70	2.52%	2,949	174	6.27%
7	100% Load Factor								
8									
9	General Service	GSD-1, GSDT-1, SS-1	350,553	358,874	8,321	2.37%	370,869	20,316	5.80%
10	Demand								
11									
12	Curtailable	CS-1, CST-1, CS-2,	3,548	3,766	218	6.14%	4,084	536	15.11%
13		CST-2, SS-3							
14									
15	Interruptible	IS-1, IST-1, IS-2, IST-2	45,057	47,279	2,222	4.93%	50,476	5,419	12.03%
16		SS-2							
17									
18	Lighting - Energy	LS-1	5,076	5,709	633	12.47%	6,641	1,565	30.83%
19	- Fixt & Maint	LS-1	26,341	26,341	-	0.00%	26,341	-	0.00%
20	- Poles	LS-1	14,618	14,618	-	0.00%	14,618	-	0.00%
21									
22	Rounding Adj (tie to Jurisdictional Separation Study)		6	(1)	(7)		3	(3)	
23									
24	Total Retail		$ 1,397,243	$ 1,397,243	-		$ 1,397,243	-	

Note: Cost of Service amounts have been reduced by allocation of revenue credits from other operating revenues reflecting present charges.

FLORIDA POWER CORPORATION
SUMMARY DEVELOPMENT OF FUNCTIONAL UNIT COSTS WITH PROPOSED REVENUE CREDITS
PROJECTED CALENDAR YEAR 2002 DATA: FULLY ADJUSTED
PRODUCTION CAPACITY ALLOCATION METHOD: 12CP & 25% AD (IS/CS TREATED AS FIRM)

Line			(1) TOTAL RETAIL	(2) RESIDENTIAL (RS)	(3) GEN SERV NON DEM (GS-1)	(4) GEN SERV 100% LF (GS-2)	(5) GEN SERV DEMAND (GSD, SS-1)	(6) CURTAIL-ABLE (CS, SS-3)	(7) INTERRUPT-IBLE (IS, SS-2)	(8) LIGHTING (LS) ENERGY	(9) LIGHTING (LS) FIXTURE/ MAINT	(10) LIGHTING (LS) POLE
	I.	**COST OF SERVICE - (000'S)**										
1	A	Production Capacity -75% 12CP	$ 425,948	$ 265,817	$ 12,272	$ 567	$ 128,198	$ 1,120	$ 17,566	$ 409	$ -	$ -
2	B	Production Capacity -25% AD	$ 141,983	$ 71,579	$ 4,505	$ 295	$ 54,783	$ 684	$ 9,071	$ 1,065	$ -	$ -
3	C	Production Energy	$ 119,942	$ 60,466	$ 3,809	$ 246	$ 46,277	$ 581	$ 7,663	$ 900	$ -	$ -
4	D	Transmission	$ 115,974	$ 72,373	$ 3,344	$ 156	$ 34,902	$ 304	$ 4,785	$ 110	$ -	$ -
5	E	Distribution Primary	$ 221,607	$ 141,278	$ 7,970	$ 218	$ 62,133	$ 1,066	$ 7,298	$ 1,644	$ -	$ -
6	F	Distribution Secondary	$ 142,199	$ 109,707	$ 7,552	$ 86	$ 24,001	$ -	$ 210	$ 643	$ -	$ -
7	G	Distribution Services	$ 50,427	$ 44,772	$ 3,642	$ 359	$ 1,642	$ -	$ 2	$ 11	$ -	$ -
8	H	Metering	$ 37,556	$ 30,696	$ 2,679	$ 213	$ 3,676	$ 12	$ 269	$ 11	$ -	$ -
9	I	Interruptible Equipment	$ 393	$ -	$ -	$ -	$ -	$ -	$ 393	$ -	$ -	$ -
10	J	Lighting Fixture/Maint	$ 26,350	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 26,350	$ -
11	K	Lighting Pole	$ 14,627	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 14,627
12	L	Customer Billing, Info, etc.	$ 88,944	$ 78,142	$ 6,337	$ 627	$ 2,889	$ 1	$ 26	$ 922	$ -	$ -
13		Total	$ 1,385,950	$ 874,830	$ 52,110	$ 2,767	$ 358,500	$ 3,769	$ 47,283	$ 5,715	$ 26,350	$ 14,627
14												
15	II.	**BILLING UNITS**										
16	A	Number of Monthly Bills										
17		1. Metered Bills	17,471,841	15,526,065	1,256,453	109,318	574,236	96	1,771	3,902	0	0
18		2. Unmetered Bills	723,906	0	6,890	15,249	0	0	0	701,767	0	0
19		3. Total Bills	18,195,747	15,526,065	1,263,343	124,567	574,236	96	1,771	705,669	0	0
20		4. Total Bills with Secondary Service Tap	17,487,326	15,526,065	1,262,896	124,567	569,389	13	494	3,902	0	0
21		5. Total Bills with IS Equipment	1,771	0	0	0	0	0	1,771	0	0	0
22	B	Annual Effective MWH Sales										
23		1. Production and Transmission Services	37,109,884	18,663,084	1,174,929	76,931	14,330,380	181,684	2,405,025	277,851	0	0
24		2. Distribution Primary Service	36,465,456	18,663,084	1,171,805	76,931	14,318,064	181,684	1,776,037	277,851	0	0
25		3. Distribution Secondary Service	31,912,750	18,663,084	1,165,177	76,931	11,631,541	650	97,516	277,851	0	0
26	C	Sum of Monthly Effective Billing KW										
27		1. Production and Transmission Services	-	-	-	-	36,442,876	517,724	6,294,067	-	-	-
28		2. Distribution Primary Service	-	-	-	-	36,089,352	517,724	4,529,125	-	-	-
29		3. Distribution Secondary Service	-	-	-	-	30,622,260	1,467	229,344	-	-	-
30	D	Lighting Facilities										
31		1. Average Number of Fixtures	-	-	-	-	-	-	-	-	390,385	-
32		2. Average Number of Poles	-	-	-	-	-	-	-	-	-	236,094
33	E	12 CP - Allocator per Allocator No. 1B	100.000%	62.406%	2.881%	0.133%	30.097%	0.263%	4.124%	0.096%	0.000%	0.000%
34		Avg Demand - Allocator per Alloctor No. 1B	100.000%	50.414%	3.173%	0.208%	38.584%	0.482%	6.389%	0.750%	0.000%	0.000%
35												
36	III.	**UNIT COSTS**										
37	A	**Customer Related Costs - $/Bill**										
38		1. Metering (L. 8/L.17)	-	$ 1.98	$ 2.13	$ 1.95	$ 6.40	$ 125.00	$ 151.89	$ 2.82	-	-
39		2. Customer Billing, Info, etc. (L. 12/L. 19)	-	$ 5.03	$ 5.02	$ 5.03	$ 5.03	$ 10.42	$ 14.68	$ 1.31	-	-
40		3. Secondary Service Tap (L. 7/L. 20)	-	$ 2.88	$ 2.88	$ 2.88	$ 2.88	$ -	$ -	$ 2.84	-	-
41		4. Interruptible Equipment (L. 9/L. 21)	-	-	-	-	-	-	$ 221.91	-	-	-
42	B	**Energy Related Costs - $/MWH**										
43		1. Production Energy (L. 3/ L. 23)	$ 3.23	$ 3.24	$ 3.24	$ 3.20	$ 3.23	$ 3.20	$ 3.19	$ 3.24	-	-
44	C	**Capacity Related Costs**										
45		a. Based on MWH Sales - $/MWH										
46		1. Prod Capacity 75% 12CP (L. 1/L. 23)	$ 11.48	$ 14.24	$ 10.44	$ 7.36	$ 8.95	$ 6.17	$ 7.30	$ 1.47	-	-
47		2. Prod Capacity 25% AD (L. 2/L. 23)	$ 3.83	$ 3.84	$ 3.83	$ 3.84	$ 3.82	$ 3.77	$ 3.77	$ 3.83		
48		3. Transmission (L. 4/L. 23)	$ 3.13	$ 3.88	$ 2.85	$ 2.03	$ 2.44	$ 1.67	$ 1.99	$ 0.40	-	-
49		4. Distribution Primary (L. 5/L. 24)	$ 6.08	$ 7.57	$ 6.80	$ 2.83	$ 4.34	$ 5.87	$ 4.11	$ 5.92	-	-
50		5. Distribution Secondary (L. 6/L. 25)	$ 4.46	$ 5.88	$ 6.48	$ 1.12	$ 2.06	$ -	$ 2.15	$ 2.31	-	-
51		Or										
52		b. Based on Billing KW Demand - $/KW/Month										
53		1. Prod Capacity 75% 12CP (L. 1/L. 27)	-	-	-	-	$ 3.52	$ 2.16	$ 2.79	-	-	-
54		2. Prod Capacity 25% AD (L. 2/L. 27)	-	-	-	-	$ 1.50	$ 1.32	$ 1.44	-	-	-
55		3. Transmission (L. 4/L. 27)	-	-	-	-	$ 0.96	$ 0.59	$ 0.76	-	-	-
56		4. Distribution Primary (L. 5/L. 28)	-	-	-	-	$ 1.72	$ 2.06	$ 1.61	-	-	-
57		5. Distribution Secondary (L. 6/L. 29)	-	-	-	-	$ 0.78	$ -	$ 0.92	-	-	-
58	D	**Lighting Facilities - $/Unit/Month**										
59		1. Fixture (L. 10/L. 31 / 12)	-	-	-	-	-	-	-	-	$ 5.62	-
60		2. Pole (L. 11/L. 32 / 12)	-	-	-	-	-	-	-	-	-	$ 5.16

FLORIDA POWER CORPORATION
TEST PERIOD: PROJECTED CALENDAR YEAR 2002
SUMMARY OF PROPOSED RATES AND CLASS RATES OF RETURN
Dollars in 000's

Line	Rate Class	(A) Present Revenues: Total Revenue	(B) Present Revenues: Allocated Revenue Credits	(C) Present Revenues: Class Revenue (A) - (B)	(D) Proposed Incr / (Decr): Allocated Revenue Credits	(E) Proposed Incr / (Decr): Class Revenue	(F) Proposed Revenues: Total Revenue (G) + (H)	(G) Proposed Revenues: Allocated Revenue Credits (B) + (D)	(H) Proposed Revenues: Class Revenue (C) + (E)	(I) Cost of Service 12CP and 25% AD with Proposed Rev Credtis	(J) Class Revenue Requirement Index (H) / (I)	(K) Rate of Return at Proposed Rates	(L) Rate of Return Index (K) / total (K)
1	Residential (RS)	913,937	26,948	886,989	9,915	(15,117)	908,735	36,863	871,872	874,825	1.00	9.731%	0.99
2													
3	General Service	63,557	1,791	61,766	819	(932)	63,444	2,610	60,834	52,132	1.17	13.770%	1.40
4	Non-Demand (GS-1)												
5													
6	Subtotal RS, GS-1	977,494	28,739	948,755	10,734	(16,049)	972,179	39,473	932,706	926,957	1.01	9.953%	1.01
7													
8	General Service 100%	2,646	104	2,542	80	223	2,949	184	2,765	2,765	1.00	9.801%	1.00
9	Load Factor (GS-2)												
10													
11	General Service	367,444	7,455	359,989	455	(1,470)	366,429	7,910	358,519	358,506	1.00	9.810%	1.00
12	Demand (GSD)												
13													
14	Curtailable (CS)	4,188	74	4,114	2	(349)	3,841	76	3,765	3,766	1.00	9.795%	1.00
15	General Service												
16													
17	Interruptible (IS)	45,124	789	44,335	24	2,935	48,083	813	47,270	47,279	1.00	9.804%	1.00
18	General Service												
19													
20	Lighting (LS)												
21	- Energy	5,416	133	5,283	10	425	5,851	143	5,708	5,707	1.00	9.815%	1.00
22	- Fixt & Maint	22,088	159	21,929	-	2,041	24,129	159	23,970	26,341	0.91	7.478%	0.76
23	- Poles	10,401	102	10,299	-	994	11,395	102	11,293	14,618	0.77	4.795%	0.49
24													
25	Total Retail Revenue	1,434,801	37,555	1,397,246	11,305	(11,250)	1,434,856	48,860	1,385,996	1,385,939	1.00	9.810%	1.00